UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit F: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2
(Tri-State, *2020 IRP/ERP,* Public (Dec. 1, 2020)

TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative

Colorado PUC E-Filings System

2020 Integrated Resource Plan/Electric Resource Plan

Volume I

December 1, 2020

Submitted to:

Western Area Power Administration
Colorado Public Utilities Commission

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1 Compliance Tables

Table 1: Comparison Reference for Rule 3605

Rule	Vol	Section	Subsection	Attachment(s)
3605(a)(I)	II	3. Assessment of Resources		
3605(a)(II)				
3605(a)(III)	I	12. Confidential & Highly Confidential Information	Highly Confidential	
3605(a)(IV)(A)	I	5. Landscape	Resource Acquisition Period	
3605(a)(IV)(B)	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member
3605(a)(IV)(C)	II	3. Assessment of Resources		Attachment Vol II 5-4 Report on Review of Existing Resources; Attachment Vol II 5-5 Benchmarking Study
3605(a)(IV)(D)	II	4. Transmission System & Planning	Transmission Planning	
3605(a)(IV)(E)	I	5. Landscape	Planning Reserve Margin; Contingency Plan	
3605(a)(IV)(F)	I	6. Assessment of Resource Needs		
3605(a)(IV)(G)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(G)	II	3. Assessment of Resources	Overview of Thermal Resources	
3605(a)(IV)(G)	II	5. Phase I Modeling Details	Generic Resource Cost, Performance & Emissions Data	
3605(a)(IV)(G)	II	6. Scenario Results Data	Emissions & Water Usage Data	Attachment Vol II 6-1 Annual Emissions & Water Usage
3605(a)(IV)(H)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(H)	II	5. Phase I Modeling Details	Social Cost of Carbon	
3605(a)(IV)(I)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(I)	II	3. Assessment of Resources	Overview of Thermal Resources	
3605(a)(IV)(I)	II	5. Phase I Modeling Details	Generic Resource Cost, Performance & Emissions Data	

Rule	Vol	Section	Subsection	Attachment(s)
3605(a)(IV)(I)	II	6. Scenario Results Data	Emissions & Water Usage Data	Attachment Vol II 6-1 Annual Emissions & Water Usage
3605(a)(IV)(J)	II	7. Phase II RFP		Attachment Vol II 7-1 Phase II All Source RFP
3605(a)(IV)(K)	I	12. Confidential & Highly Confidential Information	Confidential; Highly Confidential	
3605(a)(IV)(L)	I	8. Base Case & Alternative Scenario Results		
3605(a)(IV)(M)	I	9. Base Case & Alternative Scenario Comparison	Present Value Revenue Requirement	
3605(a)(IV)(N)	II	5. Phase I Modeling Details	Assessment of Costs & Benefits of Integration Intermittent Resources	
3605(a)(IV)(O	II	5. Phase I Modeling Details	Third Party Studies	Attachment Vol II 5-1 through 5-7
3605(a)(IV)(P)	II	5. Phase I Modeling Details	Modeling Assumptions & Analytical Methodology	
3605(a)(IV)(Q)	I	11. Resource Acquisition Plan –Action Plan	ERP Implementation Report Plan	
3605(b)	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member
3605(c)(I)	II	3. Assessment of Resources	Overview of Thermal Resources; Overview of Purchases; Forced Outage Assistance Agreements; Scheduling Agent Agreements	Attachment Vol II 5-4 Report on Review of Existing Resources
3605(c)(II)	II	3. Assessment of Resources	Benchmarking	Attachment Vol II 5-5 Benchmarking Study
3605(c)(III)	II	3. Assessment of Resources	Overview of Ancillary Services	
3605(d)i	II	4. Transmission System & Planning		Attachment Vol II 4-1 Tri-State Transmission Facility Ratings Report
3605(d)ii	II	4. Transmission System & Planning		
3605(d)iii	II	4. Transmission System & Planning		Attachment Vol II 4-3 Tri-State Transmission Project Information

Rule	Vol	Section	Subsection	Attachment(s)
3605(d)IV	I	11. Resource Acquisition Period – Action Plan	Phase II Competitive Bidding Process & Criteria	
3605(d)V	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
3605(e)	I	5. Landscape	Planning Reserve Margin; Contingency Plan	Attachment Vol II 5-2 B&V Loss of Load Probability Study; Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study
3605(f)(I)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(A)	I	6. Assessment of Resource Needs	Renewable Portfolio/Energy Standards	
3605(f)(II)(A)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(A)	II	6. Scenario Results Data	RES/RPS Data	Attachment Vol II 6-2 RES/RPS
3605(f)(II)(B)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(C)	I	6. Assessment of Resource Needs	GHG and CO_2 Regulation	
3605(f)(II)(C)	I	8. Base Case & Alternative Scenario Results		
3605(f)(II)(C)	II	5. Phase I Modeling Details	GHG & CO_2 Reduction Methodology used in Scenarios	
3605(f)(I)(III)				
3605(g)(I)				
3605(g)(II)	I	11. Resource Acquisition Period – Action Plan	Phase II Competitive Bidding Process & Criteria	
3605(g)(II)	II	7. Phase II RFP		Attachment Vol II 7-1 Phase II All Source RFP

Table 2: Compliance Reference for WAPA 10 CFR part 905

Rule	Vol	Section	Subsection	Attachment(s)
905.11(a) Full range of alternate resources	II	5. Phase I Modeling Details	Generic Resource Cost, Performance and Emissions Data	
905.11(a) Adequate and reliable service	I	5. Landscape	Planning Reserve Margin; Contingency Plan	
905.11(a) Adequate and reliable service	I	9. Base Case & Alternative Scenario Comparison	Comparison of Planning Reserve Margins	
905.11(a) Adequate and reliable service	II	5. Phase I Modeling Details	Summary of 3rd Party Studies	Attachment Vol II 5-2 B&V Loss of Load Probability Study
905.11(a) Diversity, Reliability, Dispatchability, Other risk factors	I	9. Base Case & Alternative Scenario Comparison	Diversity, Dispatchability, & Reliability Comparison	
905.11(a) Energy savings achieved through energy efficiency	I	6. Assessment of Resource Needs	Demand Side Management & Energy Efficiency	
905.11(a) Energy savings achieved through energy efficiency	II	5. Phase I Modeling Details	Modeling Assumptions & Analytical Methodology	Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study
905.11(a) Treat demand and supply resources on a consistent and integrated basis	II	5. Phase I Modeling Details	Model Description; Modeling Assumptions & Analytical Methodology	
905.11(b) Consider electrical energy resource needs	I	6. Assessment of Resource Needs		
905.11(b)(1) Conduct an assessment and comparison of available existing and future supply and demand-side	I	7. Alternative Scenario Analysis; 8. Base case & Alternative Scenario		

Rule	Vol	Section	Subsection	Attachment(s)
resource options based on its size, type, resource needs, geographic location and competitive situation.		Results; 9. Base Case & Alternative Scenario Comparison		
905.11(b)(1)(iv) Reasonable analysis of the options	I	9. Base Case & Alternative Scenario Comparison		
905.11(b)(2) Include an action plan	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(2)(i) List the time period that the action plan covers	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(2)(ii)(a-c): Include an action plan summary	I	11. Resource Acquisition Period – Action Plan	Action Plan Items	
905.11(b)(3) Minimize adverse environmental effects of new resource acquisitions	I	9. Base Case & Alternative Scenario Comparison; 10. Summary of Preferred Plan		
905.11(b)(3) Include a qualitative analysis of environmental effects in a summary format	I	10. Summary of Preferred Plan		
905.11(b)(4) Provide ample opportunity for full public participation	I	4. High Level 2020 Resource Plan Process	Public Input Process	
905.11(b)(4) Brief description of public involvement activities	I	4. High Level 2020 Resource Plan Process	Public Input Process	
905.11(b)(4)(i) Contain an approval resolution by the appropriate governing body	I	2. Executive Summary	Tri-State Board Approval	Attachment Vol 1 2-1 Tri-State Board Resolution

Rule	Vol	Section	Subsection	Attachment(s)
905.11(b)(5) Contain a statement that the customer conducted load forecasting, including specific data	II	1. Electric Energy and Demand Forecast		Attachment Vol II 1-1 Tri-State Load Forecast by State & Member
905.11(b)(6) Measurement strategies for IRP's objectives	I	9. Base Case & Alternative Scenario Comparison		
905.11(b)(6) Identify a baseline from which the customer will measure the benefits of IRP implementation	I	8. Base Case & Alternative Scenario Results	Base Case	

Table 3: Compliance Reference for November 12, 2020 Commission Guidance[1]

Item	Vol	Section	Subsection	Attachment(s)
Rework Benchmarking to reflect Staff group ranking methodology.	II	3. Assessment of Existing Resources	Benchmarking	Attachment Vol II 5-5 B&V Benchmarking Study[2]
Provide a full presentation of ancillary services.	II	3. Assessment of Existing Resources	Overview of Merchant Ancillary Services	
Provide 5 years of historical data on all input parameters as available.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of historical data on energy and demand charges for power purchases.	II	3. Assessment of Existing Resources	Overview of Purchases	
Alter model values to historic levels or provide justification for any deviations from historical data.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Justify coal cost projections; conduct a market to market analysis, or both.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of historical data on capital expenses and justification of forecasts.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Develop a record on potential pollution control related capital expenses.	N/A	N/A	N/A	Testimony of Mr. Berger
Provide additional information of the nature of its capital balances and related depreciation, amortization and impairment treatment of its	II	3. Assessment of Existing Resources	Overview of Thermal Resources	

[1] In order to provide an accurate and complete ERP filing to the Commission by December 1, 2020, Tri-State froze this report as of November 23, 2020 at 12:00pm. As of that point in time, a Commission Order related to final guidance in Proceeding No. 20M-0218E had not yet been published. Tri-State made best efforts throughout this report to meet Commission guidance as interpreted from the November 12, 2020 Commission weekly meeting.

[2] The B&V Benchmarking Study as filed on August 3, 2020 is submitted with this filing. Upon receipt of the Commission Order related to final guidance in Proceeding No. 20M-0218E, Tri-State will reengage B&V to modify the Benchmarking Study to match Commission expectations and will provide the revised study as soon as reasonably possible.

Item	Vol	Section	Subsection	Attachment(s)
assets. Identify any costs that can be avoided by early retirement.				
Identify debt obligations by plant.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide a description of the source of all unit performance parameters used in its modeling.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide 5 years of actual historical data for each parameter in B&V Review of Existing Resources,	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Provide a robust and supported explanation of any discrepancies between its model values and actual historic unit level performance.	II	3. Assessment of Existing Resources	Overview of Thermal Resources	
Apply Social Cost of Carbon to all resources (in or out of state)	I	7. Alternative Scenario Analysis		
Apply Social Cost of Carbon to all resources (in or out of state)	I	8. Base Case & Alternative Scenario Results		
Apply Social Cost of Carbon to all resources (in or out of state)	II	5. Phase I Modeling Details	Social Cost of Carbon	
Use the interagency working group Social Cost of Carbon; convert to short tons; escalate to 2020 using appropriate CPI	II	5. Phase I Modeling Details	Social Cost of Carbon	
Use a 3% discount rate for Social Cost of Carbon.	II	5. Phase I Modeling Details	Financial Analysis Process	
Use a 3% discount rate for Social Cost of Carbon.	I	9. Base Case & Alternative Scenario Comparison	Present Value Member Revenue Requirement Comparison	
Address whether same or similar approach for integrating transmission planning as identified in joint transmission proposal related to CO20-0661-1 is feasible for Tri-State.	II	4. Transmission System & Planning	Response to C20-0661-I Related to Transmission Impacts on the ERP Process	

2 Executive Summary

Introduction

Pursuant to Colorado Public Utilities Commission (Commission) Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(I) of the Commission's Rules regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) presents its Integrated Resource Plan/Electric Resource Plan ("Resource Plan"). This Resource Plan is also developed to meet the Integrated Resource Planning requirements of the Western Area Power Administration (WAPA) as described in the Energy Planning and Management Program (10 CFR part 905).

This Resource Plan also covers the following WAPA preference allocation recipients:

Pueblo of Laguna, Pueblo of Zuni, Ramah Navajo Chapter, Canoncito Band of Navajos, Ute Mountain Ute Tribe, Wind River Reservation, Nambe Pueblo, Pueblo of Jemez, Pueblo of Pojoaque, Pueblo of San Ildefonso, Pueblo of San Juan, Pueblo of Santa Clara, Pueblo of Zia, Southern Ute Indian Tribe, Mescalero Apache Tribe, Alamo Navajo Chapter, Colorado, the City of Truth or Consequences, New Mexico and Schriever Air Force Base.

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 42 Utility Member Systems located across Colorado, Nebraska, New Mexico and Wyoming. As directed by Colorado Decision CO 10-0101, Tri-State has previously filed Resource Plans in the state of Colorado in 2010 and 2015 as well as Annual Progress Reports (APR). With the passage of Senate Bill 19-236 in Colorado in May 2019, Tri-State as a wholesale generation and transmission electric cooperative operating in the state of Colorado became subject to resource planning regulation by the Commission. Rules guiding this process are per C20-0304 and were finalized in late April 2020, with an effective date of July 15, 2020. As directed by Commission Decision No. C20-0304, Tri-State filed a June 1, 2020 informational filing which was an Assessment of Existing Resources per 3605(c). On August 3, 2020, Tri-State revised the filing to include additional information and in order to be responsive to motions filed by interveners. While participating in an extensive discovery process related to these filings, Tri-State gathered necessary data, developed and analyzed scenarios and prepared this Resource Plan to be filed by December 1, 2020 as required. As required by the Commission, this Resource Plan is inclusive of Tri-State's Assessment of Resources as filed on August 3, 2020 along with an itemized list of updates. Tri-State also included additional information to address comments related to Proceeding No. 20M-0218E as well as Commission guidance as interpreted from the November 12, 2020 Commission's weekly meeting . This assessment can be found in Volume II Section 3 Assessment of Resources of this report.

Resource Need

Tri-State has selected a 20-year period from 2021 through 2040 for its Resource Planning Period (RPP). Per rule 3605(a)(IV)(A) Tri-State has set the Resource Acquisition Period (RAP) for this Resource Plan as 2021 through 2030.

Tri-State's system-wide base load forecast for the RAP shows an average annual load growth rate of ~1.6%. The system load forecast was developed using a bottom up approach based on historical Utility Member System load data, separated into nine classes and applying relevant statistical models by class.

Utility Member System forecasts were combined to arrive at regional forecasts that were used for production cost modeling and the Tri-State system-wide forecast. Many factors can potentially influence Tri-State's load forecast and projected growth. These factors include potential Utility Member System exits, potential transition of some Utility Member Systems from all requirements contracts to partial requirements contracts, increased levels of member distributed generation, long-term impacts of COVID, long-term impacts of environmental regulations on the oil and gas industries and beneficial electrification. To account for potential deviation in load growth Tri-State develops a low and high load forecast. These forecasts are described in more detail in Volume II Section 1 Electric Energy and Demand Forecast of this report.

In early 2020, Tri-State announced the Responsible Energy Plan (REP), which includes among other initiatives, the announced retirements of Escalante Generating Station in 2020 and the retirement of all three units comprising the Craig Generating Station by 2030, as well as the addition of 1 GW of renewables by 2024. These are key Tri-State actions to supply affordable, responsible, reliable energy to Tri-State Utility Member Systems.

For this Resource Planning process, Tri-State included these announced retirements in its base assumptions. Tri-State also reviewed emerging technologies and updated its generic resource dataset to reflect proven technologies, including various types of wind, solar and gas resources, as well as energy storage. Four-hour Lithium-Ion (Li-Ion) batteries of varying sizes were used in the generic resource data set. Tri-State projected that battery prices would decline by approximately 6% per year over the RAP, compared to current pricing. Renewable generation pricing is projected to rise slightly by the mid-2020s due to the scheduled expiration of tax credits, and then is forecast to decline gradually over the RPP as a result of projected technological improvements.

As illustrated in Figure 1, Tri-State forecasts a capacity need in 2029 based on planned retirements, existing owned resources and supply contracts, and the base load forecast.

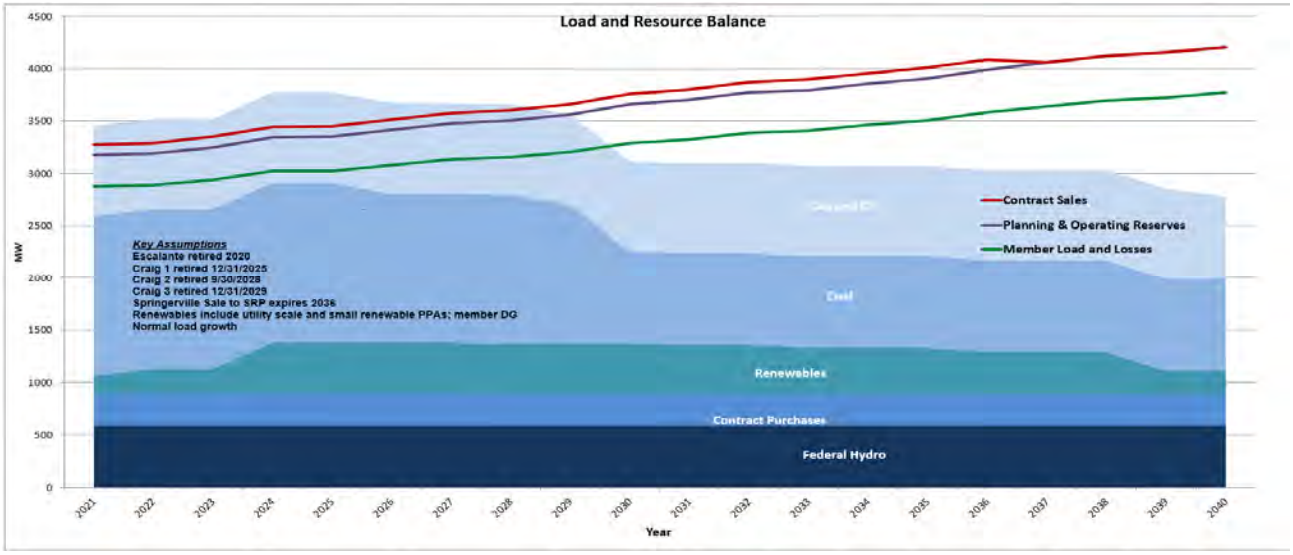

Figure 1: Tri-State Load and Resource Balance (Projected)

Industry & Regulatory Factors

Key external factors influencing this Resource Plan include potential new environmental regulation, the regional development of organized markets and state targets for Greenhouse Gases (GHG)/Carbon Dioxide ($CO_{2)}$ reductions. Tri-State is scheduled to begin operation with the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM) with its load and resources located in Public Service New Mexico's Balancing Authority (PNM-BA) in April 2021. Tri-State is also scheduled to begin operation in Southwest Power Pool's (SPP) Western Energy Imbalance Service (WEIS) in February 2021 for its Colorado, Wyoming and Western Nebraska loads and resources located in the Western Area Power Authority Balancing Authority (WAPA-BA). Tri-State developed modeling treatment for the intra hour effects of imbalance markets as described in Volume II Section 5 Phase I Modeling Details of this report. Tri-State also made adjustments to market depth in models beginning in 2025 to represent a forecast of the development of a "day-2" Regional Transmission Organization (RTO) organized market. Differences between imbalance markets and "day-2" organized markets are explained in more detail in Section 6 Assessment of Resource Needs under the Imbalance Markets, Regional Transmission Organizations and Independent System Operators subsection of this report.

Colorado GHG/CO_2 reduction targets are a key factor that heavily influence scenarios in this Resource Plan. Tri-State's alternative scenarios evaluated reductions in CO_2 emissions based on forecast and historic wholesale electricity sales in the state of Colorado and through the application of a Social Cost of Carbon (SCoC) across Tri-State's system. Details can be found in Section 7 Alternative Scenario Analysis of this report.

Preferred Resource Plan

In assessing the Base Case and Alternative Scenarios, Tri-State has selected the 80% Carbon Reduction (CR) V4 scenario as its preferred plan. Primary reasons for this selection include:

- Generation locations and technology diversity, as illustrated in Figure 2, are sufficient to fully utilize interconnection capability made available from announced retirements.
- Forecast additional thermal retirements projected to occur after the RAP and in addition to announced retirements during the RAP, allow a manageable transition to zero carbon resources while maintaining reliability and affordable rates.
- Transmission system network upgrade costs are minimized during the RAP compared to the base case.
- The PVRR for the RPP is ~$400M higher than the Base Case while achieving the state of Colorado GHG/CO_2 reduction target of 80% GHG/CO_2 reduction by 2030 from a 2005 baseline.
- Overall emissions and water usage are significantly reduced by 2030 from current levels and are significantly lower than in the Base Case.
- The scenario uses a glide path from 2025 to 2030, as illustrated in Figure 3, for CO_2 reduction goals in the state of Colorado to achieve meaningful reductions in the near term.

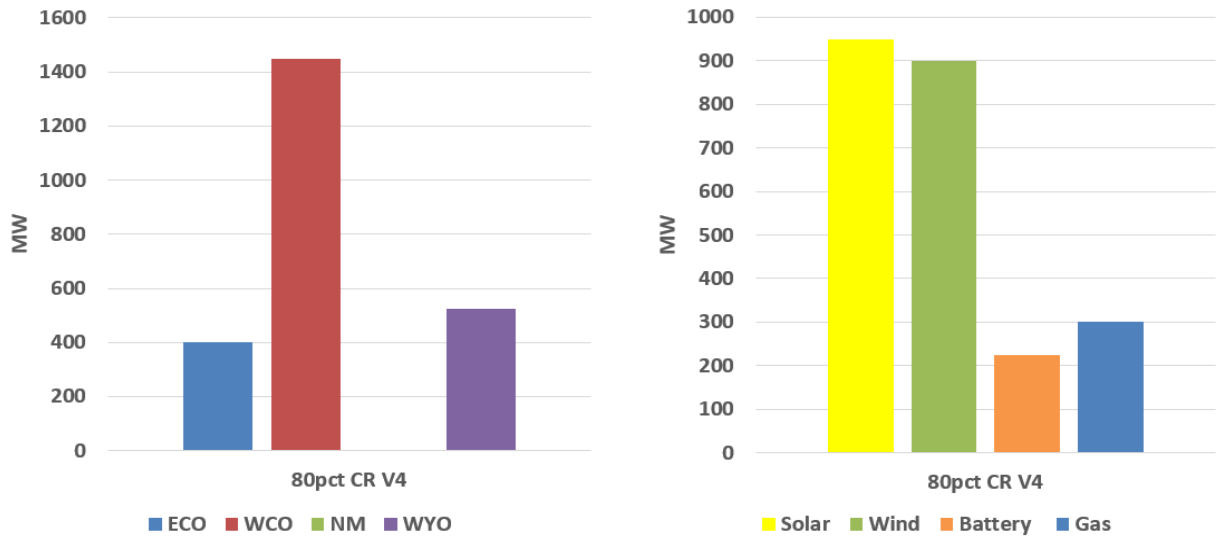

Figure 2: Preferred Plan Resource Additions over the RAP by Geographic Location and Technology

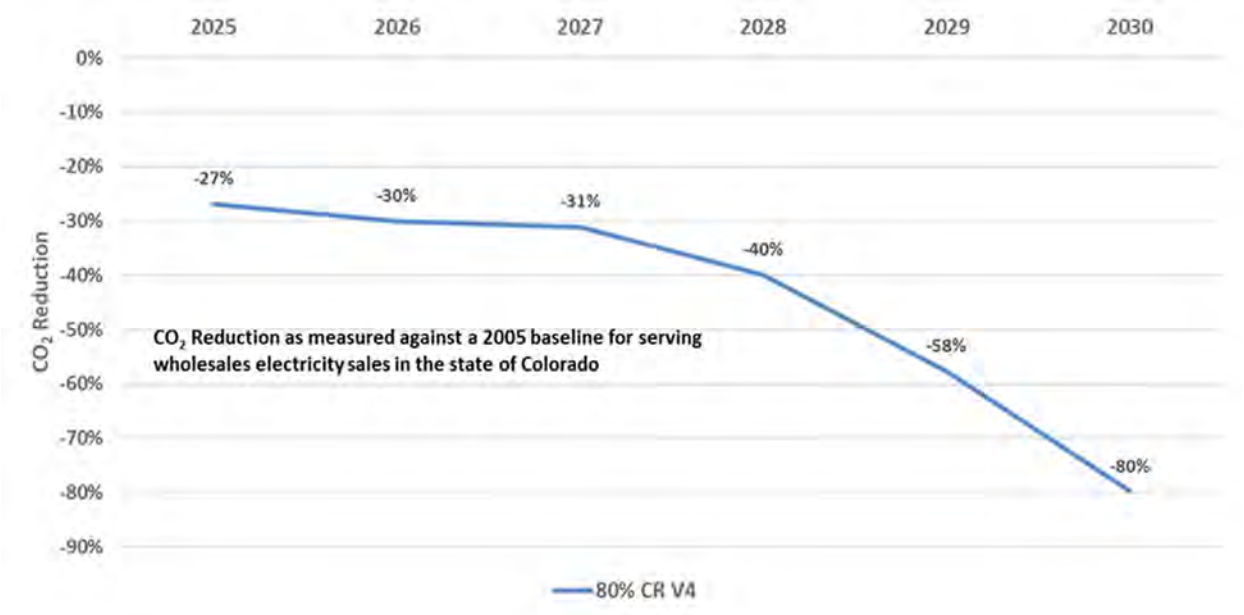

Figure 3: Preferred Plan Glide Path to CO_2 Reduction in Colorado

Action Plan

RAP – Phase II:

Tri-State's base case scenario indicates a capacity need in 2029. In order to meet near term emissions reductions additional renewable resources are forecast for deployment in the preferred plan during the RAP. Table 4 identifies resources by location, nameplate capacity, technology and year, as determined in the preferred plan

Table 4: Preferred Plan Resources during RAP

Location	Capacity (MW)	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030

Given the uncertainty related to Tri-State's Utility Member System load in the near term, Tri-State anticipates that its initial Phase II process will focus on resource needs by 2025, as indicated by the shading in Table 4. We anticipate that resources needed for the period from 2026 to 2030 will be addressed in the June 1, 2023 ERP or subsequent ERPs.

By 2023, we will have better information regarding potential load reductions that could reduce capacity needs after 2025. In addition, while the RAP extends from 2021 to 2030, Tri-State is reluctant to engage in activities to add conventional thermal resources (300 MW natural gas combined cycle in 2030) without allowing time for emerging technologies that provide equally reliable capacity, but with lower emissions, to become competitive.

Utility Member System Programs:

Tri-State plans to use the following studies as guides to work with Utility Member Systems to develop relevant programs that may be beneficial to Tri-State and its membership.

- Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study
- Attachment Vol II 5-7 Beneficial Electrification Potential Study

Retirement Requirements & Impacts:

With the announced retirement dates of Springerville Unit 1 and Springerville Unit 2, Tri-State plans to engage in discussions with Salt River Project (SRP), the owner of Springerville Unit 4, as well as other parties necessary to determine the impacts on Springerville Unit 3 (SPV3) for future resource planning.

While the preferred plan indicates a retirement of Laramie River Station (LRS) Unit 3 by 2033, we note that there is no agreement in place that would be required to implement this retirement with the co-owners of the Missouri Basin Power Project. Modeling performed under the preferred plan showed that the continued operation of both (LRS) Unit 2 and Unit 3 at levels needed to satisfy and maintain an 80% CO_2 reduction in Colorado would not be economic, which is why the preferred plan reflects a retirement of LRS Unit 3.

Modeling Improvements:

Tri-State plans to modify its current modeling software or replace if necessary, in order to improve modeling items prior to the June 1, 2023 ERP. Key items slated for modeling improvement include but are not limited to: the ability to handle emission reductions on a state-by-state basis in a robust manner, the ability to model sub-hourly effects, more robust modeling of intermittent resources, streamlined management of transmission capex impacts, and improved treatment of intermittent resource curtailments.

3 Introduction & Background

Purpose of Filing

The purpose of this Resource Plan is to meet the requirements of Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Commission's Rules regulating Electric Utilities and to meet the Integrated Resource Planning requirements of the Western Area Power Administration (WAPA) as described in its Energy Planning and Management Program (10 CFR part 905).

Tri-State's approach to developing a Resource Plan takes into consideration internal and external factors. Internal factors include being responsive to Utility Member System needs for affordable, responsible power while maintaining a reliable system. For purposes of this Resource Plan, Tri-State also focuses on the potential impacts to Tri-State's resource planning process due to Utility Member System interest in items such as wholesale electric service contract buyouts, transitioning from all requirements contracts to partial requirements contracts, and the increased deployment of distributed generation. These impacts will be discussed further in the Utility Member Sales Forecast subsection found in Volume II Section 1 Electric Energy and Demand Forecast of this report. External factors include requirements driven by legislation in any state within Tri-State's footprint. Recent legislative actions impacting this Resource Plan include CO_2 and GHG reduction requirements in Colorado and updates to the Renewable Portfolio Standard requirements in New Mexico. These impacts are discussed in more detail in Section 6 Assessment of Resource Needs of this report. While developing its Resource Plan, Tri-State must monitor

internal and external factors and ensure that the Resource Plan meets Utility Member System needs while adhering to applicable laws and regulations across a diverse footprint.

Additionally, Tri-State faces unique challenges given its diverse footprint, which include participation in joint owned generating units and wholesale electric market environments. While Tri-State's system crosses multiple states, Tri-State is only regulated for purposes of resource planning in the state of Colorado. Tri-State must meet individual state regulatory and legislative requirements while developing system-wide solutions. Tri-State has several resources that are jointly owned, which increases the difficulty and complexity of possible resource retirement decisions. Tri-State also faces resource planning challenges associated with the evolving nature of energy imbalance markets, and the possible future deployment of full "day-2" RTO markets, layered upon operations spanning multiple balancing authorities, utilizing extensive third-party transmission rights associated with long term network and point-to-point agreements. To illustrate, Tri-State's load in the PacifiCorp (PAC) BA has been part of the WEIM operated by CAISO since 2014. Tri-State is scheduled to enter the WEIS market operated by SPP in February 2021 with load and resources physically located or pseudo-tied into the WAPA-BA and is scheduled to join the WEIM in April 2021 with load and resources physically located or pseudo-tied into the PNM-BA. These challenges are discussed further throughout this report.

Finally, one key input to the Resource Plan is the Responsible Energy Plan (REP) as announced by Tri-State in January 2020. The following REP items influence Tri-State resource planning in general, and the preferred plan.

- Eliminating 100% of Tri-State emissions from coal in New Mexico by the end of 2030
- Eliminating 100% of Tri-State emissions from coal in Colorado by the end of 2030
- Achieving a 90% reduction in CO_2 emissions across the generation facilities Tri-State owns or operates in Colorado
- Achieving a 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales
- Adding 1 GW of renewable resources by 2024
- Increasing Utility Member System contract flexibility and options to deliver more local renewable generation
- Promoting participation in a RTO
- Extending the benefits of a clean grid

Tri-State's base case and alternative scenarios in the Resource Plan include the retirement of coal in New Mexico (Escalante Generating Station in November 2020), and the retirement of coal resources in Colorado as identified in the REP, which includes the retirement of all three units comprising the Craig Generating Station[3] by 2030. Tri-State's expansion plan portfolios in all alternative scenarios exceed the REP goal of a 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales.

The 1 GW of renewable resources by 2024 as identified in the REP includes resources obtained through RFP processes conducted in 2018 and 2019. These now under contract resources include Crossing Trails, Spanish Peaks, Niyol, Coyote Gulch, Dolores Canyon, Axial Basin, Escalante, and Spanish Peaks II. More

[3] The retirement of the Craig Generating Station is subject to a regulatory approval process with the Commission.

information on these resources is available in Volume II Section 3 Assessment of Existing Resources under the subsection of Overview of Purchases.

Tri-State has a long-standing Board policy allowing for member-distributed generation, which allows members to meet a portion of their energy needs with local renewable generation. Member distributed generation is included in the modeling in this Resource Plan, and more information on this modeling is located in Volume II section 5 Phase I Modeling Details.

Additionally, Tri-State's Board has approved a partial requirements contract option for Utility Member Systems. The methodology for the buy down payment to transition from an all requirements contract to a partial requirements contract is currently moving through the necessary Federal Energy Regulatory Commission (FERC) process. In 2021, Tri-State will conduct an Open Season process with its Utility Member Systems who are interested in this option. While the Low Load forecast used into two alternative scenarios is somewhat representative of potential load declines, partial requirements was not specifically modeled in this Resource Plan. Tri-State expects to have specific partial requirements driven contract changes impacting load forecasts available for its June 1, 2023 ERP process.

Tri-State is actively promoting the need for an RTO in the western interconnection to reliably interconnect more renewable resources while keeping power affordable. While full modeling for an organized market is not undertaken in the scenario analysis of this Resource Plan, starting in 2025 a market depth adjustment is made in order to simulate greater market accessibility. Further detail on modeling setup is available in Volume II Section 5 Phase 1 Modeling Details.

Tri-State engaged Mesa Point Energy to conduct a beneficial electrification potential study for Tri-State's system. This study is included as Attachment Vol II 5-7 Beneficial Electrification Potential Study. Due to the timing of the completion of this study (October 2020), this information was not included in an alternative scenario. Tri-State does expect to include beneficial electrification potential relevant to Tri-State's Utility Member System in its June 1, 2023 ERP filing.

This assessment of load and resource requirements leading to a Resource Plan is intended to meet Tri-State's obligation to provide reliable, affordable and responsible power to its Utility Member Systems and to develop options to meet resource needs in an evolving industry.

Contents and Organization of the 2020 Resource Plan

This Resource Plan is organized into two volumes with relevant sections identified as follows:

Volume I:

- Executive Summary
- Introduction and Background
- 2020 Resource Planning Process
- Landscape
    - System Energy Mix
    - External Market Dynamics
    - RPP & RAP
    - Planning Reserve Margin and Contingency Plan

  - Environmental Regulation
- Assessment of Resource Needs
- Alternative Scenario Analysis, Results and Comparison
- Preferred Plan
- Action Plan & Phase II Requirements
- Confidential and Highly Confidential Information

Volume II Technical Appendix:

- Energy and Demand Load Forecasts
- Commodity Pricing
- Assessment of Resources
- Transmission Overview
- Phase I Modeling Details
- Attachments of third party studies, scenario detail and RFP related items

4 2020 Resource Planning Process

Data and System Preparation

Tri-State's process for developing the Resource Plan includes data verification, third party reviews and related updates, development of assumptions, and scenario analysis. Regular updates of financial and energy data occur throughout the year and are used for short-term and long-term analyses and forecasting processes. Tri-State freezes base assumptions at the beginning of any scenario evaluation process, such as an ERP, to maintain the ability to reasonably compare among scenarios. Tri-State's software systems for this analysis include Hitachi ABB E7 Capacity Expansion (CE), Hitachi ABB E7 Portfolio Optimization (PO), Hyperion, and Utilities International Planner (UIPlanner). These systems, as well as their use in the resource planning process, are discussed in Volume II Section 5 Phase I Modeling Details of this report.

Tri-State engaged three outside consultants to assist in preparing material for this Resource Plan. Black & Veatch (B&V) supported review of key data including commodity pricing and unit characteristics and costs for existing and expansion plan resources. Additionally, B&V performed a Loss of Load Probability (LOLP) Study and a modified Effective Load Carrying Capability (ELCC) study. Ascend Analytics (Ascend) provided ramping analysis and a stochastic review of Tri-State's renewable resource hourly profiles. CDG Engineering provided technical system support. Various results from consultants' work products are included and incorporated into this report, and studies or results in their entirety can be found as Attachments to Volume II 5-1 to 5-7.

Upon completion of data setup and verification, scenario analyses was conducted to develop forecasts of capacity and resource needs to maintain planning reserve margins, support affordable supply to Utility Member Systems, and provide for compliance with applicable environmental regulations. The base case

and alternative scenario analysis results are discussed beginning in Section 7 Alternative Scenario Analysis of this report.

Scenario Analysis Overview

Tri-State analyzed various scenarios for this Resource Plan, by first modeling an expansion plan in CE, then running an hourly dispatch for the 20-year planning period in PO, followed by incorporation of the this dispatch and expansion plan information into Hyperion and finally transitioning Hyperion data into UIPlanner to develop a forecast of companywide expenses and revenue requirements. Transmission capital expenditures were also determined for each scenario and passed to UIPlanner. Final analysis of all scenario data in UIPlanner led to the development of a Present Value Revenue Requirement (PVRR) for each scenario. Details of these processes are discussed further in Volume II Section 5 Phase I Modeling Details of this report. Figure 4 illustrates the sequential steps of this process and the associated primary software systems:

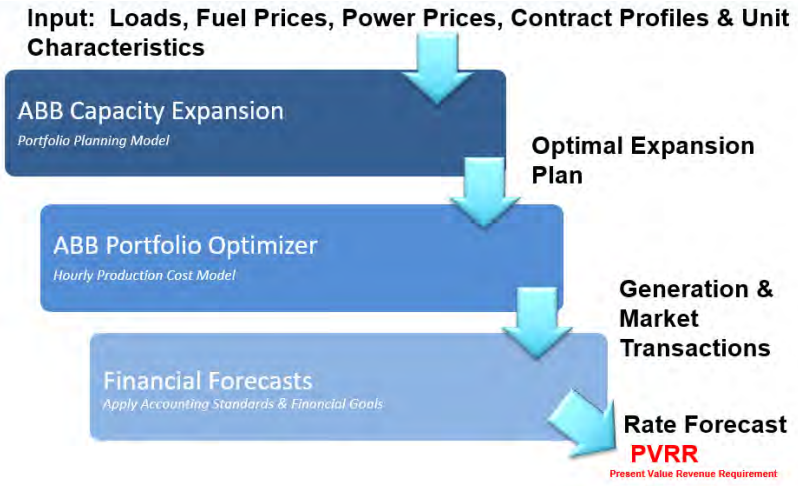

Figure 4: Scenario Modeling Flowchart

Stakeholder Outreach

Per 10 CFR part 905.11(b)(4) related to WAPA's Integrated Resource Plan (IRP) requirement, Tri-State has historically held public workshops to engage the public in the IRP process. However, due to COVID19 and related concerns for public welfare, Tri-Stated posted on its website in May 2020 that such meeting(s) would be postponed. In late July Tri-State determined that establishing a communication route for the WAPA IRP with the public that did not involve face-to-face contact would be necessary due to the continued COVID19 threat. At that time, Tri-State posted on its website in the Stakeholder Outreach and in Resource Planning pages that Tri-State was actively working on the IRP and would take comments from the public via its resourceplanning@tristategt.org email address. Additionally, Tri-State posted that it would post any such comments in the same section of the Tri-State website along with responses. Tri-State used this communication protocol to solicit concerns and input from the public as part of its WAPA IRP public process. Tri-State did not receive any comments or input through this process. Additionally, as part of the Colorado Electric Resource Plan (ERP) process under Proceeding 20M-0218E, Tri-State engaged in an extensive and far-reaching discovery processes from late July 2020 through late September 2020

with various parties. This discovery process resulted from Tri-State's June 1, 2020 informational filing, which was an Assessment of Resources per Rule 3605(c). A comment period related to this proceeding occurred in late September and early October. Tri-State's response included plans to address specific items identified as items of concerns in its December 1, 2020 Resource Plan filing. Comments from participating parties as well as Tri-State's response to those comments are available on the Commission's website.

Summary and Update of 2015 Colorado ERP

Tri-State's Action Plan from the 2015 ERP included several elements and was updated via APRs, the most recent of which was filed in December 2019. An update to the elements of this Action Plan is summarized below:

Affordable Clean Energy Rule and State Plans Review and Evaluation:

Since the 2015 ERP filing, the U.S. Environmental Protection Agency (EPA) repealed the Clean Power Plan. On July 8, 2019, the EPA finalized the Affordable Clean Energy (ACE) rule. State plans implementing the ACE rule will be due in July 2022, with initial compliance to be achieved by designated facilities no later than 24 months after State plan submittal, except if a State determines a longer period is appropriate and includes legally enforceable increments of progress. Colorado is expected to take initial steps in 2021 to implement the ACE rule. The legality of the ACE rule has been argued before the District of Columbia Court of Appeals.

Generation Planning and Development:

Since the 2015 ERP filing, Tri-State has both expanded its renewable resource portfolio and announced coal retirements. An additional 51 MW of capacity in the Missouri Basin Power Project was also acquired, which includes LRS generation rights, water rights and critical TOT 3 transmission. Tri-State past and announced retirements of coal-fired generation are as follows:

- San Juan 3 (40 MW share) retired in 2017
- Nucla Generating Station retired in 2019 (ahead of 2022 regional haze requirement)
- Escalante Generating Station retired November 2020
- Craig 1 to be retired by 12/31/2025
- Craig 2 to be retired by 9/30/2028
- Craig 3 to be retired by 12/31/2029

Renewable resource additions since 2015 are addressed in the Expansion of Renewable Portfolio subsection below. Tri-State is also moving forward with plans to participate in both the WEIM and the WEIS with expected market entry dates in 2021. It is anticipated that Tri-State load and resources located in the PNM BA and PSCO BA (in 2022) will participate in the WEIM, and load and resources located in WAPA will participate in the WEIS market.

Transmission Planning and Development:

Tri-State provides wholesale electric transmission service and makes wholesale sales of electric energy to 42 Utility Members in four states (using facilities located across five states), including the approximately 5,665 miles of high-voltage transmission lines over which Tri-State has ownership or capacity interests, as

well as the approximately 409 substations and switchyards that Tri-State owns or has a major equipment ownership interest. Tri-State's interstate transmission facilities are interconnected with those of other utilities, including WAPA, Nebraska Public Power District (NPPD), Black Hills Colorado Electric, Inc. (BHCE), PAC, PSCO, Platte River Power Authority (PRPA), Colorado Springs Utilities (CSU), Basin Electric Power Cooperative (BEPC), Tucson Electric Power (TEP), PNM, and Deseret Generation & Transmission Cooperative. The majority of Tri-State's transmission facilities operate as part of the Western Interconnection. A small portion of Tri-State's facilities supports its load centers in the Eastern Interconnection and is under the functional control of SPP.

Delivery to Tri-State Utility Member Systems also requires that Tri-State contract for transmission service from multiple third parties including PSCO, PNM, WAPA, PAC, PRPA, BHCE and others.

Tri-State continues to support regional transmission study efforts, primarily through its participation at WestConnect and the Colorado Coordinated Planning Group. Tri-State is continuing to make transmission investments to serve growing loads, increase reliability, ensure system stability, and support additional generation interconnections.

Expansion of Renewable Energy Portfolio:

Renewable energy has always been an important part of Tri-State's resource portfolio through purchases of Federal hydropower from the Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP). The CRSP and LAP hydro contracts provide approximately 580 MW of firm capacity, and are contracted to Tri-State through 2054 and 2057 respectively. Since 2010 Tri-State has significantly increased the amount of renewable generation in its supply portfolio, via power purchase agreements (PPAs) with the addition of approximately 27 MW of small hydro, 85 MW of solar and 367 MW of wind currently operating and providing energy to Tri-State under long term purchase contracts.

In 2018, Tri-State issued a Request for Proposal (RFP) for renewables resources that resulted in a competitive bidding process and PPAs for the output of the following facilities:

- 104 MW Crossing Trails Wind (COD expected late 2020 or early 2021)
- 100 MW Spanish Peaks I Solar (COD expected 2023)

In 2019, Tri-State issued another RFP that resulted in a competitive bidding process and PPAs for the output of the following facilities:

- 200 MW Niyol Wind (expected 2021)
- 200 MW Escalante Solar (expected 2023)
- 145 MW Axial Basin Solar (expected 2023)
- 120 MW Coyote Gulch Solar (expected 2023)
- 110 MW Dolores Canyon Solar (expected 2023)
- 40 MW Spanish Peaks II Solar (expected 2023)

In addition, Tri-State Utility Member Systems' local renewable and distributed generation projects that are operating or under development has grown to 131 MW.

Tri-State has over 2,000 MW of renewable generating capacity in its resource portfolio, including CRSP and LAP hydropower, existing renewable resources and additional contracted renewable resources scheduled to be on line by 2024. Tri-State continues to engage in efforts to reduce CO_2, monitor impacts to reliability and look for opportunities to increase its renewable portfolio.

Refinement and Development of new EE and DR Products & Services:

An ongoing part of Tri-State's Action Plan, Tri-State has continued to implement Energy Efficiency (EE) programs and continues to evaluate Demand Response (DR) programs. Options that have been evaluated include residential/small commercial, irrigation, large commercial and industrial programs. These offerings are annually evaluated and refined based on industry trends, effectiveness and member feedback. For demand response, the Tri-State Utility Member System rate design, effective January 1, 2016, contains a peak demand signal, which allows member systems to control or shift their peak load, and provides a strong economic incentive to do so. This has resulted in Utility Member Systems establishing successful programs around irrigation, commercial and industrial, and residential technology load control and peak load management. Tri-State's program offerings were recently expanded to include incentives for beneficial electrification, including an on-going heat pump and heat pump water heater incentive, electric vehicle (EV) charging infrastructure incentives, and non-road EV incentives. The EE program has led to cumulative energy savings of over 212 GWh in 2019. Additionally, Tri-State completed a Demand Side Management (DSM) and Energy Efficiency Potential study with an outside consultant to further evaluate the achievable potential and cost savings for use in this resource planning process. The final study can be found in Attachment Vol II 5-1 Demand Side Management and Energy Efficiency Potential Study. An additional study for Beneficial Electrification (BE) Potential was commissioned and can be found in Attachment Vol II 5-7 Beneficial Electrification Study.

Research & Development (R&D) Programs and Projects:

Tri-State keeps informed of research, development and advanced technology initiatives through its membership in Electric Power Research Institute (EPRI) and through its participation in the National Rural Electric Cooperative Association (NRECA) Cooperative Research Network (CRN).

Some examples of Tri-State's past or present involvement in R&D projects include:

- Use of unmanned aerial vehicles to improve transmission, distribution, and generation maintenance.
- Dynamic load shaping to integrate renewable energy more cost-effectively.
- Beneficial Electrification to reduce emissions, increase energy efficiency, and improve customer's lives and businesses.
- Decarbonized hydrogen/ammonia production for season scale energy storage, grid balancing, and de-carbonization of energy uses that are hard to electrify.
- Energy storage to reduce the cost of integrating renewable energy and as an alternative to transmission and distribution upgrades.
- Incorporating DERs into resource planning to account for the effects of rooftop solar and electric vehicles on load and peak forecasting.

5 Landscape

System Energy Mix

Figure 5 shows a representation of Tri-State's 2019 Resource mix. The capacity values are based on summer nameplate ratings of Tri-State's owned, leased and long-term contracted resources. The energy values are based on gross sales to both Utility Member Systems and nonmember sales, including transmission losses. The 2019 portion of JM Shafer sold to PSCo under a tolling agreement is included in both the energy and capacity representations. Renewable energy includes WAPA hydro, existing and contracted utility scale renewables, member distributed generation and the percentage of the Basin contracts for which Renewable Energy Credits (RECs) were received from BEPC (~25% of Basin West and Electrically East contract energy).

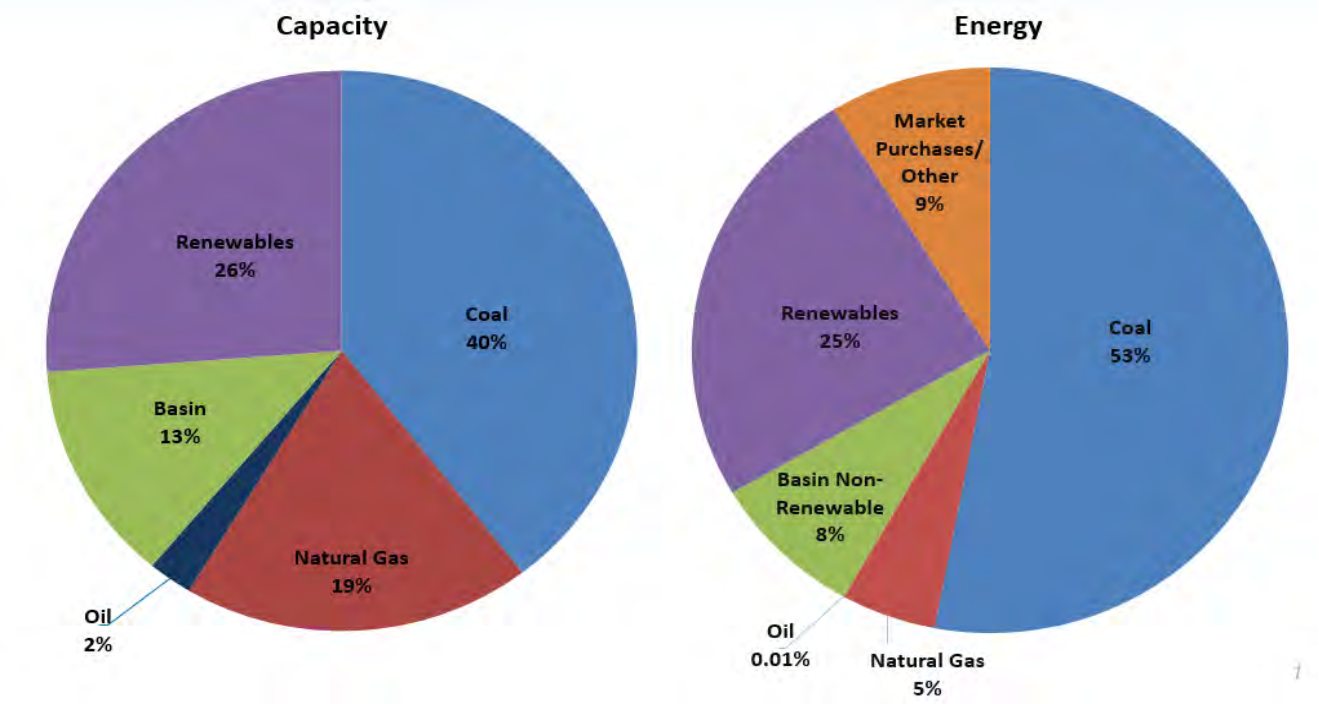

Figure 5: Tri-State 2019 Total System Resource Mix

Figure 6 shows a representation of Tri-State's forecast 2030 Resource Mix based on the preferred plan (80pct CR V4). Capacity values are based on summer nameplate ratings of owned, leased, long-term contracted resources and expansion plan resources. Energy values are based on forecast gross sales to both Utility Member Systems and nonmember sales as well as charging load for energy storage including transmission losses. Renewable energy forecasts includes WAPA hydro, existing and expansion plan utility scale renewables, member distributed generation and the percentage of the Basin contracts for which RECs are forecast to be received.

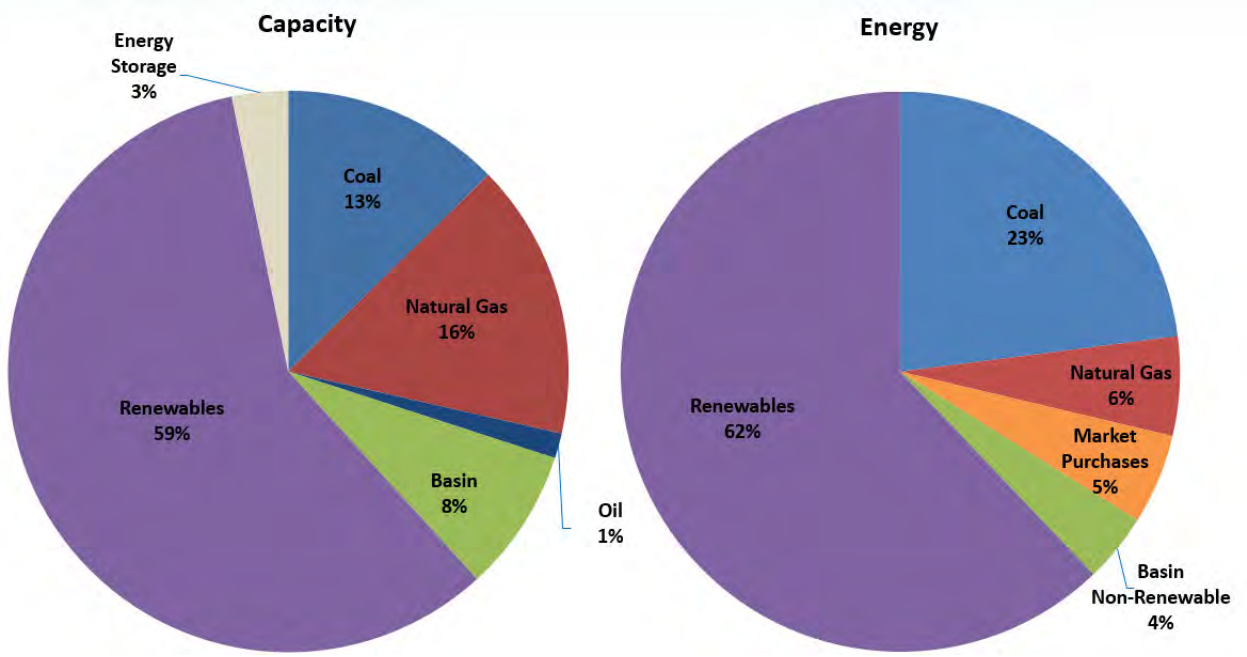

Figure 6: Tri-State Projected 2030 Resource Mix – Preferred Plan

Tri-State's preferred plan increases renewable generation on a capacity and energy basis from ~25% of system mix in 2019 to ~60% of system mix in 2030. This occurs along with a significant reduction in the capacity and energy contribution of coal fired generation. Coal capacity is forecast to decrease from ~40% in 2019 to ~13% in 2030, based on capacity and from ~53% in 2019 to ~23% in 2030 based on energy. Gas is forecast to remain reasonably constant on an energy basis from 2019 to 2030 and is forecast to be slightly reduced on a capacity basis. Along with the addition of energy storage by 2030, gas provides a reliability backstop for the integration of intermittent renewable resources.

Energy Market Dynamics and External Factors

Changing wholesale electricity market environments and external factors were considered in the development of this Resource Plan. The following factors are significant:

- Fuel Pricing
- Organized Market Development Timelines
- Possible Future Environmental Regulations
- Shift to Renewables & Increased Deployment of Distributed Energy Resources (DER)

Fuel pricing has an impact on the development of the load forecast as described below, and influences the selection of resources in the expansion plan to meet system capacity and energy needs, and the dispatch order of resources. In some instances, electricity that Tri-State Utility Member Systems offers to retail customers competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and Annual Energy Outlook. This data is used in the evaluation of the potential competition for purposes of load forecasting. Separately Tri-State's expansion planning and hourly dispatch models are populated with coal and natural gas forward price curves to forecast resource dispatch costs as they compare to other resources and forward wholesale electricity market power pricing.

Tri-State is currently planning entry, as a market participant, into the WEIM and WEIS in 2021. Entry into the WEIM is planned for Tri-State's load and resources located in the PNM-BA in April 2021. Additionally, Tri-State has a small portion of load that has been in the WEIM in PAC's BA since PAC's entry in 2014. PSCo has announced its intent to enter WEIM in 2022. Tri-State's load in the PSCo BA will enter the WEIM at that time and relevant resource participation remains under evaluation. Separately, Tri-State is planning to enter the WEIS market as a market participant in February 2021 for those load and resources located within the WAPA-BA.

In 2019, New Mexico passed legislation increasing the Renewable Portfolio Standard (RPS) percentages in New Mexico to 40% by 2025 and 50% by 2030. In Colorado, SB 19-236 and HB 19-1261 were also passed, addressing GHG and CO_2 reduction targets for all sectors including electricity sales. Specific rules addressing these emission targets are under development by the Colorado Air Quality Control Commission (AQCC). With uncertainty around final rules, Tri-State made reasonable efforts to meet and verify emission reductions based on known proposed methodologies. Both higher RPS standards and emission reduction targets impact the resource planning process in regards to resource mix. The latter has an impact both on the type of supply resources Tri-State can consider as well as the potential impact to forecast load as some of Tri-State's Utility Member Systems have load driven by industries that will also be impacted by GHG/CO_2 emission regulations.

As Utility Member Systems and their customers continue to deploy more DERs, the long-term potential effect on Tri-State's load forecast and overall Resource Plan continues to be evaluated.

The treatment of these evolving market environments and external factors are described in more detail in Section 6 Assessment of Resource Needs of this report.

Resource Planning Period

Tri-State's resource planning process uses a 20-year planning period. Tri-State selected a 20-year planning period from 2021 through 2040. For resource planning purposes Tri-State believes that this planning period appropriately maintains a focus on nearer term impacts, and properly addresses forecasts for commodity pricing, load growth rates and emerging technologies. The selection of a 20-year planning period allows the opportunity to evaluate and respond to changes in markets, technology, load and environmental and regulatory impacts over time.

Resource Acquisition Period

The RAP represents the timeframe during which detailed implementation plans are outlined. As required by Rule 3605(a)(IV)(A), the RAP must encompass the years through 2030, representing an initial 10-year RAP. The 10-year RAP provides sufficient time to allow for selection and implementation of various demand-side and supply-side actions, as well as supporting activities including permitting, RFPs, contract negotiations, and transmission interconnection. This will also provide adequate time to complete competitive market assessments of resource expansion opportunities. By not extending the RAP beyond the 10-year period, risks due to uncertainties with the bidding process, load forecasts, and commodity and labor prices are reduced.

While the Resource Acquisition Period spans from 2021 through 2030, Tri-State's next Colorado ERP filing defined by rule 3605(a)(II) is due by June 1, 2023 and every four years thereafter. Due to the timing of the next ERP, as well as the substantial uncertainty related to Tri-State's load forecast Tri-State generally would prefer to delay irreversible resource decisions as long as possible, particularly related to capital intensive options. The next 12 to 24 months will be particularly informative in regards to Tri-State's projected system load. Additionally, Tri-State would prefer to allow additional time for technology to advance non-CO_2 emitting dispatchable options that will potentially be more cost-competitive with thermal resources in the future.

Planning Reserve Margin

Tri-State has historically used a fixed 15 percent minimum planning reserve margin in its planning process. This minimum level of desired planning reserve margin is calculated as 15 percent of net load. Net load is calculated as firm load, minus firm purchases, plus firm sales. Firm purchases include Tri-States' WAPA hydro power and BEPC Western Interconnection[4], which together provide approximately 850 MW of firm capacity during peak load periods. After subtracting the capacity of firm purchases from firm load, the reserve requirement is reduced by approximately 130 MW. Tri-State's operating reserve requirements, which are inclusive of contingency reserve obligations in the Southwest Reserve Sharing Group (SRSG), and via sub-entity agreements with PSCO and WAPA who are members of the Northwest Power Pool, are

[4] Basin Electrically East contract is a full requirements contract served by BEPC and the contract and associated load are excluded from the planning reserve margin calculation.

included as part of the planning reserve margin. A 15 percent minimum planning reserve margin is a conservative measure and is comparable to industry standards. Tri-State uses the minimum planning reserve margin in the base case and all alternative scenarios.

In 2020, Tri-State engaged B&V to conduct a probabilistic LOLP study to analyze the adequacy of the current planning reserve margin and the viability of expansion plans under different scenarios including a base case, a CO_2 reduction scenario and two versions of low load scenarios. This analysis began in late spring 2020 in order to provide Tri-State input into the ERP base case and alternative scenarios. One key takeaway from the study is the value of dispatchable or semi-dispatchable resources when integrating renewables in relation to avoiding unserved energy. In the LOLP study B&V used 4-hour Lithium ion (Li-ion) batteries as needed to satisfy planning reserve margins. Tri-State's ERP scenarios follow this methodology and include standalone batteries as selected by the models in the base case and alternative scenarios evaluated in this Resource Plan. The conclusion of this B&V study is that the current planning reserve margin is adequate to continue to provide reliable service to Tri-State's Utility Member Systems. The results of the study can be found in Attachment Vol II 5-2 B&V Loss of Load Probability study.

Contingency Plan

Tri-State recognizes the need to be flexible in regards to changing demands. Forecast electric generation and customer demand will not actualize exactly as planned, and transmission or generation projects could be unexpectedly delayed for many reasons. This section attempts to identify contingencies that could occur during the RAP and to develop alternatives to address them.

Potential Contingency Events:

- Failed contract negotiations with selected bidders or proposal withdrawal
- Project development delays or cancellation
- Transmission development delays
- Higher than anticipated electric demand
- Extended outages of transmission or generation facilities

Contingency Plan options available to Tri-State include:

- Purchase of short-term capacity via an RFP process to cover anticipated shortfalls.
- Initiation of negotiations with replacement bidder(s)
- Issuance of additional RFPs
- Acceleration of the in-service dates of projects

Depending on the need and severity of the contingency, any combination of the options listed above could be implemented. In the event Tri-State forecasts a near-term capacity shortage, the appropriate course of action would depend upon several factors including magnitude of shortage, timing and length of shortage, market conditions, and projects currently in progress.

Environmental Regulation

Regional Haze Rule and Retirement of Coal-Fired Electric Generating Units:

The Regional Haze Rule establishes requirements for states to periodically create State Implementation Plans ("SIPs") to protect visibility in national parks and wilderness areas throughout the United States, with a visibility goal of returning to natural visibility conditions by 2064. The Regional Haze Rule could require additional controls for particulate matter, SO2 and NOx emissions from any source with such emissions, including certain utility sources. The Regional Haze Rule requires that states revise their SIPs every ten years.

Under the existing, approved Colorado SIP, Tri-State committed to NOx emissions rates that resulted in the installation of selective catalytic reduction on Craig Station Unit 2 and the owners of Craig Station Unit 1 will retire Craig Station Unit 1 by December 31, 2025.

The APCD is now developing its second SIPs, which are due to the EPA by July 2021. The AQCC on November 20, 2020 took preliminary final action to adopt a regional haze regulation and SIP that, if finally approved, would incorporate the voluntarily announced retirement of Craig Station Unit 2 no later than September 30, 2028 and would require accelerated retirement of Craig Station Unit 3 no later than December 31, 2028. The AQCC anticipates taking final action in December 2020.

See Mr. Berger's testimony for more detail on environmental regulations applicable to Tri-State.

6 Assessment of Resource Needs

Resource Capacity & Energy

Traditional utility resource planning requires that a comparison of demand forecasts, existing generation, and purchase and sale commitments be developed in order to forecast the need for additional resources to maintain appropriate reserve margins.

The assumptions for the load and resource balance are as follows:

- Total obligations are defined as firm load, losses, firm contract sales, operating reserves, and planning reserves.
    - 2020 long term load forecast data
- All existing purchase and sales contracts are assumed to expire on their terms, with the exception of distributed generation under Tri-State Board Policy 115 and Board Policy 119, which are continued through the entire planning period.
- Craig 1 station will be retired by 12/31/2025.
- Craig 2 station will be retired 9/30/2028.
- Craig 3 station will be retired 12/31/2029.
- No spot purchases or sales are included.

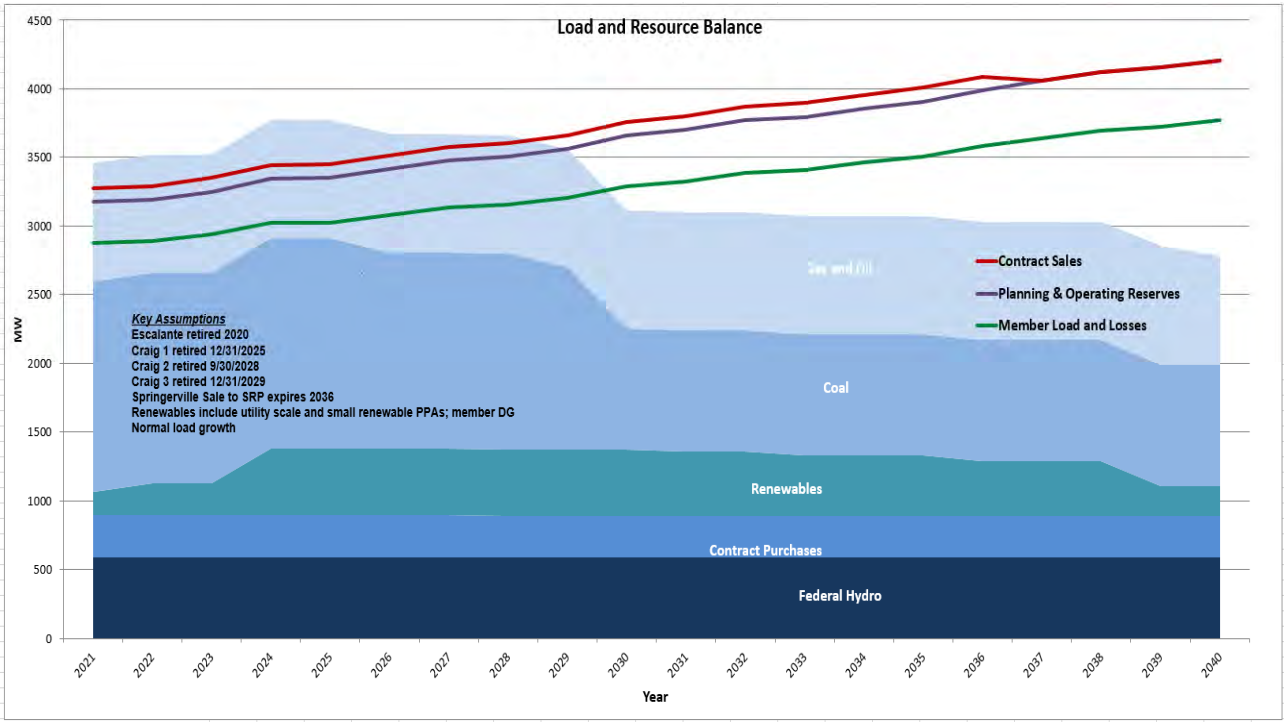

Figure 7: Tri-State Load and Resource Balance (Projected)

The above graph indicates a capacity resource need in 2029, which is later than the 2019 APR assessment. It is important to note that other factors may drive the need for additional generation beyond the scope of the above standard assessment. The scenarios described in Section 7 Alternative Scenario Analysis of this report are designed to demonstrate the potential impact that various load growth and legislative and environmentally driven conditions have on resource planning. In the evaluation of each scenario, the overall environmental impact and costs are considered in addition to resource diversity, dispatchability and reliability.

The capacity credit for existing and expansion plan resources is determined by technology. Capacity credit for dispatchable resources or semi-dispatchable resources is 100% of the summer rating. The contribution of renewables to system peak is based on B&V's modified ELCC Study as identified in Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study. This study takes into account the impact of additional renewables to the timing of the system peak. For example, as more solar is added to the system, the peak is pushed further into evening hours where solar is not capable of fully contributing to the peak, thus resulting in a decline in capacity credit. Final capacity credit values by technology are shown in Table 5.

Table 5: Modeled Capacity Credits by Technology

Resource Technology	**Capacity Credit** *(% of Nameplate)*
Thermal – Existing and Generic Resources	100%
Standalone Batteries	100%
Existing Solar (Commercial & Under Contract)	35%
Existing Wind (Commercial & Under Contract) & Wind Generic Resources	30%
Solar Generic Resources	15%
Solar + 25 MW Battery Generic Resources	15% Solar; 100% for Battery
Wind + 25 MW Battery Generic Resources	30% for Wind; 100% for Battery

Renewable Portfolio/Energy Standards

Overview:

The purpose of this analysis is to document Tri-State's forecasted compliance with the Colorado Renewable Energy Standard (RES) and the New Mexico Renewable Portfolio Standard (RPS), as well as any future compliance obligations for specific amounts of renewable and carbon free energy resources that may be enacted on the state or federal level affecting Tri-State or its member systems. Currently only Colorado and New Mexico have regulations requiring renewable, recycled or carbon neutral energy sources.

Compliance Obligations:

A RES/RPS requires a utility to generate, or cause to be generated, electricity from certain eligible renewable energy resources, at a percentage of retail electricity sales or as a percentage of energy provided to members. The definition of a renewable energy resource varies slightly depending on the state, but generally includes solar, wind, biomass, geothermal and small hydro resources. The Colorado statute also allows the application of recycled energy or waste heat energy and greenhouse gas neutral resources to count toward the total compliance requirement. The combination of these resources, together with renewable energy, is termed eligible energy.

The Colorado General Assembly left the RES unchanged in 2019, and the focus has shifted to GHG/CO_2 reduction requirements for which rules are still to be promulgated. It remains uncertain how this legislation applies to Tri-State. For the RES, Tri-State, as a Qualifying Wholesale Utility (QWU) under Colorado statute must meet a 20% Renewable Energy Standard (RES) by 2020. The Colorado RES also imposes a requirement on Tri-State's Utility Member Systems, as Qualifying Retail Utilities (QRU) under Colorado statute, increasing renewable energy at various levels until reaching 10% in 2020. The 20% Tri-State obligation may include Utility Member System-located renewable projects used towards satisfaction of the 10% requirement on cooperative electric associations by 2020.

In New Mexico, SB 489, also known as the Energy Transition Act, was signed into law in 2019. It leaves in place the RPS requirement through 2024 and increases renewable requirements starting in 2025. Tri-State Utility Member Systems are still required to meet a 5% RPS by 2015, which then escalates 1% per year to 10% in 2020 through 2024. The RPS requirement then rises to 40% for 2025 through 2029 and to 50%

beginning in 2030 through 2049. In 2050, the legislation sets a target of serving all retail sales with 100% zero carbon resources, composed of at least 80% renewable energy. This target is conditioned upon compliance solutions being technically feasible, and not having negative impacts to reliability or affordability. Another significant change to the NM RPS is that for co-ops, "hydropower facilities supplying no greater than the amount of energy from hydropower facilities that were part of an energy supply portfolio prior to July 1, 2007" (§ 62-15-37) can now be applied toward compliance. This category of renewable energy for Tri-State's New Mexico Utility Member Systems is essentially the CRSP allocation from the Western Area Power Administration's SLCA/IP projects that are assigned to New Mexico.

The current Colorado RES and New Mexico RPS requirements by year through 2020 are shown in Table 6.

Table 6: RES/RPS Requirements in Colorado and New Mexico

	Colorado		New Mexico
Year	**Co-ops**	**Tri-State**	**Co-ops**
2008-2010	1%		
2011-2014	3%		
2015	6%		5%
2016	6%		6%
2017	6%		7%
2018	6%		8%
2019	6%		9%
2020 – 2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%
2050 - beyond	10%	20%	80%

The Colorado RES includes a distributed generation (DG) requirement applicable to cooperative electric associations in an amount of 1% of total retail electricity sales starting in 2020. For cooperative electric associations with fewer than ten thousand (10,000) meters, the DG requirement is three quarters of 1% or 0.0075.

Only renewable energy resources count toward the DG requirement and of this requirement, one-half must come from wholesale DG and the other half from retail DG. Wholesale DG is defined as a renewable energy resource with a nameplate rating of ≤ 30 MW. Retail DG is defined as a renewable energy resource that is located on the customer's side of the utility meter and supplies no more than 120% percent of the average annual consumption. The most common example of retail DG is rooftop solar. Colorado statute allows subscription-based renewable energy facilities (ex., community solar) ≤ 5 MW to count towards meeting retail DG requirements. Cooperative electric associations may subtract industrial retail sales from total retail sales in calculating its retail DG requirement.

Compliance Reporting

Tri-State and its Utility Member Systems must submit a written report to the state utility regulatory bodies each spring documenting its compliance with state RES/RPS requirements for the preceding calendar year.

Tri-State documents its own as well as its Utility Member Systems' compliance with the Colorado RES and the New Mexico RPS through the retirement of Renewable Energy Certificates (REC). A REC represents the environmental attributes from one (1) megawatt-hour (MWh) of electricity generated from a renewable energy source. Both Colorado and New Mexico statutes provided for the use of multipliers depending on the technology and location of the project, whereby one MWh of energy could result in more than one REC being produced. All multipliers have been phased out since the RPS requirements were first developed; however many of the projects Tri-State uses for compliance achieved commercial operation before the expiration of the multipliers, and continue to benefit from grandfathered REC multipliers.

Most RECs used for state compliance are registered with the Western Renewable Energy Generation Information System (WREGIS) or in some cases, (BEPC non-hydro RECs) with the Midwest Renewable Energy Tracking System (M-RETS). RECs which are not used for compliance, sold or otherwise transferred in the year in which the associated renewable energy was generated may be carried forward for up to 5 years in Colorado and 4 years in New Mexico.

Tri-State's Compliance Analysis Methodology

Compliance with the Colorado RES and the New Mexico RPS is based on actual retail sales, although it should be noted that not all energy provided by Tri-State to its members translates into retail sales. This is due to system losses and members' own sales for resale. In order to forecast retail sales and determine projected RES and RPS compliance, the year-over-year growth rates for Colorado and New Mexico sales are calculated from the long-term financial forecast (LTFF) provided by the Load Forecasting Group and are applied to the actual retail sales values reported in previous years' Compliance Reports. Then using the RPS requirement levels shown in Table 6, the required number of RECs (corresponding to GWhs) by year to achieve RPS/RES compliance is calculated for Colorado and New Mexico.

Beginning in 2020, Tri-State's Colorado RES compliance obligation as a Qualified Wholesale Utility will be based on the amount of energy Tri-State provides to its Colorado Utility Member Systems. Therefore, the most current long-term load forecast for the energy Tri-State expects to provide its Colorado Utility Member Systems (excluding member generation) is used together with Table 6 to calculate the Colorado compliance obligation.

For both load and resources, forecast values are replaced with actual values at the beginning of each year for the preceding year. The forecasts for existing large utility scale projects, WAPA hydro and small hydro projects assume a continuation of past performance; although solar generation forecasts reflect a 0.5% degradation factor. In addition, any new projects with Tri-State Board approved PPAs are included using the forecasts provided by the developer. Forecasts reflect projected energy through the term of the PPAs.

The actual and forecast requirements are plotted graphically against the actual and forecast supply of RECs to depict Tri-State's compliance progress.

Results

The chart in Figure 8 is a graphical representation of Tri-State and its Utility Member Systems' progress towards meeting Colorado and New Mexico compliance obligations through 2040 on a yearly basis. Based on current progress, Tri-State and its member systems are exceeding the RES and RPS requirements.

The chart does not reflect banking effects of RECs that are provided for in each of the Colorado and New Mexico renewable energy statutes. During years when Tri-State and its Utility Member Systems are exceeding compliance levels, these entities may bank their unused RECs and apply them toward future years' obligations. Additionally, the figure represents only Tri-State's current renewable resource portfolio and respective PPA durations, without the inclusion of additional resources or expansion plan scenarios. It also does not reflect REC sales, or Tri-State-owned WAPA RECs not applicable toward compliance or Basin REC allocations from previous years (ex., in addition to the current year allocations, WAPA and BASIN may provide additional RECs with a prior year's vintage that it or other members/customers cannot use).

Considering the actual and forecast data in Figure 8 below and those factors not reflected in the chart, Tri-State remains confident in its ability to meet both its own and its Utility Member Systems' compliance obligations over the long term.

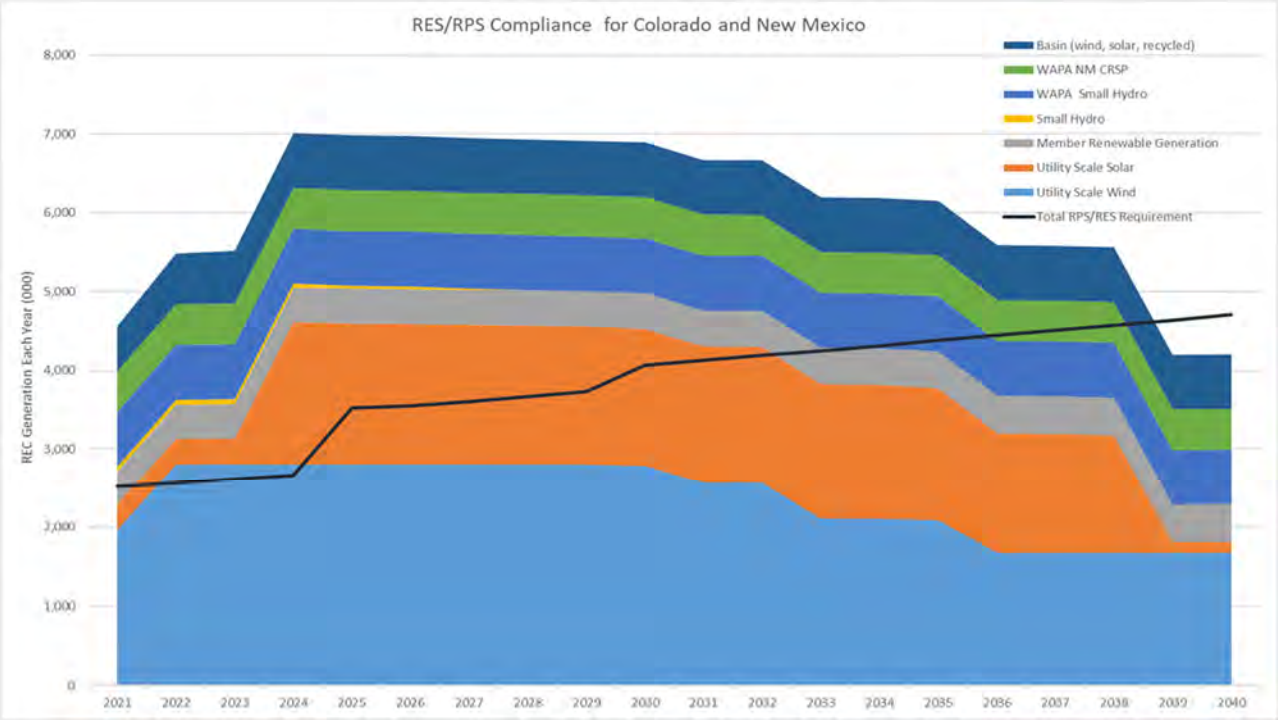

Figure 8: RES/RPS Compliance for Colorado and New Mexico

Demand Side Management and Energy Efficiency

As stated in Tri-State's 2019 APR, an important and ongoing part of Tri-State's Action Plan is the on-going implementation of Demand Side Management (DSM) measures. Options that have been evaluated include programs related to residential, small commercial, irrigation, large commercial and industrial programs. These offerings are continually refined based on effectiveness and Utility Member System feedback. As a generation and transmission provider, Tri-State does not have retail load and is reliant upon Utility Member System participation in DSM program implementations.

Demand Response:

Tri-State's current A-40 rate design provides Tri-State's Utility Member Systems an incentive to control load during Tri-State's defined peak period. Tri-State's A-40 rate consists of energy, generation demand and transmission demand rates. Some Tri-State Utility Member Systems successfully use active load control methods during Tri-State's defined peak period to reduce their monthly demand usage and related demand charges. Tri-State provides tools such as a real time load graph to help inform our members on when it may be optimal for them to control. Demand Response programs that have been developed at the Utility Member System level include:

- Irrigation Demand Response
- Commercial and Industrial Peak Load Management
- Water Heater and Air Conditioning Demand Response

Energy Efficiency:

Tri-State's electric energy efficiency program has been in place since 1985, and many of our current measures have been a strong part of our offerings for the past several years. However, with naturally evolving markets and consumer interest, these programs are continually monitored and discussed with our member system staff to ensure that they are creating value for their consumers. As we conduct our resource planning efforts, Tri-State is evaluating energy efficiency programs and offerings in order to achieve value and energy savings for our members and their consumers. Considerations in our program design include the diverse and small distribution coop staff, and historical and current membership feedback on program needs and focus. Current offerings include, but are not limited to, the following:

- Residential and commercial heating and cooling, including air source and ground source heat pumps and energy star air conditioners
- Residential LED lighting as a post-purchase rebate; Tri-State is evaluating alternative implementation pathways for this measure for the future.
- Commercial retrofit and new construction LED lighting, including refrigerated case doors, occupancy sensors, and other efficient LED lighting measures
- Heat pump water heaters
- Low-income weatherization
- Premium efficiency electric motors and variable speed drives
- Energy Star appliances

Pilot projects are available to all Utility Member Systems and can lead to DSM products.

In addition to these incentives, Tri-State offers a multitude of other programs to promote energy efficiency and the sharing of information around such programs. These include:

- R&D projects, such as the cold climate heat pump and irrigation efficiency projects done in partnership with the Electric Power Research Institute (EPRI) and our Utility Member Systems.
- Rebates on member system staff education, such as energy audit training.

- Working partnerships with external stakeholders such as state energy offices, efficiency groups, and others to promote their available programs to our membership and collaboration strengthening the market availability for energy efficient measures and contractors.
- Consumer education material on EE measures, including newsletter pieces, blog posts, educational webinars, social media pieces and others.

Table 7: 2019 Year-End Cumulative Energy Efficiency Results

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	13,446	22,513,016
C&I HVAC	Air Source and Ground Source Heat Pumps	4,858	5,312,892
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	37,055	133,388,834
C&I Motors	Variable Speed Drive Retrofits	4,207	8,577,080
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	83,924	56,681,586
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	52,531	26,080,067
Total		**196,020**	**252,553,476**

Energy Efficiency Historical Results:

- 2016 - $2,078,582
- 2017 - $2,349,835
- 2018 - $3,338,435
- 2019 - $3,327,027
- 2020 Budget - $6,697,353

Additionally, in late 2019, Tri-State initiated a DSM & EE Potential study through an outside consultant with the goal of receiving updated information in regards to achievable potential and cost savings in the areas of energy efficiency, demand response, and distributed energy resources for use in Tri-State's 2020 ERP process. Tri-State intends to leverage this study along with Utility Member Systems' input to evolve and expand products and service offerings in a manner beneficial to Tri-State and its member systems. Key findings from this study include:

- Identifies significant cost effective opportunities for energy and demand savings for energy efficiency programs.

- Identifies limited opportunities for DR programs; long-term operation is key for cost effectiveness.
- Distributed Energy Resource (DER) programs are not cost effective except for larger systems in specific regions.

The complete study is included as Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study.

GHG & CO_2 Regulation

Tri-State continually evaluates current and proposed legislation while identifying appropriate strategies for its resource portfolio. The following legislation passed in 2019 by the state of Colorado significantly affects Tri-State's assessment of existing and future resources and is incorporated into this resource planning process:

- Colorado HB 19-1261 GHG statewide reduction goals and targets
- Colorado SB 19-096 GHG reporting
- Colorado SB 19-236 Clean Energy Plan and CO_2 Reduction

Tri-State has actively participated in Colorado AQCC working groups and sessions related to this legislation. Through this process, Tri-State has gathered insight and information from related regulations and guidance document processes and forms to create a GHG/CO_2 reduction spreadsheet to apply to each scenario that uses Colorado AQCC methodologies and expected calculations while trying to reflect Tri-State's unique position as a utility serving load in multiple states on a wholesale basis only. Some key components of Tri-State approach to addressing these emission reductions include:

- Addressing CO_2 reduction in relation to all wholesale electricity sales in Colorado whether to Tri-State's Utility Member Systems or non-members.
- Removing Tri-State Utility Member Systems in Colorado who have exited Tri-State (baseline and forecast).
- Addressing GHG reduction at a retail level based on retail sales of Tri-State Utility Member Systems.
- Incorporating all emissions produced by Tri-State owned generation located in Colorado.
- Applying emissions to out of state resources or purchases that are forecast to serve Colorado load or sales.

Tri-State's methodology for CO_2 and GHG emission reductions is based on a mass based comparison of 2030 forecast emissions to a 2005 emissions baseline. Some scenarios include a glide path to CO_2 reduction beginning in 2025. Details of the GHG/ CO_2 calculations can be found in Volume II Section 5 Phase I Modeling Details of this report and results can be found in Section 8 Base Case and Alternative Scenario Results of this report.

Beneficial Electrification

In addition to energy efficiency and demand response, Tri-State has identified Beneficial Electrification (BE) as a key goal in its on-going action plan. Tri-State has long standing electrification programs such as incentives for air source and ground source heat pumps, electric outdoor power equipment such as lawn mowers, and has established several electric vehicle programs, including funding to assist members in expanding public charging infrastructure.

In early 2020, Tri-State commissioned a BE potential study to evaluate measures and their potential to be impactful in Tri-State's service area. The primary objective of this study is to assess the technical, beneficial, and achievable electrification potential from a variety of measures over the planning horizon. This study was designed to measure achievable potential, not program potential, and is intended to assist Tri-State in developing future ERPs. The achievable potential focuses on what *could be*, but does not account for limitations that could come from program portfolio structure or organization limitations.

The study evaluated measures in the residential, irrigation, commercial, and industrial sectors. Measures must meet one of the following criteria without adversely impacting the other three:

- Saves the member-consumer money
- Reduces emissions
- Improves quality of life
- Fosters grid resiliency

The complete study can be found in Attachment Vol II 5-7 Tri-State Beneficial Electrification Potential Study. Key findings from this study include:

- Technologies assessed include electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.
- The achievable-moderate scenario would result in approximately 2.5 GWh of load growth in year 1, rising to 653 GWh of cumulative growth through the planning study.
- BE provides for emissions reductions.
- The irrigation sector carries significant potential from electrification of motors currently powered by natural gas, propane, or diesel.
- The commercial sector includes a large portion of potential emissions reductions from off-road EV measures such as electric forklifts.
- The top 7 most impactful measures are:
    - Small, light duty battery electric vehicles
    - Irrigation pump motors
    - Heat pump water heaters
    - Electric forklifts (class V and IV)
    - Air source heat pumps
    - Electric buses
- Customer adoption will be a hurdle to overall beneficial electrification uptake.

Due to the timing of the completion of this study, along with the additional necessary work to establish programs and implement the potential, the BE load growth is not included in any alternative scenario.

Tri-State expects to have a clearer picture of an overall BE program and related Utility Member System customer acceptance for use in preparation for the June 1, 2023 Colorado ERP filing.

Imbalance Markets, Regional Transmission Organizations and Independent System Operators (ISO)

Tri-State has the following current and expected activity in relation to imbalance markets:

- Tri-State's load located in PAC has been in the CAISO WEIM since 2014.
- Tri-State's load and resources in WAPA-BA will enter SPP's WEIS in February 2021 or such date as the Western Markets Executive Committee determines.
- Tri-State's load and resources in PNM will enter CAISO WEIM in April 2021.
- PSCo has announced entry into CAISO WEIM in 2022. Tri-State's load in PSCo will move into the WEIM at that time and prior to PSCo's entry date Tri-State will assess whether to participate in the WEIM with resources in PSCo.

To represent this market entry in the Resource Plan Tri-State modeled two imbalance markets, WEIS and WEIM, in addition to existing modeled markets of Craig, Ault, LRS, and Four Corners. The WEIS and WEIM are tied to the Colorado East power curve and Palo Verde power curve, respectively as described in Volume II Section 2 Commodity Pricing of this report. After entry into the market, Tri-State will begin to use appropriate locational marginal pricing as it becomes available to improve forward curve predictors for these markets and will adjust market depths to reflect imbalance activity. The WEIS and WEIM markets are modeled from their entry dates in 2021 through 2024, at which time Tri-State takes these markets to zero in the model and expands the depths of Craig, Ault, LRS, and Four Corners markets to reflect potential formation of an RTO across Tri-State's system footprint in which Tri-State can fully participate.

Expected benefits of the WEIM and WEIS include:

- accessibility to a wider market for Tri-State resources,
- lower power purchase prices,
- potential for development of a "day-2" market, and
- additional ability to integrate renewables.

Tri-State believes entry into imbalance markets will improve reliability and help to reduce the cost of serving Utility Member System load. Additionally, the formation of a full RTO or ISO will further increase the ability to integrate renewables, while maintaining reliability and reducing costs as both day ahead and real time functions related to unit commitment and economic dispatch of both energy and ancillary services will be under the umbrella of one market operator over an extended footprint.

7 Alternative Scenario Analysis

Overview

Tri-State uses scenario analysis for resource planning. The process is designed to measure the effect of changes to key assumptions and the impact of sensitivities on key inputs. For the 2020 IRP/ERP process, Tri-State established a base case using inputs known as of June 2020. This case does not include changes

from normal assumptions or any regulatory impacts. The purpose of the base case is for use as a standard against which other scenarios can be measured. Each alternative scenario is analyzed for financial, reliability and environmental impact. Financial impacts include transmission capital expenditures, resource build costs, and resulting PVRR for the RPP. Reliability impacts include dispatchability, diversity and reliability assessment. Environmental impacts include system-wide emissions rates and water usage for hourly dispatch, as well as required GHG/CO_2 reduction in the state of Colorado. Compliance with RES in Colorado and RPS in New Mexico is also assessed for each scenario.

Tri-State used base inputs as well as scenario-specific assumptions, and employed an iterative process to reach an optimal expansion plan for a given study. The expansion plan was then analyzed for transmission capital expenses, run through the production cost hourly dispatch model, and analyzed in financial forecasting software to arrive at a final PVRR.

In the Section 9 Base Case & Alternative Scenario Comparison of this report, comparisons of PVRR, GHG/CO_2 reduction in Colorado, transmission capital expense, SCoC, and emissions and water usage can be found. A qualitative comparison of reliability impacts is also included. Scenarios are given rankings for diversity, dispatchability and reliability with scores ranging from one to three, where one is lowest and three is highest.

- High diversity is determined by having variability in fuel supply and location in resource mix.
- High dispatchability is determined as the operational ease of increasing or curtailing the resource mix, as well as financial impact.
- High reliability is determined as a resource mix with strong ability to support the grid and flexibility in providing ancillary services.

Alternative Scenario Process

Method for Developing Alternative Scenarios:

The CE model optimized alternative scenario expansion plans by selecting the plan with the lowest costs while adhering to various constraints. Some constraints include 1) minimum levels of planning / operating reserve margins, 2) limits on CO_2 and nitrous oxides (NO_x) emissions to specified levels, and 3) limits on new resources in a given location, so as not to exceed transmission link capacities.

For scenarios with a CO_2 emission constraint applied, CE was unable to completely model the constraint. CE accounts for CO_2 emissions associated with thermal units located within Colorado. However, for thermal generation located outside of Colorado serving loads both in Colorado and in other states, the CO_2 emissions cannot be included in the CE constraint. Therefore, the resulting CE expansions plans did not fully meet the targeted emission limits. In order to meet the carbon emission targets, the CE expansion plans for each scenario were modified outside of CE through additional analysis. Adjustments included adding more renewable resources and/or changing the installation dates of resources identified in the expansion plan. Some considerations for making adjustments were locating resources to minimize transmission network upgrades, the feasibility of wind or solar in any given transmission area, maximizing the use of transmission made available through resource retirements, ensuring the minimum reserve requirement is met and balancing the mix of technologies.

Scenarios:

In an effort to develop alternative plans, Tri-State first developed the base case. As previously stated, the base case serves as a standard against which other scenarios can be measured. The base excludes GHG/CO_2 reductions in Colorado. It was developed using the following main inputs:

- Load forecast – 2020 annual long term forecast
- Electric price forecast – May 2020 spring reset long term forecast
- Gas price curves - May 2020 spring reset long term forecast
- Coal price forecast – 2020 forecast
- Announced coal unit retirements
- A set of generic resources as listed in Volume II Section 5 Phase I Plan Modeling Details of this report.

Note that in all scenarios, 2021 preliminary budget data was used as it represented the best available data on Tri-State's expected 2021 budget. These resource planning processes will not drive a change in the 2021 budget.

For a more complete summary of the remaining inputs, see Volume II Section 5 Phase I Plan Modeling Details under the Modeling Assumptions subsection in this report.

Two primary metrics against which alternative plans were evaluated were PVRR and reduction in GHG/CO_2 emissions in the state of Colorado. Each alternative scenario was required to meet minimum reserve requirements, serve Utility Member System loads, and not exceed the capacities of the transmission links serving the various modeling regions.

Tri-State developed the following alternative scenarios:

- 80pct CR Version 1
- 80pct CR Version 2
- 80pct CR Version 3
- 80pct CR Version 4
- Low Load 80pct CR Version 1
- Low load 80pct CR Version 2
- Social Cost of Carbon (SCC)

The 80pct CR Version 1 scenario was developed by calculating an emissions constraint of 20% of the Colorado 2005 Baseline emissions. The resulting mass-based emissions quantity was then applied as a restriction within the expansion plan and dispatch models to the extent technically feasible for the year 2030. This resulted in CO_2 emissions being reduced in 2030 by 80% from 2005 levels, in regards to emissions from wholesale electricity sales in Colorado. Additionally, this scenario includes a glide path beginning in 2025 for further reducing emissions annually until arriving at the requirement of 80% reduction in CO_2 emissions in Colorado for 2030 relative to the 2005 Colorado Baseline. This scenario also included forced aggressive level EE and low level DR in Colorado.

The 80pct CR Version 2 scenario is similar to the 80pct CR Version 1 scenario but with the removal of generic DR& EE resources as supply-side options. The scenario was analyzed to see how the PVRR and overall costs would be impacted by the removal of aggressive energy efficiency in Eastern Colorado and Western Colorado, which were present in Version 1.

The 80pct CR Version 3 scenario is similar to the 80pct CR Version 2 scenario but includes an additional wind resource to improve CO_2 reduction and enhance reliability.

The 80pct CR Version 4 scenario is similar to the 80pct CR Version 2 scenario but includes an additional solar resource to improve carbon reduction and enhance reliability.

The Low Load 80pct CR Version 1 uses the low load forecast. The load forecast used is the lower end of a 90% prediction interval estimated for the expected load. This scenario also achieves an 80% reduction in CO_2 emissions related to emissions from wholesale electricity sales in Colorado in 2030, using the year 2005 as a baseline.

The Low Load 80pct CR Version 2 is similar to the Low Load 80pct CR Version 1 but with the removal of generic DR & EE resources as supply-side options.

The SCC scenario uses the technical support document under *Executive Order 12866 – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis,* to determine the social cost of carbon. Values were converted from metric to short tons and escalated from 2007 to 2020 dollars. Tri-State used revised values for real and nominal prices per PUC Staff's comments[5] in Proceeding No. 20M–0218E and as interpreted from guidance in Commission's November 12, 2020 weekly meeting. The social cost of carbon per ton for each existing and generic resource was calculated by multiplying in each year the social cost of carbon per short ton (in real dollars) times the CO_2 emission rate of each resource. Social Cost of Carbon was applied to both in state and out of state resources. This value was added to the variable operating & maintenance (VOM) cost for each resource in each year of the RPP. Only the CE expansion plan model used these escalated VOMs. Market purchases are not used in expansion planning. SCC was not applied to the Basin contracts, as the expansion plan tool is not set up to evaluate retiring contracts.

The nominal social cost of carbon for the final dispatch of the SCC scenario including existing and generic resources, market purchases, energy imbalance purchases and the Basin contracts were passed to UIPlanner for calculation of the PVRR. The social cost of carbon specific to each resource for each year in both real and nominal dollars can be found in Volume II Section 5 Phase I Modeling Details under the subsection of Social Cost of Carbon of this report.

8 Base Case & Alternative Scenario Results

This section identifies key data assumptions and results related to expansion plan, capacity factors of thermal resources, annual emissions by owned or contracted resource, CO_2 reduction in Colorado by 2030 from a 2005 Colorado Baseline and social cost of carbon.

[5] See Volume II Section 5 Phase I Modeling Details under subsection of Social Cost of Carbon for values used.

Tri-State transmission areas that represent modeling regions are as follows:

- Eastern Colorado (ECO)
- Western Colorado (WCO)
- Wyoming (WYO)
- New Mexico (NM)
- Nebraska (NE)
- Springerville (SPV)
- Mt Elbert
- Wyoming Green

Load, resources and markets are assigned to these transmission areas. More detail on these transmission areas can be found in Volume II Section 5 Phase I Modeling Details under the subsection of CE and PO of this report.

Base Case

Base Case assumptions are as listed in Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report.

Assumptions Unique to this Case:

- No additional assumptions unique to this case.

Results:

Table 8: Expansion Plan (Base Case)

Location	MW	Technology	Year
East Colorado	400	Solar	2029
East Colorado	100	Solar	2030
New Mexico	100	Wind	2030
New Mexico	200	Natural Gas - Combustion Turbine	2030
West Colorado	200	Natural Gas - Combustion Turbine	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
East Colorado	200	Wind	2031
East Colorado	100	Wind	2032
East Colorado	300	Wind	2033
East Colorado	100	Wind	2034
West Colorado	100	Stand Alone Battery	2036
West Colorado	200	Solar	2038
East Colorado	100	Stand Alone Battery	2039
West Colorado	200	Solar	2039
Wyoming	300	Wind	2039
East Colorado	100	Stand Alone Battery	2040
New Mexico	100	Stand Alone Battery	2040
West Colorado	300	Solar	2040

Location	MW	Technology	Year
Wyoming	200	Wind	2040

Note: No DSM or EE generic resources were chosen as part of this scenario.

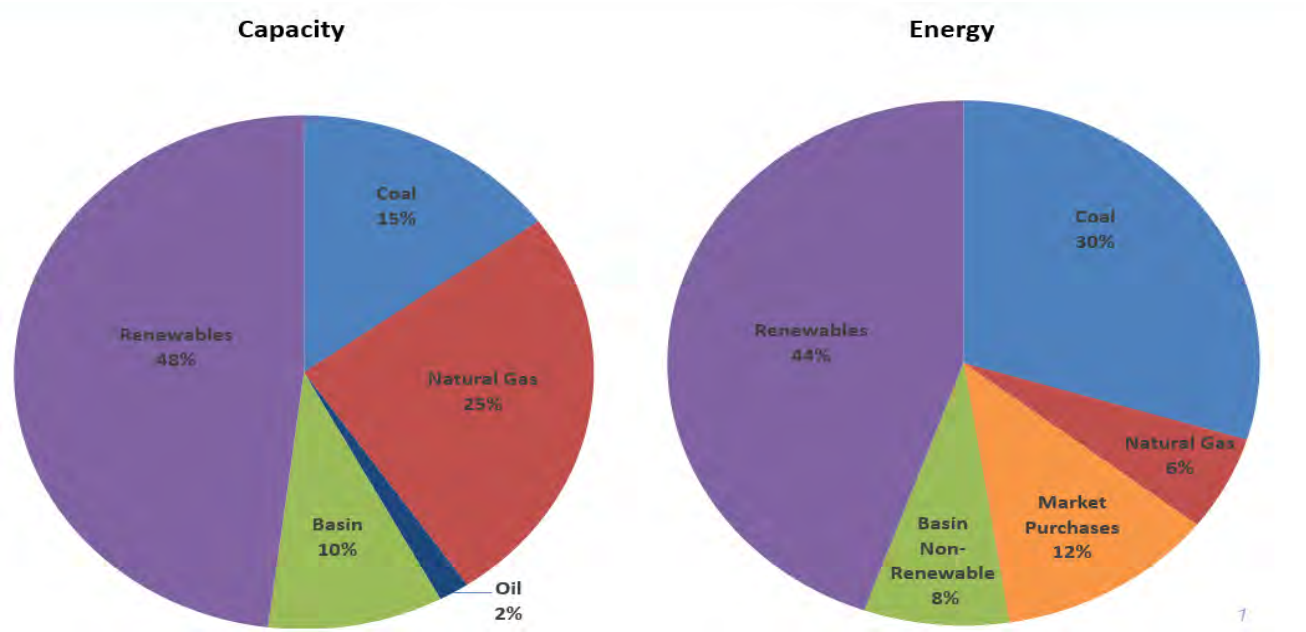

Figure 9: Projected Tri-State System Resource Mix 2030 (Base Case)

Table 9: Projected Annual Capacity Factors for Thermal Resources (Base Case)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	77%	75%	77%	77%	73%	0%	0%	0%	0%	0%
Craig 2	94%	92%	79%	87%	84%	89%	93%	70%	0%	0%
Craig 3	81%	89%	83%	78%	80%	91%	83%	94%	89%	0%
LRS 2	96%	79%	95%	88%	82%	94%	94%	83%	93%	93%
LRS 3	81%	85%	93%	72%	94%	92%	82%	93%	82%	93%
SPV3	54%	46%	52%	49%	53%	62%	67%	65%	70%	75%
JM Shafer	19%	14%	16%	14%	32%	26%	23%	21%	15%	19%
Rifle	0%	0%	0%	0%	2%	5%	4%	3%	0%	4%
Limon	0%	0%	0%	0%	2%	4%	3%	1%	0%	0%
Knutson	0%	0%	0%	0%	2%	4%	3%	1%	0%	0%
Pyramid	2%	5%	2%	1%	6%	7%	7%	8%	6%	5%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
200MW CT NM	0%	0%	0%	0%	0%	0%	0%	0%	0%	9%
200MW CT WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	12%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%

Table 10: Environmental Impact - System Wide (Base Case)

Year	CO_2 *(tons)*[6]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,575,649	6413	10,820	0.2473	449	6,063,231,450	*C*	*C*
2022	13,112,030	6377	10,697	0.2521	440	5,866,523,011	*C*	*C*
2023	13,465,748	6612	11,054	0.2542	465	6,081,369,710	*C*	*C*
2024	12,418,246	5999	10,129	0.2325	409	5,645,835,819	*C*	*C*
2025	13,311,462	6450	10,861	0.2455	474	6,089,406,874	*C*	*C*
2026	13,503,812	6843	10,799	0.2646	487	6,259,139,589	*C*	*C*
2027	13,328,387	6526	10,238	0.2476	456	6,078,848,688	*C*	*C*
2028	13,458,489	6840	10,629	0.2648	470	6,146,381,311	*C*	*C*
2029	12,695,812	6595	10,149	0.2526	431	5,759,577,146	*C*	*C*
2030	10,741,321	4578	6,802	0.1124	370	4,454,365,320	*C*	*C*
2031	10,364,206	4336	6,491	0.1048	362	4,214,761,807	*C*	*C*
2032	10,531,882	4424	6,632	0.1079	358	4,412,138,345	*C*	*C*
2033	10,578,004	4562	6,816	0.1115	374	4,480,370,331	*C*	*C*
2034	10,228,549	4365	6,493	0.1047	360	4,288,332,918	*C*	*C*
2035	10,579,417	4411	6,671	0.1071	363	4,454,780,697	*C*	*C*
2036	10,817,841	4545	6,819	0.1109	376	4,464,021,434	*C*	*C*
2037	10,697,018	4334	6,594	0.1047	374	4,258,808,429	*C*	*C*
2038	10,621,067	4299	6,622	0.1046	367	4,348,735,743	*C*	*C*
2039	10,701,330	4508	6,829	0.1103	380	4,418,473,131	*C*	*C*
2040	10,332,855	4452	6,559	0.1058	360	4,258,987,351	*C*	*C*
Total	235,063,123	107,467	168,703	3.446	8,125	102,044,089,106		
per MWh**	*1,197*	*0.55*	*0.86*	*0.00002*	*0.04*	*260*		

*C = compliant; N = noncompliant; Sulfur Dioxide (SO_2), Mercury (Hg), Particulate Matter (PM)
**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 11: Social Cost of Carbon Nominal Dollars – System Wide (Base Case)

Year	Annual Social Cost of Carbon

[6] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

2021	$644,979,092
2022	$650,487,802
2023	$697,256,412
2024	$670,833,641
2025	$749,701,519
2026	$792,673,740
2027	$815,030,848
2028	$856,901,966
2029	$824,466,048
2030	$726,005,894
2031	$728,810,985
2032	$770,301,855
2033	$804,245,666
2034	$808,259,972
2035	$868,464,333
2036	$922,220,916
2037	$946,793,068
2038	$975,757,409
2039	$1,020,050,781
2040	$1,021,609,331
Total	**$16,294,851,278**

Table 12: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Base Case)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		271,700		
Standalone battery load (90% efficiency) charging & Mt Elbert net		0		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	3,423,670	1.15	3,945,779
Nucla	Coal - Retired		1.30	0
Rifle	Gas	29,362	0.60	17,617
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	121	0.75	91
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	463,143	0.49	226,940
CRSP East & West (CO)	Federal Hydro	929,700	0.00	0
LAP (CO)	Federal Hydro	717,301	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	0	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	353,145	0.40	141,258
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	363,599	0.75	272,699
Expansion Plan Solar (CO)	Solar	1,263,895	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,658,231	0.64	1,061,268
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
Basin Electrically East	Egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,246	0	0
			Carbon Tons	6,375,603
			GHG tons	6,407,189
Mass Based Carbon Reduction for Electricity Sales	-31%			
Mass Based GHG Reduction For Electricity sales	-31%			

Table 13: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Base Case)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,114,549	3,799,652	5,720,761
Carbon Rate (Tons/MWh)		0.29	0.44
GHG Emission		3818383.83	5,748,964
Carbon Reduction for retail sales		-38%	-8%
GHG Reduction for retail sales		-38%	-9%
Resources Expected to Exclusively Serve Load			
Rifle	29,362	17,617	
CRSP East & West (CO)	929,700	0	
LAP (CO)	717,301	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	0	0	
Expansion Plan Solar (CO)	1,263,895	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Policy 115 - CO only	356,246	0	
Total	8,117,699	578,504	
Net After transmission losses	7,711,814	549,578	
Balance	5,402,735	3,250,074	

Table 14: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$20,878
Expansion Plan Capex + IDC : Generation (Millions)	$1,249
Expansion Plan Capex + IDC : Transmission (Millions)	$1,624
Diversity	2
Dispatchability	3
Reliability	3

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$400M in New Mexico in 2030
- ~$300M in Eastern Colorado in 2031
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 15: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Base Case)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Solar	0	5.89	0
2029	100	Solar	0	2.6	419.56
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2031	100	Wind	0	12.98	334.39
2031	100	Wind	0	5.2	0
2032	100	Wind	0	2.6	0
2033	100	Wind	0	5.2	0
2033	100	Wind	0	2.6	0
2033	100	Wind	0	5.2	0
2034	100	Wind	0	2.6	0
2039	100	Battery	2.19	5.2	283.39
2040	100	Battery	2.19	2.6	0
Western Colorado (WCO) Transmission Area					
2030	200	CT	1.63	0.5	0
2030	300	CC	1.63	0.5	0
2036	100	Battery	2.19	0.5	0
2038	100	Solar	0	3.7	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2038	100	Solar	0	1.85	0
2039	100	Solar	0	3.7	0
2039	100	Solar	0	1.85	0
2040	100	Solar	0	2.6	0
2040	100	Solar	0	2.6	0
2040	100	Solar	0	2.6	0
Wyoming (WYO) Transmission Area					
2039	100	Wind	0	11.43	0
2039	100	Wind	0	2.6	0
2039	100	Wind	0	2.6	22.04
2040	100	Wind	0	2.6	0
2040	100	Wind	0	11.43	0
New Mexico (NM) Transmission Area)					
2030	200	CT	2.19	2.6	0
2030	100	Wind	0	1.85	385.34
2040	100	Battery	2.19	2.6	13.4

80pct CR Version 1

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 16: Unique Assumptions (80pct CR V1)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of Salt River Project (SRP) contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV 3 **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV 3 **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300

Assumption Item	Description
	• Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Aggressive EE and Low DR forced for ECO and WCO
CO_2 Reduction	80% CO_2 in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 17 for detail
Market Depths	See Tables 18 & 19 for detail

Table 17: Applied Transmission Link Capacity (80pct CR V1)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 -2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 18: Market Sales Hourly Capacity (80pct CR V1)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 19: Market Purchases Hourly Capacity (80pct CR V1)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 20: Expansion Plan (80pct CR V1)

Location	MW[7]	Technology	Year
East Colorado	See Profile	Aggressive - Energy Efficiency	2022
West Colorado	See Profile	Aggressive - Energy Efficiency	2022
East Colorado	See Profile	Low – Demand Response	2022
West Colorado	See Profile	Low – Demand Response	2022
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Standalone Battery	2027
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	100	Standalone Battery	2029
West Colorado	200	Solar	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2032
Wyoming	100	Wind	2033
East Colorado	100	Wind	2033
Wyoming	100	Wind	2034
East Colorado	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
Wyoming	25	Standalone Battery	2037
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039

[7] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

Location	MW[7]	Technology	Year
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 21: Proposed Retirements (80pct CR V1)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

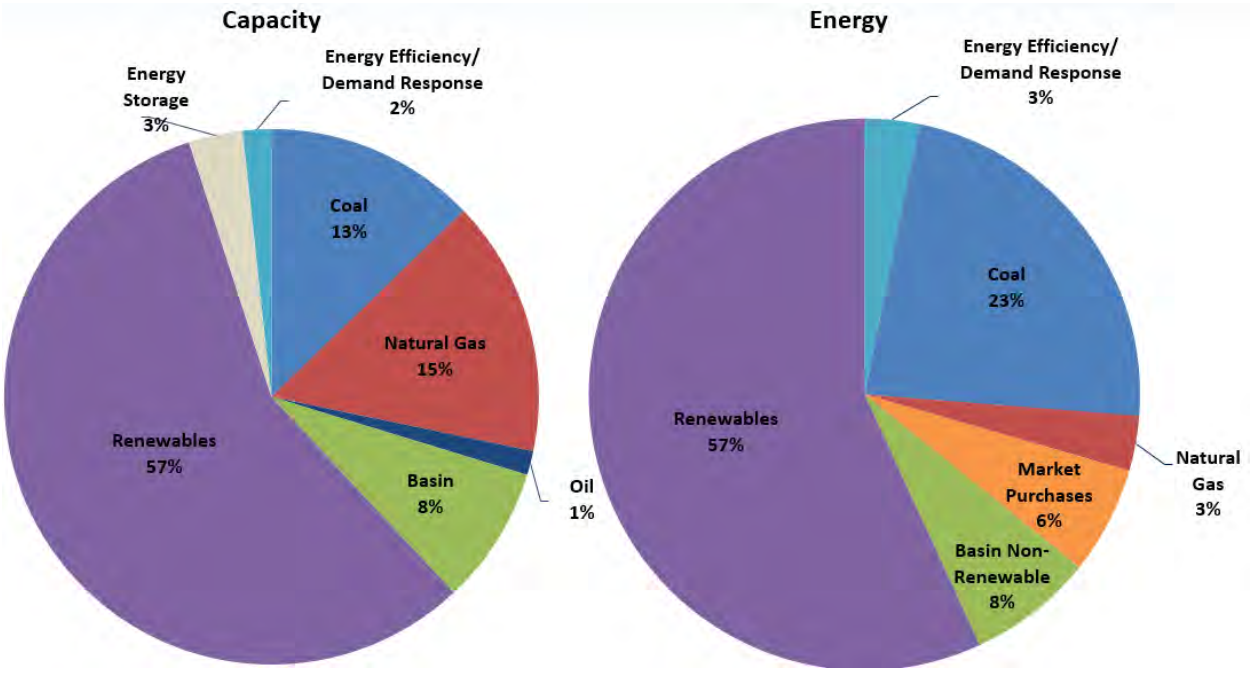

Figure 10: Projected System Capacity and Energy Mix (80pct CR V1)

Table 22: Projected Annual Capacity Factors for Thermal Reources (80pct CR V1)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	85%	82%	83%	68%	0%	0%	0%	0%	0%
Craig 2	86%	91%	78%	87%	76%	85%	87%	37%	0%	0%
Craig 3	73%	87%	79%	79%	70%	87%	78%	67%	19%	0%
LRS 2	93%	74%	94%	78%	82%	92%	93%	82%	91%	85%
LRS 3	80%	80%	92%	66%	93%	90%	81%	91%	81%	81%
SPV3	48%	46%	50%	48%	43%	45%	52%	51%	59%	56%
JM Shafer	21%	13%	15%	13%	31%	22%	15%	11%	6%	1%
Rifle	0%	0%	0%	0%	1%	1%	0%	0%	5%	0%
Limon	0%	0%	0%	0%	4%	3%	0%	0%	0%	0%

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Knutson	0%	0%	0%	0%	3%	3%	0%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	5%	5%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	26%

Table 23: Environmental Impact – System Wide (80pct CR V1)

Year	CO_2 *(tons)*[8]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,940,848	6188	10,482	0.2448	424	5,743,726,155	*C*	*C*
2023	13,306,681	6480	10,886	0.2471	457	5,968,245,238	*C*	*C*
2024	12,121,536	5776	9,812	0.2257	387	5,473,733,881	*C*	*C*
2025	12,483,909	5993	10,165	0.2238	450	5,613,203,615	*C*	*C*
2026	12,437,232	6412	10,180	0.2499	456	5,718,226,436	*C*	*C*
2027	12,137,777	6137	9,604	0.2337	421	5,532,345,140	*C*	*C*
2028	11,141,134	5835	8,918	0.2124	399	5,052,210,969	*C*	*C*
2029	9,596,311	4577	6,770	0.1316	323	4,113,955,503	*C*	*C*
2030	8,605,190	3995	5,913	0.0972	309	3,785,176,551	*C*	*C*
2031	8,562,944	3946	5,819	0.0948	310	3,703,433,543	*C*	*C*
2032	8,673,832	3971	5,889	0.0961	304	3,831,399,175	*C*	*C*
2033	7,583,638	2890	4,418	0.0652	181	3,327,906,815	*C*	*C*
2034	6,984,456	2540	3,896	0.0545	153	3,022,665,802	*C*	*C*
2035	7,307,532	2703	4,129	0.0594	161	3,182,198,961	*C*	*C*
2036	7,389,922	2721	4,093	0.0594	159	3,200,812,876	*C*	*C*
2037	6,627,845	2427	3,707	0.0520	141	2,828,444,813	*C*	*C*
2038	5,001,214	1659	3,092	0.0365	117	1,836,504,994	*C*	*C*
2039	4,835,095	1574	3,001	0.0347	113	1,716,243,528	*C*	*C*
2040	5,053,335	1618	2,997	0.0340	110	1,694,937,299	*C*	*C*
Total	186,038,552	83,497	134,028	2.683	5,804	81,072,225,351		
per MWh**	*947*	*0.43*	*0.68*	*0.00001*	*0.03*	*206*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[8] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 24: Social Cost of Carbon Nominal Dollars – System Wide (80pct CR V1)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$641,995,465
2023	$689,019,949
2024	$654,805,398
2025	$703,093,750
2026	$730,065,535
2027	$742,225,046
2028	$709,356,028
2029	$623,184,442
2030	$581,624,779
2031	$602,146,210
2032	$634,404,075
2033	$576,583,984
2034	$551,911,706
2035	$599,875,322
2036	$629,990,844
2037	$586,630,517
2038	$459,461,507
2039	$460,881,226
2040	$499,623,184
Total	**$12,306,297,253**

Table 25: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V1)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		683,100		
Standalone battery load (90% efficiency) charging & Mt Elbert net		42,476		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	71,268	1.15	82,136
Nucla	Coal - Retired		1.30	0
Rifle	Gas	813	0.60	488
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	27,244	0.49	13,350
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,049,679	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	679,058	0.40	271,623
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,112,498	0.64	711,998
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	750,658	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,789,546
			GHG tons	1,792,630
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 26: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V1)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,486,853	1,573,601
Carbon Rate (Tons/MWh)		0.11	0.12
GHG Emission		1489411.15	1,576,308
Carbon Reduction for retail sales		-76%	-75%
GHG Reduction for retail sales		-76%	-75%
Resources Expected to Exclusively Serve Load			
Rifle	813	488	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,049,679	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,253,327	625,234	
Net After transmission losses	11,640,661	593,972	
Balance	1,610,499	892,881	

Table 27: Financial (Nominal Dollars) & Reliability Impact (80pct CR V1)

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,406
Expansion Plan Capex + IDC : Generation (Millions)	$1,263
Expansion Plan Capex + IDC : Transmission (Millions)	$2,406
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2030
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2034
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2040

Detailed transmission expenses related to generic resources are shown in the following table.

Table 28: Transmission Interconnection & Network Upgrade Expenses(2020 Real Dollars) (80pct CR V1)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2030	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2032	100	Wind	0	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	12.98	334.39
2035	100	Wind	0	5.2	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	2.6	0
2037	100	Battery	2.19	5.2	0
2039	100	Battery	2.19	2.6	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	5.2	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	5.2	283.39

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Battery	1.63	0.5	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 2

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 29: Unique Assumptions (80pct CR V2)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WYO 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt Elbert	Off
Transmission Links	See Table 30 for details
Market Depth	See Tables 31 & 32 for details

Table 30: Applied Transmission Link Capacities (80pct CR Version 2)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 31: Market Sales Hourly Capacity (80pct CR Version V2)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 32: Market Purchases Hourly Capacity (80pct CR Version 2)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 33: Expansion Plan (80pct CR V2)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2032
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034

Location	MW	Technology	Year
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 34: Proposed Retirements (80pct CR V2)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

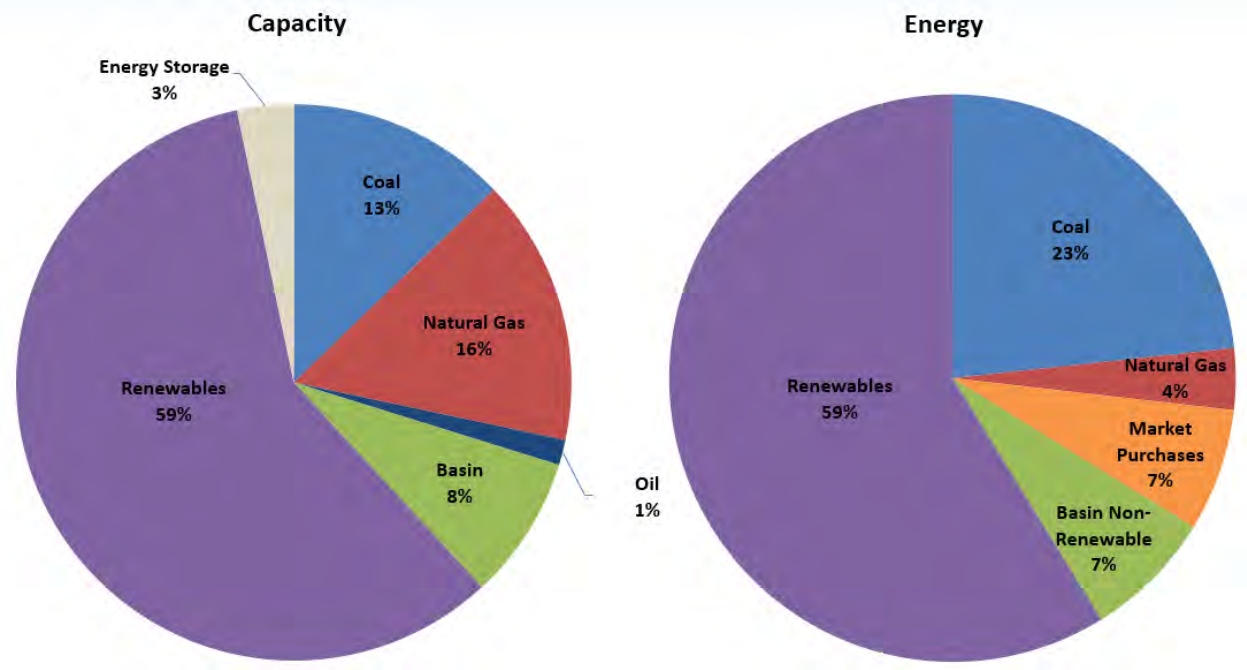

Figure 11: Projected System Capacity and Energy Mix (80pct CR V2)

Table 35: Projected Annual Capacity Factors (80pct CR V2)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	85%	83%	84%	68%	0%	0%	0%	0%	0%
Craig 2	86%	91%	78%	88%	76%	85%	86%	44%	0%	0%
Craig 3	73%	88%	80%	80%	69%	88%	77%	65%	18%	0%
LRS 2	93%	73%	94%	79%	82%	93%	93%	82%	92%	85%
LRS 3	80%	80%	93%	66%	93%	91%	81%	91%	81%	82%
SPV3	48%	46%	51%	48%	45%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	1%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	3%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	28%

Table 36: Environmental Impact – System Wide (80pct CR V2)

Year	CO_2 *(tons)*[9]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,984,474	6197	10,508	0.2457	425	5,759,294,460	*C*	*C*
2023	13,409,879	6515	10,964	0.2492	460	6,012,037,957	*C*	*C*
2024	12,268,619	5836	9,936	0.2287	392	5,539,999,761	*C*	*C*
2025	12,588,836	6005	10,167	0.2231	452	5,654,821,299	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,749,703	4017	5,967	0.0978	313	3,824,718,238	*C*	*C*
2031	8,679,065	3938	5,859	0.0949	314	3,701,224,831	*C*	*C*
2032	8,947,358	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,775,321	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,238,511	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,640,839	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,748,707	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,200,745	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,414,627	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,288,539	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,552,251	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	190,724,082	84,087	135,252	2.699	5,884	82,079,934,163		

[9] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons)*[9]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
per MWh**	*971*	*0.43*	*0.69*	*0.00001*	*0.03*	*209*		

*C = compliant; N = noncompliant
**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 37: Social Cost of Carbon Nominal Dollars - System Wide (80pct CR V2)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$644,159,756
2023	$694,363,556
2024	$662,750,812
2025	$709,003,249
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$591,392,410
2031	$610,311,817
2032	$654,409,754
2033	$591,157,628
2034	$571,987,104
2035	$627,236,443
2036	$660,577,286
2037	$637,337,962
2038	$497,441,767
2039	$504,103,527
2040	$548,951,023
Total	**$12,681,332,597**

Table 38: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V2)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (Tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		606,743		
Standalone battery load (90% efficiency) charging & Mt Elbert net		44,862		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	12,090	1.15	13,934
Nucla	Coal - Retired		1.30	0
Rifle	Gas	488	0.60	293
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	28,656	0.49	14,041
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	900,034	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,436,970	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	733,674	0.40	293,470
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,265,067	0.64	809,643
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,841,331
			GHG tons	1,844,017
Mass Based Carbon Reduction for Electricity Sales	-80%			
Mass Based GHG Reduction For electricity sales	-80%			

Table 39: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V2)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,188,856	1,627,124
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		1190587.93	1,629,494
Carbon Reduction for retail sales		-81%	-74%
GHG Reduction for retail sales		-81%	-74%
Resources Expected to Exclusively Serve Load			
Rifle	488	293	
CRSP East & West (CO)	929,860	0	
LAP (CO)	900,034	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,436,970	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,823,025	625,039	
Net After transmission losses	12,181,874	593,787	
Balance	1,069,285	595,069	

Table 40: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,283
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,373
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2032
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 41: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V2)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2032	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2040	100	Battery	2.19	2.6	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 3

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 42: Unique Assumptions (80pct CR V3)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 43 for detail
Market Depth	See Tables 44 & 45 for detail

Table 43: Applied Transmission Link Capacities (80pct CR Version 3)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 44: Market Sales Hourly Capacity (80pct CR Version 3)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 45: Market Purchases Hourly Capacity (80pct CR Version 3)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 46: Expansion Plan (80pct CR V3)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	200	Solar	2030
East Colorado	300	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035

Location	MW	Technology	Year
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 47: Proposed Retirements (80pct CR V3)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

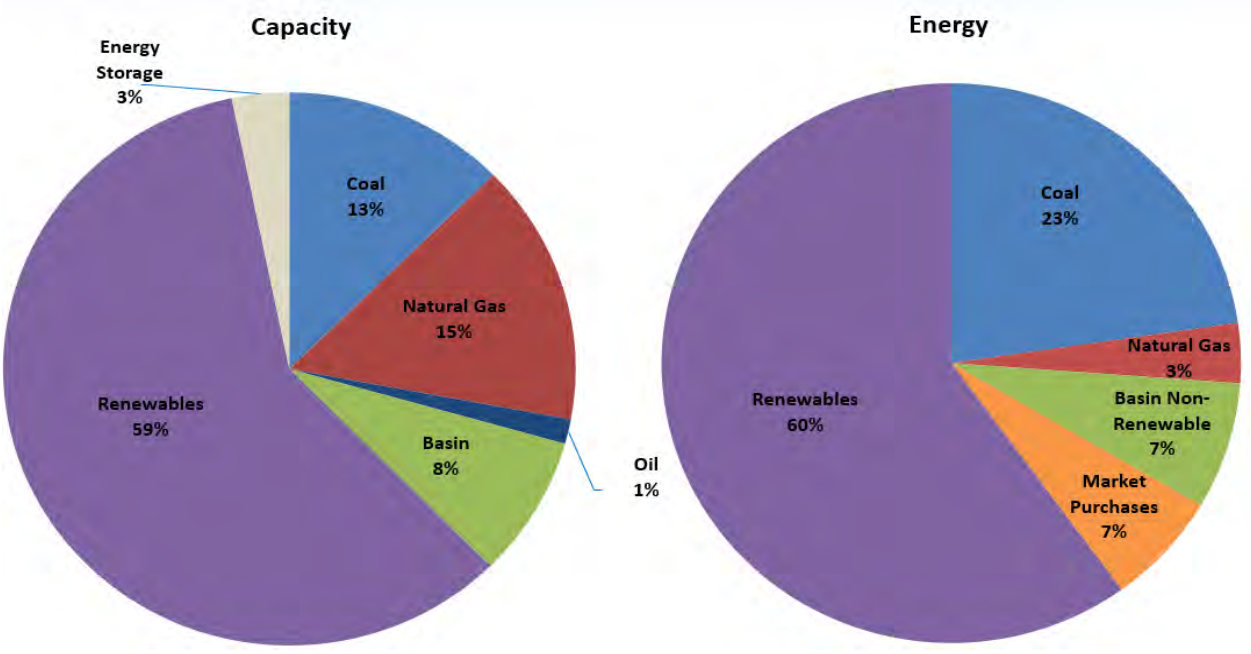

Figure 12: Projected System Capacity and Energy Mix (80pct CR V3)

Table 48: Projected Annual Capacity Factors (80pct CR V3)

Resource	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	77%	62%	0%	0%	0%	0%	0%
Craig 2	86%	91%	79%	88%	77%	85%	86%	44%	0%	0%
Craig 3	73%	88%	81%	81%	70%	88%	77%	65%	18%	0%
LRS 2	93%	74%	94%	80%	82%	93%	93%	82%	92%	83%
LRS 3	80%	82%	92%	67%	93%	91%	81%	91%	81%	80%
SPV3	48%	46%	51%	48%	43%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	1%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	28%

Table 49: Environmental Impact - System Wide (80pct CR V3)

Year	CO_2 *(tons)*[10]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,523,385	3947	5,853	0.0955	306	3,769,596,165	*C*	*C*
2031	8,542,638	3921	5,833	0.0941	312	3,735,005,592	*C*	*C*
2032	8,887,830	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,714,484	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,177,841	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,592,733	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,701,227	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,151,550	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,364,139	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,239,415	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,502,009	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*

[10] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons)*[10]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
Total	189,779,811	84,063	134,957	2.700	5,879	81,997,475,457		
per MWh **	966	0.43	0.69	0.00001	0.03	209		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 50: Social Cost of Carbon Nominal Dollars - Sytem Wide (80pct CR V3)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$643,889,557
2023	$693,500,123
2024	$662,592,985
2025	$704,451,699
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$576,095,568
2031	$600,718,318
2032	$650,055,906
2033	$586,532,220
2034	$567,192,958
2035	$623,287,453
2036	$656,529,612
2037	$632,983,704
2038	$492,803,489
2039	$499,421,024
2040	$543,983,650
Total	**$12,610,186,773**

Table 51: GHG/CO_2 Emissions for Serving Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V3)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		671,284		
Standalone battery load (90% efficiency) charging & Mt Elbert net		38,516		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	1,041	0.60	624
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	28,608	0.49	14,018
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,786,193	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	730,369	0.40	292,147
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,275,011	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,171,662	0.64	749,864
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,766,603
			GHG tons	1,769,132
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 52: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,097,647	1,555,055
Carbon Rate (Tons/MWh)		0.08	0.12
GHG Emission		1099215.75	1,557,278
Carbon Reduction for retail sales		-82%	-75%
GHG Reduction for retail sales		-82%	-75%
Resources Expected to Exclusively Serve Load			
Rifle	1,041	624	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,786,193	0	
Expansion Plan Solar (CO)	2,275,011	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,990,069	625,371	
Net After transmission losses	12,340,566	594,102	
Balance	910,594	503,544	

Table 53: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,359
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,356
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2030
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 54: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V3)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2030	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	2.6	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	12.98	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

80pct CR Version 4

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 55: Unique Assumptions (80pct CR V4)

Assumption Item	Description
Additional Retirements	Allowed – coal retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – ECO 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 300 • Max Study – WY 650 • Max Annual – Renewable 1000
DSM & EE Level	Existing DSM EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Mt. Elbert	Off
Transmission Links	See Table 56 for details
Market Depths	See Tables 57 & 58 for details

Table 56: Applied Transmission Link Capacities (80pct CR V4)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	150	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2025 - 2040

Table 57: Market Sales Hourly Capacity (80pct CR V4)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 58: Market Purchases Hourly Capacity (80pct CR V4)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 59: Expansion Plan (80pct CR V4)

Location	MW	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030
East Colorado	100	Wind	2033
Wyoming	100	Wind	2033
East Colorado	100	Wind	2034
Wyoming	100	Wind	2034
West Colorado	100	Solar	2035
East Colorado	100	Wind	2035
New Mexico	100	Standalone Battery	2036
East Colorado	100	Wind	2036
East Colorado	100	Standalone Battery	2037

Location	MW	Technology	Year
West Colorado	100	Standalone Battery	2037
Wyoming	25	Standalone Battery	2037
East Colorado	100	Wind	2037
New Mexico	200	Wind	2037
West Colorado	300	Solar	2038
New Mexico	100	Wind	2038
East Colorado	100	Standalone Battery	2039
East Colorado	400	Solar	2039
East Colorado	100	Standalone Battery	2040
West Colorado	25	Standalone Battery	2040

Table 60: Proposed Retirements (80pct CR V4)

Location	MW	Technology	Year
LRS 3	231	Coal	2033
SPV3	417	Coal	2038

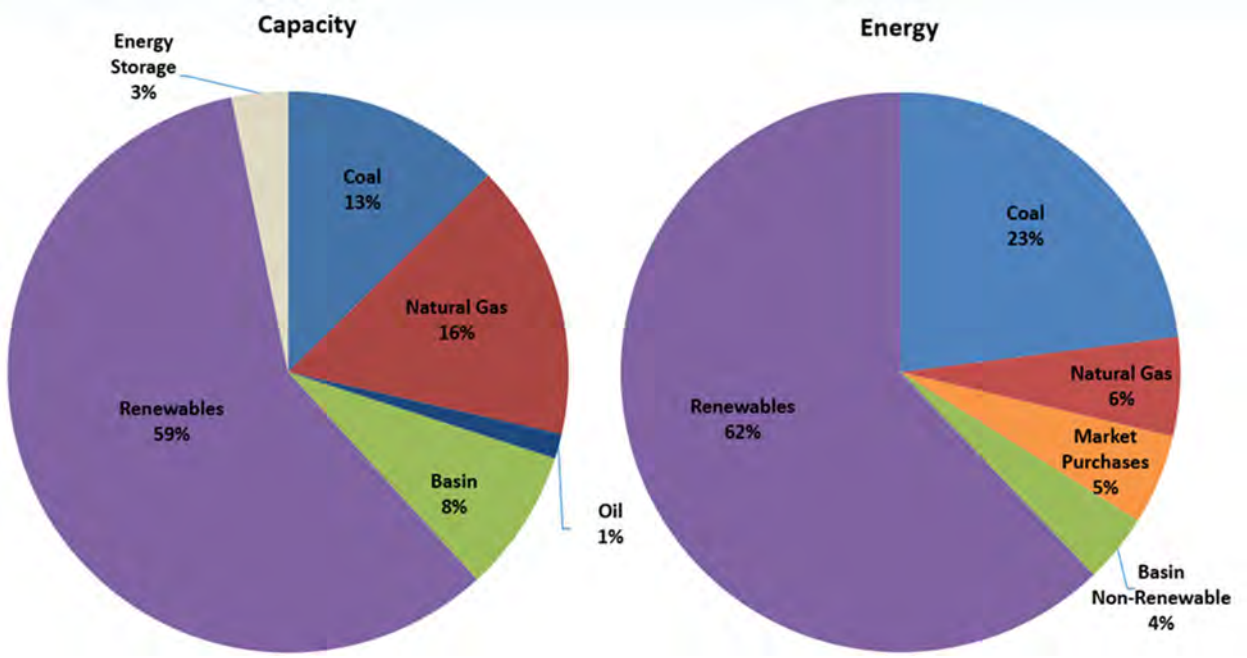

Figure 13: Projected System Capacity and Energy Mix (80pct CR V4)

Table 61: Projected Annual Capacity Factors (80pct CR V4)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	77%	62%	0%	0%	0%	0%	0%
Craig 2	86%	91%	79%	88%	77%	85%	86%	44%	0%	0%
Craig 3	73%	88%	81%	81%	70%	88%	77%	65%	18%	0%
LRS 2	93%	74%	94%	80%	82%	93%	93%	82%	92%	85%
LRS 3	80%	82%	92%	67%	93%	91%	81%	91%	81%	82%
SPV3	48%	46%	51%	48%	43%	49%	52%	53%	62%	57%
JM Shafer	21%	14%	16%	14%	32%	23%	19%	12%	6%	6%
Rifle	0%	0%	0%	0%	2%	2%	1%	0%	8%	0%
Limon	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	4%	4%	1%	0%	0%	0%
Pyramid	0%	5%	2%	1%	8%	6%	6%	6%	5%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	44%

Table 62: Environmental Impact –System Wide (80pct CR V4)

Year	CO_2 *(tons[11])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,721,869	4008	6,146	0.0974	334	4,000,402,823	*C*	*C*
2031	8,635,907	3920	5,834	0.0944	313	3,684,306,893	*C*	*C*
2032	8,901,974	4016	5,979	0.0972	310	3,912,469,252	*C*	*C*
2033	7,726,018	2864	4,432	0.0648	184	3,313,847,970	*C*	*C*
2034	7,190,904	2540	3,940	0.0546	157	3,049,319,450	*C*	*C*
2035	7,621,654	2735	4,186	0.0604	164	3,223,841,371	*C*	*C*
2036	7,683,293	2726	4,108	0.0595	160	3,210,817,842	*C*	*C*
2037	7,025,629	2460	3,760	0.0528	145	2,881,023,549	*C*	*C*
2038	5,409,698	1693	3,183	0.0377	122	1,882,871,435	*C*	*C*
2039	5,261,336	1606	3,093	0.0360	118	1,759,877,993	*C*	*C*
2040	5,514,701	1641	3,068	0.0349	114	1,729,523,811	*C*	*C*
Total	190,075,543	83,964	135,098	2.699	5,901	81,980,889,875		

[11] All tons are in short tons. CO2, SO2 and NOx are per net MWh; HG and PM are per gross MWh.

Year	CO_2 *(tons[11])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
per MWh**	968	0.43	0.69	0.00001	0.03	209		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

Table 63: Social Cost of Carbon Nominal Dollars – System Wide (80pct CR V4)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$643,889,557
2023	$693,500,123
2024	$662,592,985
2025	$704,451,699
2026	$744,150,231
2027	$747,054,076
2028	$719,677,747
2029	$635,848,166
2030	$589,511,102
2031	$607,276,988
2032	$651,090,393
2033	$587,409,167
2034	$568,225,210
2035	$625,661,540
2036	$655,000,760
2037	$621,838,465
2038	$496,988,999
2039	$501,510,544
2040	$545,238,447
Total	**$12,630,334,485**

Table 64: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (80pct CR V4)

Carbon Emissions : Serving Wholesale sales in Colorado				
2030	**Fuel Type**	**Energy (MWh)**	**Emission Rate (tons/MWh)**	**Carbon Emissions (tons)**
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		732,851		
Standalone battery load (90% efficiency) charging & Mt Elbert net		42,439		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	51,959	1.15	59,883
Nucla	Coal - Retired		1.30	0
Rifle	Gas	2,378	0.60	1,427
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	140,637	0.49	68,912
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	3,436,970	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	1,163,236	0.40	465,294
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,401,401	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	861,791	0.64	551,547
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,857,014
			GHG tons	1,859,786
Mass Based Carbon Reduction for Electricity Sales	-80%			
Mass Based GHG Reduction For electricity sales	-80%			

Table 65: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (80pct CR V4)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	13,251,159	1,165,886	1,627,558
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		1167623.65	1,629,984
Carbon Reduction for retail sales		-81%	-74%
GHG Reduction for retail sales		-81%	-74%
Resources Expected to Exclusively Serve Load			
Rifle	2,378	1,427	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	3,436,970	0	
Expansion Plan Solar (CO)	2,401,401	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	12,768,573	626,173	
Net After transmission losses	12,130,144	594,865	
Balance	1,121,015	571,021	

Table 66: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$21,292
Expansion Plan Capex + IDC : Generation (Millions)	$1,257
Expansion Plan Capex + IDC : Transmission (Millions)	$2,380
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2032
- ~$400M in New Mexico in 2037
- ~$300M in Eastern Colorado in 2039

Detailed transmission expenses related to generic resources are shown in the following table.

Table 67: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (80pct CR V4)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2032	100	Wind	0	12.98	334.39
2033	100	Wind	0	2.6	0
2034	100	Wind	0	5.2	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Wind	0	5.2	0
2037	100	Battery	2.19	2.6	0
2039	100	Battery	2.19	5.2	0
2039	100	Solar	0	1.85	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	5.2	283.39
2039	100	Solar	0	1.85	0
2040	100	Battery	2.19	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2026	100	Solar	0	1.85	0
2027	100	Solar	0	3.7	0
2028	100	Solar	0	1.85	0
2028	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2029	100	Solar	0	2.6	0
2027	100	Battery	1.63	0.5	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	11.43	0
2030	100	Solar	0	2.6	0
2030	300	CC	2.19	0.5	167.67
2030	50	Solar	0	2.6	0
2035	100	Solar	0	2.6	0
2037	100	Battery	2.19	12.98	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	1.03	0
2038	100	Solar	0	5.2	0
2040	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2028	100	Wind	0	2.6	22.04
2029	100	Wind	0	2.6	0
2030	100	Wind	0	11.43	0
2030	25	Battery	2.19	2.6	0
2033	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2036	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2037	100	Wind	0	1.85	0
2038	100	Wind	0	1.85	0

Low Load 80pct CR Version 1

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 68: Unique Assumptions (Low Load 80pct CR V1)

Assumption Item	Description
Load Forecast	2020 Annual Load Forecast – LCL 90
Additional Retirements	Allowed – coal retirements in 2026; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• ECO 2021 to 2023 Annual Max: 0 • ECO 2024 to 2027 Annual Max: 100 • ECO 2028 to 2040 Annual Max: 10000 • Max Annual – Renewable: 1000 • Max Study – ECO: 2000 • Max Study – NM: 400 • Max Study – Storage: 1200 • Max Study – Thermal: 300 • Max Study – WY: 650
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Transmission Links	See Table 69 for detail
Market Depths	See Table 70 & 71 for details

Transmission Links

Table 69: Applied Transmission Link Capacities (Low Load 80pct CR V1)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	177	176	2021 - 2029
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	227	176	2030 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	220	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	50	0	2025
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	150	0	2026
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	250	0	2027
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	350	0	2028
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	380	0	2029
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2030 - 2040

Table 70: Market Sales Hourly Capacity (Low Load 80pct CR V1)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 71: Market Purchases Hourly Capacity (Low Load 80pct CR V1)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 72: Expansion Plan (Low Load 80pct CR V1)

Location	MW[12]	Technology	Year
West Colorado	See profile	Aggressive Energy Efficiency	2025
West Colorado	100	Solar	2026
West Colorado	100	Solar	2027
Wyoming	100	Wind	2027
Wyoming	100	Wind	2028
West Colorado	100	Standalone Battery	2029
West Colorado	100	Solar	2029
East Colorado	200	Wind	2029
West Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	500	Solar	2030
East Colorado	100	Wind	2030
Wyoming	100	Wind	2030
Wyoming	25	Standalone Battery	2031
Wyoming	200	Wind	2031
Wyoming	100	Wind	2032
West Colorado	100	Solar	2033
Wyoming	100	Wind	2034
East Colorado	100	Wind	2035
East Colorado	100	Standalone Battery	2036
East Colorado	200	Wind	2036
New Mexico	100	Battery	2037
New Mexico	100	Wind	2037
East Colorado	100	Wind	2038
East Colorado	100	Standalone Battery	2039
New Mexico	100	Standalone Battery	2039
West Colorado	200	Solar	2039
East Colorado	50	Standalone Battery	2040
Wyoming	25	Standalone Battery	2040
New Mexico	100	Wind	2040

Table 73: Proposed Retirements (Low Load 80pct CR V1)

Location	MW	Technology	Year
LRS 3	231	Coal	2027
SPV3	417	Coal	2039

[12] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

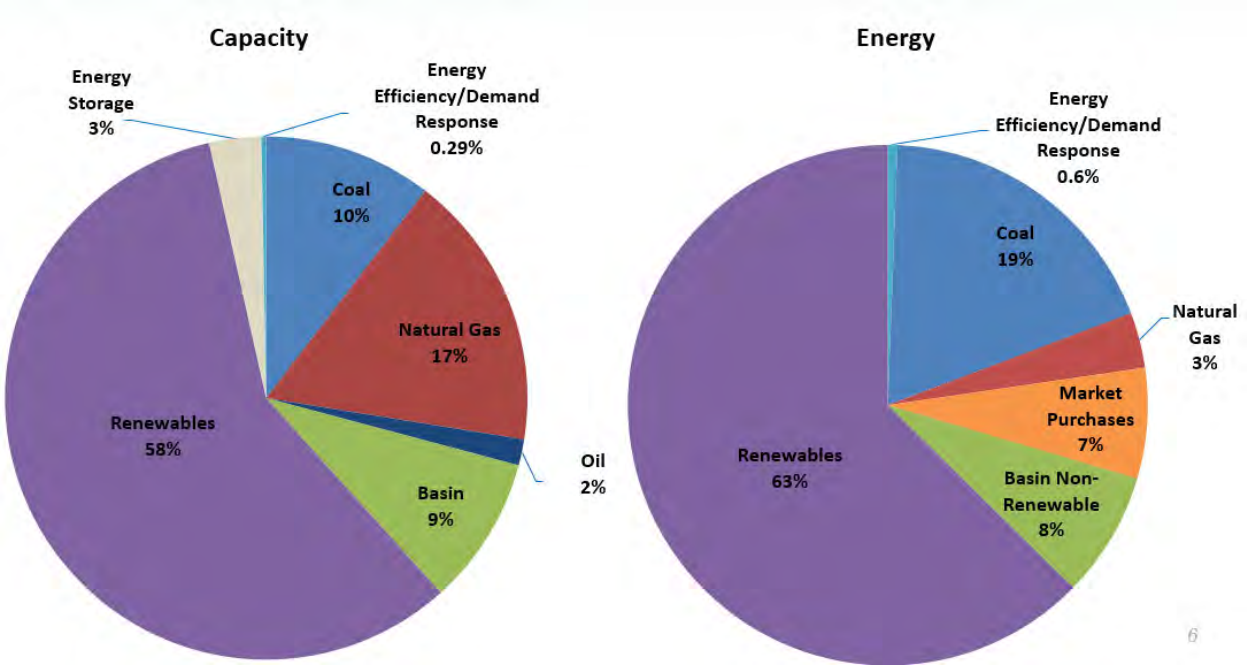

Figure 14: Projected System Capacity and Energy Mix (Low Load 80pct CR V1)

Table 74: Projected Annual Capacity Factors (Low Load 80pct CR V1)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	79%	73%	71%	63%	0%	0%	0%	0%	0%
Craig 2	86%	86%	72%	78%	70%	85%	85%	40%	0%	0%
Craig 3	73%	76%	63%	61%	66%	85%	76%	66%	18%	0%
LRS 2	93%	74%	92%	78%	82%	92%	93%	84%	93%	88%
LRS 3	80%	75%	89%	62%	93%	90%	0%	0%	0%	0%
SPV3	48%	38%	43%	41%	32%	39%	52%	51%	57%	52%
JM Shafer	21%	6%	7%	4%	26%	19%	22%	13%	5%	2%
Rifle	0%	0%	0%	0%	0%	1%	0%	0%	2%	0%
Limon	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Pyramid	0%	1%	0%	0%	4%	4%	5%	5%	4%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	23%

Table 75: Environmental Impact – System Wide (Low load 80pct CR V1)

Year	CO_2 *(tons[13])*	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	11,528,749	5574	9,507	0.2207	383	5,214,422,141	*C*	*C*
2023	11,643,176	5728	9,637	0.2143	411	5,316,878,666	*C*	*C*
2024	10,397,412	4982	8,479	0.1899	338	4,781,929,764	*C*	*C*
2025	11,438,864	5579	9,543	0.2124	424	5,202,302,115	*C*	*C*
2026	11,816,446	6137	9,864	0.2448	443	5,525,884,368	*C*	*C*
2027	9,997,041	4469	7,518	0.1891	270	4,678,925,102	*C*	*C*
2028	9,010,857	4031	6,627	0.1651	227	4,109,705,244	*C*	*C*
2029	7,425,906	2921	4,626	0.0888	163	3,172,306,802	*C*	*C*
2030	6,251,603	2331	3,807	0.0556	150	2,830,107,973	*C*	*C*
2031	5,875,778	2156	3,522	0.0497	138	2,657,620,281	*C*	*C*
2032	6,203,957	2371	3,828	0.0562	150	2,885,822,021	*C*	*C*
2033	6,341,186	2382	3,867	0.0566	153	2,912,561,758	*C*	*C*
2034	6,040,991	2218	3,605	0.0510	142	2,743,321,204	*C*	*C*
2035	6,425,910	2434	3,921	0.0576	155	2,975,816,027	*C*	*C*
2036	6,187,211	2364	3,819	0.0558	150	2,878,253,164	*C*	*C*
2037	5,747,902	2157	3,531	0.0502	138	2,633,939,407	*C*	*C*
2038	6,120,559	2360	3,804	0.0558	150	2,873,040,605	*C*	*C*
2039	4,592,993	1556	3,124	0.0396	121	1,816,343,814	*C*	*C*
2040	4,539,358	1486	2,962	0.0367	114	1,746,585,719	*C*	*C*
Total	160,834,022	69,290	115,849	2.320	4,651	72,682,620,234		
per MWh**	*975*	*0.42*	*0.70*	*0.00001*	*0.03*	*220*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[13] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 76: Social Cost of Carbon Nominal Dollars – System Wide (Low Load 80pct CR V1)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$571,941,254
2023	$602,883,664
2024	$561,668,182
2025	$644,236,823
2026	$693,625,403
2027	$611,319,027
2028	$573,721,262
2029	$482,238,325
2030	$422,545,870
2031	$413,184,702
2032	$453,757,407
2033	$482,120,400
2034	$477,359,124
2035	$527,502,938
2036	$527,459,708
2037	$508,746,776
2038	$562,295,763
2039	$437,804,118
2040	$448,806,365
Total	**$10,632,635,396**

Table 77: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Low Load 80pct CR V1)

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		11,811,422		
CO Sales to Members inc Transmission Losses (5%)		12,401,993		
COMarket Sales (including 5% markup for transmission losses)		652,384		
Standalone battery load (90% efficiency) charging & Mt Elbert net		63,455		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	98	0.60	59
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	36,293	0.49	17,784
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid rmpa	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,252,982	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	601,811	0.40	240,724
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid rmpa	133,131	0.64	85,204
CO Market Purchases	egrid rmpa	962,332	0.64	615,892
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	117,720	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,584,409
			GHG tons	1,587,143
Mass Based Carbon Reduction for Electricity Sales	-83%			
Mass Based GHG Reduction For electricity sales	-83%			

Table 78: GHG/CO_2 Emissions for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Low Load 80pct CR V1)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	11,338,965	978,823	1,369,553
Carbon Rate (Tons/MWh)		0.09	0.12
GHG Emission		980508.76	1,371,911
Carbon Reduction for retail sales		-84%	-78%
GHG Reduction for retail sales		-84%	-78%
Resources Expected to Exclusively Serve Load			
Rifle	98	59	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,252,982	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,203,136	624,805	
Net After transmission losses	10,642,979	593,565	
Balance	695,986	385,258	

Table 79: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$19,037
Expansion Plan Capex + IDC : Generation (Millions)	$1,191
Expansion Plan Capex + IDC : Transmission (Millions)	$1,946
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2033
- ~$300M in Eastern Colorado in 2036
- ~$400M in New Mexico in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 80 : Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Low Load 80pct CR V1)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2036	100	Wind	0	2.6	334.39
2036	100	Battery	2.1	12.98	0
2038	100	Wind	0	5.2	0
2039	100	Battery	2.19	2.6	0
2040	25	Battery	1.63	1.85	0
2040	25	Battery	1.63	1.85	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2027	100	Solar	0	1.85	0
2029	100	Solar	0	3.7	0
2029	100	Battery	1.63	0.5	0
2030	100	Solar	0	1.85	0
2030	100	Solar	0	2.6	0

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	11.43	0
2030	100	Battery	1.63	0.5	0
2030	300	CC	2.19	0.5	0
2033	100	Solar	0	2.6	167.67
2039	100	Solar	0	2.6	0
2039	100	Solar	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2027	100	Wind	0	11.43	0
2028	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2031	100	Wind	0	2.6	0
2031	100	Wind	0	11.43	0
2031	25	Battery	2.19	0.5	0
2032	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2040	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2037	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2039	100	Battery	2.19	2.6	13.4
2040	100	Wind	0	1.85	0

Low Load 80pct CR Version 2

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 81: Unique Assumptions (Low Load 80pct CR V2)

Assumption Item	Description
Load Forecast	2020 Annual Load Forecast – LCL 90
Additional Retirements	Allowed – coal retirements in 2026; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2024 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2025 - 2040:** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• ECO 2021 to 2023 Annual Max: 0 • ECO 2024 to 2027 Annual Max: 100 • ECO 2028 to 2040 Annual Max: 10000 • Max Annual – Renewable: 1000 • Max Study – ECO: 2000 • Max Study – NM: 400 • Max Study – Storage: 1200 • Max Study – Thermal: 300 • Max Study – WY: 650
DSM & EE Level	Existing DSM/EE only
CO_2 Reduction	80% CO_2 reduction in 2030 from 2005 baseline in relation to electricity sales in Colorado; Glide path from 2025 to 2030
Transmission Links	See Table 82 for details
Market Depths	See Table 83 & 84 for details

Table 82: Applied Transmission Link Capacities (Low Load 80pct CR V2)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	176	176	2021 - 2029
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	227	176	2030 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2026
LK-W_CO>NM	West_Colorado	New Mexico	50	100	2027
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2028 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	450	400	2026
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	350	400	2027
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	250	400	2028
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	220	400	2029
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	50	400	2030 - 2040
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	0	0	2021 - 2024
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	50	0	2025
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	150	0	2026
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	250	0	2027
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	350	0	2028
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	380	0	2029
LK-WYGreen--E_CO	Wyoming Green	WACM_Eastern_Colorado	600	0	2030 - 2040

Table 83: Market Sales Hourly Capacity (Low Load 80pct CR V2)

Dates	MS-4 Corner-N_NM *(MW)*	MS-WEIM *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	MS-Ault-E_CO *(MW)*	MS-Craig-NW_CO *(MW)*	MS-LRS-WY *(MW)*	MS-WEIS *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	50	200	0
2030-2040	50	50	200	0

Table 84: Market Purchases Hourly Capacity (Low Load 80pct CR V2)

Dates	MP-4 Corner-N_NM *(MW)*	MP-WEIM *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2034	200	0
2035-2040	400	0

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2034	200	200	200	0
2035-2040	400	400	400	0

Results:

Table 85: Expansion Plan (Low Load 80pct CR V2)

Location	MW	Technology	Year
West Colorado	100	Solar	2026
West Colorado	100	Solar	2027
Wyoming	100	Wind	2027
Wyoming	100	Wind	2028
West Colorado	100	Solar	2029
East Colorado	200	Wind	2029
West Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	500	Solar	2030
East Colorado	100	Wind	2030
Wyoming	100	Wind	2030
Wyoming	25	Standalone Battery	2031
Wyoming	200	Wind	2031
Wyoming	100	Wind	2032
West Colorado	100	Solar	2033
West Colorado	100	Standalone Battery	2034
Wyoming	100	Wind	2034
East Colorado	100	Wind	2035
East Colorado	100	Standalone Battery	2036
East Colorado	200	Wind	2036
New Mexico	100	Standalone Battery	2037
New Mexico	100	Wind	2037
East Colorado	100	Wind	2038
East Colorado	100	Standalone Battery	2039
New Mexico	100	Standalone Battery	2039
West Colorado	200	Solar	2039
East Colorado	50	Standalone Battery	2040
Wyoming	25	Standalone Battery	2040
New Mexico	100	Wind	2040

Table 86: Proposed Retirements (Low Load 80pct CR V2)

Location	MW	Technology	Year
LRS 3	231	Coal	2027
SPV3	417	Coal	2039

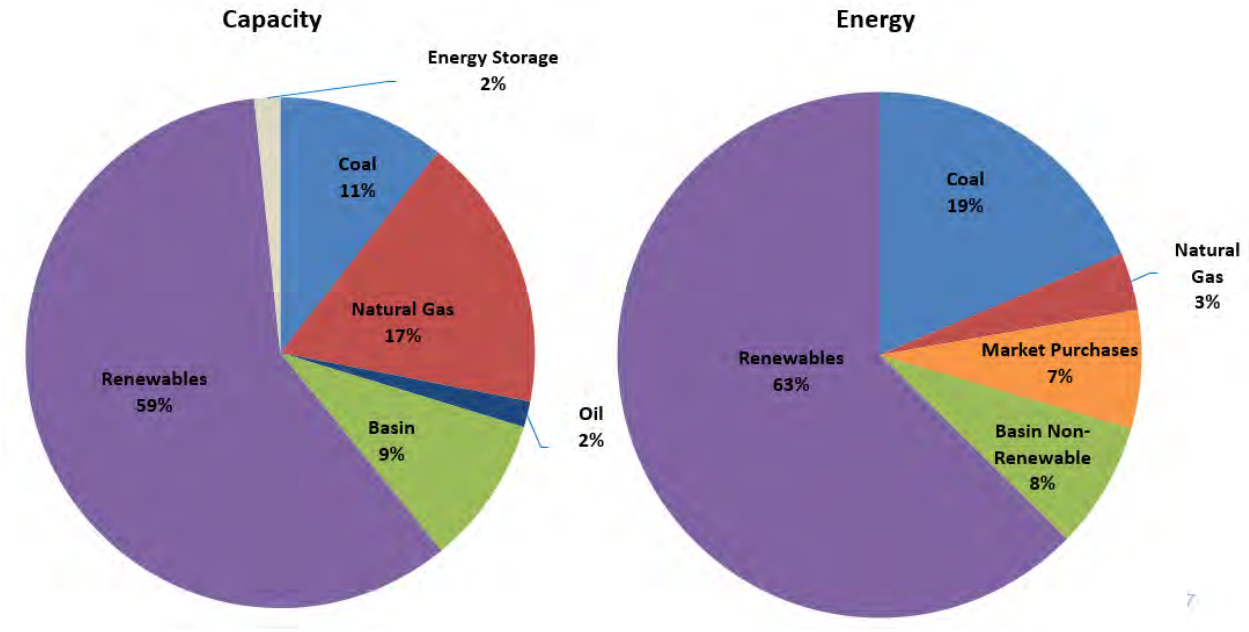

Figure 15: Projected System Capacity and Energy Mix (Low Load 80pct CR V2)

Table 87: Projected Annual Capacity Factors (Low Load 80pct CR V2)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	79%	73%	71%	61%	0%	0%	0%	0%	0%
Craig 2	86%	86%	72%	78%	69%	85%	85%	40%	0%	0%
Craig 3	73%	76%	63%	61%	66%	85%	76%	66%	19%	0%
LRS 2	93%	74%	92%	78%	82%	92%	93%	84%	93%	87%
LRS 3	80%	75%	89%	62%	92%	89%	0%	0%	0%	0%
SPV3	48%	38%	43%	41%	33%	42%	52%	51%	57%	52%
JM Shafer	21%	6%	7%	4%	26%	20%	21%	13%	6%	2%
Rifle	0%	0%	0%	0%	0%	1%	0%	0%	4%	0%
Limon	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%
Knutson	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%
Pyramid	0%	1%	0%	0%	4%	4%	4%	5%	4%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	23%

Table 88: Environmental Impact – System Wide (Low Load 80pct CR V2)

Year	CO_2 *(tons)*[14]	SO_2 *(tons)*	NO_x *(tons)*	Hg *(tons)*	PM *(tons)*	Water *(gallons)*	RES CO*	RPS NM
2021	13,772,442	6061	10,778	0.2305	486	6,212,774,902	*C*	*C*
2022	11,677,025	5575	9,655	0.2207	400	5,351,839,163	*C*	*C*
2023	11,756,302	5729	9,750	0.2143	423	5,421,719,931	*C*	*C*
2024	10,455,187	4982	8,537	0.1899	344	4,835,473,497	*C*	*C*
2025	11,659,972	5591	9,748	0.2129	447	5,418,219,347	*C*	*C*
2026	11,971,919	6179	9,945	0.2456	449	5,620,633,053	*C*	*C*
2027	10,009,492	4478	7,529	0.1897	270	4,681,453,646	*C*	*C*
2028	9,029,592	4033	6,629	0.1653	227	4,109,573,873	*C*	*C*
2029	7,488,990	2951	4,703	0.0909	167	3,217,480,869	*C*	*C*
2030	6,308,408	2332	3,814	0.0556	150	2,841,022,883	*C*	*C*
2031	5,934,993	2152	3,524	0.0495	139	2,660,199,189	*C*	*C*
2032	6,259,339	2363	3,833	0.0559	152	2,890,999,203	*C*	*C*
2033	6,487,689	2411	3,902	0.0571	155	2,957,106,895	*C*	*C*
2034	6,099,728	2219	3,609	0.0511	143	2,745,683,389	*C*	*C*
2035	6,624,580	2494	3,992	0.0590	159	3,053,690,095	*C*	*C*
2036	6,427,319	2435	3,891	0.0573	154	2,976,732,821	*C*	*C*
2037	5,852,185	2163	3,542	0.0503	139	2,644,867,071	*C*	*C*
2038	6,142,921	2326	3,774	0.0550	149	2,835,025,820	*C*	*C*
2039	4,734,087	1561	3,145	0.0398	123	1,828,353,105	*C*	*C*
2040	4,686,507	1488	2,970	0.0368	115	1,751,077,609	*C*	*C*
Total	163,378,677	69,524	117,270	2.327	4,788	74,053,926,362		
per MWh**	*990*	*0.42*	*0.71*	*0.00001*	*0.03*	*224*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[14] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 89: Social Cost of Carbon Nominal Dollars – System Wide (Low Load 80pct CR V2)

Year	Annual Social Cost of Carbon
2021	$654,328,717
2022	$579,297,232
2023	$608,741,336
2024	$564,789,183
2025	$656,689,648
2026	$702,751,656
2027	$612,080,458
2028	$574,914,124
2029	$486,335,006
2030	$426,385,286
2031	$417,348,714
2032	$457,808,066
2033	$493,258,959
2034	$482,000,498
2035	$543,811,750
2036	$547,928,915
2037	$517,976,877
2038	$564,350,172
2039	$451,253,140
2040	$463,354,911
Total	**$10,805,404,649**

Table 90: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Low Load 80pct CR V2

2030	Fuel Type	Energy (MWh)	Emission Rate (tons/MWh)	Carbon Emissions (tons)
CO Sales to Members		11,811,422		
CO Sales to Members inc Transmission Losses (5%)		12,401,993		
COMarket Sales (including 5% markup for transmission losses)		708,810		
Standalone battery load (90% efficiency) charging & Mt Elbert net		49,040		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports	Coal	106,727	1.15	123,003
Nucla	Coal - Retired		1.30	0
Rifle	wou	98	0.60	59
Knutson 1&2	Gas	0	0.75	0
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	48,697	0.49	23,862
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid RMPA	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,294,556	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	612,152	0.40	244,861
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.60	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid RMPA	133,131	0.64	85,204
CO Market Purchases	egrid RMPA	1,014,426	0.64	649,233
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction		0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	1,750,967
			GHG tons	1,754,285
Mass Based Carbon Reduction for Electricity Sales	-81%			
Mass Based GHG Reduction For electricity sales	-81%			

Table 91: GHG/CO_2 Emission for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Low Load 80pct CR V2)

		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & transm	11,457,079	1,023,254	1,524,408
Carbon Rate (Tons/MWh)		0.09	0.13
GHG Emission		1025189.24	1,527,291
Carbon Reduction for retail sales		-83%	-76%
GHG Reduction for retail sales		-83%	-76%
Resources Expected to Exclusively Serve Load			
Rifle	98	59	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,294,556	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,244,710	624,805	
Net After transmission losses	10,682,474	593,565	
Balance	774,605	429,689	

Table 92: Financial (Nominal Dollars) & Reliability Impact

Impact Item	Value
Present Value Member Revenue Requirement (Millions)	$18,985
Expansion Plan Capex + IDC : Generation (Millions)	$1,185
Expansion Plan Capex + IDC : Transmission (Millions)	$1,951
Diversity	3
Dispatchability	2
Reliability	2

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2029
- ~$150M in Western Colorado in 2034
- ~$300M in Eastern Colorado in 2036
- ~$400M in New Mexico in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 93: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Low Load 80pct CR Version 2)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind	0	5.89	0
2029	100	Wind	0	2.6	419.56
2030	100	Wind	0	2.6	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2036	100	Wind	0	2.6	334.39
2036	100	Battery	2.1	12.98	0
2038	100	Wind	0	5.2	0
2039	100	Battery	2.19	2.6	0
2040	25	Battery	1.63	1.85	0
2040	25	Battery	1.63	1.85	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	3.7	0
2027	100	Solar	0	1.85	0
2029	100	Solar	0	3.7	0
2030	100	Solar	0	1.85	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	11.43	0
2030	100	Battery	1.63	0.5	0
2030	300	CC	2.19	0.5	0
2033	100	Solar	0	2.6	0
2034	100	Battery	1.63	0.5	167.67
2039	100	Solar	0	2.6	0
2039	100	Solar	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2027	100	Wind	0	11.43	0
2028	100	Wind	0	2.6	0
2030	100	Wind	0	2.6	0
2031	100	Wind	0	2.6	0
2031	100	Wind	0	11.43	0
2031	25	Battery	2.19	0.5	0
2032	100	Wind	0	2.6	0
2034	100	Wind	0	2.6	0
2040	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2037	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	385.34
2039	100	Battery	2.19	2.6	13.4
2040	100	Wind	0	1.85	0

Social Cost of Carbon

Assumptions Unique to this Scenario:

Modeling assumptions are per Volume II Section 5 Phase I Plan Modeling Details under the subsection of Modeling Assumptions of this report with the following exceptions:

Table 94: Unique Assumptions (Social Cost of Carbon)

Assumption Item	Description
Additional Retirements	Allowed – Coal and Gas retirements after 2025; SPV3 not allowed to retire until after end of SRP contract (first year 2037)
Social Cost of Carbon	Used Social Cost of Carbon adder for all thermal resources
Thermal Resource Status: **Econ** - Model can choose to turn resource on and off but resource has a 168 hour on line min. **Must Run** - Model can choose what level to run the resource at but resource cannot go lower than min.	**Must Run 2021 - 2040 :** Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV **Econ 2021 - 2040:** Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and Shafer
Build Limits	• Max Study – Eco 2000 • Max Study – NM 400 • Max Study – Storage 1200 • Max Study – Thermal 1000 • Max Study - Wyo: 650 • Max Annual – Renewable 1000
EE & DR DSM Level	Aggressive EE and Low DR forced for ECO and WCO
CO_2 Reduction	RestrictedCO_2 levels on Colorado thermal resources
Transmission Links	See Table 95 for detail

Table 95: Applied Transmission Link Capacities (Social Cost of Carbon)

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	177	176	2021 - 2040
LK-LAP>WY	Mt_ Elbert	WACM_Wyoming	0	0	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2035
LK-SPRV>NM	Springerville	New Mexico	359	0	2036
LK-SPRV>NM	Springerville	New Mexico	417	0	2037 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2029
LK-W_CO>NM	West_Colorado	New Mexico	50	50	2030 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2025
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	650	400	2026 - 2040

Results:

Table 96: Expansion Plan (Social Cost of Carbon)

Location	MW[15]	Technology	Year
East Colorado	See Profile	Aggressive - Energy Efficiency	2022
West Colorado	See Profile	Aggressive - Energy Efficiency	2022
East Colorado	See Profile	Low – Demand Response	2022
West Colorado	See Profile	Low – Demand Response	2022
Wyoming	200	Wind	2025
West Colorado	545	Natural Gas – Combined Cycle	2026
West Colorado	200	Solar	2026
Wyoming	500	Wind	2026
East Colorado	100	100 MW Wind + 25 MW Battery	2026
Wyoming	200	Wind	2027
West Colorado	125	Standalone Battery	2028
East Colorado	100	Solar	2028
West Colorado	100	Solar	2028
East Colorado	100	Wind	2028
New Mexico	100	Wind	2028
New Mexico	100	Standalone Battery	2029
West Colorado	100	Solar	2029
East Colorado	100	Standalone Battery	2030
West Colorado	300	Natural Gas – Combined Cycle	2030
West Colorado	100	Solar	2030

[15] See Volume II Section 5 Phase I Modeling Details under the subsection of Modeling Assumptions & Methodology>DSM & EE of this report for profile information.

Location	MW[15]	Technology	Year
East Colorado	200	Solar	2030
West Colorado	100	Solar	2031
Wyoming	100	Wind	2031
East Colorado	100	Standalone Battery	2032
West Colorado	200	Standalone Battery	2032
West Colorado	100	Solar	2032
East Colorado	200	Wind	2032
West Colorado	200	Solar	2033
East Colorado	100	Wind	2033
East Colorado	100	Wind	2035
East Colorado	100	Wind	2036
West Colorado	25	Standalone Battery	2037
East Colorado	175	Standalone Battery	2037
Wyoming	50	Standalone Battery	2037
East Colorado	300	Wind	2037
New Mexico	100	Wind	2037
West Colorado	200	Solar	2038
West Colorado	25	Standalone Battery	2039
West Colorado	300	Solar	2039
East Colorado	200	200 MW Wind + 50 MW Battery	2039

Table 97: Proposed Retirements (Social Cost of Carbon)

Location	MW	Technology	Year
LRS 2	230	Coal	2026
LRS 3	231	Coal	2026
Limon 1	70	Gas	2026
Rifle	81	Gas	2026
Craig 3	448	Coal	2026
Burlington 2	55	Oil	2028
Limon 2	70	Gas	2028
Shafer	272	Gas	2030
Burlington 1	55	Oil	2031
Knutson 2	70	Gas	2031
Pyramid 2	40	Gas	2031
SPV 3	417	Coal	2037

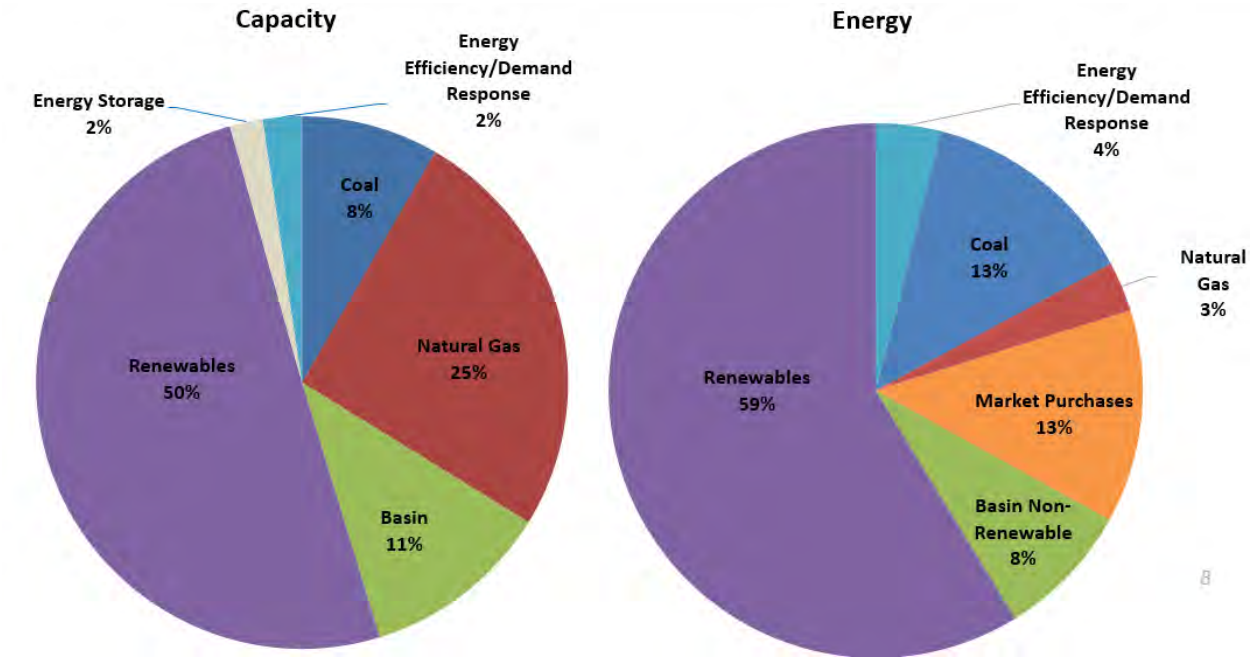

Figure 16: Projected System Capacity and Energy Mix (Social Cost of Carbon)

Table 98: Projected Annual Capacity Factors (Social Cost of Carbon)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	75%	75%	76%	76%	72%	0%	0%	0%	0%	0%
Craig 2	86%	92%	79%	88%	81%	89%	92%	68%	0%	0%
Craig 3	73%	89%	81%	80%	77%	0%	0%	0%	0%	0%
LRS 2	93%	76%	94%	80%	81%	0%	0%	0%	0%	0%
LRS 3	80%	83%	92%	67%	91%	0%	0%	0%	0%	0%
SPV3	48%	45%	50%	47%	50%	68%	70%	66%	73%	69%
JM Shafer	21%	13%	14%	12%	23%	35%	30%	24%	21%	0%
Rifle	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Limon	0%	0%	0%	0%	1%	5%	2%	0%	0%	0%
Knutson	0%	0%	0%	0%	1%	11%	4%	0%	0%	0%
Pyramid	0%	4%	2%	1%	3%	12%	11%	8%	7%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
300MW CC WCO	0%	0%	0%	0%	0%	0%	0%	0%	0%	7%
545MW CC WCO	0%	0%	0%	0%	0%	6%	5%	4%	3%	8%

Table 99: Environmental Impacts –System Wide (Social Cost of Carbon)

Year	CO_2 (tons)[16]	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO*	RPS NM
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,991,001	6287	10,539	0.2490	431	5,776,661,343	*C*	*C*
2023	13,319,145	6518	10,884	0.2497	458	5,975,892,700	*C*	*C*
2024	12,166,643	5846	9,868	0.2288	392	5,503,236,276	*C*	*C*
2025	12,750,912	6255	10,442	0.2371	447	5,823,983,448	*C*	*C*
2026	6,908,114	1870	2,617	0.0275	123	2,791,679,589	*C*	*C*
2027	6,793,620	1899	2,567	0.0282	111	2,778,778,901	*C*	*C*
2028	6,144,670	1802	2,328	0.0254	90	2,514,938,704	*C*	*C*
2029	5,855,718	1803	2,186	0.0231	75	2,327,107,117	*C*	*C*
2030	5,670,966	1755	2,053	0.0221	59	2,211,328,045	*C*	*C*
2031	5,137,515	1598	1,855	0.0188	51	1,953,497,247	*C*	*C*
2032	5,419,677	1791	2,042	0.0227	58	2,213,570,810	*C*	*C*
2033	5,432,133	1790	2,022	0.0227	56	2,190,540,133	*C*	*C*
2034	5,340,999	1734	2,006	0.0215	57	2,144,928,469	*C*	*C*
2035	5,508,779	1817	2,126	0.0232	64	2,290,939,115	*C*	*C*
2036	5,418,447	1800	2,052	0.0228	59	2,216,417,034	*C*	*C*
2037	3,130,833	707	1,146	0.0000	24	848,869,064	*C*	*C*
2038	3,113,742	709	1,173	0.0000	26	871,207,757	*C*	*C*
2039	3,071,525	711	1,178	0.0000	26	876,782,122	*C*	*C*
2040	3,299,587	773	1,248	0.0000	28	898,694,707	*C*	*C*
Total	140,722,148	53,518	80,589	1.453	3,063	57,935,906,637		
*per MWh***	*717*	*0.27*	*0.41*	*0.00001*	*0.02*	*148*		

*C = compliant; N = noncompliant

**Pounds per MWh of Member Load for emissions; Gallons per MWh of Member Load for water

[16] All tons are in short tons. CO_2, SO_2 and NO_x are per net MWh; HG and PM are per gross MWh.

Table 100: Social Cost of Carbon Nominal Dollars – System Wide (Social Cost of Carbon)

Year	Annual Social Cost of Carbon
2021	$629,418,285
2022	$644,483,544
2023	$689,665,326
2024	$657,242,050
2025	$718,131,344
2026	$405,506,288
2027	$415,429,841
2028	$391,231,132
2029	$380,270,355
2030	$383,300,620
2031	$361,270,078
2032	$396,395,170
2033	$413,005,058
2034	$422,045,732
2035	$452,215,696
2036	$461,922,593
2037	$277,110,063
2038	$286,059,468
2039	$292,777,766
2040	$326,230,168
Total	**$9,003,710,579**

Table 101: GHG/CO_2 Emissions for Serving Wholesale Electricity Sales in Colorado Projected in 2030 from a 2005 Baseline (Social Cost of Carbon)

Carbon Emissions : Serving Wholesale sales in Colorado				
2030	**Fuel Type**	**Energy (MWh)**	**Emission Rate (tons/MWh)**	**Carbon Emissions (tons)**
CO Sales to Members		13,660,989		
CO Sales to Members inc Transmission Losses (5%)		14,344,038		
COMarket Sales (including 5% markup for transmission losses)		301,642		
Standalone battery load (90% efficiency) charging & Mt Elbert net		74,348		
Craig 1 & 2	Coal - Retired		1.17	0
Craig 3	Coal - Retired		1.05	0
LRS Imports - Retired	Coal	0	1.15	0
Nucla	Coal - Retired		1.30	0
Rifle	Gas	0	0.60	0
Knutson 1&2	Gas	1,863	0.75	1,397
Limon 1 & 2	Gas	0	0.75	0
Burlington 1 & 2	Oil	0	1.12	0
Shafer	Gas	0	0.49	0
CRSP East & West (CO)	Federal Hydro	929,860	0.00	0
LAP (CO)	Federal Hydro	717,302	0.00	0
Small Power Producers	Small Hydro	710	0.00	0
Basin AU PPA	egrid rmpa	876,385	0.64	560,886
Expansion Plan Wind PPAs (CO & WY)	Wind	2,600,896	0.00	0
Expansion Plan Gas (CO) combined cycle	Gas	544,694	0.40	217,878
Expansion Plan Gas (CO) Aeroderivative, RICE, CT	Gas	0	0.75	0
Expansion Plan Solar (CO)	Solar	2,022,232	0.00	0
Energy Imbalance (PSCO and prorate of WAPA)	egrid rmpa	133,131	0.64	85,204
CO Market Purchases	egrid rmpa	1,735,914	0.64	1,110,985
Kit Carson	Wind	165,656	0	0
Carousel	Wind	653,199	0	0
Colorado Highlands	Wind	361,418	0	0
Crossing Trails	Wind	408,330	0	0
Spanish Peaks	Solar	244,985	0	0
San Isabel	Solar	67,207	0	0
Twin Buttes	Solar	307,745	0	0
Niyol	Wind	890,207	0	0
Coyote Gulch	Solar	279,776	0	0
Dolores Canyon	Solar	250,291	0	0
Axial	Solar	315,286	0	0
DSM/EE	Load Reduction	753,474	0	0
Basin Electrically East	egrid MROW	103,000	0.62	63,860
Policy 115 - CO only	Mix	356,467	0	0
			Carbon Tons	2,040,211
			GHG tons	2,044,496
Mass Based Carbon Reduction for Electricity Sales	-78%			
Mass Based GHG Reduction For electricity sales	-78%			

Table 102: GHG/CO_2 Emission for Serving Utility Member System Retail Sales in Colorado in 2030 from a 2005 Baseline (Social Cost of Carbon)

GHG Emissions: Serving TS Utility Member System Retail Sales in Colorado			
		Option 1	Option 2
	MWh	Carbon Emissions Based on How served	Carbon Emissions based on Percentage of Sales
Retail Load (Member load reduced for distribution & Transn	13,114,549	1,848,150	1,826,917
Carbon Rate (Tons/MWh)		0.14	0.14
GHG Emission		1852023.56	1,830,746
Carbon Reduction for retail sales		-70%	-71%
GHG Reduction for retail sales		-70%	-71%
Resources Expected to Exclusively Serve Load			
Rifle	0	0	
CRSP East & West (CO)	929,860	0	
LAP (CO)	717,302	0	
Small Power Producers	710	0	
Basin AU PPA	876,385	560,886	
Expansion Plan Wind PPAs (CO & WY)	2,600,896	0	
Expansion Plan Solar (CO)	2,022,232	0	
Kit Carson	165,656	0	
Carousel	653,199	0	
Colorado Highlands	361,418	0	
Crossing Trails	408,330	0	
Spanish Peaks	244,985	0	
San Isabel	67,207	0	
Twin Buttes	307,745	0	
Niyol	890,207	0	
Coyote Gulch	279,776	0	
Dolores Canyon	250,291	0	
Axial	315,286	0	
Basin Electrically East	103,000	63,860	
Policy 115 - CO only	356,467	0	
Total	11,550,952	624,746	
Net After transmission losses	10,973,405	593,509	
Balance	2,141,145	1,254,641	

Table 103: Financial (Nominal Dollars) & Reliability Impact (Social Cost of Carbon)

Impact Item	SCC w SCoC	SCC w/o SCoC	SCC w SCoC (3% DR)	SCC w/o SCoC (3% DR)
Present Value Member Revenue Requirement (Millions)	$30,118	$22,715	$33,579	$25,445
Expansion Plan Capex + IDC : Generation (Millions)		$2,109		
Expansion Plan Capex + IDC : Transmission (Millions)		$2,328		
Diversity	3			
Dispatchability	2			
Reliability	2			

Transmission Impact

Beyond normal interconnection transmission expenses, significant additional network upgrades for size in this plan (Costs are in 2020 dollars) were incurred as follows:

- ~$400M in Eastern Colorado in 2028
- ~$400M in New Mexico in 2028
- ~$150M in Western Colorado in 2030
- ~$300M in Eastern Colorado in 2030
- ~$300M in Eastern Colorado in 2037

Detailed transmission expenses related to generic resources are shown in the following table.

Table 104: Transmission Interconnection & Network Upgrade Expenses (2020 Real Dollars) (Social Cost of Carbon)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	100	Wind+battery	0	5.89	0
2028	100	Solar	0	2.6	419.56
2028	100	Wind	0	2.6	0
2030	100	Solar	0	2.6	0
2030	100	Solar	0	2.6	334.39
2030	100	Battery	2.19	12.98	0
2032	100	Wind	0	5.2	0
2032	100	Wind	0	2.6	0
2032	100	Battery	2.19	5.2	0
2033	100	Wind	0	1.85	0
2035	100	Wind	0	2.6	0
2036	100	Wind	0	1.85	0
2037	100	Battery	2.19	5.2	0
2037	100	Wind	0	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2037	100	Wind	0	5.2	283.39
2037	100	Wind	0	2.6	0
2037	25	Battery	2.19	5.2	0
2037	25	Battery	2.19	2.6	0
2037	25	Battery	1.63	1.85	0
2039	100	Wind+battery	0	1.85	0
2039	100	Wind+battery	0	5.2	0
Western Colorado (WCO) Transmission Area					
2026	100	Solar	0	2.6	0
2026	100	Solar	0	3.7	0
2026	545	CC	2.19	0.5	0
2028	100	Battery	1.63	1.85	0
2028	25	Battery	1.63	0.5	0
2028	100	Solar	0	3.7	0
2029	100	Solar	0	1.85	0
2030	100	Solar	0	2.6	0
2030	300	CC	1.63	0.5	167.67
2031	100	Solar	0	2.6	0
2031	100	Battery	2.19	2.6	0
2031	100	Battery	2.19	2.6	0
2032	100	Solar	0	11.43	0
2033	100	Solar	0	12.98	0
2033	100	Solar	0	2.6	0
2037	25	Battery	2.19	2.6	2.01
2038	100	Solar	0	2.6	0
2038	100	Solar	0	1.03	33.6
2039	100	Solar	0	5.2	0
2039	100	Solar	0	2.6	0
2039	100	Solar	0	1.03	0
2039	25	Battery	2.19	2.6	0
Wyoming (WYO) Transmission Area					
2025	100	Wind	0	11.43	0
2025	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	11.43	0
2026	100	Wind	0	2.6	0
2026	100	Wind	0	2.6	0

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2027	100	Wind	0	2.6	0
2027	100	Wind	0	11.43	0
2031	100	Wind	0	2.6	0
2037	25	Battery	2.19	0.5	0
2037	25	Battery	2.19	0.5	0
New Mexico (NM) Transmission Area)					
2028	100	Wind	0	1.85	385.34
2029	100	Battery	2.19	2.6	0
2037	100	Wind	0	1.85	0

9 Base Case & Alternative Scenario Comparison

Comparison of Key Inputs

Table 105: Key Inputs Applied for Alternative Scenario Modeling

Scenario Name	Base Case	80pct CR V1	80pct CR V2, V3 & V4	Low Load 80pct CR V1	Low Load 80pct CR V2	Social Cost of Carbon
Load Forecast	May 2020 - Base	May 2020 - Base	May 2020 - Base	May 2020 - Low	May 2020 - Low	May 2020 - Base
Electric Price Forecast	May 2020	May 2020	May 2020	May 2020	May 2020	May 2020
Gas Price Forecast	May 2020	May 2020	May 2020	May 2020	May 2020	May 2020
Coal Price Forecast	2020	2020	2020	2020	2020	2020
Coal Retirement	Announced	Announced & Allowed	Announced & Allowed	Announced & Allowed	Announced & Allowed	Announced & Allowed
Generic Resources for new Energy Efficiency & Demand Response	Additional Low or Aggressive EE and/or Low DR Allowed to be Selected but not Forced	Forced Aggressive EE & Low DR additional resources in CO	Existing DSM/EE only	Additional Low or Aggressive EE and/or Low DR Allowed to be Selected but not Forced	Existing DSM/EE only	Forced Aggressive EE & Low DR additional resources in CO
RPS Level	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements	NM & CO Requirements
Carbon Reduction[17]	No Carbon Restriction	80%	80%	80%	80%	Restricted CO resources

[17] Amount of CO_2 reduction required from 2005 baseline in regards to serving wholesale electricity sales in Colorado.

Comparison by Location

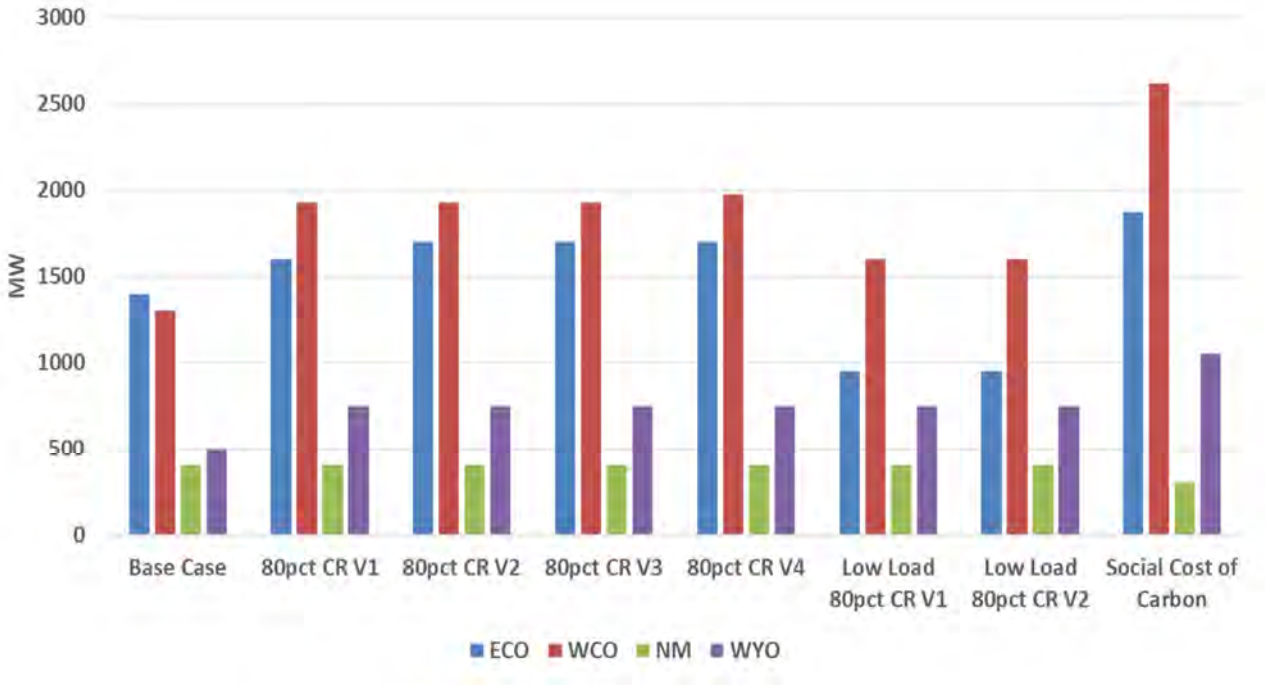

Figure 17: Resource Additions by Region for the RPP

Comparison by Technology

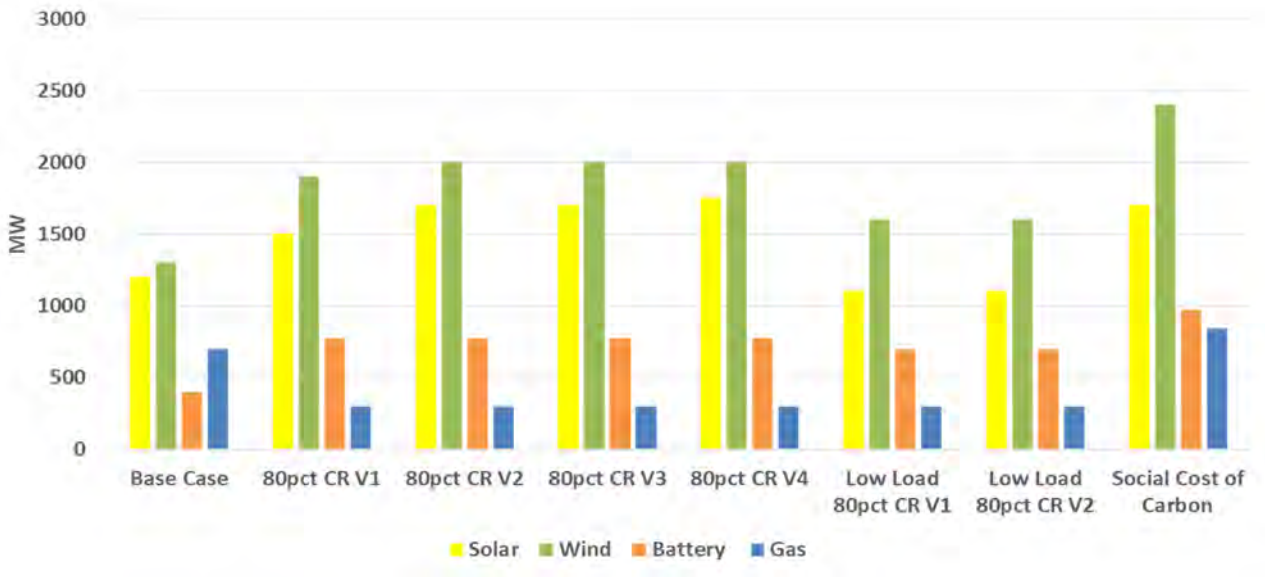

Figure 18: Resource Additions by Technology Type for the RPP

Comparison of Thermal Resource Retirements

All retirements show in first year offline.

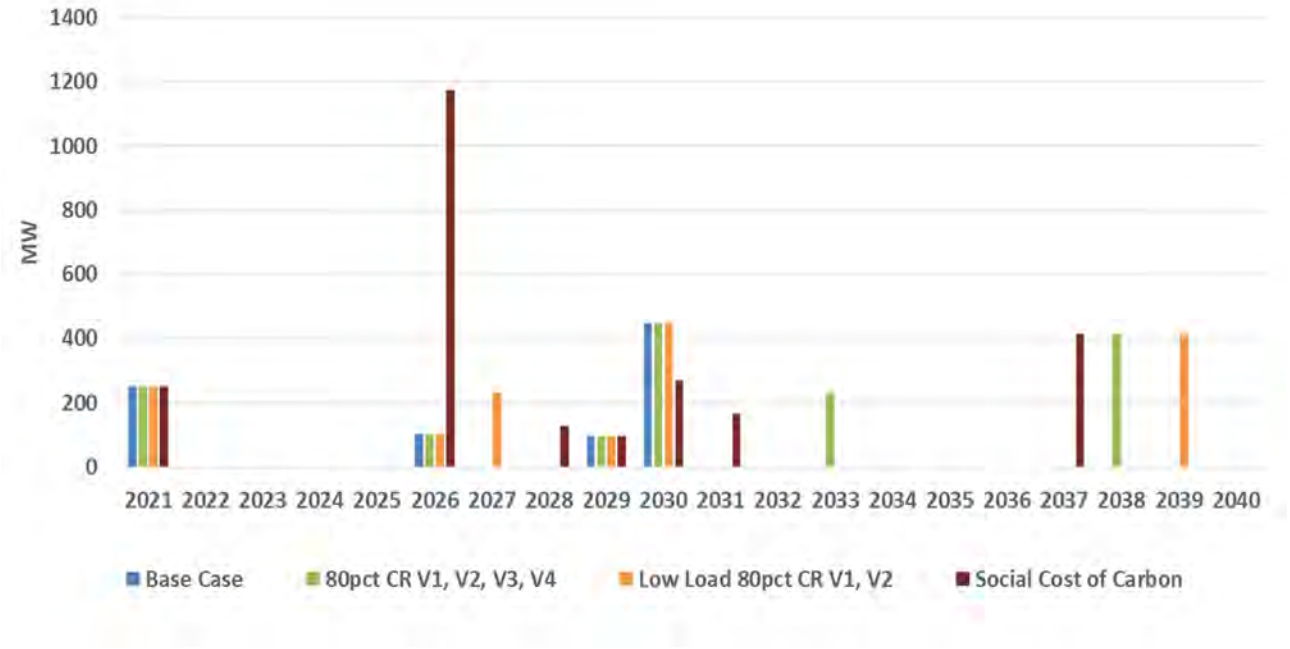

Figure 19: Thermal Retirement Comparison by Year

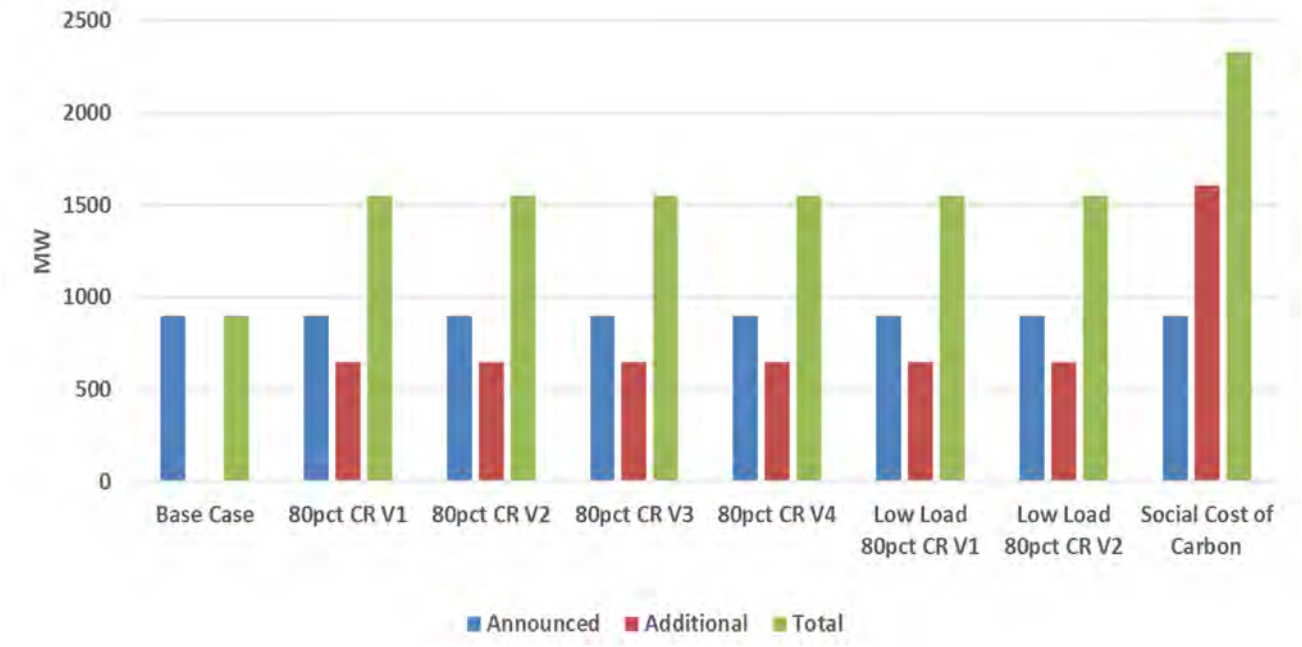

Figure 20: Thermal Retirement Comparison by Type for the RPP

Comparison of Planning Reserve Margins

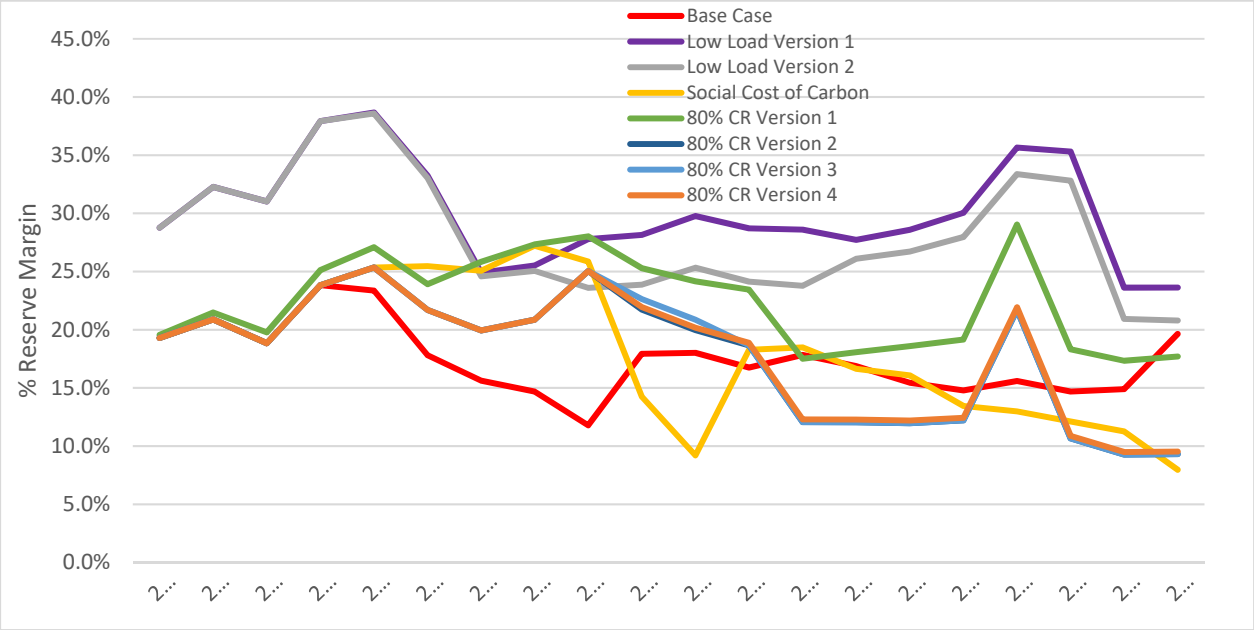

Figure 21: Comparison of Planning Reserve Margins

Social Cost of Carbon Comparison– System Wide (Nominal $)

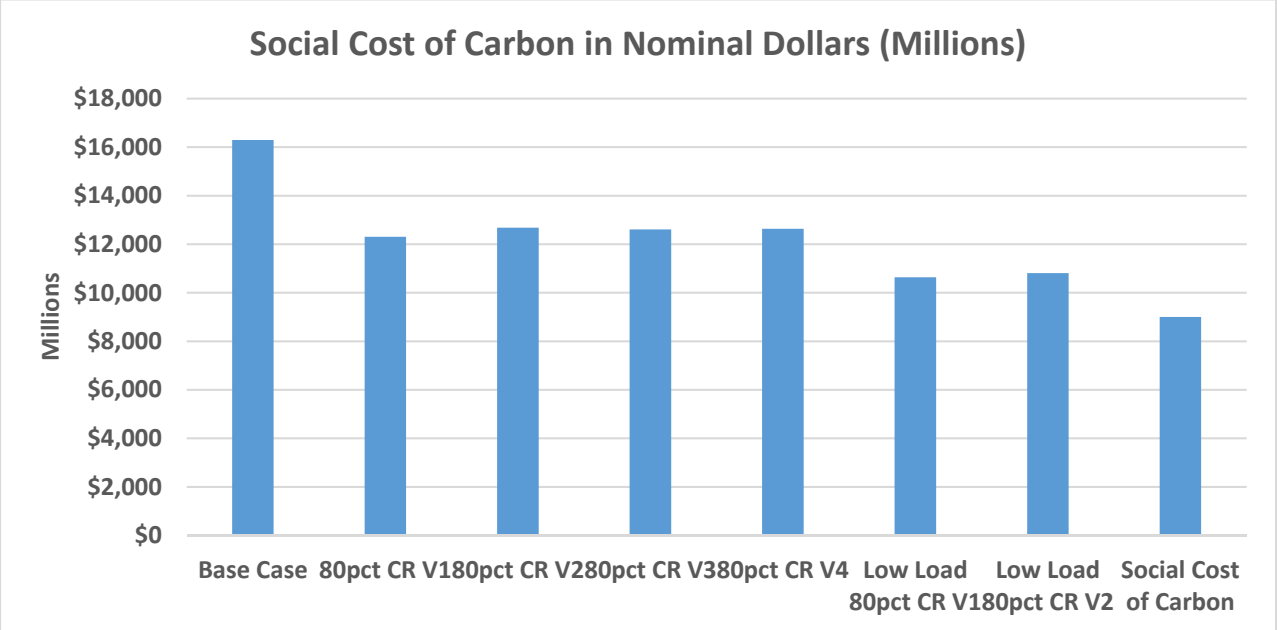

Figure 22: Comparison of Nominal Dollars for Social Cost of Carbon for the RPP

Comparison of CO2 Emissions & Reduction in Colorado in 2030

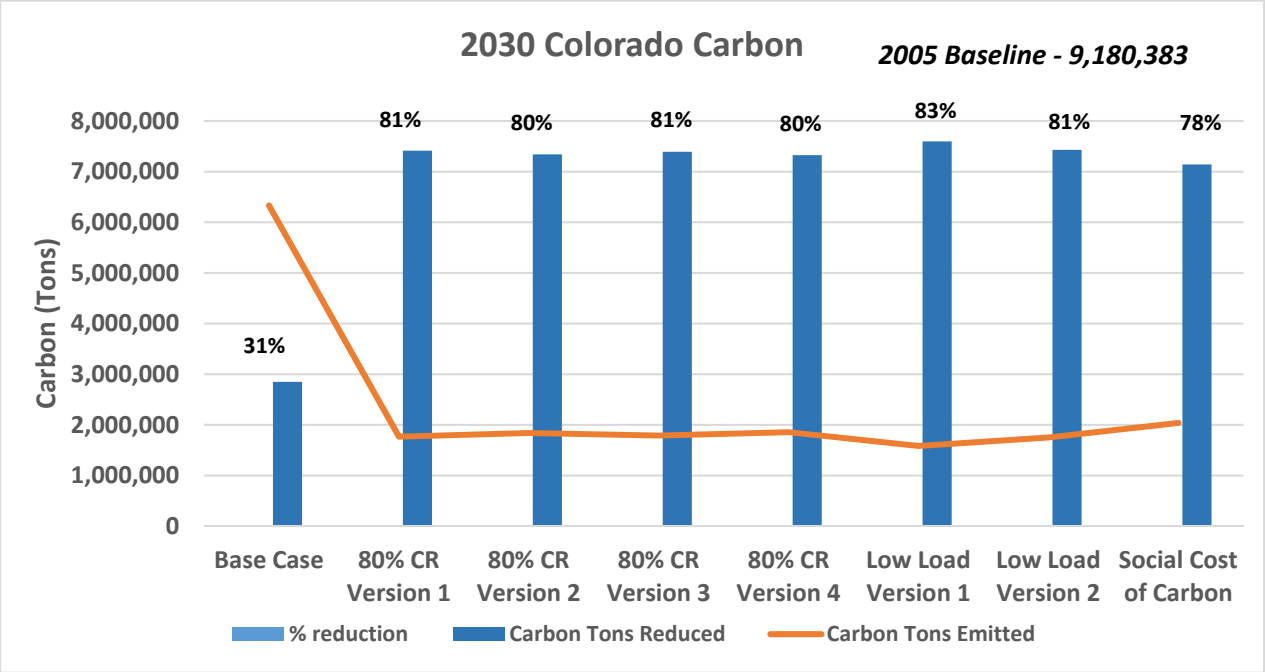

Figure 23: Comparison of Carbon Reduction in Colorado in 2030 (versus 2005 Baseline Levels)

Comparison of Significant Transmission Network Upgrades

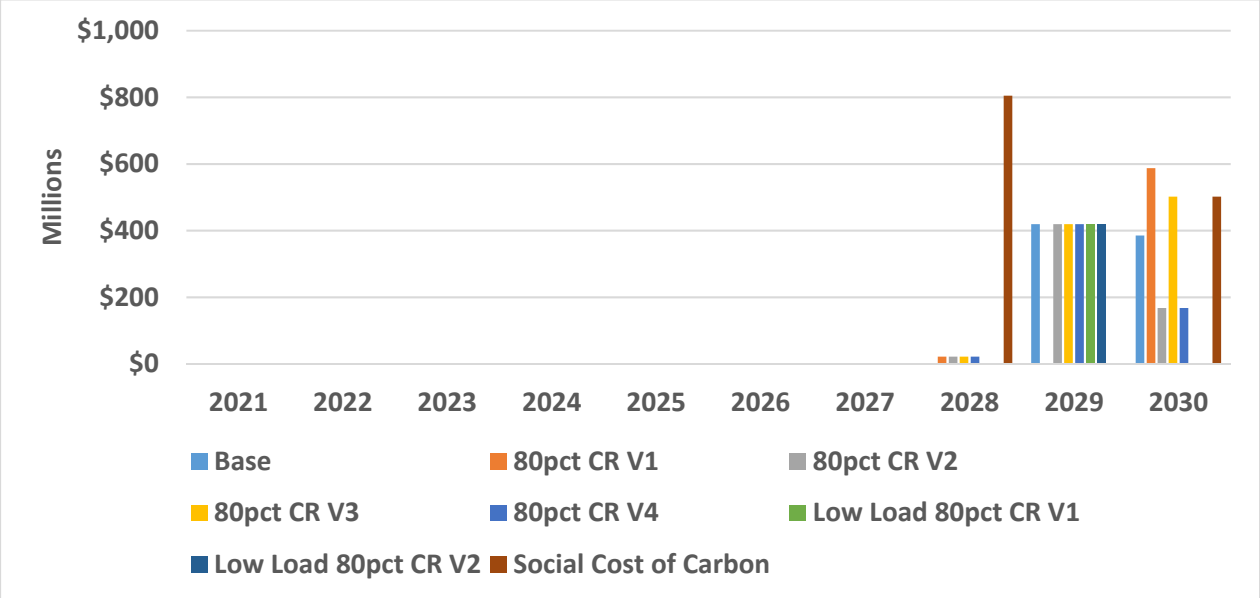

Figure 24 Significant Transmission Network Upgrades over RAP

Present Value Member Revenue Requirement Comparison (nominal dollars)[18]

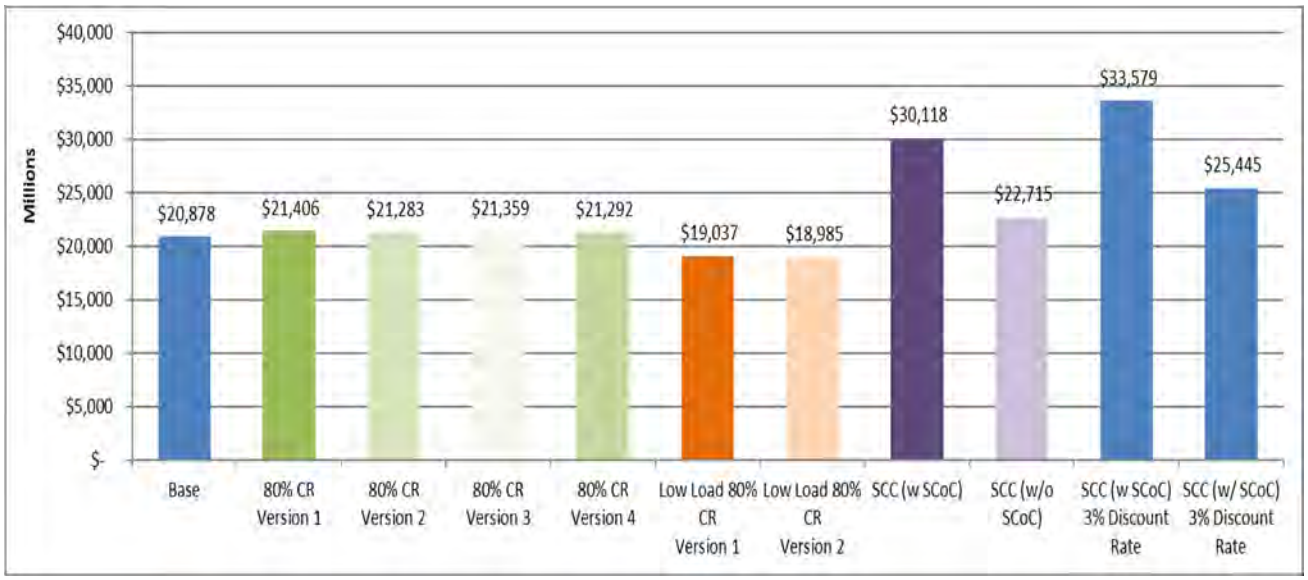

Figure 25: Comparison of Present Value Member Revenue Requirement over RPP

Expansion Plan Capex + IDC Comparison (nominal dollars)

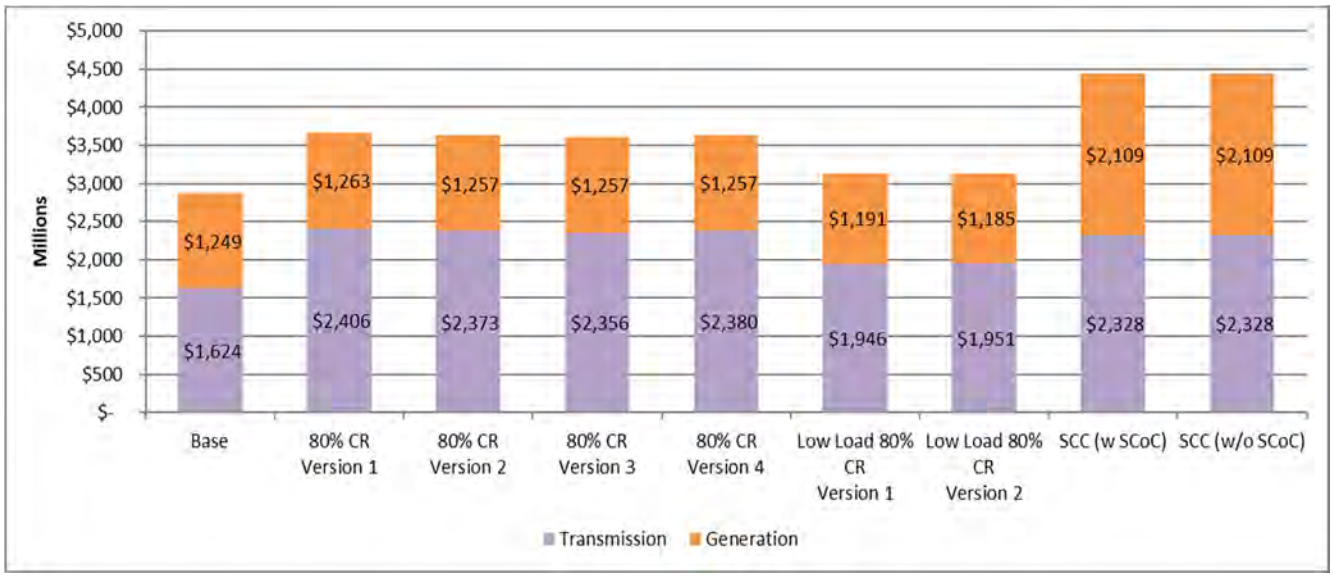

Figure 26: Comparison of Capital Expenditures and Interest During Construction over RPP

[18] A discount rate of 4.15% was used in calculating PVRR for all scenarios. An additional PVRR for the SCC scenario was calculated based on a 3% discount rate.

Emission & Water Usage Comparison System-Wide

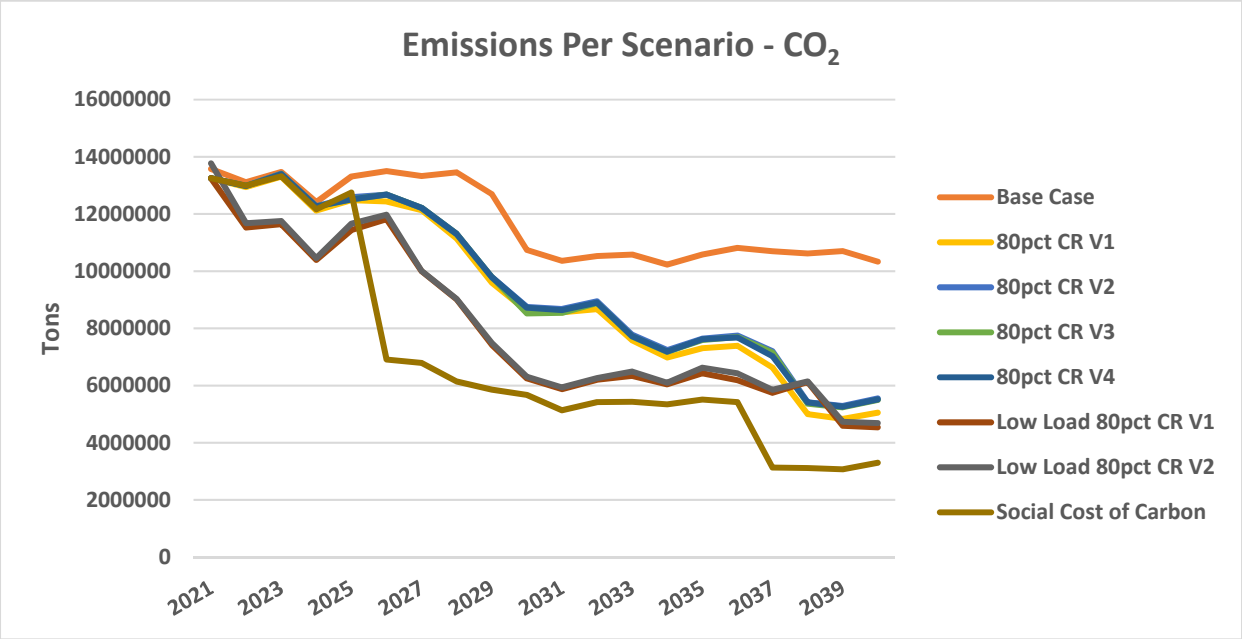

Figure 27: Comparison of CO_2 Emissions per Scenario

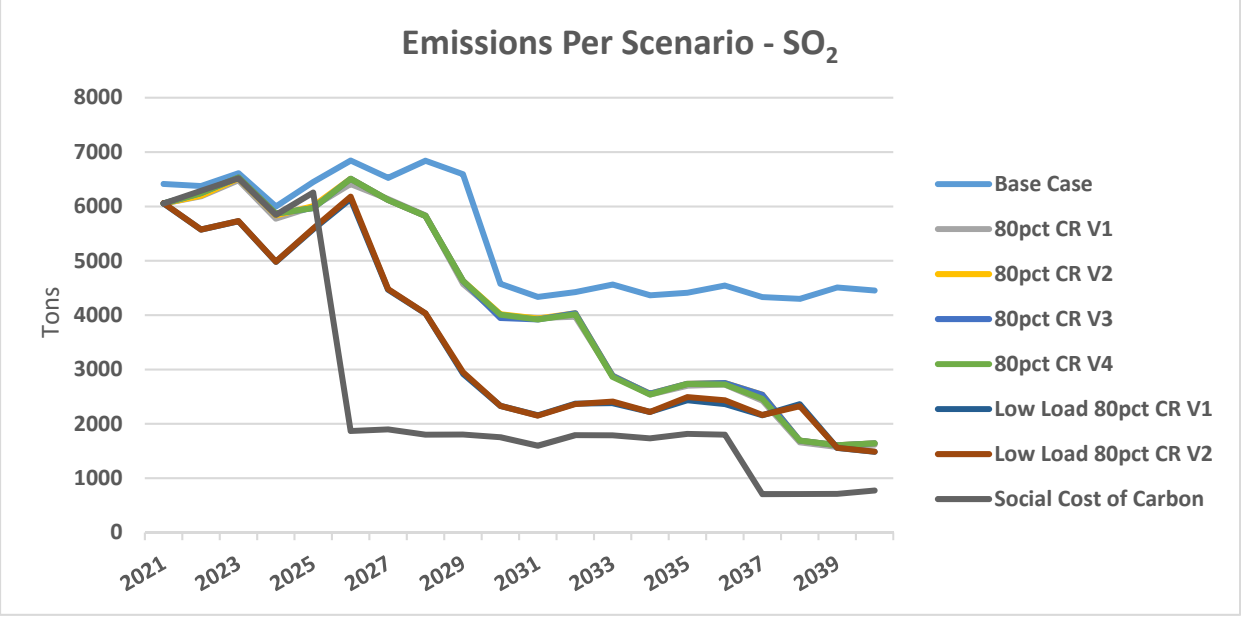

Figure 28: Comparison of SO_2 Emissions per Scenario

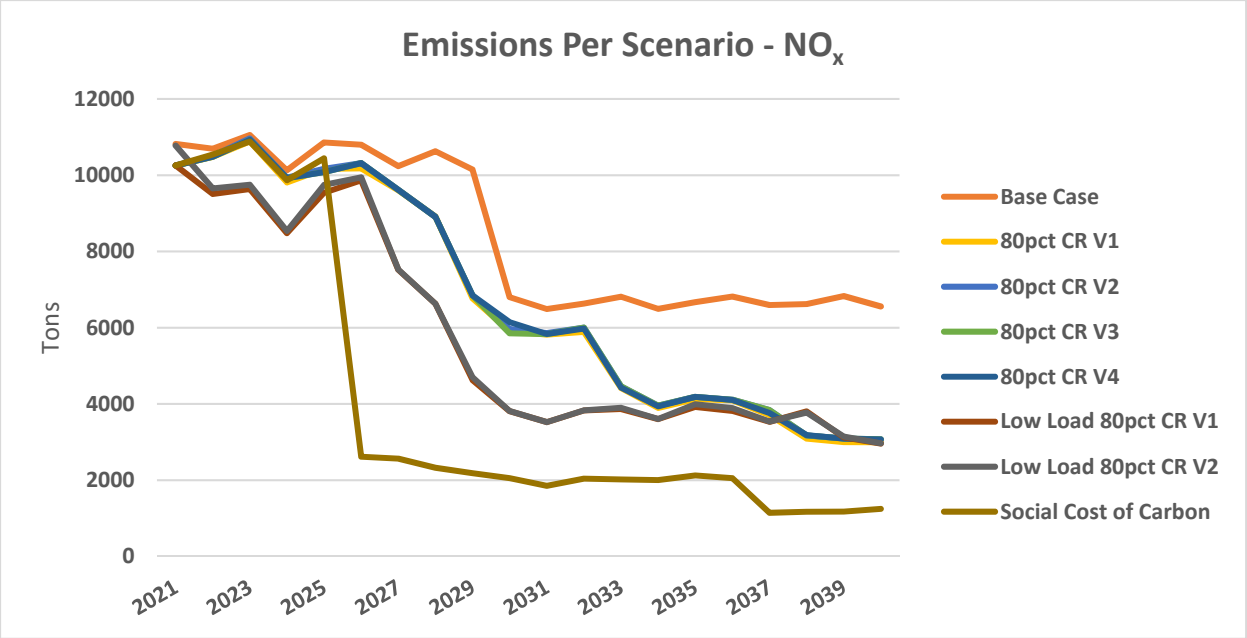

Figure 29: Comparison of NO_x Emissions per Scenario

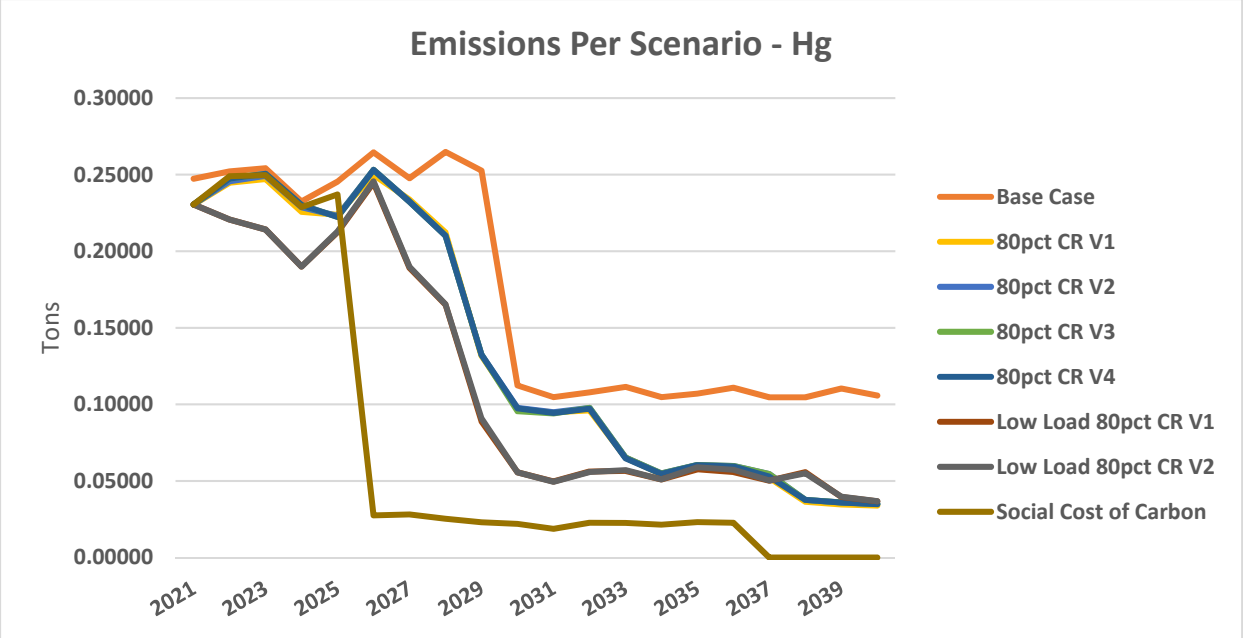

Figure 30: Comparison of Hg Emissions per Scenario

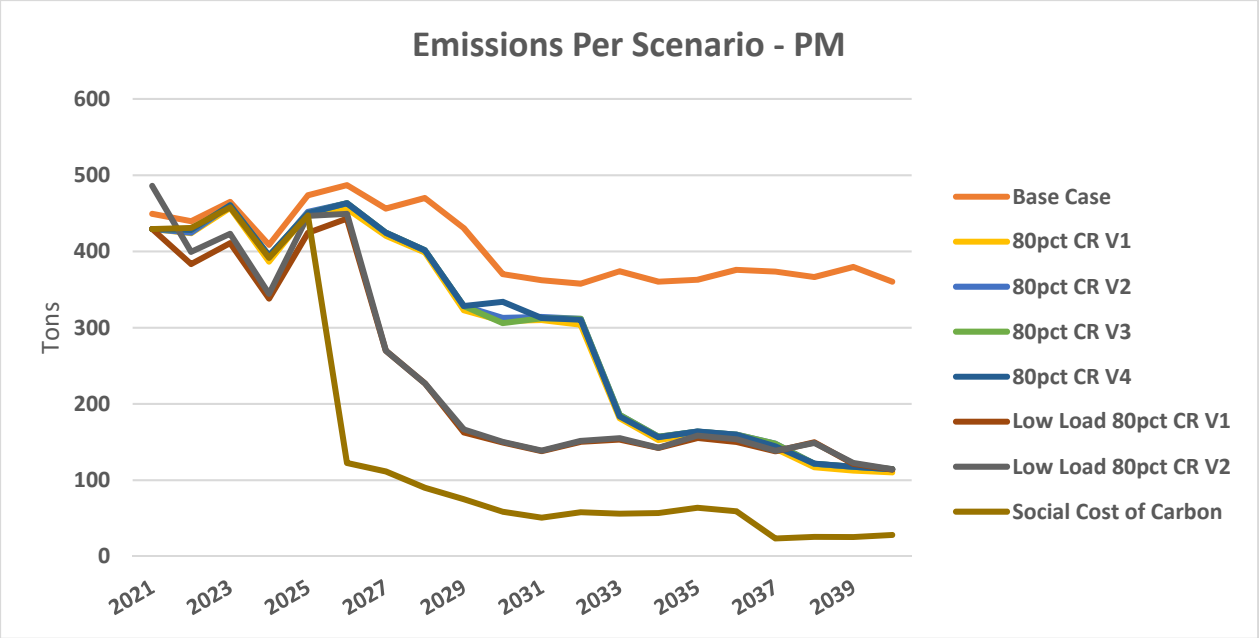

Figure 31: Comparison of PM Emissions per Scenario

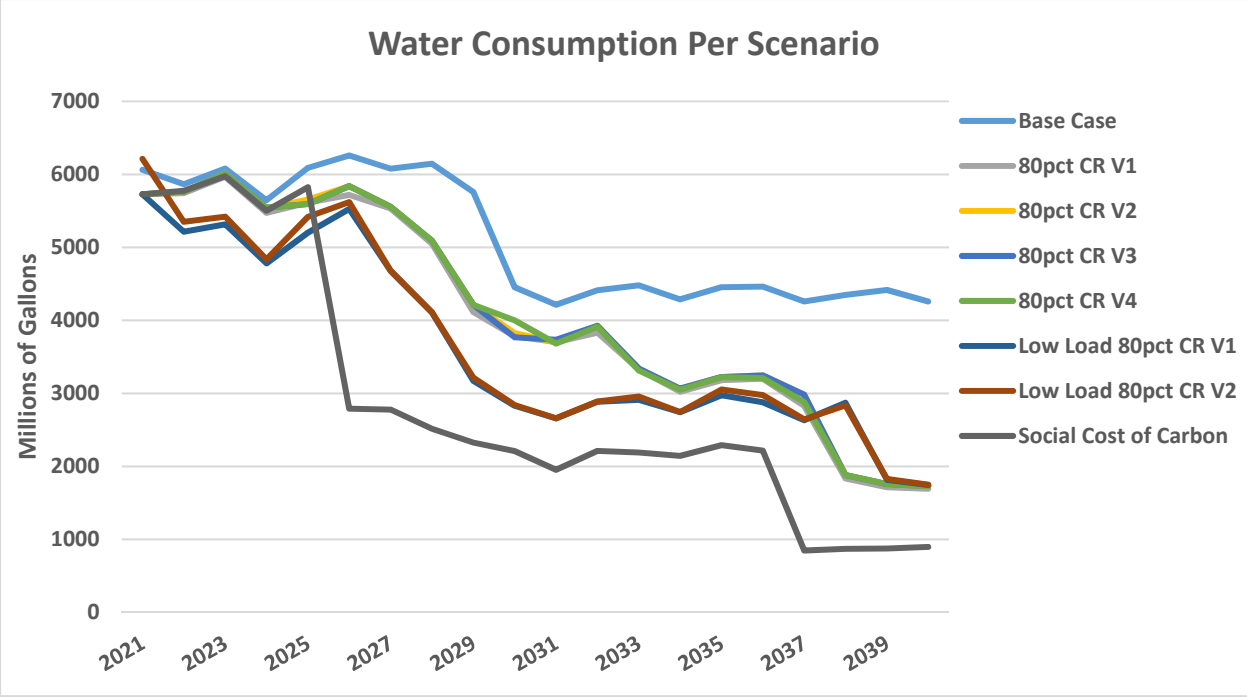

Figure 32: Comparison of Water Consumption per Scenario

RES/RPS Comparison

All scenarios fully meet Colorado RES and New Mexico RPS over the RAP. Data was checked both with contract energy profiles for existing and under contract, resources as stored in Hyperion for financial analysis and with the variable (intermittent) energy resource profiles as developed and used for dispatch in PO. Key drivers for meeting renewable energy or portfolio standards include retirement of thermal resources, significant planned addition of renewables and a focus on carbon reduction targets in the state of Colorado. See Attachment Vol II 6-2 RES/RPS for renewable standard evaluation of each scenario.

Diversity, Dispatchability, & Reliability Comparison

Tri-State applied a qualitative analysis to each scenario based on diversity, dispatchability and reliability defined as follows:

- Diversity is determined as having variability in fuel supply and location in resource mix.
- Dispatchability is determined as the operational ease of increasing or curtailing the resource mix as well as financial impact.
- Reliability is determined as a resource mix with strong ability to support the grid and flexibility in providing ancillary services

A score of 1 = Low, 2 = Medium and 3 = High.

Each alternative scenario scored high on diversity for both technology and location. All scenarios include varying levels of solar, wind, energy storage and gas resources and such resources are dispersed across the eastern Colorado, western Colorado, New Mexico and Wyoming regions within the model. The base case scores at a medium level on diversity due to a high quantity of thermal resources, both existing and generic. There are technical or economic feasibility limitations to the location of particular technologies within Tri-State's footprint. For instance, solar is technically feasible in western Colorado, but wind is not. Conversely, in Wyoming wind is more feasible than solar. The generic resource data set used for all scenarios reflected these feasibilities.

Dispatchability is highest in the base case as the expansion plan has a higher level of dispatchable resources allowing more ramping flexibility to handle the integration of intermittent resources. However, all GHG/CO_2 reductions scenarios have a reasonable level of dispatchability, as a significant portion of existing thermal resources, primarily gas, are retained in the plan along with the addition of a combined cycle gas resource and adequate amounts of energy storage. The SCC scenario retires significantly more thermal resources, but does add a larger quantity of expansion plan gas resources.

Reliability is the highest in the base case as the expansion plan includes a higher quantity of thermal resources, which historically have a greater capacity to support the grid in regards to reserves, regulation and voltage support. However, all GHG/CO_2 reduction scenarios have a reasonable level of retention of existing thermal resources along with addition of energy storage that will be used to help integrate renewables in a transitioning grid.

Table 106 illustrates the base case and scenario ranking in all three of these areas.

Table 106: Diversity, Dispatchability & Reliability Scoring

Scenario	Diversity	Dispatchability	Reliability	Total Score
Base	2	3	3	8
80% CR V1	3	2	2	7
80% CR V2	3	2	2	7
80% CR V3	3	2	2	7
80% CR V4	3	2	2	7
Low Load 80% Carbon Reduction V1	3	2	2	7
Low Load 80% Carbon Reduction V2	3	2	2	7
Social Cost of Carbon	3	2	2	7

Comparison Summary

The Base Case and seven alternative scenarios all share assumptions such as the same generic resource data set, commodity pricing, and announced coal retirements. Assumptions varied between scenarios in regards to DSM/EE, allowable thermal retirements, build limits by technology and location, transmission links and GHG/CO_2 reduction levels and/or costs.

All scenarios had a reasonable mix of solar, wind, energy storage and gas. The Base Case and SCC scenario had the most gas additions, but this is primarily due to a restriction on all other scenarios to meet GHG/CO_2 reduction goals in the state of Colorado. The SCC scenario also had significantly higher quantities of thermal resource retirements resulting in additional expansion plan gas resources. Energy Storage becomes increasingly more competitive across the RPP. Renewables begin and remain competitive throughout the RPP.

All scenarios to some extent utilize transmission interconnection capacity made available by thermal retirements. All plans show considerable resource additions in WCO due to the transmission capacity that will become available through the retirement of the Craig facility. Tri-State's primary transmission constraints resulting in a need for network upgrades occur in ECO. The ECO load area represents a significant portion of Tri-State's system load and most long-term load growth is focused in this area.

Retirement of existing thermal resources vary by scenario with SCC showing the highest volume of retirements. Announced retirement dates are included in all scenarios, and all scenarios except for the Base Case allow additional coal retirements starting in either 2025 or 2026. This timing limit allows for a reasonable timeframe for replacement decisions and acquisition of replacement resources. The SCC scenario also allows gas retirements.

Planning Reserve Margins (PRM) primarily run high between ~15% to ~25% during the RAP. Spikes are seen when thermal retirements occur and additional resources are brought on. The elevated PRM is due to the low energy cost of renewables coupled with lower capacity credits for renewables than their thermal counterparts as well as the semi-dispatchable nature of energy storage.

The Base Case shows GHG/CO_2 reduction of 31% in the state of Colorado as measured against a 2005 baseline. All other scenarios have GHG/CO_2 reductions in the state of Colorado as measured against a 2005 baseline of ~80%. System wide emissions and water usage are significantly reduced for all scenarios over the RAP. The calculated SCoC is the lowest in the SCC scenario but is also substantially reduced from

the base case in all 80% CR (base and low load) scenarios. The overall environmental impact of GHG/CO_2 reduction in all alternative scenarios is significant.

All scenarios easily meet Colorado and New Mexico RPS/RES requirements. This is driven by both the competitiveness of renewable resources as well as the GHG/CO_2 restrictions to meet state of Colorado goals.

As more thermal retirements result in fewer dispatchable resources on the bulk electric system. Tri-State has concerns about potential financial impacts driven by Balancing Authority alternative steps to continue to secure the reliability of the grid. While all of these scenarios have a reasonable diversity, dispatchability, and reliability mix from a planning perspective, it is critical for Tri-State to be aware of resource mix changes occurring in relation to the actions of other utilities in the Rocky Mountain and Southwest regions and to step into changes to resource mix in a responsible manner to ensure reliability and financial stability for Tri-State's Utility Member Systems. A representation of this regional impact can be seen in Figure 33.

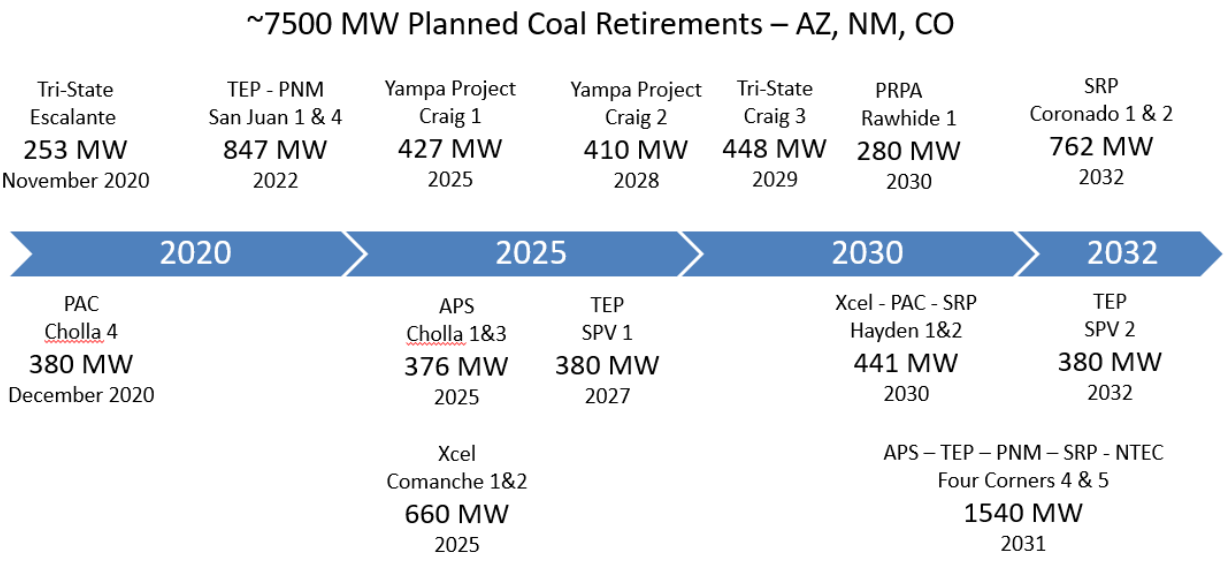

Figure 33: Planned Coal Retirements in Arizona, New Mexico and Colorado

10 Summary of Preferred Plan

In assessing the Base Case and Alternative Scenarios, Tri-State has selected the 80% CR V4 scenario as its preferred plan. Primary reasons for this selection include:

- Generation locations and technology diversity, as illustrated in Figure 34 are sufficient to fully utilize interconnection capability made available from announced retirements.
- Forecast additional thermal retirements projected to occur after the RAP as shown in Figure 35 and in addition to announced retirements during the RAP, allow a manageable transition to zero carbon resources while maintaining reliability and affordable rates.
- Transmission system network upgrade costs are minimized during the RAP compared to the base case.
- The PVRR for the RPP is ~$400M higher than the Base Case while achieving the state of Colorado GHG/CO_2 reduction target of 80% GHG/CO_2 reduction by 2030 from a 2005 baseline.
- Overall emissions and water usage are significantly reduced by 2030 from current levels and are significantly lower than in the Base Case.
- The scenario uses a glide path from 2025 to 2030, as illustrated in Figure 36, for carbon reduction goals in the state of Colorado to achieve meaningful reductions in the near term.

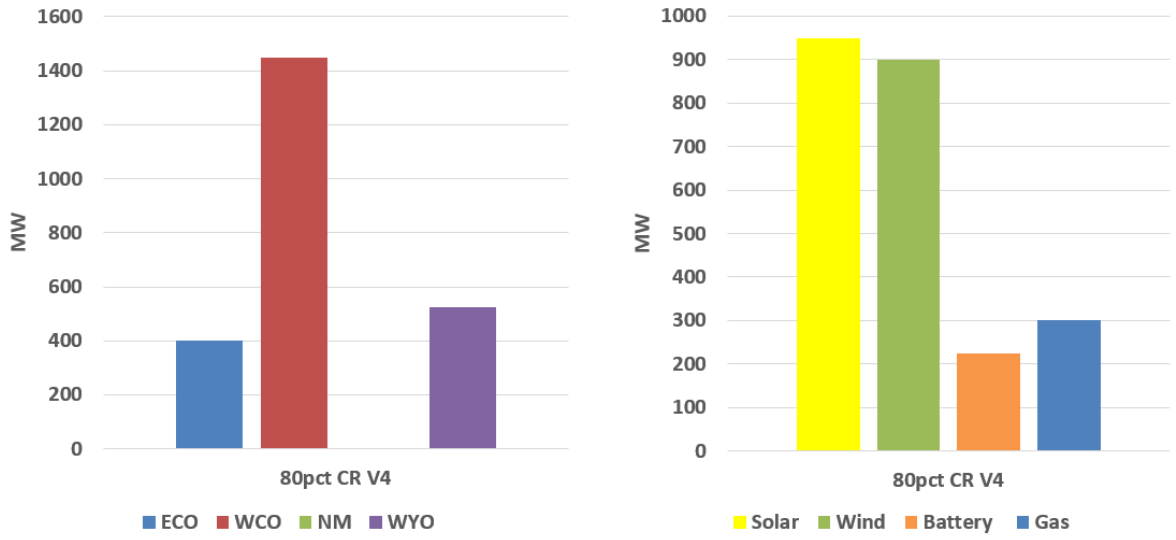

Figure 34: Preferred Plan Resource Additions over the RAP

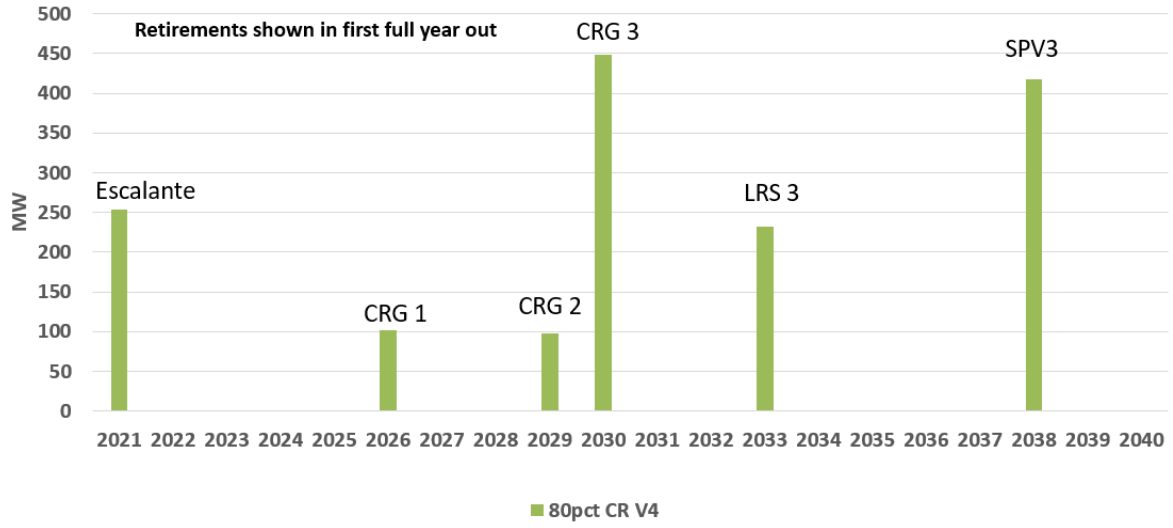

Figure 35: Preferred Plan Announced & Proposed Retirements

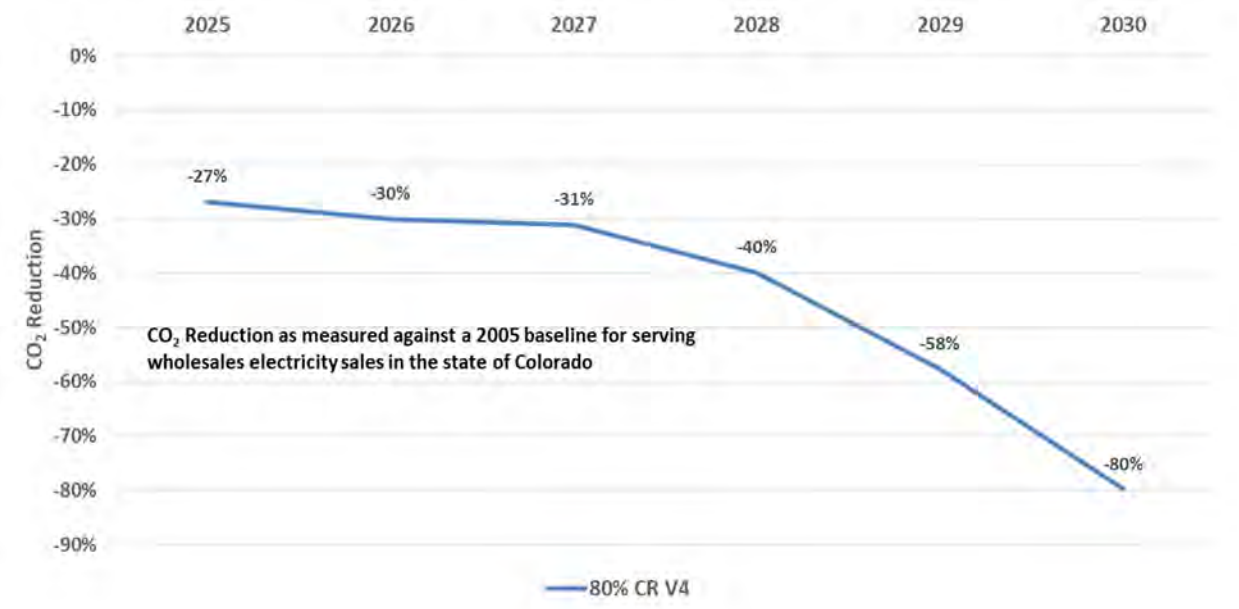

Figure 36: Glide Path to 80% CO_2 Reduction in 2030 from 2005 Base (Serving electricity sales in Colorado)

While this particular scenario does not include increases in DSM as an expansion plan resource, Tri-State is actively working on expanding DSM and EE programs to the extent Utility Member Systems are interested. As these programs are developed and expanded the resulting decrease to capacity needs in relevant years may affect future expansion plans. This scenario like all scenarios has a significant transmission capital expense component. As future resource plans are developed through the Commission ERP and WAPA IRP processes, Tri-State will continue to investigate ways to incorporate higher quantities of renewable resources while limiting transmission expense including the need for

network upgrades. DSM and EE as well as the expected move of some Utility Member Systems from all requirements contracts to partial requirements contracts driven by the desire to serve retail load with more distributed generation will help this effort and will continue to be explored in Tri-State's 2023 ERP.

This scenario retires thermal generation and replaces it primarily with renewables along with some energy storage and one 300 MW gas resource. The evolution of the grid away from thermal dispatchable resources to intermittent resources creates the potential for reliability and financial uncertainty, but the preferred plan takes a measured approach to minimize this risk.

11 Resource Acquisition Period - Action Plan

Action Plan Items

Tri-State's Action Plan covers the period of 2021 to 2030 (RAP). Items will be addressed as necessary between the Phase I final ruling and the next Colorado ERP filing, which is June 1, 2023. Tri-State will file annual updates to this Resource Plan and related Action Plan items with the Commission and WAPA.

Phase II Capacity Need:

Tri-State's base case scenario indicates a capacity need in 2029. In order to meet near term emissions reductions additional renewable resources are forecast for deployment in the preferred plan during the RAP. Table 107 identifies resources by location, nameplate capacity, technology and year, as determined in the preferred plan.

Table 107: Preferred Plan Resources during RAP

Location	Capacity (MW)	Technology	Year
East Colorado	100	Wind	2025
Wyoming	100	Wind	2025
West Colorado	200	Solar	2026
Wyoming	100	Wind	2026
West Colorado	100	Solar	2027
West Colorado	200	Solar	2028
Wyoming	100	Wind	2028
West Colorado	200	Standalone Battery	2029
West Colorado	200	Solar	2029
East Colorado	100	Wind	2029
Wyoming	100	Wind	2029
Wyoming	25	Standalone Battery	2030
West Colorado	300	Natural Gas - Combined Cycle	2030
West Colorado	250	Solar	2030
East Colorado	200	Wind	2030
Wyoming	100	Wind	2030

Given the uncertainty related to Tri-State load in the near term, Tri-State anticipates that its initial Phase II process will focus on resource needs by 2025, as indicated by the shading in Table 107. We anticipate that resources needed for the period from 2026 to 2030 will be addressed in the June 1, 2023 ERP or subsequent ERPs.

By 2023, we will have better information regarding potential load reductions that could reduce capacity needs after 2025. In addition, while the RAP extends from 2021 to 2030, Tri-State is reluctant to engage in activities to add conventional thermal resources (300 MW natural gas combined cycle in 2030) without allowing time for emerging technologies that provide equally reliable capacity, but with lower emissions, to become competitive.

Milestone – Tri-State intends to procure all resources in the preferred plan through 2025 as part of a competitive bidding process in Phase II. The start of Phase II will be dependent upon the timing of Phase I and the overall direction or the Commission. Tri-State plans to update progress on this item each year in its required IRP and ERP APR process.

Utility Member System Programs:

Tri-State plans to use the DSM EE Potential study produced by Mesa Point Energy and included as Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study as a starting point from which to work with Utility Member Systems to establish additional DSM and EE programs over the RAP.

Tri-State plans to use the BE study produced by Mesa Point Energy and included as Attachment Vol II 5-7 Beneficial Electrification Potential Study as a guide from which to work with Utility Member Systems to establish BE programs over the RAP.

Milestone – Tri-State plans to update progress on this item each year in its required IRP and ERP APR process. Established programs with forecast growth will be utilized in the modeling for the June 1, 2023 IRP/ERP process.

Retirement Analysis:

With the announced retirement dates of Springerville Unit 1 and Springerville Unit 2, Tri-State plans to engage in discussions with SRP, the owner of Springerville Unit 4, as well as other parties necessary to determine the impacts on Springerville Unit 3 for future resource planning.

While the preferred plan indicates a retirement of LRS Unit 3 by 2033, we note that there is no agreement in place to that would be required to implement this retirement with the co-owners of the Missouri Basin Power Project. Modeling performed under the preferred plan showed that the continued operation of both LRS Unit 2 and Unit 3 at levels needed to satisfy and maintain an 80% CO_2 reduction in Colorado would not be economic, which is why the preferred plan reflects a retirement of LRS Unit 3.

Milestone – Tri-State plans to update progress on this item each year in its required IRP and ERP APR process. Tri-State will incorporate relevant changes in its modeling for the June 1, 2023 IRP/ERP process.

Model Improvements:

Tri-State plans to modify its current modeling software or replace if necessary, in order to improve modeling items prior to June 1, 2023 ERP. Key items slated for modeling improvement include but are not limited to: ability to handle emission reductions on a state-by-state basis in a robust manner, ability to model sub-hourly effects, more robust modeling of intermittent resources, streamlined management of transmission capex impacts, and improved treatment of intermittent resource curtailments.

Milestone – Tri-State plans to begin efforts for modeling software replacement or improvements in 2021 with completion in 2022 in time to begin the modeling for the Jun 1, 2023 IRP/ERP process.

Phase II Competitive Bidding Process & Criteria

A Request for Proposals (RFP) will be released soon after the issuance of the Commission's final Phase I decision approving and/or modifying Tri-State's ERP application. In support of this RFP, Tri-State has prepared competitive bidding documents organized as a single, all-source RFP seeking proposals for three different resource types. The RFP focuses on Power Purchase Agreements (PPA) as the likely transactional structure and does not contemplate any utility build or ownership options at this time.

The Phase I decision will define the scope of the RFP. As a result, this competitive bidding process description and RFP documents may be modified or supplemented as necessary to conform to the Commission's Phase I decision.

The RFP currently identifies three distinct categories of resources Tri-State will consider for resource additions.

1. Renewable Resources - All intermittent renewable and carbon-free resources without co-located storage whose pricing will be offered on an annual energy-only price. This includes, but is not limited to, wind and solar, hydroelectric, geothermal, biomass, and in Colorado, recycled energy or eligible coal-mine methane.

2. Semi-Dispatchable Resources - All stand-alone energy storage systems or resources coupled with storage systems that are limited in the amount of energy delivered during a particular cycle. This includes, but is not limited to, stand-alone battery systems, pumped hydro, compressed air energy storage systems as well as renewable resources with co-located thermal or battery storage.

3. Firm Capacity Resources - New or existing gas generation or any other resource that can be dispatched by Tri-State for a reasonable amount of time without any restriction on duration at the rated maximum capacity threshold. Renewable or carbon-free resources such as hydroelectric, biomass, and geothermal capable of this requirement may be bid into this resource type. Resources that include carbon capture technologies may be considered under this category as well.

RFP Documents

The RFP documents will be posted on the Tri-State website when the RFP is released. Any confidential or highly confidential information will be made available in accordance with a nondisclosure agreement as directed by Rule 3605(g)(II)(G)(iv) and which form is filed in an appendix to this ERP.

1. **RFP** – Announces the solicitation for resources. Provides a general description of Tri-State's system, outlines proposal submittal deadlines and other key dates in the evaluation schedule, identifies the required contents of a proposal, provides evaluation criteria, describes the resource types, contract terms, and minimum project size Tri-State is seeking. The RFP also includes contact information for submitting questions about the process.
2. **Model Contracts** - Developed for each of the resource type categories and that reflect Tri-State's expected PPA terms and conditions.
3. **Form Nondisclosure Agreement (NDA) -** Rule 3605(g)(II)(G)(iv) requires that bidders be provided with an NDA necessary for gaining access to confidential and highly confidential modeling inputs and assumptions filed in the Docket.
4. **Voluntary Consent Agreement** - Requests that entities proposing projects interconnecting with the Tri-State transmission system provide consent to allow the merchant function to communicate with the interconnection administrator (Tri-State Transmission function) regarding the project or projects submitted into the RFP.
5. **Bidder Response Forms** - These forms are in Microsoft Excel format with multiple tabs that request key data related to each proposal to allow Tri-State to evaluate each project and option offered.

Bid Fee

A non-refundable bid fee of $5,000 will be required. The bid fee is applicable to a single project location and single project technology. A bidder may propose up to three different combinations of pricing, contract term, size or commercial operation date options for a single project without having to submit an additional fee. Projects that are proposed with additional technology options (i.e., wind + solar or solar + battery storage) or different interconnection points will be considered different projects requiring an additional bid fee. Failure to submit the required bid fee will result in a proposal being disqualified from further evaluation.

RFP Release through Receipt of Bids

Pursuant to Rule 3605(g)(III)(D), the Phase I Decision will establish the deadline for the submittal of the ERP Implementation Report that will detail the cost-effective resource portfolios to be presented to the Commission. Given this deadline and the necessary time to fully evaluate the proposals submitted into the RFP and model various resource portfolios, the RFP will be issued to allow bidders approximately six weeks to submit their proposals to Tri-State.

Tri-State will send an email to all developers who have submitted proposals to past Tri-State RFPs to notify them when the RFP is released, as well as sending an email to developers or other entities that have contacted Tri-State since the last RFP and requested notification of future RFPs. Tri-State will announce the RFP release on its corporate website, as well as maintain a dedicated area on its website where the RFP, Commission Orders and other related documents will be posted.

Tri-State will ask bidders to submit a Notice of Intent to Bid (NOI) form (which will be located on the RFP website) within two weeks of the RFP being issued. This is not a mandatory step for bidders to participate in the RFP, but bidders will be encouraged to submit the NOI by the deadline.

Tri-State will answer questions from prospective bidders by posting and regularly updating a Q&A on the RFP website during the period after the RFP is released and before the proposal submittal deadline. This Q&A is intended to benefit all potential bidders and provide for efficient use of Tri-State staff time in providing answers to bidders that may have similar questions. In answering questions, care will be taken not to include identifying information about the bidder or project.

On or prior to the proposal due date, bidders will submit their proposals, bidder response forms, model contract comments, NDAs, and, if applicable, a voluntary form of consent electronically by email through the dedicated RFP email address, as well as ensure that a hard copy of the proposal has also been delivered. Bid fees are to be sent to Tri-State via check or wire transfer.

Upon receipt, Tri-State will ensure that proposals are complete. This includes having received both a hard and electronic copy of the proposals and associated documents, and the appropriate amount of bid fees. If any initial oversight or discrepancy is found, the bidder will be promptly notified and will be given the opportunity to immediately correct the issue.

Bid data will be imported and verified utilizing the bidder response forms. Each proposal and project option will be given the same attention and evaluated individually. The bid data will then be reviewed for completeness to identify any apparent bad data or misunderstandings. If any corrections or additional data are required, Tri-State will notify the bidder within 14 days of the receipt of the proposals.

Analysis of Bids

An initial economic analysis will be conducted where the Levelized Cost of Energy (LCoE) for each project option is calculated using the discount rate approved by the Commission in its Phase I decision. The LCoE will be calculated by determining the “all in” Net Present Value (NPV) of the average annual costs divided by the NPV of the average annual energy.

Projects will be categorized by technology within each resource type, commercial operation date, contract term, size, and location in order to ensure a meaningful comparison and analysis.

Projects will then be reviewed with respect to non-price factors. These will include the following:

- Best Value Employment Metrics
- Contribution to meeting GHG reduction goals of Colorado
- Location in a Tri-State utility member system service territory
- Financial viability of the bidder, including its parent or any other guarantor of services under the bidder's proposal

- Bidder's prior experience with project development
- Certainty of outside funding sources (i.e. tax credits or government subsidies)
- Compliance with all applicable local, state and federal laws, rules and orders
- Renewal and purchase options at the end of PPA
- Project retirement / decommissioning plan
- Legal, engineering and other costs required to implement the proposed project
- Forecasting capability

Tri-State may consider other factors that it deems to be relevant to its supply portfolio needs.

Following the initial analysis of projects on price and non-price factors, projects will then be evaluated with respect to transmission interconnection and network upgrade costs. Bidders are expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid.

Following the analysis noted above, Tri-State may contact bidders with questions and requests for clarifying information, including a request to update or refresh pricing.

Short List, Modeling, Portfolio Analysis

Following the interconnection and transmission costs review, certain projects will be advanced to the Resource Planning Modeling group for development of resource portfolios utilizing a capacity expansion planning model, a production cost model, and financial models. The expansion planning and production cost modeling will take advantage of the detailed project data provided by bidders to better determine an overall system dispatch cost in the context of serving forecast load on the Tri-State system and the financial models will incorporate additional corporate data to determine the Net Present Value Revenue Requirement of each portfolio.

The modeling process will culminate in various resource portfolios, which together with a discussion of the non-price factors, will be included in an ERP Implementation Report to be filed as directed by the Phase I decision. The report will present various cost-effective portfolios comprised of projects bid into the RFP.

Project Agreement Negotiations and RFP Conclusion

Based on a final Commission Phase II Decision giving approval of a portfolio and potential back-up bids, Tri-State will complete its contract negotiations to implement the approved plan. Contingent on the final Phase II Decision, Tri-State may choose to commence contract negotiations after submitting its ERP Implementation Report.

Once agreement is reached on key terms, a contract will be signed if all terms are within the scope of the approval granted by the Commission and the Tri-State Board of Directors.

Once all contracts are finalized and the RFP has concluded, Tri-State will provide feedback to any bidder whose projects were not selected in the RFP process that has requested such feedback. This usually takes place on a phone call, but could occur in person or by email. Further, pursuant to 3605(h)(III) and (IV) Tri-

State will file a proposal to refile all confidential and highly confidential information related to the bids as well as post this information to the website.

ERP Implementation Report Plan

Tri-State proposes to include the following information in its Phase II ERP Implementation Report:

Proposed Resource Information

- Name of Bidder
- Project Name
- Location of Resource
- Resource Technology
- Nameplate Rating of Resource
- In-Service Year
- Contract Term
- Interconnection Point
- Interconnection Costs
- Levelized Cost of Energy
- Storage Capacity (if applicable)
- Storage Duration (if applicable)

Proposed Portfolio Information

- PVRR with and without SCoC
- Generation and Transmission CapEx
- Timing and location of network upgrades if applicable
- CO_2 reduction in Colorado in 2030 from a 2005 baseline
- SCoC totals by portfolios (Total emissions times SCoC)
- Planning Reserve Margin
- Emissions and Water Usage

12 Confidential and Highly Confidential Information

Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this ERP Filing and which Tri-State has designated as confidential information:

- Scheduled Outage Plan (Maintenance)

Highly Confidential Information

Tri-State believes the following information requires extraordinary protection as highly confidential information:

- Fixed O&M expenses
- Variable O&M expenses
- Coal contract pricing and forward curve
- Unit specific capital balances, depreciation, amortization, impairment and decommissioning
- Contract/PPA energy rate, except in regards to Tri-State's LAP and CRSP hydropower purchase contracts with WAPA.
- Contract/PPA capacity rate, except in regards to Tri-State's LAP and CRSP hydropower purchase contracts with WAPA.
- Performance or operating output guarantees and any associated pricing adjustments included in Tri-State' Renewable PPAs
- Any information protected by a confidentiality clause in a PPA.
- Load forecast information at the Utility Member System level
- Renewable PPA and build transfer pricing for generic resources based on B&V proprietary model.

List of Acronyms

ACE	Affordable Clean Energy Rule
APR	Annual Progress Report
ARIMA	Auto Regressive Integrated Moving Average
BA	Balancing Authority
BE	Beneficial Electrification
BEPC	Basin Electric Power Cooperative
BHCE	Black Hills Colorado Electric, Inc.
BHCT	Black Hills Colorado Transmission
B&V	Black & Veatch
CAISO	California Independent System Operator
CE	Capacity Expansion
CO_2	Carbon dioxide
CR	CO_2 Reduction
CRN	Cooperative Research Network
CRSP	Colorado River Storage Project
CSU	Colorado Springs Utility
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
ECO	Eastern Colorado
EE	Energy Efficiency
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERPI	Electric Research Power Institute
ERP	Electric Resource Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
Hg	Mercury
IRP	Integrated Resource Plan
ISO	Independent System Operator
LAP	Loveland Area Projects
LAPT	WAPA Rocky Mountain Region Loveland Area Projects
LCoE	Levelized Cost of Energy
LGIP	Large Generation Interconnection Process
LOLP	Loss of Load Probability
LRS	Laramie River Station

MBPP	Missouri Basin Power Project
MCP	Member Coincident Peak
M-RETS	Midwest Renewable Energy Tracking System
NERC	North American Reliability Corporation
NO_x	Nitrogen Oxides
NRECA	Nation Rural Electric Cooperative Association
NREL	National Renewable Energy Laboratory
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
PM	Particulate Matter
POI	Point of Interconnection
PR	Partial Requirements
PPA	Power Purchase Agreement
PSCo	Public Service of Colorado
PNM	Public Service of New Mexico
PO	Portfolio Optimization
POD	Point of Delivery
PRPA	Platte River Power Authority
PVRR	Prevent Value Revenue Requirement
QRU	Qualifying Retail Utility
QWU	Qualifying Wholesale Utility
RAP	Resource Acquisition Period
REC	Renewable Energy Credit
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposal
RPP	Resource Planning Period
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	Social Cost of Carbon (Scenario)
SCoC	Social Cost of Carbon
SIP	Regional Haze State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SPV 3	Springerville Unit 3
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TA	Transmission Area
TEP	Tucson Electric Power
TP	Transmission Provider
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration
WCO	Western Colorado

WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WMPA	Wyoming Municipal Power Agency
WREGIS	Western Renewable Energy General Information System

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TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative

2020 Integrated Resource Plan/Electric Resource Plan

Volume II Technical Appendix

December 1, 2020

Submitted to:

Western Area Power Administration
Colorado Public Utilities Commission

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1 Electric Energy and Demand Forecast

Description of Process 3605(b)(IV)

The base long-term load forecast is prepared with each of Tri-State's Utility Member Systems every year. Tri-State has a four state service territory, with 42 Utility Member Systems and each consists of up to nine retail classes in which a bottom-up forecast methodology is employed.

Inputs:

The primary source for historical retail data by each class of consumers is Rural Utilities Service (RUS) Form 7. Information on the number of accounts, energy use per account, total energy and the average price of electricity is collected monthly from each Member. In addition, data on large commercial accounts is gathered on RUS Form 345. Wholesale Utility Member System billing data is obtained from Tri-State monthly bills to Utility Member Systems.

Weather data from 20 weather stations within Tri-State's region is supplied through DTN Meteorlogix. Tri-State's database includes temperature, heating and cooling degree-days, and precipitation. Weather normalizations of this data are used in forecast models (defined as 10-year average values).

Tri-State obtains economic and demographic data for each Utility Member System from Woods & Poole Economics, Inc. (W&P). The vast majority of data from W&P originates with the Department of Commerce and Bureau of Economic Analysis (BEA). All projections of the economic and demographic data have been performed by W&P. Tri-State uses more than 20 measures of employment and income activity by sector from the W&P data.

The electricity that Tri-State Utility Member Systems provides to its retail customers often competes with propane, natural gas and fuel oil as an energy source. Historical price data for these alternative energy sources is obtained annually from the Department of Energy's (DOE) Energy Information Administration (EIA) State Energy Data System, Petroleum Marketing Monthly and Annual Energy Outlook. Tri-State based its price projections for each of these alternative fuels on information from the EIA.

The statistical models are estimated using annual historical data from 2000 through 2019.

Forecasting Process:

The nine retail classes include residential, seasonal, irrigation, small commercial, large commercial, public authorities, streetlights, resales to RUS, and resales to others. Each retail class, with the exception of large commercial, is broken into the number of customers and use-per-customer, which are then modeled separately and aggregated to arrive at forecast energy. By separating the demand forecast into the use-per-customer and customer components, Tri-State is able to better distinguish between the trends driving growth in the number of customers versus technology or weather impacts on customer-level usage.

Customer forecasts are generated using a combination of econometric techniques, time series regressions and simple trend analyses. Time Series processes typically utilize Auto Regressive Integrated Moving Average (ARIMA) modeling. Econometric models for customers consist of a multiple regression with explanatory variables including, but not limited to, population, employment and income.

Use-per-customer is also modeled using econometric models or simple trend analysis. Multiple regressions on use-per-customer typically consider weather, fuel prices and electric prices; however, in the event that there is not a good model fit, a five-year average is used. The residential use forecast is an exception and utilizes an end-use model when possible.

Additional detail on the forecast modeling by retail class can be found in Ms. Tiffin's direct testimony. Once the forecasts are completed for each Utility Member System, the final step is forecast aggregation to arrive at the Tri-State system forecast.

Demand Forecast:

The projected values of the Member Coincident Peak (MCP) demands are based upon an hourly load forecast. Hourly loads are generated for each calendar month by applying the projected purchased energy requirement to a corresponding normalized historical load duration curve. The resultant hourly loads are dispatched chronologically based upon known historical loads appearing in a typical month. Once individual members' hourly demand forecasts have been determined, they are summed to arrive at a total Tri-State hourly load forecast (using a bottom-up approach), allowing the coincident peak demand to be established.

The peak period used for billing is defined as the period between 12:00 (noon) and 10:00 PM, Monday through Saturday, except certain holidays. The Tri-State aggregate billing peak is the sum of the individual member coincident peaks from the hourly demand forecasts, which occur within the defined peak period. The Tri-State Coincident Peak for capacity planning is the highest hourly sum of Utility Member System hourly demand forecasts in July, as Tri-State is a summer peaking system.

Range of Forecasts 3605(b)(II):

Tri-State developed a range of forecasts including the base, low and high forecasts. To develop the low and high forecasts, Tri-State established prediction intervals to express uncertainty around the expected value forecast. The total variance includes both economic and weather related uncertainty. Intervals are generated for one standard deviation (68.27%) and 90%, meaning that the actual value should be within the given interval with a probability of 68.27% or 90% respectively. The lower limit of the 90% prediction interval was used as the Low Load forecast for Low Load scenarios. Many potential factors exist which could significantly reduce Tri-State's load, including:

- Potential Utility Member System buy-outs
- Transition of some Utility Member Systems from all to partial requirements wholesale electric service contracts
- Increased Utility Member System distributed generation
- Increased demand side management and energy efficiency
- Load reduction due to COVID impacts
- Load loss related to environmental and regulatory impacts to the oil and gas industries

The Low Load forecast represents the potential load reduction that could result from any combination or subset of these items. Figure 1 illustrates the deviation from the base load forecast for the Low load (TS LCL 90^{tH}) forecast as well as other potential load reductions such as Partial Requirements (PR), increased community solar subscription under Board Policy 119, increased distributed generation deployment under Board Policy 115, or the exit of a Utility Member System such as United Power. The figure indicates that the Low Load forecast is comparable during the early years of the RAP to the combination of low load drivers with the exception of a United Power Withdrawal (Total Drivers w/o UP out).

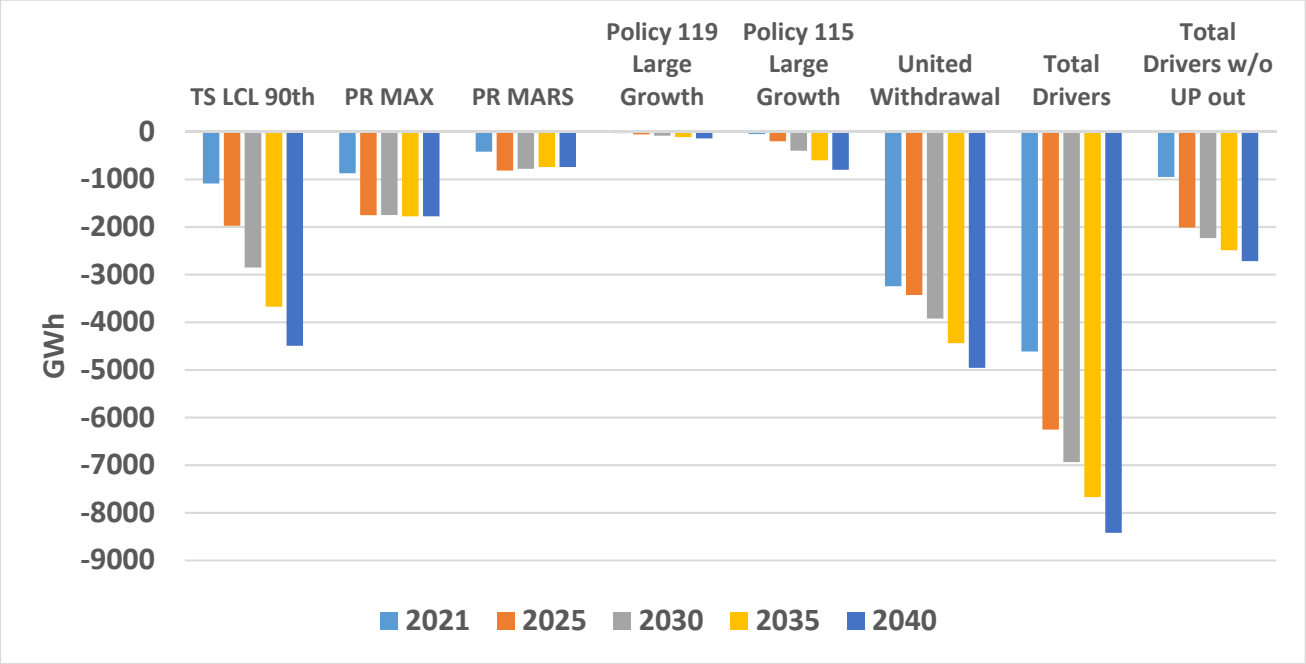

Figure 1: Comparison of Low Load Forecast to Potential Load Reductions - Energy

Tri-State did not conduct an alternative scenario for purposes of this Resource Plan in regards to UCL 90th (High) load forecast due to the number of potential risks that could result in significant reductions to Tri-State's system load. However, both the High Load forecast and Low Load forecast are presented in the following subsection, as well as in "Attachment Vol II 1-1 Tri-State Load Forecasts by Member and State".

Utility Member Sales Forecasts 3650(b)(I)(A)

The following graphs show Tri-State's load forecasts for the RPP for the Tri-State System. Tri-State's annual system energy average growth over the RPP is 1.55%, while summer coincident system demand has an annual average growth rate of 1.44%.

Where appropriate, data is presented for a range of forecasts, including Base, High and Low Load forecasts. Base, High and Low Load forecasts are marked with the following identifiers on all graphs:

- Base Load Forecast Scenario – PRS20 Expected Value
- High Load Forecast Scenario – UCL90_00
- Low Load Forecast Scenario – LCL90_00

Tri-State System Annual Energy Sales, Summer Peak & Winter Peak*:*

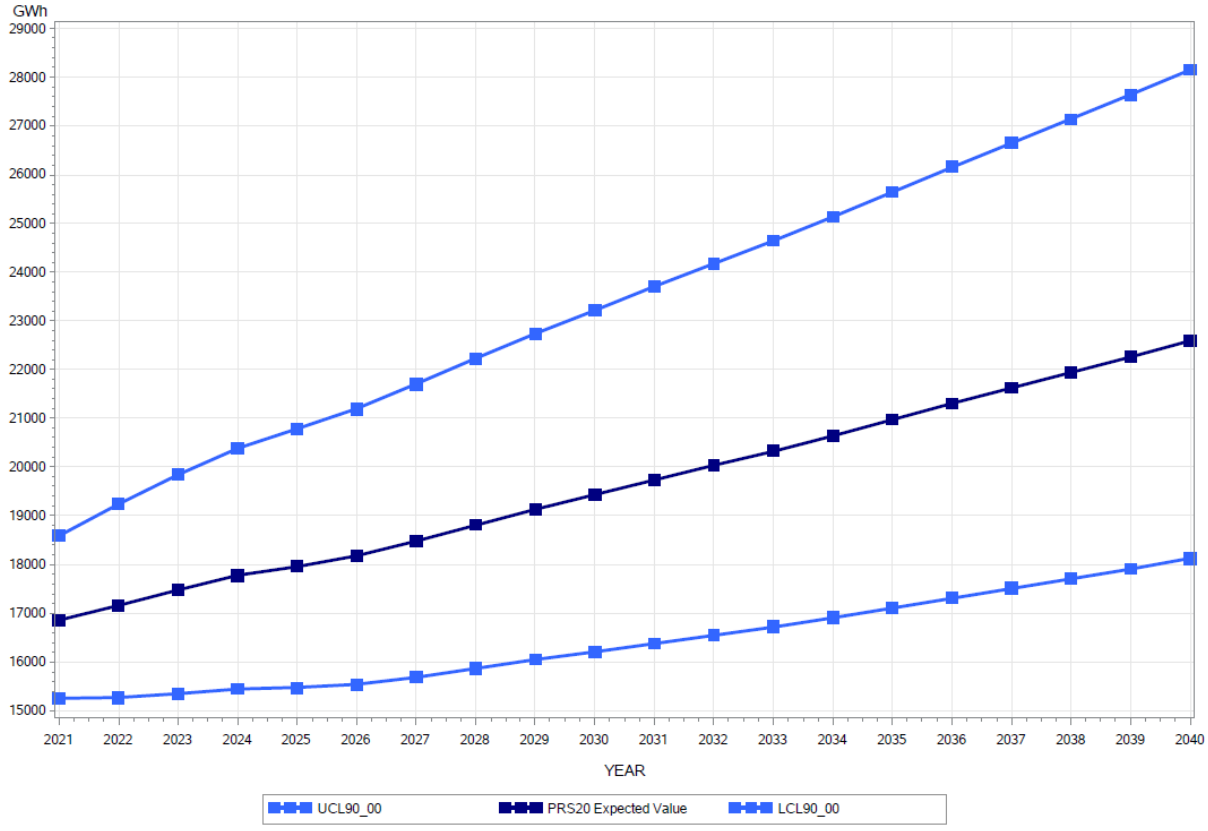

Figure 2: Tri-State System Annual Energy Sales to Utility Member Systems

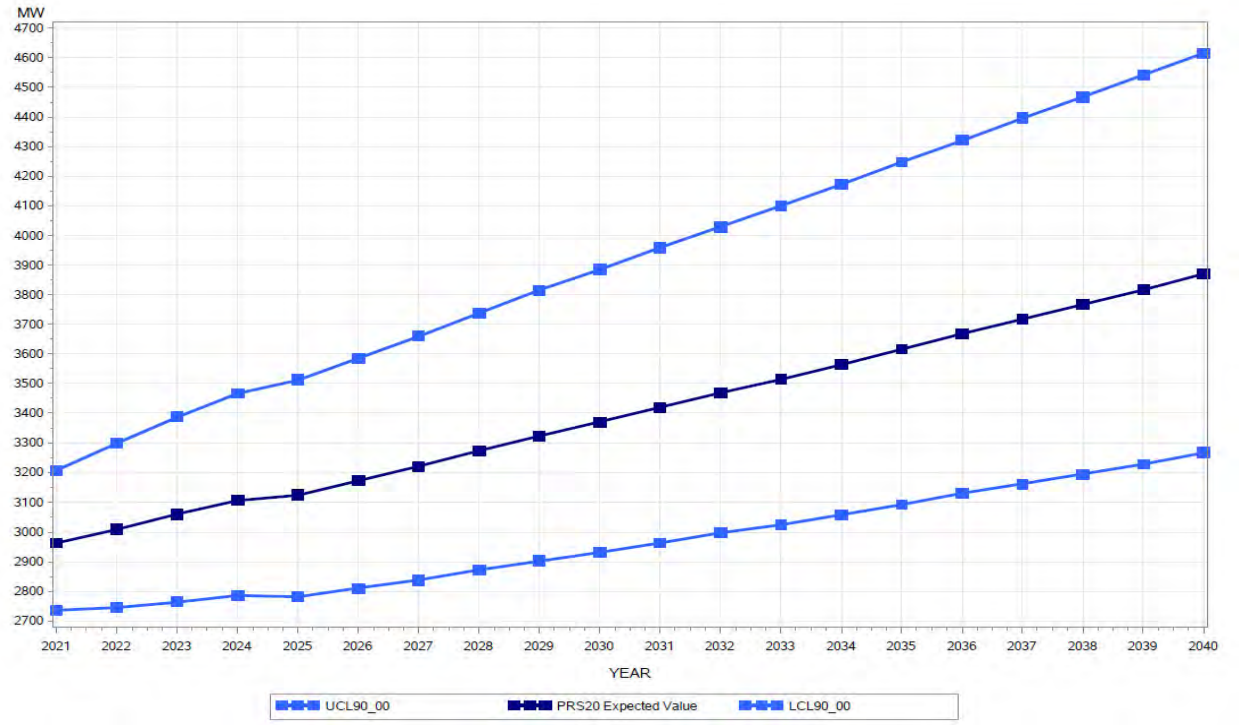

Figure 3: Tri-State System Annual Coincident Summer Peak

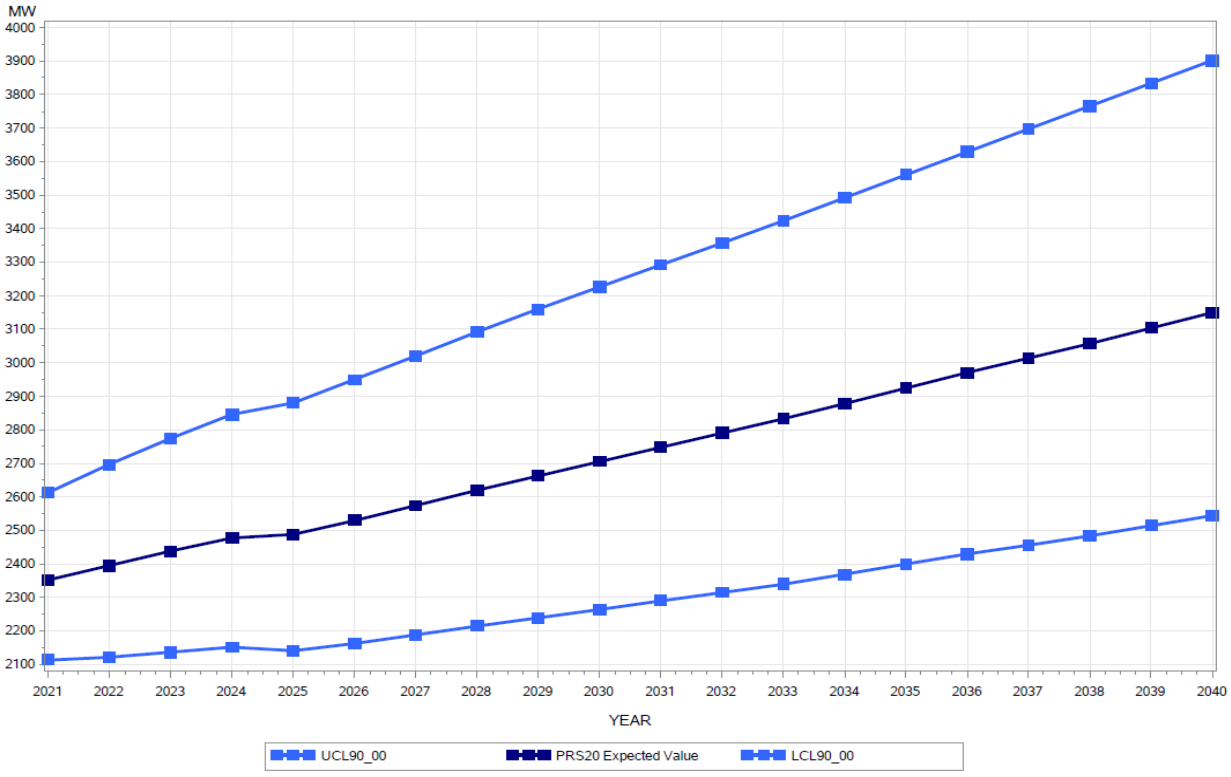

Figure 4: Tri-State System Annual Coincident Winter Peak

Tri-State's load forecasts for the RPP by State and Utility Member System are located in Attachment Volume II 1-1 Tri-State Load Forecasts by State and Member.

Table 1: Reference Guide for Attachment Vol II 1-1 State and Utility Member System Data

Rule	Item	Granularity	Page(s)
3605(b)(I)(A)	Annual Energy Sales	States	1-4
3605(b)(I)(A)	Annual Coincident Summer Peak	States	47-50
3605(b)(I)(A)	Annual Coincident Winter Peak	States	93-96
3605(b)(I)(A)	Annual Energy Sales	Utility Member System	5-46
3605(b)(I)(A)	Annual Coincident Summer Peak	Utility Member System	51-92
3605(b)(I)(A)	Annual Coincident Winter Peak	Utility Member System	97-138
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	States	139-186
3605(b)(I)(E)	Hourly Off Peak Day by Calendar Month	States	691-738
3605(b)(I)(E)	Hourly Average Day by Calendar Month	States	1243-1290
3605(b)(I)(E)	Hourly Peak Day By Calendar Month	Utility Member System	187-690
3605(b)(I)(E)	Hourly Off Peak Day by Calendar Month	Utility Member System	739-1242
3605(b)(I)(E)	Hourly Average Day by Calendar Month	Utility Member System	1290-1794

Comparison of Load Forecasts (3605)(b)(III):

Comparison of 2015 ERP to 2020 ERP Load Forecast:

Tri-State has experienced changes in base load between the release of the 2015 ERP and the 2020 ERP. In 2015, Tri-State had 44 Utility Member Systems; however, 2020 reflects the departure of both Kit Carson and Delta Montrose Electric Association (DMEA). Another key difference is an improvement in the methodology used to forecast the large commercial class. Most individual large commercial and industrial accounts exhibit random walk behavior making it difficult to generate a forecast. The 2020 forecast combines the accounts and generates a forecast for energy using the growth exhibited in the previous 20 years resulting in a large commercial forecast for Tri-State system that better reflects historical patterns.

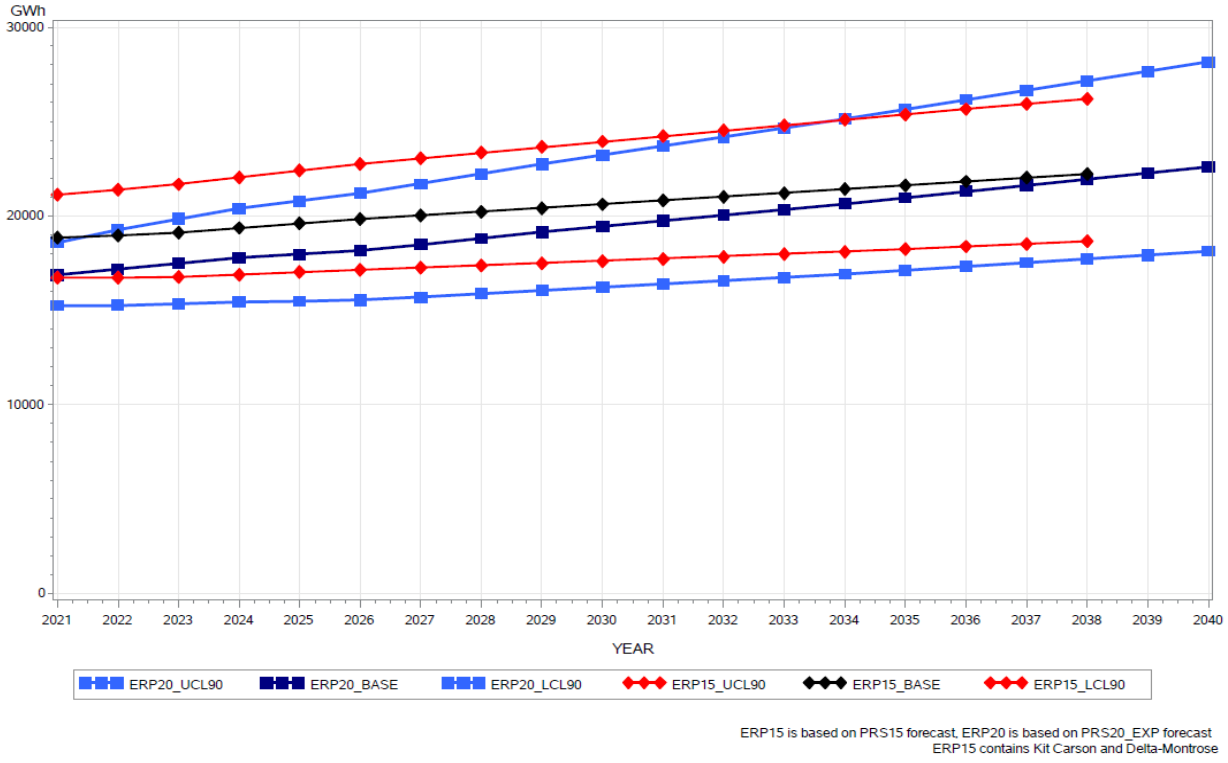

Figure 5: Tri-State System Annual Energy Sales to Utility Member Systems

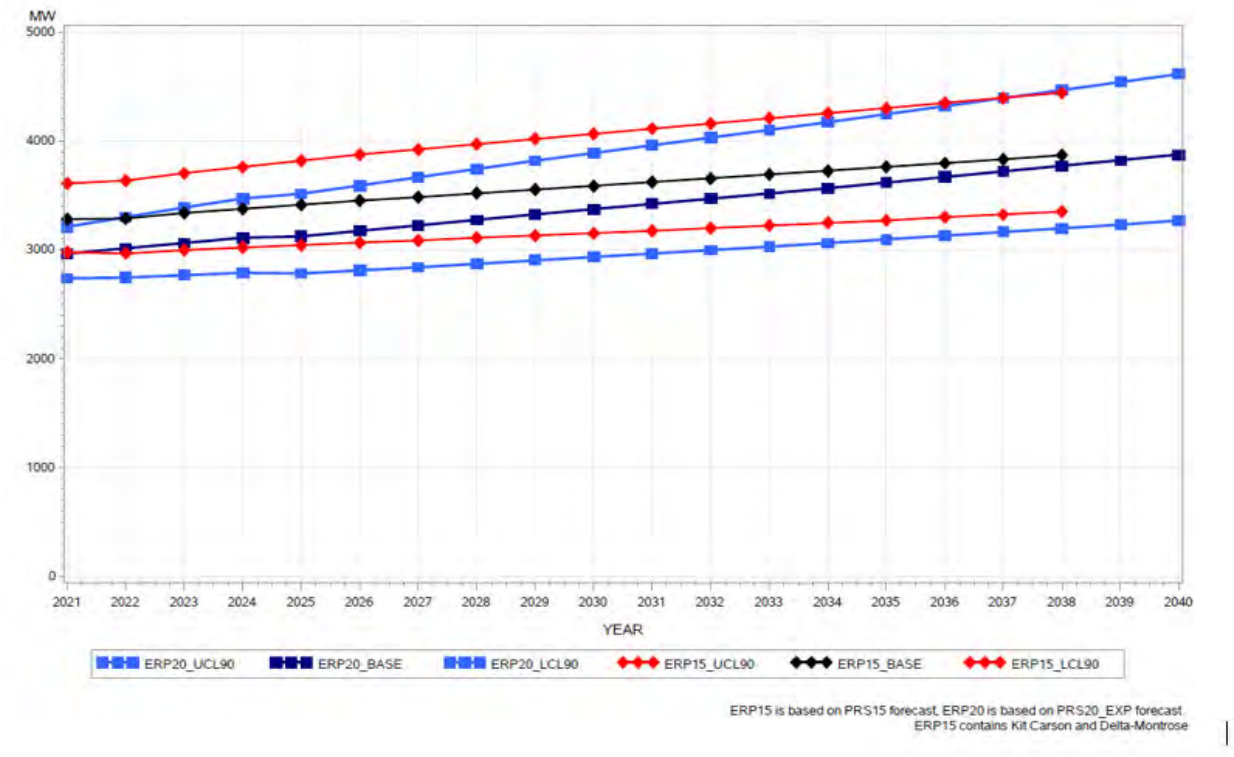

Figure 6: Tri-State System Annual Summer Coincident Peak

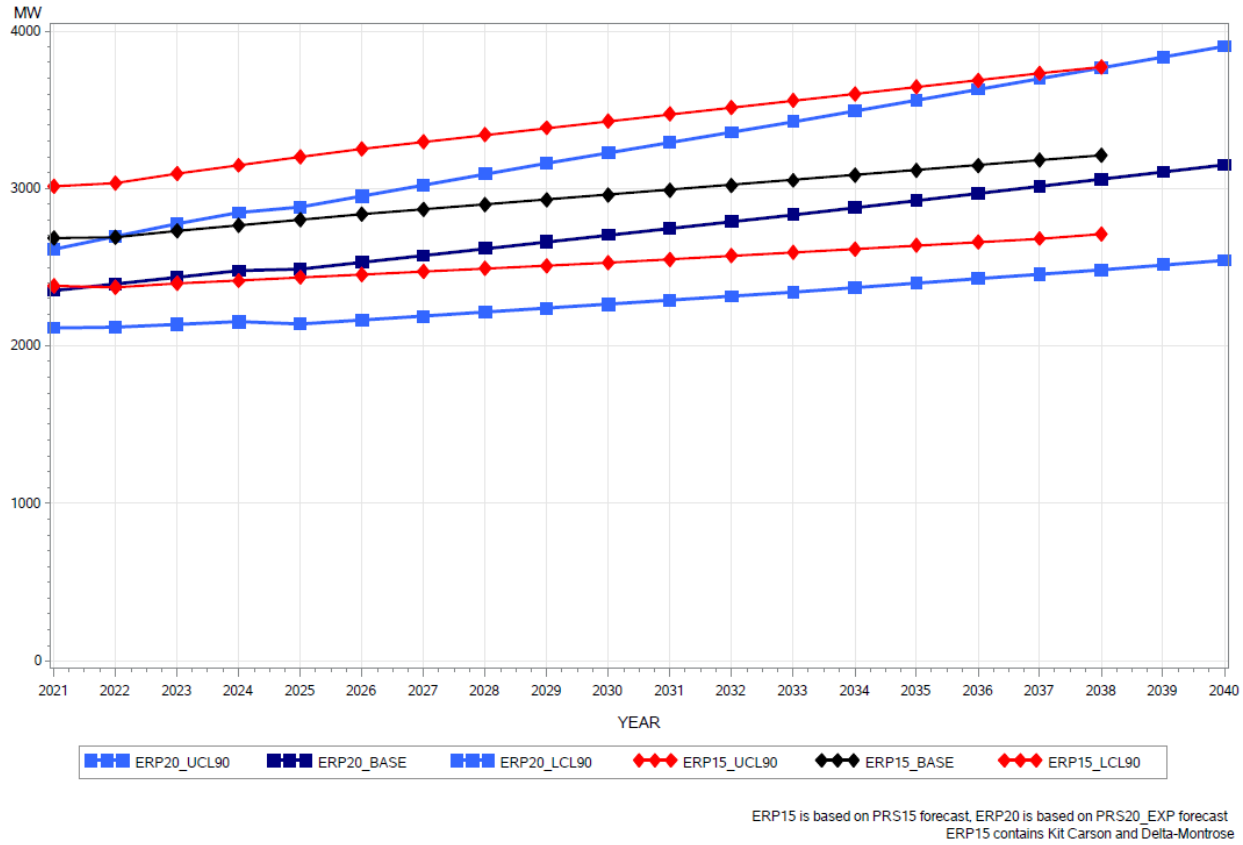

Figure 7: Tri-State System Annual Winter Coincident Peak

Comparison of Historical Forecasts & Actuals:

For the following tables Kit Carson is included in actuals and forecasts for 2015-2016 and DMEA is included in actuals and forecasts for 2015-2019. "PRS" and the corresponding year represents the forecast value.

Table 2: Tri-State System Annual Energy Sales to Utility Member Systems (Base) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	16,316	.	.	.	.	.
2	2016	15,952	.	16,741	.	.	.	.
3	2017	16,159	.	.	16,181	.	.	.
4	2018	16,719	.	.	.	16,630	.	.
5	2019	16,752	.	.	.	.	17,080	.
6	2020	.	.	.	.	.	.	16,516
7	2021	.	.	.	.	.	.	16,857
8	2022	.	.	.	.	.	.	17,161
9	2023	.	.	.	.	.	.	17,476
10	2024	.	.	.	.	.	.	17,773
11	2025	.	.	.	.	.	.	17,958
12	2026	.	.	.	.	.	.	18,172
13	2027	.	.	.	.	.	.	18,479
14	2028	.	.	.	.	.	.	18,809
15	2029	.	.	.	.	.	.	19,131
16	2030	.	.	.	.	.	.	19,426
17	2031	.	.	.	.	.	.	19,733
18	2032	.	.	.	.	.	.	20,032
19	2033	.	.	.	.	.	.	20,326
20	2034	.	.	.	.	.	.	20,644
21	2035	.	.	.	.	.	.	20,974
22	2036	.	.	.	.	.	.	21,306
23	2037	.	.	.	.	.	.	21,624
24	2038	.	.	.	.	.	.	21,939
25	2039	.	.	.	.	.	.	22,262
26	2040	.	.	.	.	.	.	22,596

Table 3: Tri-State System Annual Energy Sales to Utility Member Systems (High Load) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	17,121	.	.	.	.	.
2	2016	15,952	.	17,182	.	.	.	.
3	2017	16,159	.	.	16,939	.	.	.
4	2018	16,719	.	.	.	17,578	.	.
5	2019	16,752	.	.	.	.	17,857	.
6	2020	.	.	.	.	.	.	17,777
7	2021	.	.	.	.	.	.	18,596
8	2022	.	.	.	.	.	.	19,245
9	2023	.	.	.	.	.	.	19,844
10	2024	.	.	.	.	.	.	20,388
11	2025	.	.	.	.	.	.	20,780
12	2026	.	.	.	.	.	.	21,188
13	2027	.	.	.	.	.	.	21,696
14	2028	.	.	.	.	.	.	22,221
15	2029	.	.	.	.	.	.	22,733
16	2030	.	.	.	.	.	.	23,210
17	2031	.	.	.	.	.	.	23,698
18	2032	.	.	.	.	.	.	24,173
19	2033	.	.	.	.	.	.	24,641
20	2034	.	.	.	.	.	.	25,137
21	2035	.	.	.	.	.	.	25,645
22	2036	.	.	.	.	.	.	26,156
23	2037	.	.	.	.	.	.	26,650
24	2038	.	.	.	.	.	.	27,140
25	2039	.	.	.	.	.	.	27,640
26	2040	.	.	.	.	.	.	28,152

Table 4: Tri-State System Annual Energy Sales to Utility Member Systems (Low Load) (GWh)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	15,941	15,534	.	.	.	.	.
2	2016	15,952	.	15,721	.	.	.	.
3	2017	16,159	.	.	15,445	.	.	.
4	2018	16,719	.	.	.	15,426	.	.
5	2019	16,752	.	.	.	.	16,325	.
6	2020	.	.	.	.	.	.	15,324
7	2021	.	.	.	.	.	.	15,248
8	2022	.	.	.	.	.	.	15,263
9	2023	.	.	.	.	.	.	15,345
10	2024	.	.	.	.	.	.	15,443
11	2025	.	.	.	.	.	.	15,467
12	2026	.	.	.	.	.	.	15,532
13	2027	.	.	.	.	.	.	15,686
14	2028	.	.	.	.	.	.	15,866
15	2029	.	.	.	.	.	.	16,046
16	2030	.	.	.	.	.	.	16,207
17	2031	.	.	.	.	.	.	16,381
18	2032	.	.	.	.	.	.	16,553
19	2033	.	.	.	.	.	.	16,721
20	2034	.	.	.	.	.	.	16,911
21	2035	.	.	.	.	.	.	17,114
22	2036	.	.	.	.	.	.	17,319
23	2037	.	.	.	.	.	.	17,515
24	2038	.	.	.	.	.	.	17,708
25	2039	.	.	.	.	.	.	17,910
26	2040	.	.	.	.	.	.	18,121

Table 5: Tri-State System Annual Summer Coincident Peak (Base) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,857	.	.	.	.	.
2	2016	2,803	.	2,887	.	.	.	.
3	2017	2,850	.	.	2,786	.	.	.
4	2018	2,974	.	.	.	2,929	.	.
5	2019	3,010	.	.	.	.	2,993	.
6	2020	.	.	.	.	.	.	2,905
7	2021	.	.	.	.	.	.	2,963
8	2022	.	.	.	.	.	.	3,010
9	2023	.	.	.	.	.	.	3,060
10	2024	.	.	.	.	.	.	3,107
11	2025	.	.	.	.	.	.	3,125
12	2026	.	.	.	.	.	.	3,173
13	2027	.	.	.	.	.	.	3,221
14	2028	.	.	.	.	.	.	3,273
15	2029	.	.	.	.	.	.	3,324
16	2030	.	.	.	.	.	.	3,371
17	2031	.	.	.	.	.	.	3,420
18	2032	.	.	.	.	.	.	3,469
19	2033	.	.	.	.	.	.	3,515
20	2034	.	.	.	.	.	.	3,565
21	2035	.	.	.	.	.	.	3,617
22	2036	.	.	.	.	.	.	3,669
23	2037	.	.	.	.	.	.	3,718
24	2038	.	.	.	.	.	.	3,767
25	2039	.	.	.	.	.	.	3,818
26	2040	.	.	.	.	.	.	3,871

Table 6: Tri-State System Annual Summer Coincident Peak (High Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,975	.	.	.	.	.
2	2016	2,803	.	2,940	.	.	.	.
3	2017	2,850	.	.	2,895	.	.	.
4	2018	2,974	.	.	.	3,011	.	.
5	2019	3,010	.	.	.	.	3,106	.
6	2020	.	.	.	.	.	.	3,085
7	2021	.	.	.	.	.	.	3,208
8	2022	.	.	.	.	.	.	3,300
9	2023	.	.	.	.	.	.	3,388
10	2024	.	.	.	.	.	.	3,467
11	2025	.	.	.	.	.	.	3,513
12	2026	.	.	.	.	.	.	3,587
13	2027	.	.	.	.	.	.	3,661
14	2028	.	.	.	.	.	.	3,738
15	2029	.	.	.	.	.	.	3,815
16	2030	.	.	.	.	.	.	3,885
17	2031	.	.	.	.	.	.	3,959
18	2032	.	.	.	.	.	.	4,029
19	2033	.	.	.	.	.	.	4,099
20	2034	.	.	.	.	.	.	4,172
21	2035	.	.	.	.	.	.	4,248
22	2036	.	.	.	.	.	.	4,321
23	2037	.	.	.	.	.	.	4,396
24	2038	.	.	.	.	.	.	4,467
25	2039	.	.	.	.	.	.	4,541
26	2040	.	.	.	.	.	.	4,614

Table 7: Tri-State System Annual Summer Coincident Peak (Low Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,627	2,743	.	.	.	.	.
2	2016	2,803	.	2,731	.	.	.	.
3	2017	2,850	.	.	2,681	.	.	.
4	2018	2,974	.	.	.	2,705	.	.
5	2019	3,010	.	.	.	.	2,884	.
6	2020	.	.	.	.	.	.	2,735
7	2021	.	.	.	.	.	.	2,736
8	2022	.	.	.	.	.	.	2,745
9	2023	.	.	.	.	.	.	2,764
10	2024	.	.	.	.	.	.	2,786
11	2025	.	.	.	.	.	.	2,782
12	2026	.	.	.	.	.	.	2,811
13	2027	.	.	.	.	.	.	2,837
14	2028	.	.	.	.	.	.	2,872
15	2029	.	.	.	.	.	.	2,903
16	2030	.	.	.	.	.	.	2,932
17	2031	.	.	.	.	.	.	2,964
18	2032	.	.	.	.	.	.	2,997
19	2033	.	.	.	.	.	.	3,024
20	2034	.	.	.	.	.	.	3,058
21	2035	.	.	.	.	.	.	3,093
22	2036	.	.	.	.	.	.	3,130
23	2037	.	.	.	.	.	.	3,162
24	2038	.	.	.	.	.	.	3,195
25	2039	.	.	.	.	.	.	3,229
26	2040	.	.	.	.	.	.	3,268

Table 8: Tri-State System Annual Winter Coincident Peak (Base) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,346	.	.	.	.	.
2	2016	2,201	.	2,397	.	.	.	.
3	2017	2,191	.	.	2,282	.	.	.
4	2018	2,323	.	.	.	2,355	.	.
5	2019	2,288	.	.	.	.	2,393	.
6	2020	.	.	.	.	.	.	2,307
7	2021	.	.	.	.	.	.	2,352
8	2022	.	.	.	.	.	.	2,395
9	2023	.	.	.	.	.	.	2,438
10	2024	.	.	.	.	.	.	2,478
11	2025	.	.	.	.	.	.	2,487
12	2026	.	.	.	.	.	.	2,530
13	2027	.	.	.	.	.	.	2,574
14	2028	.	.	.	.	.	.	2,620
15	2029	.	.	.	.	.	.	2,663
16	2030	.	.	.	.	.	.	2,705
17	2031	.	.	.	.	.	.	2,749
18	2032	.	.	.	.	.	.	2,791
19	2033	.	.	.	.	.	.	2,833
20	2034	.	.	.	.	.	.	2,878
21	2035	.	.	.	.	.	.	2,925
22	2036	.	.	.	.	.	.	2,970
23	2037	.	.	.	.	.	.	3,014
24	2038	.	.	.	.	.	.	3,058
25	2039	.	.	.	.	.	.	3,104
26	2040	.	.	.	.	.	.	3,150

Table 9: Tri-State System Annual Winter Coincident Peak (High Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,485	.	.	.	.	.
2	2016	2,201	.	2,485	.	.	.	.
3	2017	2,191	.	.	2,410	.	.	.
4	2018	2,323	.	.	.	2,526	.	.
5	2019	2,288	.	.	.	.	2,523	.
6	2020	.	.	.	.	.	.	2,513
7	2021	.	.	.	.	.	.	2,613
8	2022	.	.	.	.	.	.	2,697
9	2023	.	.	.	.	.	.	2,775
10	2024	.	.	.	.	.	.	2,845
11	2025	.	.	.	.	.	.	2,881
12	2026	.	.	.	.	.	.	2,950
13	2027	.	.	.	.	.	.	3,020
14	2028	.	.	.	.	.	.	3,091
15	2029	.	.	.	.	.	.	3,160
16	2030	.	.	.	.	.	.	3,226
17	2031	.	.	.	.	.	.	3,292
18	2032	.	.	.	.	.	.	3,357
19	2033	.	.	.	.	.	.	3,424
20	2034	.	.	.	.	.	.	3,492
21	2035	.	.	.	.	.	.	3,561
22	2036	.	.	.	.	.	.	3,630
23	2037	.	.	.	.	.	.	3,698
24	2038	.	.	.	.	.	.	3,765
25	2039	.	.	.	.	.	.	3,834
26	2040	.	.	.	.	.	.	3,902

Table 10: Tri-State System Annual Winter Coincident Peak (Low Load) (MW)

Obs	YEAR	ACTUAL	PRS15	PRS16_EXP	PRS17_EXP	PRS18_EXP	PRS19_EXP	PRS20_EXP
1	2015	2,261	2,213	.	.	.	.	.
2	2016	2,201	.	2,236	.	.	.	.
3	2017	2,191	.	.	2,158	.	.	.
4	2018	2,323	.	.	.	2,189	.	.
5	2019	2,288	.	.	.	.	2,268	.
6	2020	.	.	.	.	.	.	2,115
7	2021	.	.	.	.	.	.	2,113
8	2022	.	.	.	.	.	.	2,121
9	2023	.	.	.	.	.	.	2,136
10	2024	.	.	.	.	.	.	2,152
11	2025	.	.	.	.	.	.	2,141
12	2026	.	.	.	.	.	.	2,163
13	2027	.	.	.	.	.	.	2,188
14	2028	.	.	.	.	.	.	2,215
15	2029	.	.	.	.	.	.	2,239
16	2030	.	.	.	.	.	.	2,263
17	2031	.	.	.	.	.	.	2,290
18	2032	.	.	.	.	.	.	2,316
19	2033	.	.	.	.	.	.	2,340
20	2034	.	.	.	.	.	.	2,368
21	2035	.	.	.	.	.	.	2,399
22	2036	.	.	.	.	.	.	2,429
23	2037	.	.	.	.	.	.	2,455
24	2038	.	.	.	.	.	.	2,483
25	2039	.	.	.	.	.	.	2,514
26	2040	.	.	.	.	.	.	2,544

Losses 3605(b)(I)(D):

Tri-State adds a 5% transmission loss factor to load across Tri-State's system in the Western Interconnection for modeling purposes. Tri-State load in the Western Interconnection is located in multiple BA and TP systems. The 5% transmission loss factor is meant to represent an average of expected transmission losses. Tri-State's load in the Eastern Interconnection is covered by a full requirements contract.

Energy and Capacity Sales to Other Utilities (3605)(b)(I)(B)

Annual contract energy and capacity sales to other utilities and counterparties are described below:

SRP Sale: SPV 3 Facility located in Arizona, 100MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036.

PNM Unit Contingent Sale: 100MW unit contingent sale at SJ345. 100 MW (Maximum Capacity) ~876 GWh/year. Effective Date 06/01/2017; Contract Expires 05/31/2022. This is the sale side of a swap that reduces spinning reserve obligations.

WAPA Regulation Sale: Rate Schedule L-AS3 Partial Self Supply Utilizing Craig Station Unit 3: As the BA operator, WAPA provides Regulation and Frequency Response under Rate Schedule L-AS3. Tri-State currently purchases these services from WAPA. Historically, WAPA has provided this service by adjusting its Federal hydropower resources to balance load, generation, and interchange. This contract allows WAPA to diversify its availability of regulation and frequency response resources by utilizing 30MW of capacity of Craig Unit 3. Effective Date 07/01/2020. Contract Expires 10/01/2021. Either party may choose to discontinue service under this contract by providing sixty (60) days advance written notice to the other party.

Municipal Energy Agency of Nebraska (MEAN) Reserve Sale[1]: Tri-State provides operating reserves to Northwest Power Pool on behalf of MEAN under the terms of the MEAN sub-entity agreement. Effective Date 09/30/2020. Contract Expires 09/30/2021. Contract is evergreen unless terminated by either party via 180 day advanced written notice.

For all sales for purposes of resource planning, contract capacity at the time of peak is considered to be at maximum. This approach is based on conservative business practices. Dispatch energy is based on contract or forecast values.

Intra-utility Energy and Capacity Use (3605)(b)(I)(C)

Tri-State intra-utility loads consist of a number of service centers and the headquarters building. For these loads, Tri-State takes retail service from the local provider. Accordingly, Tri-State has no intra-utility loads that contribute to energy and capacity requirements for purposes of Tri-State resource planning.

[1] This sale was finalized after the start of the ERP process and was not included in the modeling.

2 Commodity Pricing

Electric Forward Curve

Tri-State models six markets to forecast purchase and sale activity across its Western Interconnection footprint, including four transaction points where trading activity currently occurs and two entities representing the real time energy imbalance markets of WEIS and WEIM:

- LRS – located in Wyoming
- AU – Ault in Eastern Colorado
- CRG – Craig in Western Colorado
- 4C – Four Corners in New Mexico
- WEIS – imbalance market in Colorado and Wyoming (WAPA BA)
- WEIM – imbalance market in New Mexico (PNM BA)

Tri-State employs a four-step approach to obtain its electric price forecast. First, a long-term Palo Verde price is derived from third-party data including Bloomberg energy future prices ("Market" prices) and Hitachi ABB & Wood Mackenzie forecasts ("Fundamental" prices). The Market prices are taken at the Palo Verde trading hub at a monthly temporal resolution for on-peak, off-peak, and composite periods. The Fundamental prices are determined from production cost modelling for the Palo Verde hub. For the near-term period (the first three years), Market prices are used, whereas in the long-term (years 11 to 20) Fundamental prices are used. For the mid-term (years four to ten), Market and Fundamental prices are blended to facilitate a smooth transition. Second, the blended Palo Verde prices are then used to derive regional (Colorado East, Colorado West, and New Mexico) prices using a basis adder[2]. Third, a system-wide price is then derived by taking a 30%, 30%, and 40% weighting of the Colorado East, Colorado West, and New Mexico regional prices, respectively creating a blended curve. Finally, Fundamental-based hourly scalars are used to calculate "8760" (all-hours) price streams for Palo Verde, Colorado East, Colorado West, New Mexico and Blended.

For modeling purposes, the 8760 price stream is applied as follows:

- Blended curve is applied to LRS, AU, CRG and NM markets
- Colorado East (COE) curve is applied to WEIS market
- Palo Verde (PV) curve is applied to WEIM market

Additionally, different multipliers are applied to the curves for purchase and sales as follow:

- Blended curve – purchases 95% and sales 85%
- COE curve – purchases 110% and sales 85%
- PV Curve – purchases 105% and sales 95%

The WEIS and WEIM markets are in effect in the model from 2021 to 2024. In 2025, Tri-State opens up market depth to reflect participation in a RTO for its entire footprint. At that point, only the four transaction point markets (LRS, AU, CRG and 4c) remain in use in the model. For more information on

[2] Basis adder is provided by Hitachi ABB.

market depths see Section 5 Phase 1 Modeling Details under the Modeling Assumptions subsection of this report.

Figure 8 represents the power forward curve data in real (2020) dollars for the RPP:

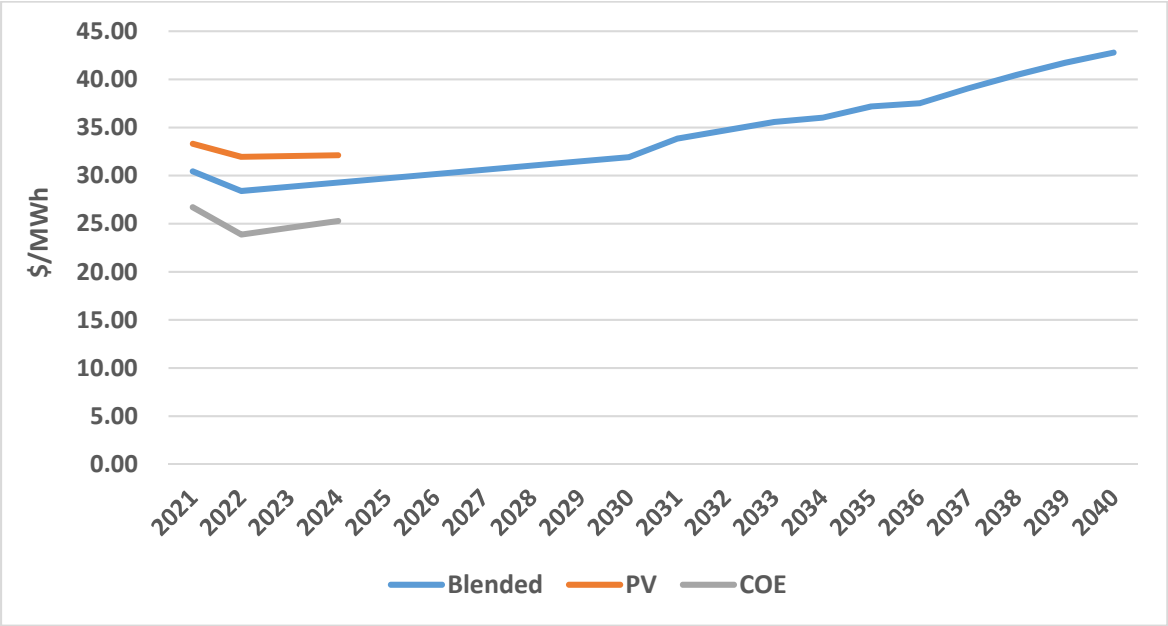

Figure 8: Electric Forward Curve

Gas Forward Curve

Tri-State uses a similar approach for gas forward pricing. First, prices are derived from a combination of third-party data including Bloomberg energy future prices ("Market" prices) and Hitachi ABB & Wood Mackenzie forecasts ("Fundamental" prices). The Market prices are taken at CIG hub and Waha hub at a monthly granularity. The Fundamental prices are derived from a production cost modelling approach for the Palo Verde hub. In the near-term (first five years) the Market prices are used, whereas in the long-term (years 11 to 20) the Fundamental prices are used. For the mid-term (years six to ten) the Market prices are blended with the Fundamental prices for a smooth transition. The monthly values are applied to all applicable days within the model.

For modeling purposes, the daily price stream is applied as follows:

- CIG curve is applied to JM Shafer, Rifle, Limon, Knutson and generic gas resources in Wyoming and Colorado.
- Waha curve is applied to Pyramid units and generic gas resources in New Mexico.

Figure 9 represents the gas forward curve in real (2020) dollars. Additional transport costs apply.

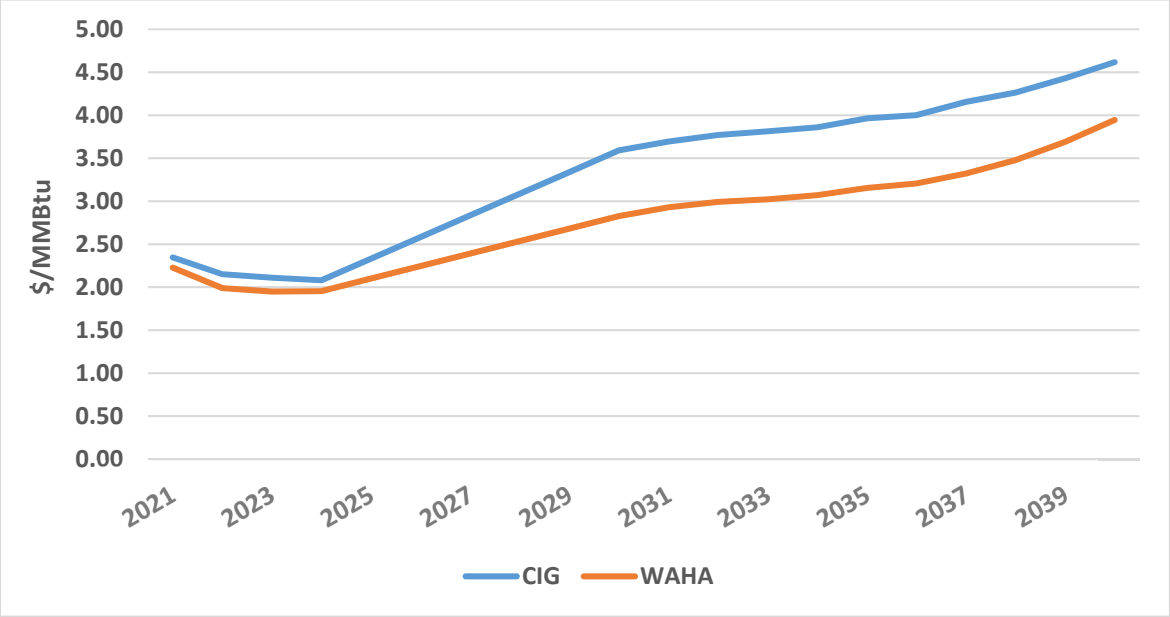

Figure 9: Gas Forward Curve

Table 11 summarizes the additional transport costs and forward curves associated with each gas generating unit:

Table 11: Transportation Costs & Fuel Forward Curve for Gas Resources

Existing Gas Plant	**Transport Adder** *($/MMBtu)*	**Forward Curve**
Limon	$0.31	CIG
Knutson	$0.31	CIG
Pyramid	$0.90	Waha
Rifle	$0.42	CIG
JM Shafer	$0.17	CIG
Generic Gas Resources – CO & WY	$0.31	CIG
Generic Gas Resources - NM	$0.70	Waha

Tri-State uses interruptible gas transport service except for a portion of service for JM Shafer. Tri-State has contractual rights to 14,697 Decatherm (Dth) of firm CIG transportation, (8,000 Dth from King to Lakin, 2,000 Dth from Lost Cabin to Lakin, and another 4,697 Dth from Beaver to Milton). For modeling purposes Tri-State assumes JM Shafer uses the firm transport at a sunk cost and then the additional potentially needed interruptible transport cost is considered and prorated. Therefore, JM Shafer has a lower transport adder than other units.

Coal Forward Curve

Tri-State forward coal prices change annually. Figure 10 shows the coal forward curve in real (2020) dollars. LRS and SPV3 values are all inclusive costs of fuel. CRG (Inc.) is the Craig coal cost as an incremental value. These values are used in CE and PO. Figure 11 shows the coal forward curve in nominal dollars, and all values are all inclusive costs of fuel. These values are used in the final PVRR analysis in UIPlanner.

Figure 10: Coal Forward Curve for CE & PO (2020 Dollars)

The Craig coal forward curve is based on the actual mine plan as forecast by Colowyo. The SPV 3 coal forward curve is based on an estimation of 2% annual escalation rate of the total delivered price (coal + freight). The LRS coal forward curve is provided by Basin and is an estimation of escalation occurring at the rate of 3% per year. Historical coal prices for these resources are located in Section 3 Assessment of Existing Resources.

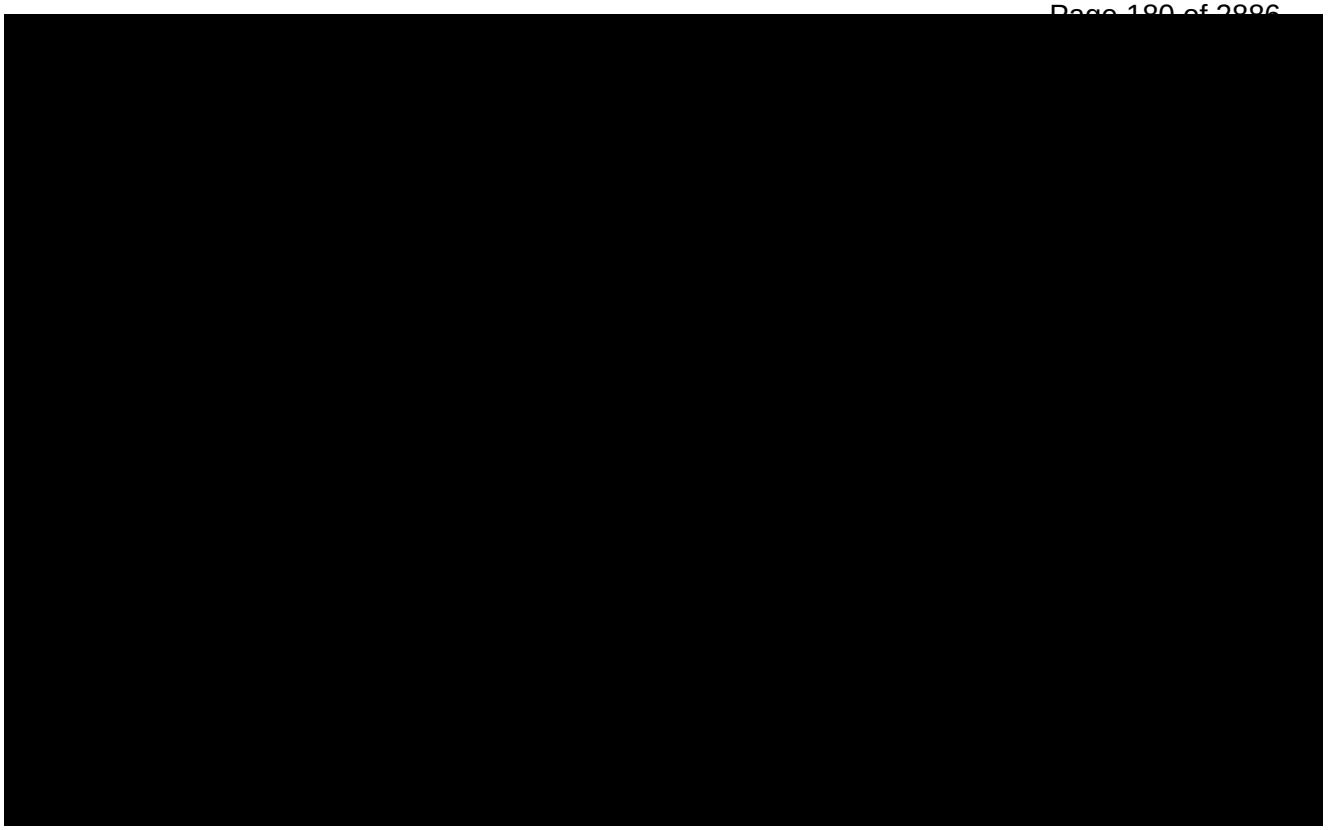

Figure 11: Coal Forward Curve for UIPlanner (Nominal dollars)

3 Assessment of Resources

Overview of Thermal Resources

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. The assessment excludes the following items, as Tri-State does not have any applicable resources in these categories:

- Thermal resources under contract (3605(c)(I)(A))
- Utility-owned energy storage resources (3605(c)(I)(A))
- Utility-owned thermal resources that are not in service at this time (3605(c)(I)(D))

The following assumptions and interpretations apply:

- The Springerville 3 minimum operating level was lowered from 251 MW to 109 MW in the fall of 2019 as a result of modifications to the coal mills and related logic. The modifications allow pulverizers to operate in a 4-burner operation per pulverizer vs the normal 6-burner operation. This allows velocity to be maintained through the mills at lower fuel throughput.
- NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.
- Capacity credits values were updated. See Section 5 Phase I Modeling Details “Table 56: Capacity Credit Values”.

- Tri-State has transitioned to the use of random hourly profiles for renewable resources instead of average hourly profiles.
- Escalante is excluded, as it was retired November 2020.
- Craig units 1, 2, and 3 useful life dates are identified as their respective announced retirement date.
- Net Dependable Capacity for coal resources is the same MW value as Maximum Capacity. (3605(c)(I)(B))
- Net Dependable Capacity for gas resources varies by season and is identified by Summer and Winter Capacity MW values. Gas resources reach their maximum capacity level in the winter. (3605(c)(I)(B))
- Marginal heat rate is calculated as the average heat rate over the RAP, which is identified as 2021 to 2030, for a typical dispatch.
- Fuel cost can be derived from provided heat rates for each resource and forward fuel curves for each fuel type. Tri-State does not utilize a forward fuel curve for oil, as its oil units are used for reliability events rather than economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental.
- For Revenue Requirements where Tri-State has partial ownership in a resource, costs represent Tri-State's prorata share.
- There are no planned significant new investment or maintenance expenses. O&M and Capex costs are representative of necessary maintenance and improvements to maintain reliability of the resources. (3605(c)(I)(E))
- Annual capital expenses[3] are an average of annual expenses over the RPP of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Operating and Maintenance costs (fixed and variable) are held constant over the planning period in planning and dispatch models (2020 dollars). UIPlanner (financial model) escalates costs for inflation.
- Costs associated with the use of emissions control systems are not separately forecast, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, SCoC is included in the revenue requirement tables for thermal resources as Tri-State is aware of the requirement to consider this value in its assessment of resources and resulting dispatches in relation to the ERP process. The SCoC is calculated as the resource CO_2 emission rate of each unit in tons per MWh times $46.60/ton SCoC for 2021. SCoC annual costs and calculated cost by resource can be found in Section 5 Phase I Modeling Details under the Social Cost of Carbon subsection of this report.

[3] Tri-State's Generation Engineering Department works with generating station engineering personnel as well as station management and corporate finance, to develop and recommend the annual capital budget request for generation. The engineering staff also develops a list of future capital expenditures needed to maintain availability and reliability of the generation stations along with maintaining regulatory and environmental compliance. These future capital expenditures make up the long-term capital forecast for Tri-State resources.

- Tri-State's gas fleet consists of intermediate and peaking units, which are designed for cycling; therefore, no cycling or integration costs are identified for those resources. (3605(c)(I)(J))
- Forecast values for model inputs are based on a combination of historical data and known or upcoming changes that will impact model input values.

Data Updates since August 3, 2030 Revision:

- Tri-States entitlement of LRS was re-rated at 461MW.
- Rifle minimum operating level was updated to 65MW.
- Craig 1, Craig 2, and Craig 3 VOMs were updated to $1.93, $1.78, & $2.45 respectively.
- Scheduled Outages for 2021 to 2030 updated from filing.
- Tri-State is using May 2020 versus March 2020 gas and power forwards curves
- Updated SCoC costs based on Commission Staff feedback

Coal-Fueled Generation Resources:

Craig Generating Station: Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Tri-State owns a 24% interest in Craig Units 1 and 2 (Yampa Project)[4], which have nameplate ratings of 427 MW and 410 MW, respectively; a 100% interest in Craig Unit 3, which has a capacity of 448 MW; and a 49% interest in the common facilities, which serve all three units. Tri-State is the operating agent for all three units and is responsible for the daily management, administration and maintenance of the facility. The non-fuel costs associated with operating Craig units 1 and 2 are divided on a pro-rata basis among all the participants[5]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado regional haze State Implementation Plan. Tri-State has also announced that Craig Units 2 and 3 will be retired by 2030.

Laramie River Generating Station: The Laramie River Station (LRS) is a three-unit, 1,700 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[6], Tri-State has a 27.1% interest (461 MW) in LRS. For operational purposes, Tri-State receives energy only from LRS 2 and 3 due to their location in the Western Interconnection. LRS 1 is scheduled solely to the Eastern Interconnection, and Tri-State does not receive energy from this resource. LRS is operated by BEPC.

Springerville Unit 3: Springerville Unit 3 is a 417 MW coal-fired electric generating unit that is part of the four-unit generation station located near Springerville, Arizona. One hundred percent of Unit 3 is leased by Tri-State. Tucson Electric Power (TEP) is the plant operator for the Springerville Generating Station.

[4] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[5] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.
[6] The Missouri Basin Power Project is the Laramie River Electric Generating Station and Transmission System located in Wyoming. Its participants include Tri-State, BEPC, the Western Minnesota Municipal Power Agency (Missouri River Energy Services), the Lincoln Electric System, and the Wyoming Municipal Power Agency (WMPA).

Table 12: Unit Characteristics for Coal Resources

	Average Heat Rate *(btu/kWh)*	**Marginal Heat Rate** *(btu/kWh)*	**Quick Start Capable** *(Yes/No)*	**Minimum Operating Level** *(MW)*	**Useful Life**[7]
Craig 1	10,316	10,518	No	31	12/31/2025[8]
Craig 2	10,219	10,273	No	31	9/30/2028[9]
Craig 3	10,135	10,256	No	130	12/31/2029[10]
LRS 2	9,926	9,877	No	94	12/31/2041
LRS 3	10,286	10,205	No	94	12/31/2042
SPV3	9,945	10,174	No	109	12/31/2066

Table 13: Emission Rates and Water Usage for Coal Resources

	CO_2 *(lb/MWh)*	**SO_2** *(lb/MWh)*	**NOx** *(lb/MWh)*	**PM** *(lb/MWh)*	**HG** *(lb/MWh)*	**Water Usage** *(gal/MWh)*
Craig 1	2319	0.378	2.771	0.042	0.00001700	492
Craig 2	2350	0.345	0.672	0.047	0.00001400	492
Craig 3	2090	1.308	2.248	0.061	0.00007800	492
LRS 2	2203	1.101	2.331	0.095	0.00004110	528
LRS 3	2407	1.823	2.410	0.177	0.00004680	528
SPV3	2139	0.838	0.787	0.031	0.00001600	546

CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh

Table 14: Revenue Requirements for Coal Resources (Real $)

	Fixed O&M[11] **Annual** *($000s)*	**Variable O&M** *($/MWh)*	**CapEx Costs Annual** *($000s)*	**Social Cost of Carbon** *($/MWh)*	**Integration & Cycling Costs** *($/MWh)*	**Fuel Curve**
Craig 1	[redacted]		~$800	$54.03	$0.129	CRG (Inc)
Craig 2			~$500	$54.76	$0.131	CRG (Inc)
Craig 3			~$3,000	$48.70	$0.124	CRG (Inc)
LRS 2			~$1,500	$51.33	$0.111	LRSG
LRS 3			~$1,500	$56.08	$0.108	LRSG
SPV3			~$6,500	$48.94	$0.138	SPV3

[7] Useful Life is determined by Tri-State's 2017 Generation Depreciation study unless otherwise identified.
[8] This date is the announced retirement date per the YAMPA participants
[9] This date is the announced retirement date per the YAMPA participants
[10] This date has been modified from 12/31/2044 per Tri-State's 2017 Generation Depreciation Study and reflects Tri-State's announcement to retire all of Craig station by 2030.
[11] Fixed O&M forecasts are arrived at on a resource specific basis by taking the VOM provided by TS generation engineering and multiply the value times recent historical annual generation and subtracting the production from total O&M expense for the same year. This value divided by total O&M of the historical year provides a percentage for fixed costs. The percentage is then applied to forecasted O&M to arrive at the fixed portion.

Tri-State forward coal prices change annually. Figure 10 in Section 2 Commodity Pricing of this report shows the Coal Forward Curve in real (2020) dollars as used in CE and PO for the ERP scenario modeling.

Gas & Oil-Fueled Generation Resources:

JM Shafer Generating Station: JM Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is wholly-owned by Tri-State subsidiary, Thermo Cogeneration Partnership, L.P., and operated by Tri-State.

Rifle Generating Station: Rifle Station is an 81 MW, natural gas-fueled combined-cycle power plant located near Rifle, Colorado. The facility is wholly-owned and operated by Tri-State.

Limon Generating Station: Limon Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Limon, Colorado. It is wholly-owned and operated by Tri-State.

Knutson Generating Station: Knutson Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Brighton, Colorado. It is wholly-owned and operated by Tri-State.

Pyramid Generating Station: Pyramid Station is a four-unit, 160 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Lordsburg, New Mexico. It is wholly-owned and operated by Tri-State.

Burlington Generating Station: Burlington Station is a two-unit, 110 MW, oil-fired simple cycle combustion turbine facility located in Burlington, Colorado. It is wholly-owned and operated by Tri-State.

Table 15: Unit Characteristics for Gas Resources

	Summer Capacity *(MW)*	**Winter Capacity** *(MW)*	**Fuel Type**	**Average Heat Rate** *(btu/kWh)*	**Marginal Heat Rate** *(btu/kWh)*	**Quick Start Capable** *(Yes/No)*	**Minimum Operating Level** *(MW)*	**Useful Life**[12]
JM Shafer	272	272	NG	9,322	9,254	No	41	12/31/2047
Rifle	72	84	NG	10,321	9,676	No	65	12/31/2028
Limon	67	74	NG/FO	11,449	11,900	Yes	40	12/31/2048
Knutson	67	74	NG/FO	11,449	11,900	No	40	12/31/2048
Pyramid	40	40	NG/FO	9,742	9,909	Yes	25	12/31/2049
Burlington	48	60	FO	14,000	-[13]	Yes	25	12/31/2037

NG = Natural Gas; FO = Fuel Oil

[12] Useful Life is determined by Tri-State's 2017 Generation Depreciation study.
[13] Burlington did not dispatch over the RAP.

Table 16: Emission Rates and Water Usage for Gas Resources

	CO_2 *(lb/MWh)*	SO_2 *(lb/MWh)*	NOx *(lb/MWh)*	PM *(lb/MWh)*	HG *(lb/MWh)*	Water Usage *(gal/MWh)*
JM Shafer	981	0.008	0.747	0.080	n/a	348
Rifle	1206	0.001	2.611	0.239	n/a	1273
Limon	1495	0.008	0.378	0.062	n/a	57
Knutson	1502	0.009	0.341	0.124	n/a	21
Pyramid	1240	0.012	1.223	0.070	n/a	120
Burlington	2149	0.194	12.383	0.158	n/a	8.82

CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh

Table 17: Revenue Requirements for Gas Resources

	Fixed O&M Annual *($000s)*	Variable O&M *($/MWh)*	CapEx Costs Annual *($000s)*	Social Cost of Carbon *($/MWh)*	Fuel Curve
JM Shafer	[redacted]		~$1,500	$22.86	CIG
Rifle			~$200	$28.10	CIG
Limon			~$275	$34.83	CIG
Knutson			~$400	$35.00	CIG
Pyramid			~$300	$28.90	Waha
Burlington			~$450	$50.07	N/A

Tri-State forward gas prices change monthly. Figure 9 in Section 2 Commodity Pricing of this report shows the gas forward curve used in the ERP scenario modeling in real (2020) dollars. Additional transport costs apply.

Depreciation, Capital Balance, Amortization and Impairment:

Table 18 shows resource depreciation as of 4th Quarter 2019. Table 19 shows the capital balance, amortization and impairment of early retirements as identified in the preferred plan. It is important to note that Tri-State does not have project financing. Tri-State finances its assets as a portfolio; therefore, debt is not tied to specific units. In addition, annual fixed O&M and capital expenses are the only avoidable costs upon early retirement of a resource.

Table 18: Resource Depreciation as of 4th Quarter 2019

FACDESC	LAND_COST	FAS_COST	106_COST	CURRENT CAPITAL INVESTMENTS	TOTAL COST EXCLUDING LAND	DEPR_RESERVE	DEPRECIATION RATE	ESTIMATED ANNUAL DEPRECIATION
[redacted]								

Table 19: Capital Balance, Amortization and Impairment of Resources per Preferred Plan[14]

Facility Description	Additional Capital Expenditures 2020 to Retirement	Early Retirement Date	Impaired Amount at Retirement	Annual amortization Early Retirement Date to Original Accounting Date (includes amortization of	Decommissioning (Including dismantling, severance, community assistance)
[redacted]					

[14] The retirement of LRS 3 and SPV3 as identified in the preferred plan are subject to further study. Any retirement of an LRS facility will be determined by the MBPP participants.

Tri-State proactively works to reduce and eliminate capital expenses related to early retirement of resources as can be seen by the historical capital expense for the Nucla facility. Nucla was set to retire by December 31, 2022 as part of an agreement in 2016, which resulted in revisions to the Colorado Visibility and Regional Haze State Implementation Plan. Tri-State retired Nucla even earlier, in September 2019. Table 20 below shows that Nucla capital expenses were reduced to zero beginning in 2017.

Table 20: Nucla Historical Capital Expenses

	2015	2016	2017	2018	2019
NUCLA	$1,573,481	$1,334,631	$0	-	$0

Tri-State eliminated capital expenses for Nucla in the years leading up to the early retirement of the facility.

Projected Availability Factors:

For modeling purposes, availability factors are a result of modeled forced outage factors as well as planned outage hours. Tri-State assumes a 4% forced outage factor for all coal-fired generation. Historically, gas and oil resources are not assigned a forced outage factor due to their limited annual capacity factors. Tri-State updated its models to reflect recommended forced outage factors as provided by B&V in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

Any required Phase 1 modeling work will include forced outage factors by unit. These factors were developed using 5 years of historical data from MicroGADS (2015-2019). Table 21 shows the forced outage factors for each thermal unit for the 5-year historical period.

Table 21: Historical MicroGADS Forced Outage Factors for Tri-State Thermal Units

Resource	2015	2016	2017	2018	2019
Craig 1	4.85	1.59	2.11	5.53	1.21
Craig 2	2.31	1.19	7.03	0.27	2.18
Craig 3	6.71	6.42	5.35	45.24[15]	3.39
LRS 2	6.80	0.27	1.81	3.14	2.20
LRS 3	11.03	1.96	1.10	0.01	0.51
SPV3	2.11	15.08	15.88	7.77	9.09
Burlington 1	0.01	0.29	2.14	2.46	0.70
Burlington 2	1.98	0.00	0.10	0.67	0.32
Knutson 1	0.18	1.45	0.07	0.33	0.89
Knutson 2	0.10	1.71	0.05	0.21	0.66
Limon 1	0.02	2.16	0.11	1.71	0.29
Limon 2	0.31	0.88	1.15	0.45	0.57
Pyramid 1	0.01	0.53	0.15	0.27	0.35

[15] The Craig 3 steam turbine generator experienced a failure in 2018 resulting in a significant forced outage for repair. Due to the low probability of this type of event, Tri-State only considered 4 years of historical data to determine the forced outage factor for this thermal unit.

Resource	2015	2016	2017	2018	2019
Pyramid 2	0.02	0.42	0.30	2.76	0.07
Pyramid 3	0.16	0.78	0.02	0.26	0.97
Pyramid 4	0.01	0.46	0.04	0.26	2.41
Rifle[16]	0.00	5.17	2.64	2.01	1.43
JM Shafer	3.59	1.46	1.61	5.04	13.13

Table 22 provides the forced outage factors that will be used for any Phase 1 modeling for each thermal unit.

Table 22: Forced Outage Factors to be used in Phase 1 modeling

Unit	5-yr average (%)
Craig 1	3.06
Craig 2	2.60
Craig 3	5.47
LRS 2	2.84
LRS 3	2.92
SPV3	9.99
Burlington 1	1.12
Burlington 2	0.61
Knutson 1	0.58
Knutson 2	0.55
Limon 1	0.86
Limon 2	0.67
Pyramid 1	0.26
Pyramid 2	0.71
Pyramid 3	0.44
Pyramid 4	0.64
Rifle	2.25
JM Shafer	4.97

[16] For combined cycle plants (Rifle and JM Shafer), forced outage factors are reported for reach gas turbine and each steam turbine. The Plant-wide forced outage factor is determined as the average forced outage factor of all units comprising the entire plant.

Table 23: Applicable Scheduled Outage Plan over the RAP

	Craig 1	Craig 2	Craig 3	LRS 2	LRS 3	SPV3
Start Date	[redacted]					
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						
Start Date						
Stop Date						

Third Party Assessment:

In preparation for Tri-State's 2020 Resource Plan processes, Tri-State engaged B&V to assist Tri-State with this assessment of existing resources. The above data reflects the outcome of that assessment where applicable. Specific areas of recommended change were as follows:

Table 24: Summary of Third-Party Recommendations

B&V Recommendation	Conclusion
Increase Burlington Heat Rate	Adjustment made to heat rate curve
Change Availability Factor of Combined Cycle resources to 90%	Capacity factors are relatively low on Combined Cycle resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Change Availability Factor of Combustion Turbine dual fuel resources to 96%	Capacity factors are relatively low on Combustion Turbine dual fuel resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Change Availability Factor of Combustion Turbine oil resources to 98%	Capacity factors are relatively low on Combustion Turbine oil resources and remain so in CO_2 reduced cases, so Tri-State did not make this change at this time
Reduction in Rifle Fixed Costs	Rifle fixed costs are based on historical data. Tri-State will continue to monitor Rifle fixed costs and adjust as necessary.
Reduction to Burlington and Rifle NOx emission rate	Burlington and Rifle NOx emissions are based on historical data. There are conditions specific to these units that make their emissions rates higher than industry averages, so this will remain at the higher level for modeling purposes so as not to under represent potential emissions.
Increase to Rifle and JM Shafer SO_2 emission rates	Rifle and JM Shafer SO_2 emission rates are based on historical data. Tri-State will continue to monitor SO_2 for these units and update as needed.
Decrease of availability factor and related increase in equivalent forced outage factor for all gas units	JM Shafer and Rifle were modeled with the recommended 3% forced outage factor. Because capacity factors are relatively low on the remaining Combustion Turbine oil and

B&V Recommendation	Conclusion
	natural gas resources and remain so in CO_2 reduced cases, they were modeled at their winter and summer capacities.

The B&V evaluation of resources detail can be found in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

Resource Reference Data:

Table 25: Resource Characteristics Reference

Tri-State Resource Table										
State	Fuel	Name	Type	Unit Net Capacity (MW)	Modeled Capacity (MW)	Net Dependable Capacity (MW)	Year in Service/Contract Start	Estimated Retirement/End Date	Heat Rate	Availability Factor %*
--	Basin	East Basin_East Basin	Unspecified	317	317	317	Effective 1/16/1975	2050	N/A	N/A
--	Basin	West Basin_West Basin	Unspecified	268	268	268	Effective 1/16/1975	2050	N/A	N/A
AZ	Coal	Springerville 3	Steam Turbine	417	317	317	2006	2066	9,945	84.11
CO	Coal	Craig 1	Steam Turbine	427	102	102	1980	2025	10,316	91.93
CO	Coal	Craig 2	Steam Turbine	410	98	98	1979	2028	10,219	91.11
CO	Coal	Craig 3	Steam Turbine	448	448	448	1984	2029	10,135	82.34
WY	Coal	LRS 2	Steam Turbine	570	231	231	1981	2041	9,926	93.02
WY	Coal	LRS 3	Steam Turbine	570	230	230	1982	2042	10,286	93.57
CO	Oil	Burlington 1	Frame CT	55	55	48	1977	2037	14,000	97.92
CO	Oil	Burlington 2	Frame CT	55	55	48	1977	2037	14,000	98.73
CO	Gas/Oil	Knutson 1	Frame CT	70	70	67	2002	2048	11,449	96.78
CO	Gas/Oil	Knutson 2	Frame CT	70	70	67	2002	2048	11,449	95.99
CO	Gas/Oil	Limon 1	Frame CT	70	70	67	2003	2048	11,449	96.66
CO	Gas/Oil	Limon 2	Frame CT	70	70	67	2003	2048	11,449	92.96
CO	Gas	Rifle	Combined Cycle	81	81	72	1987	2028	10,321	90.77
CO	Gas	Shafer	Combined Cycle	272	272	272	1994	2047	9,322	88.06
NM	Gas/Oil	Pyramid 1	Aeroderivative CT	40	40	40	2003	2049	9,742	98.58
NM	Gas/Oil	Pyramid 2	Aeroderivative CT	40	40	40	2003	2049	9,742	98.62
NM	Gas/Oil	Pyramid 3	Aeroderivative CT	40	40	40	2003	2049	9,742	98.62
NM	Gas/Oil	Pyramid 4	Aeroderivative CT	40	40	40	2003	2049	9,742	98.53
--	Hydro	WAPA CRSP	Hydro	231	231	231	Effective 10/1/1989	2057	N/A	N/A
--	Hydro	WAPA LAP	Hydro	353	353	353	Effective 10/1/1989	2054	N/A	N/A
CO	Hydro	Small PPAs	Hydro PPA	22	22	22	various	various	N/A	N/A
CO	Solar	Axial	Tracking Array	145	145	51	2023	2038	N/A	N/A
CO	Solar	Coyote Gulch	Tracking Array	120	120	42	2023	2038	N/A	N/A
CO	Solar	Dolores	Tracking Array	110	110	39	2023	2038	N/A	N/A
CO	Solar	San Isabel	Tracking Array	30	30	11	2016	2041	N/A	N/A
CO	Solar	Spanish Peaks	Tracking Array	100	100	35	2023	2038	N/A	N/A
NM	Solar	Alta Luna	Tracking Array	25	25	9	2017	2042	N/A	N/A
NM	Solar	First Solar	Fixed	30	30	11	2010	2035	N/A	N/A
NM	Solar	SpanishPeaksTwo	Tracking Array	40	40	14	2023	2038	N/A	N/A
NM	Solar	TPE/Escalante	Tracking Array	200	200	70	2023	2040	N/A	N/A
CO	Wind	Carousel	Wind	150	150	45	2015	2041	N/A	N/A
CO	Wind	Colo Highlands	Wind	91	91	27	2012	2032	N/A	N/A
CO	Wind	Crossing Trails	Wind	104	104	31	2020	2035	N/A	N/A
CO	Wind	Kit Carson	Wind	51	51	16	2010	2030	N/A	N/A
CO	Wind	Niyol	Wind	200	200	60	2021	2041	N/A	N/A
CO	Wind	Twin Buttes	Wind	76	76	23	2017	2042	N/A	N/A

* Based on historical data 2015 -2019

Resource Historical Data:

Historical data for key modeling inputs are located in this subsection. Forecasts of modeling inputs are based on a combination of historical data and known present or upcoming changes that might impact forecasts. Explanations of deviations in historical data are included in this section.

Table 26 shows actual O&M expenses from 2015 to 2019 by resource or facility as available. Source of the data is Tri-State financials.

Table 26: Annual Historical O&M by Resource ($000s)[17]

Resource	2015	2016	2017	2018	2019
[redacted]					

Table 27 Annual Historical Capital Expenses by Resource ($)

Resource	2015	2016	2017	2018	2019
Craig 1&2	$15,292,219	$18,831,363	$14,207,660	$954,865	$733,093
Craig 3	$23,259,837	$13,183,323	$4,452,621	$1,031,365	$1,309,988
Burlington 1&2	$280,336	$17,504	$16,817	$479,627	$210,512
Limon 1&2	$66,250	$422,075	$746,182	$1,877,331	$387,852
Knutson 1&2	$23,427	$186,834	$331,991	$1,614,627	$164,062
Pyramid 1,2,3,&4	$397,258	$287,402	$11,604	$798,934	$133,503
Rifle	$193,100	$173,330	$109,516	$0	$0
JM Shafer	$26,070,218	$5,556,312	$1,810,132	$18,514,466	$10,295,315
LRS 2&3	$9,128,577	$7,341,987	$24,835,767	$28,798,723	$14,340,410
SPV3	$6,654,229	$7,873,305	$232,853	$4,230,232	$15,185,386
MISCELLANEOUS - OTHER	$16,606,825	$9,311,148	$5,573,490	$16,650,994	$5,874,228
TOTAL GENERATION	**$97,972,276**	**$63,184,583**	**$52,328,633**	**$74,951,164**	**$48,634,349**

[17] Note that until June 30, 2019, a portion of JM Shafer was under a tolling contract to PSCO, and therefore history of resource operation and resulting costs is not necessarily reflective of future use.

Capital expenditures fluctuate to reflect ongoing needs that have been determined by site personnel, guidelines by equipment manufacturers and regulations for environmental, safety and regulatory compliance. The timing of larger capital upgrades is planned with major maintenance work when feasible. Table 28 explains larger capital expenditures by facility in recent history.

Table 28: Explanation of Historical Capital Expenses

Facility	Explanation of Historical Capital Expenses
CRAIG 1&2	Primary capex driver in 2015 and 2017 were environmental upgrades. Primary capex drivers in 2016 were environmental upgrades and controls upgrades.
CRAIG 3	Primary capex drivers in 2015 were environmental upgrades, controls upgrades and water purchases. Primary capex driver in 2016 was the continuation of the environmental upgrades.
BURLINGTON 1&2	Primary capex driver in 2018 was replacing various protective relaying.
LIMON 1&2	Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines.
KNUTSON 1&2	Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines.
PYRAMID 1,2,3&4	Primary capex driver in 2018 replacing various protective relaying.
RIFLE	Tri-State has been actively trying to decrease capital expenses at Rifle other than what is necessary for compliance.
JM SHAFER	Primary capex drivers for 2015 and 2018 were water purchases and water infrastructure for operations. Primary capex drivers for 2019 were large maintenance projects including a complete engine overhaul/rebuild.
LRS 2&3	Primary capex drivers in 2017 and 2018 were environmental compliance projects. (Selective Catalytic Reduction and Selective Noncatalytic Reduction).
SPV3	Primary capex driver in 2019 was the superheater reheater pendant replacement.

Table 29: Annual Historical Fuel Price by Pipeline ($/MMBtu)

Hub	2015	2016	2017	2018	2019
CIG	$2.39	$2.25	$2.63	$2.58	$2.06
WAHA	$2.46	$2.33	$2.68	$2.01	$0.86

The average of the last 5 years (2015-2019) of CIG prices is $2.38/MMBtu while WAHA's 5 year average is $2.07/MMBtu. In Section 2 - Commodity Pricing - Gas Forward Curve Tri-State describes the methodology for developing its forward gas curves. The 1st five years (2021 – 2025) of forward curve pricing show CIG's average to be $2.20/MMBtu and WAHA is at $2.07/MMBtu. Following those years, the forecast shows gas prices increasing based upon blended midterm and fundamental pricing.

Table 30: Historical Coal Fuel Pricing by Resource ($/MMBtu)

Coal Source	2016	2017	2018	2019
CRG	[redacted]			
LRS				
SPV3				

Table 31 Annual Historical Heat Rate (btu/kWh)

Resource	2015	2016	2017	2018	2019
Craig 1&2	10153	10196	10165	10232	9370
Craig 3	10157	10219	10121	10472	9526
LRS 2 & 3	9345	9965	9080	9800	9082
SPV3	10115	10404	10211	9236	10700
Burlington 1&2	*	*	*	*	13444
Knutson 1&2	*	12803	12761	9070	12399
Limon 1&2	12860	12434	12525	12381	12048
Pyramid 1,2,3,&4	10415	10319	10444	10421	8163
Rifle	10272	9677	10135	*	9663
JM Shafer	8820	8368	8642	7840	8930

*** insufficient data**

Table 32: Annual Historical CO_2 Emissions Rate by Resource

Unit	CO_2 (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	2350	2265	2225	2203	2379
LRS 3	2510	2530	2556	2407	2671
Craig 1	2282	2244	2299	2319	2395
Craig 2	2312	2252	2315	2350	2406
Craig 3	2110	2076	2084	2090	2171
Springerville 3	2250	2278	2160	2139	2392
Burlington 1	2174	2444	2452	2212	2248
Burlington 2	2145	2122	2261	2086	2259
Pyramid 1	1271	1203	1167	1240	1179
Pyramid 2	1196	1211	1252	1232	1203
Pyramid 3	1215	1372	1289	1250	1187
Pyramid 4	1275	1218	1237	1238	1206
Rifle	1197	1109	1195	1206	1154
Limon 1	1560	1525	1453	1498	1480
Limon 2	1528	1566	1546	1492	1479
Knutson 1	1469	1489	1479	1504	1481
Knutson 2	1507	1992	1533	1500	1517
JM Shafer	1050	986	981	981	944

Table 33: Annual Historical SO_2 Emissions Rate by Resource

Unit	SO_2 (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	1.209	0.819	1.073	1.101	1.164
LRS 3	1.972	1.545	1.598	1.823	1.525
Craig 1	0.525	0.470	0.489	0.378	0.511
Craig 2	0.555	0.497	0.501	0.345	0.460
Craig 3	1.266	1.384	1.251	1.308	1.248
Springerville 3	0.708	0.816	0.932	0.838	0.810
Burlington 1	0.000	0.000	0.222	0.206	0.113
Burlington 2	0.000	0.000	0.174	0.182	0.113
Pyramid 1	0.017	0.011	0.011	0.013	0.006
Pyramid 2	0.014	0.020	0.027	0.017	0.006
Pyramid 3	0.011	0.063	0.024	0.012	0.006
Pyramid 4	0.011	0.012	0.015	0.006	0.006
Rifle	0.000	0.000	0.000	0.001	0.000
Limon 1	0.011	0.008	0.009	0.008	0.010
Limon 2	0.008	0.008	0.008	0.008	0.008
Knutson 1	0.008	0.007	0.009	0.009	0.008
Knutson 2	0.008	0.011	0.009	0.010	0.008
JM Shafer	0.005	0.005	0.005	0.008	0.005

Table 34: Annual Historical NOx Emissions Rate by Resource

Unit	NOx (lbs/net MWh)				
	2015	2016	2017	2018	2019
LRS 2	1.682	1.650	1.648	2.331	1.600
LRS 3	1.774	1.786	1.906	2.410	1.824
Craig 1	2.735	2.622	2.748	2.771	2.878
Craig 2	2.790	2.681	2.482	0.672	0.721
Craig 3	2.972	2.937	2.815	2.248	2.404
Springerville 3	0.827	0.817	0.900	0.787	0.963
Burlington 1	11.573	12.661	13.210	12.482	12.132
Burlington 2	11.657	11.502	12.123	12.283	12.193
Pyramid 1	1.358	1.087	1.208	1.253	1.189
Pyramid 2	1.306	1.190	1.122	1.169	1.218
Pyramid 3	1.176	1.287	1.299	1.253	1.178
Pyramid 4	1.607	1.186	1.127	1.218	1.157
Rifle	1.974	3.771	1.827	2.611	2.016
Limon 1	0.445	0.321	0.359	0.432	0.375
Limon 2	0.342	0.337	0.405	0.324	0.383
Knutson 1	0.368	0.349	0.363	0.345	0.341
Knutson 2	0.373	0.488	0.392	0.337	0.358
JM Shafer	0.773	0.735	0.749	0.747	0.703

Table 35: Annual Historical Hg Emissions Rate by Resource

Unit	Hg (lbs/gross MWh)				
	2015	2016	2017	2018	2019
LRS 2	0.0000053	0.0000064	0.0000061	0.0000411	0.0000086
LRS 3	0.0000042	0.0000091	0.0000097	0.0000468	0.0000111
Craig 1	0.0000014	0.0000017	0.0000030	0.0000170	0.0000044
Craig 2	0.0000027	0.0000036	0.0000025	0.0000140	0.0000036
Craig 3	0.0000089	0.0000092	0.0000091	0.0000780	0.0000070
Springerville 3	0.0000038	0.0000024	0.0000053	0.0000160	0.0000045
Burlington 1	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A
JM Shafer	N/A	N/A	N/A	N/A	N/A

Table 36: Annual Historical PM Emissions Rate by Resource

Unit	PM (lbs/gross MWh)				
	2015	2016	2017	2018	2019
LRS 2	0.1410	0.0702	0.0544	0.0953	0.1052
LRS 3	0.1767	0.2115	0.0758	0.1770	0.1778
Craig 1	0.0845	0.0980	0.0649	0.0421	0.0379
Craig 2	0.0893	0.0552	0.0462	0.0469	0.0467
Craig 3	0.0522	0.0478	0.0399	0.0614	0.0124
Springerville 3	0.0378	0.0287	0.0748	0.0306	0.2478
Burlington 1	0.1601	0.1799	0.1803	0.1620	0.1654
Burlington 2	0.1580	0.1562	0.1653	0.1530	0.1663
Pyramid 1	0.0707	0.0661	0.0641	0.0710	0.0643
Pyramid 2	0.0666	0.0682	0.0709	0.0720	0.0658
Pyramid 3	0.0670	0.0835	0.0723	0.0720	0.0645
Pyramid 4	0.0699	0.0673	0.0686	0.0650	0.0660
Rifle	0.2829	0.1699	0.1881	0.2390	0.2370
Limon 1	0.0735	0.0598	0.0606	0.0616	0.0614
Limon 2	0.0604	0.0620	0.0618	0.0625	0.0593
Knutson 1	0.1170	0.1158	0.1142	0.1237	0.1156
Knutson 2	0.1221	0.1205	0.1186	0.1237	0.1174
J M Shafer	0.0570	0.0545	0.0551	0.0804	0.0514

Table 37: Annual Historical Water Usage Rate by Resource

Unit	Water Usage (gal/MWh)				
	2015	2016	2017	2018	2019
LRS 2	543	541	509	528	492
LRS 3	514	507	543	528	475
Craig 1	488	496	494	492	498
Craig 2	488	496	494	492	498
Craig 3	488	496	494	492	498
Springerville 3	555	571	584	546	625
Burlington 1	16	12	4	8.82	1
Burlington 2	16	12	4	8.82	1
Pyramid 1	107	129	132	120	93
Pyramid 2	107	129	132	120	93
Pyramid 3	107	129	132	120	93
Pyramid 4	107	129	132	120	93
Rifle	1350	1372	1951	1273	495
Limon 1	31	17	59	57	47
Limon 2	31	17	59	57	47
Knutson 1	46	10	32	21	18
Knutson 2	46	10	32	21	18
J M Shafer	255	472	451	348	460

Overview of Purchases

The following list provides summary information regarding current firm purchase power agreements in regards to capacity, energy and demand side resources. Tri-State does not have any wheeling or coordination agreements that provide capacity and energy.

Contract Purchases and Renewable PPAs differ from thermal resources in regards to applicable characteristics and costs. The format used below is intended to present the applicable data for these agreements as required in Rule 3605(c).

Summer capacities are representative of contract demand available to serve July peak.

Net Dependable Capacities (Capacity Credit) for renewable resources are identified in Section 5 Phase I Modeling Details under the Modeling Assumptions subsection of this report.

Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[18]. Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

[18] Profile detail is shown in the Contract Profile Information subsection.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[19], Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

CRSP WAPA: 231 MW summer capacity ~1424 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract. Effective Date 10/1/1989; Renewed Date 10/1/2017; Contract Expires 9/30/2057.

- Contracts TS-89-0005 and PL-89-0002 expire end of day, 9/30/2024. Contract TS-17-0128 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/1/2024 through end of day 9/30/2057.

LAP WAPA: 353 MW summer capacity, ~900 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract, Effective Date 10/1/1989; Contract Expiration 9/30/2054.

- Contract TS-89-0002 expires end of day, 9/30/2024. Contract TS-14-0238 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/01/2024 through end of day, 9/30/2054.
- LAP contract includes rights to Mt. Elbert pump back storage 176 MW summer capacity with a 68% efficiency and prescribed generating and pumping hours. The Mt. Elbert contract capacity shares transmission with the LAP contract and the combination of usage cannot exceed the LAP contract max capacity in any hour.

Native American WAPA Allocations: Monthly (fixed schedule peaking) at 5 MW annually, ~28 GWh/year. Effective Date 10/1/2004; Expires 10/1/2024.

Central Valley Electric: ~1 MW capacity, ~5 GWh/year. Effective Date 12/05/1996; Contract Expires Evergreen

Public Service Company of New Mexico Unit Contingent Purchase: 100MW unit contingent purchase from PNM at SJ345. 100 MW (Maximum Capacity) ~876 GWh/year. Effective Date 06/01/2017; Contract Expires 05/31/2022. This is the purchase side of a swap that reduces spinning reserve obligations.

Additionally, Tri-State has several contracts under WSPP agreements that serve Utility Member system load associated with wind and solar facility station service for generators that are under contract and deliver energy to third party utilities but are located in a Tri-State Utility Member's service territory. These contracts are de minimis in nature (i.e., under 1 GWh in annual energy; 2 MW maximum demand).

- PRPA – Rawhide Solar Station Service (SS): Contract commenced 9/1/2016; contract expires 9/1/2021 – Expected to renew making the new contract expiration 9/1/2026
- PRPA – Prairie Solar SS: Contract commenced 5/1/2020; contract expires 5/1/2025

[19] Profile detail is shown in the Contract Profile Information subsection.

- PRPA – Roundhouse Wind SS: Contract commenced 6/3/2020; contract expires 6/1/2025
- CSU – Palmer Solar SS: Contract commenced 4/1/2020; contract expires 4/1/2025

Contract Profile Information:

Projected Basin Contract Energy & Demand

Basin CROD Western Interconnection contract energy profile is a set hourly profile identified by point of delivery. Stegall West 230KV Bus is located in Nebraska. AU 230KV and Story 230KV busses are located in Colorado. Figures 12 and 13 show the hourly profiles by point of delivery for each month:

POINT OF DELIVERY: STEGALL WEST 230KV BUS

Month\HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
JAN	73	71	72	71	74	75	84	92	91	88	86	85	82	81	79	80	86	94	97	95	94	90	85	75	2,000
FEB	73	72	72	72	74	81	85	91	90	89	88	86	83	82	81	81	85	89	97	96	94	91	85	74	2,011
MAR	69	67	68	68	72	76	83	82	82	81	80	77	75	75	74	74	75	79	84	84	84	80	74	69	1,832
APR	48	46	46	46	47	51	56	57	58	58	58	55	55	54	54	54	55	56	58	59	60	58	53	49	1,291
MAY	54	52	51	51	52	55	61	63	65	65	65	65	65	65	65	65	67	67	67	68	68	67	63	58	1,484
JUN	80	75	73	72	73	76	81	93	98	100	102	105	105	106	106	107	107	108	107	108	107	107	100	88	2,284
JUL	89	85	84	83	83	84	88	99	104	108	112	114	115	117	118	119	119	119	118	118	115	115	107	94	2,507
AUG	88	85	84	83	83	85	90	99	104	107	110	112	113	114	115	117	117	117	117	117	117	113	104	92	2,483
SEP	54	53	52	51	52	55	61	70	71	73	73	74	74	74	76	76	76	78	79	81	81	76	69	56	1,635
OCT	55	52	51	51	52	55	60	69	71	72	72	70	68	68	69	70	72	73	73	73	73	70	67	55	1,561
NOV	67	67	67	67	70	74	78	81	81	82	80	77	76	75	74	76	80	85	86	85	84	80	75	70	1,837
DEC	72	72	72	72	73	76	84	90	90	89	87	85	83	81	80	87	93	99	100	99	97	94	87	76	2,038

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

Figure 12: Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile

POINT OF DELIVERY: AULT 230KV and STORY 230KV BUSSES

Month\HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
JAN	92	90	90	90	93	95	105	115	114	111	109	107	103	102	99	100	108	118	122	119	118	114	106	95	2,515
FEB	91	90	90	90	93	102	107	114	114	112	110	108	104	103	102	102	106	112	122	121	119	114	107	93	2,526
MAR	86	85	85	86	90	96	104	104	104	102	100	96	94	94	94	94	94	100	105	106	105	100	93	87	2,304
APR	60	58	57	57	59	64	70	72	72	72	72	70	69	68	67	67	69	71	72	73	75	73	66	61	1,614
MAY	67	65	64	64	65	70	76	80	81	82	82	82	82	82	82	82	85	85	85	85	85	84	80	72	1,867
JUN	100	95	92	92	92	96	102	118	123	126	130	131	132	133	133	135	136	136	136	136	136	134	126	110	2,880
JUL	111	107	106	104	104	106	110	123	130	135	140	143	145	146	148	149	149	149	148	148	145	144	135	117	3,142
AUG	110	107	106	104	105	107	111	124	129	135	137	140	142	143	145	146	146	146	146	146	146	146	140	130	115	3,106
SEP	68	66	64	64	65	69	76	88	90	91	92	93	93	93	95	95	96	98	98	102	102	95	85	70	2,048
OCT	68	65	64	64	65	69	76	86	89	90	90	88	85	85	86	88	90	92	92	92	91	88	84	69	1,956
NOV	84	83	83	83	87	93	98	102	102	102	100	97	95	93	93	96	99	106	108	106	104	100	94	87	2,295
DEC	90	90	89	89	91	96	105	113	113	111	108	106	103	102	100	108	117	123	125	124	122	118	109	95	2,547

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

Figure 13: Basin CROD Western Interconnection AU 230KV and STORY 230KV Busses Hourly Profile

Basin Electrically East contract has an energy and demand profile based on forecast Electrically East (Nebraska and Colorado) load, as this is a full requirements contract. The load served by this full requirements contract is located in the Eastern Interconnection primarily in the state of Nebraska with a small amount of Colorado load in the far northeastern portion of Colorado. On an average annual basis, ~15% of this purchase serves Colorado. The balance of this purchase serves load in Nebraska.

Hourly Profiles for the Basin Electrically East contract vary by season and are heavily impacted by irrigation. Figure 14 shows a typical hourly profile in a given day for the Irrigation and Non-Irrigation seasons. As shown by the orange line in the graph the hourly load during non-irrigation season barely exceeds 50 MW with a sharp morning peak, while the hourly load during irrigation season (yellow line) has a sustained daytime peak closer to ~280MW.

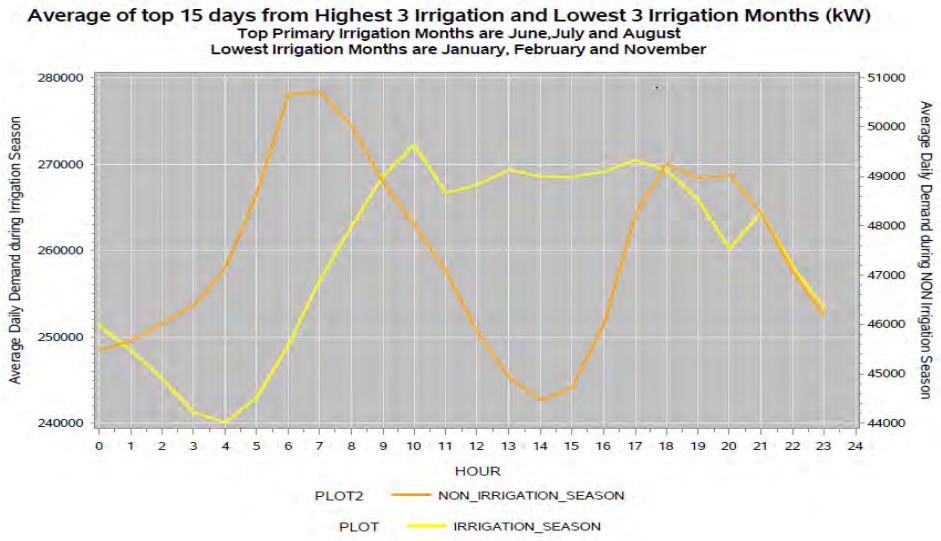

Figure 14: Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

Below is a snapshot of historical energy and demand for the Basin Electrically East contract by month:

Table 38: Historical Energy and Demand for Basin Electrically East

Year	Data/UOM	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018	Energy *(GWh)*	38	35	36	37	38	72	129	138	59	28	28	30
2018	Demand *(MW-Mo)*	76	76	62	64	88	191	335	269	126	55	49	53
2019	Energy *(GWh)*	29	29	27	23	35	45	137	117	60	24	29	29
2019	Demand *(MW-Mo)*	52	54	57	55	73	155	305	255	208	48	51	47

Below summarizes the annual projected energy and demand for each Basin contract.

Table 39: Annual Projected Energy for Basin Contracts

Energy *(GWh)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Basin CROD Western Interconnection[20]	1575	1575	1575	1580	1575	1575	1575	1580	1575	1575
Basin Electrically East [21]	664	683	686	689	692	694	698	701	704	707

Table 40: Annual Projected Demand for Basin Contracts

Annual Demand *(Sum of MW-Mo)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Basin CROD Western Interconnection	2458	2458	2458	2458	2458	2458	2458	2458	2458	2458
Basin Electrically East	1383	1553	1559	1566	1572	1579	1586	1594	1600	1608

Projected WAPA Contracts – LAP & CRSP Energy & Demand

LAP and CRSP contracts provide a set amount of energy delivered to each sub region by month. Additionally, an hourly minimum and maximum MW take is provided for each sub region by month. Tri-State is required to schedule on a two-day ahead basis the hydro in each sub region by "dispatching" the energy within the hourly minimum and maximum ranges.

Table 41 below summarizes the annual projected energy and demand for the WAPA CRSP and LAP contracts.

Table 41: Annual Projected Energy by Contract

Energy *(GWh)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CRSP Total	1424	1424	1424	1424	1424	1424	1424	1424	1424	1424
Colorado Deliveries	930	930	930	930	930	930	930	930	930	930
New Mexico Deliveries	494	494	494	494	494	494	494	494	494	494
LAP Total	900	900	900	900	900	900	900	900	900	900
Colorado/Wyoming Deliveries	711	711	711	711	711	711	711	711	711	711
Nebraska Deliveries	189	189	189	189	189	189	189	189	189	189

[20] Energy is delivered to Colorado and Wyoming.
[21] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska. Energy and Demand data is per the 2020 annual load forecast.

Table 42: Annual Projected Demand by Contract

Annual Demand [22] *(Sum of MW-Mo)*	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CRSP Total	4807	4807	4807	4807	4807	4807	4807	4807	4807	4807
Colorado Deliveries	3105	3105	3105	3105	3105	3105	3105	3105	3105	3105
New Mexico Deliveries	1702	1702	1702	1702	1702	1702	1702	1702	1702	1702
LAP Total	3823	3823	3823	3823	3823	3823	3823	3823	3823	3823
Colorado/Wyoming Deliveries	3029	3029	3029	3029	3029	3029	3029	3029	3029	3029
Nebraska Deliveries	794	794	794	794	794	794	794	794	794	794

Energy and Capacity Payments for Contract Purchases:

The following rates are averaged over the RAP:

Table 43: Average Energy and Demand Rates over the Resource Acquisition Period

Resource	**Energy Rate** *($/MWh)*	**Demand Rate** *($/KW-month)*
Basin CROD Western Interconnection		
Basin Electrically East		
CRSP	$12.19	$5.18
LAP	$15.72	$4.12
Native American WAPA Allocations		
Central Valley Electric		

Table 44: Historical Contract Pricing

Contracts	**Rate Type**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
WAPA LAP	Demand Rate ($/kW)	$5.43	$5.43	$4.79	$4.12	$4.12	$4.12
	Energy Rate ($/MWh)	$20.71	$20.71	$18.28	$15.72	$15.72	$15.72
WAPA CRSP	Demand Rate ($/kW)	$5.18	$5.18	$5.18	$5.18	$5.18	$5.18
	Energy Rate ($/MWh)	$12.19	$12.19	$12.19	$12.19	$12.19	$12.19
Basin Nebraska	Demand Rate ($/kW)						
	Energy Rate ($/MWh)						
Basin CO/WY	Demand Rate ($/kW)						
	Energy Rate ($/MWh)						
WAPA Native American Allocations	Average Energy Rate ($/MWh)						
WAPA Resource Balancing Purchase	Energy Rate ($/MWh)						
Central Valley Electric	Average Energy Rate ($/MWh)						
PNM UC	Energy Rate ($/MWh)						
PRPA - Rawhide Solar SS	Energy Rate ($/MWh)						
PRPA - Prairie Solar SS	Energy Rate ($/MWh)						
PRPA - Roundhouse Wind SS	Energy Rate ($/MWh)						
CSU - Palmer Solar SS	Energy Rate ($/MWh)						

[22] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.
[23] Composite rate encompassing energy and demand components
[24] Composite rate encompassing energy and demand components

Renewable Power Purchase Agreements:

Cimarron (First Solar) Purchase: Facility located in northeastern New Mexico, 30 MW (Maximum Capacity), ~64 GWh/year. Effective Date 2/23/2009; COD 11/25/2010; Contract Expires 11/24/2035.

Kit Carson Wind Purchase: Facility located in eastern Colorado, 51 MW (Maximum Capacity), ~185 GWh/year. Effective Date 6/30/2009; COD 11/19/2010; Contract Expires 11/30/2030.

Colorado Highlands Wind Purchase: Facility located in northeastern Colorado, 94 MW (Maximum Capacity) 91 MW (Nameplate Capacity), ~369 GWh/year. Effective Date 2/28/2012; COD 12/6/2012; Contract Expires 12/31/2032.

Carousel Wind Purchase: Facility located in eastern Colorado, 150 MW (Maximum Capacity), ~665 GWh/year. Effective Date 12/27/2013; COD 07/07/2016; Contract Expires 7/31/2041.

San Isabel Solar Purchase: Facility located in southern Colorado, 30 MW (Maximum Capacity), ~77 GWh/year. Effective Date 8/19/2015; COD 12/5/2016; Contract Expires 12/31/2041.

Alta Luna Solar Purchase: Facility located in southern New Mexico, 25 MW (Maximum Capacity), ~77 GWh/year. Effective Date 9/24/2015; COD 1/12/2017; Contract Expires 01/31/2042.

Twin Buttes II Wind Purchase: Facility located in southeastern Colorado, 75 MW (Maximum Capacity), ~302 GWh/year. Effective Date 6/1/2015; COD 12/28/2017, Contract Expires 12/31/2042.

Spanish Peaks Solar Purchase: Facility located in southern Colorado, 100 MW (Maximum Capacity), ~267 GWh/year. Effective Date 12/12/2018; Expected COD 11/01/2023, Contract Expires 11/30/2038*.Crossing Trails Wind Purchase: Facility located in eastern Colorado, 104 MW (Maximum Capacity), ~439 GWh/year. Effective Date 2/5/2019; Expected COD 12/18/2020, Contract Expires 12/31/2035*.

Niyol Wind Purchase: Facility located in northeastern Colorado, 200 MW (Maximum Capacity), ~843 GWh/Year. Effective Date 12/18/2019; Expected COD 12/31/2021, Contract Expires 12/31/2041*.

Escalante Solar Purchase: Facility located in western New Mexico, 200 MW (Maximum Capacity), ~566 GWh/Year. Effective Date 12/10/2019; Expected COD 11/30/2023, Contract Expires 11/30/2040*.

Axial Basin Solar Purchase: Facility located in northwestern Colorado, 145 MW (Maximum Capacity), ~370 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Dolores Canyon Solar Purchase: Facility located in southwestern Colorado, 110 MW (Maximum Capacity), ~297 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Spanish Peaks II Solar Purchase: Facility located in southern Colorado, 40 MW (Maximum Capacity), ~107 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Coyote Gulch Solar Purchase: Facility located in southwestern Colorado, 120 MW (Maximum Capacity), ~331 GWh/Year. Effective Date 1/13/2020; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

All solar power purchase agreements are assumed to have declining annual energy at approximately 0.5% per year to reflect solar panel degradation

*Contract expiration calculated from expected COD

Small Power Producers (Hydropower) Contracts:

Table 45: Summary of Small Power Producers (Hydro) Contracts

Facility Name (Maximum Capacity)	Effective Date	Expiration	Location
Boulder Hydro (5MW) & Other Facilities (1.27 MW)	6/1/2018	5/31/2028	Colorado
Denver Water/Williams Fork (3.5 MW)	1/1/2007	12/31/2026	Colorado
Mancos/Jackson Gulch (0.26 MW)	9/1/1995	2/8/2035	Colorado
Vallecito/Ptarmigan (5.6 MW)	6/25/2004	6/24/2024	Colorado
Garland Canal (2.9 MW)	12/10/2014	12/31/2024	Wyoming
Tri-County Water/Ridgway (8 MW)	8/22/2012	9/30/2023	Colorado

Energy Payments for Renewable Power Purchase Agreements:

The following rates are averaged over the RAP. Capacity rates are not applicable to our Renewable Power Purchase Agreements:

Table 46: Energy Prices for PPAs over the Resource Acquisition Period.

Resource	Energy Rate *($/MWh)*
Cimarron	[redacted]
Kit Carson	
Colorado Highlands	
Carousel	
San Isabel	
Alta Luna	
Twin Buttes II	
Spanish Peaks	
Crossing Trails	
Niyol	
Escalante	
Axial	
Dolores Canyon	
Spanish Peaks II	
Coyote Gulch	
Boulder Hydro & Other Facilities	
Denver Water/Williams Fork	
Mancos/Jackson Gulch	
Vallecito/Ptarmigan	
Garland Canal	
Tri-County Hydropower	

Table 47: Historical Renewable PPA Pricing ($/MWh)[25]

Renewables	2015	2016	2017	2018	2019	2020
Cimmaron						
Kit Carson						
Colorado Highlands						
Carousel						
San Isabel						
Alta Luna						
Twin Buttes						
Boulder Canyon Hydro						
Denver Water Board						
Garland Canal Hydro						
Mancos Water						
Vallectio						
Tri-County						

Contract Provisions – Modification of Capacity and Energy Purchased:

The above contract purchases and renewable purchase power agreements are a combination of must take energy or take or pay energy. Limited ability to modify capacity or energy purchased under these contracts exists. The few exceptions are listed below:

- Annually LAP contract capacity and energy is adjusted by WAPA per the contract formula. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- At predetermined dates in the CRSP contract, WAPA will adjust capacity and energy as necessary up to the maximum 1% withdrawal limit for the resource pool. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- All utility scale renewable projects have a right of first refusal option with regard to facility expansion and exercise of such option when made available could result in additional capacity and energy.
- All utility scale renewable projects allow for Tri-State to take excess energy produced over and above expected contract energy as defined by each contract
- The majority of Tri-State's utility scale renewable contracts have a provision to curtail energy production without penalty under certain conditions through an allowable curtailment option. The allowable curtailment amount varies by contract but does not exceed 1% of annual contract energy.

[25] Low pricing in 2015 for Carousel and 2017 for Twin Buttes is a result of test energy.

Note:

- The Basin CROD Western Interconnection contract does not expressly allow for the modification of capacity or energy amounts purchased. The contract exhibit identifies a set hourly energy profile that supplier will deliver and Tri-State will receive.
- The Basin Electrically East contract does not expressly allow for the modification of capacity or energy amounts purchased. The Basin Electrically East contract is a full requirements contract, and supplier is obligated to serve Tri-State Utility Member System load located in the Eastern Interconnection in its entirety at delivery points as identified in the contract including changes to Utility Member System load as a result of natural cycles of load growth or decline.

Emissions & RECs Associated with Contract Purchases and Renewable Purchase Power Agreements:

Tri-State receives Renewable Energy Credits (RECs) associated with its Renewable Purchase Power Agreements. Tri-State's renewable PPAs are non-CO_2 emitting resources.

The WAPA LAP contract energy is generally sourced from power generated at federal dams in the Pick-Sloan Missouri Basin Program – Western Division and the Frying pan-Arkansas Project, collectively Loveland Area Projects. The WAPA CRSP Contract energy is generally sourced from power generated by the Salt Lake Area Integrated Projects. WAPA purchases energy from other sources as needed to meet the marketing plan obligations of its federal electric service customers including the LAP and CRSP contracts with Tri-State. Primarily these deliveries are from hydro. Annually, Tri-State receives RECs for prior year deliveries, which are recorded in WREGIS. These contracts are considered non-CO_2 emitting resources.

The Basin CROD Western Interconnection contract and the Basin Electrically East contract do not specify a source within the contract. Basin has the sole ability to determine the source of the energy for these contracts on a daily and hourly basis. Both contracts do require the energy to be delivered to specific delivery points. Based on this, the energy provided by these contracts are "unspecified energy" as identified in the Colorado AQCC Regulation 22. In order to estimate emissions of these contracts for the purpose of this Resource Plan, Tri-State considered the following:

Basin CROD Western Interconnection Contract: while historically this contract has been primarily served by LRS, future supply of this contract is in no way limited to a source of LRS. Organized market development, changing environmental landscape in the Western Interconnection, changing market or business conditions for BEPC or other factors can potentially influence BEPC's choice for hourly sourcing of this contract energy.

Basin Electrically East: This load in its entirety is within the Southwest Power Pool (SPP) footprint and BEPC supplies this load through the SPP market process.

Actual CO_2 emission rates used for the Basin contracts are discussed further in Section 5 Phase I Modeling Details under the GHG & CO_2 Reduction Methodology subsection of this report.

Additionally, it is noted that Tri-State receives RECs related to both of the Basin contracts as a Class A member of BEPC under an associated board policy, Renewable Resource Obligations Policy. The allocation process is similar to Basin's capital credit allocation process for Class A members. Allocation of RECs is determined annually for prior year. Recent historical allocations have been equal to ~25% of energy delivered under the Basin Western Interconnection and Basin Electrically East contracts.

Utility Member System Distributed Generation:

Tri-State's wholesale power contract with each of its Utility Member systems and applicable Tri-State Board policies allow for and facilitate the development of local distributed generation projects in Tri-State Utility Members' service territories, including community solar projects. These renewable and distributed projects help to fulfill both Colorado and New Mexico RES/RPS requirements, as well as satisfy Utility Members' and consumers' interest in purchasing renewable power from locally-sited projects.

As of October 2020, over 60 renewable or distribution generation projects, totaling 131 MW of capacity and capable of producing ~370 GWh/year are operating or under development. Approximately 85% of Utility Member System distributed generation is located in Colorado, and on a capacity basis, approximately 80% of the distributed generation in Colorado and New Mexico is solar. It is expected that the number of these projects will continue to grow as pricing for renewable resources continues to be attractive and Utility Member Systems continue to show interest in supporting local renewable projects. These numbers are also expected to grow as a result of Tri-State's Board of Directors approving a new policy in 2019 that will facilitate the development of community solar projects throughout its Utility Member Systems' service territories.

These resources are neither owned by nor contracted to Tri-State, but instead serve Utility Member system load directly. Tri-State has not attempted to provide a detailed assessment of these generation projects.

Forced Outage Assistance Agreements

TEP Hazard Agreement[26]: Upon any full forced outage of Springerville Unit 2, Tri-State shall deliver 100 MW per hour to TEP. TEP will deliver 100 MW per hour for any full forced Springerville Unit 3 loss. Hazard supply is limited to 168 hours of delivery. Contract energy is optional. Expected Effective Date 12/01/2020; Contract Expires 03/31/2022. Contract is evergreen unless Parties submit notice of greater than 150 days or designated unit retires.

PRPA Hazard Agreement: Upon any full forced outage of Craig Unit 3, PRPA will deliver 100MW per hour to Tri-State. Upon any full forced outage of Rawhide Unit 1, Tri-State will deliver 100MWper hour to PRPA. Hazard supply is limited to 168 hours of delivery. Contract energy is must take. Effective Date 04/01/2014. Contract expires 03/31/2024. Contract can be terminated by either party on two years written notice.

[26] Replaces prior agreement.

Table 48: Forced Outage Assistance Agreements Historical Pricing

Average Energy Rate	2016	2017	2018	2019	2020
TEP Hazard Agreement					
PRPA Hazard Agreement					

Scheduling Agent Agreements

WMPA Contract: Tri-State acts as WMPA's scheduling agent for its WAPA Network Integrated Transmission Service Agreement, Federal hydropower, generation resources, sales of available energy, and purchases of replacement energy. Effective Date 09/26/2017; Commencement Date 10/01/2017; Contract Expires 6/30/2021.

- WMPA sells Tri-State ~125 GWh of excess energy/year in instances where WMPA's resources are in excess of its load requirements.
- Tri-State sells WMPA ~6 GWh of energy to serve WMPA's load/year when WMPA's resources are not sufficient to serve its load.
- Additionally, Tri-State provides WMPA's spinning and operating reserves in the amount of WMPA's Pro Rata Reserve Share as determined in accordance with the WMPA Sub-Entity Agreement with WAPA for participation in NWPP.

Overview of Merchant Transmission

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 42 Utility Member systems located across four states, operating within multiple Balancing Authorities and served by multiple Transmission Providers. Additionally, Tri-State's load is dispersed in multiple states and in both the Eastern Interconnection grid and the Western Interconnection grid. Tri-State's load in the Eastern Interconnection, which primarily includes loads in Nebraska along with a small amount of northeastern Colorado load, is served by an all requirements contract with BEPC. Resources for serving Tri-State load in the Western Interconnection, which includes loads in Wyoming, Nebraska, Colorado and New Mexico, are a combination of company owned resources and PPAs.

Figure 15 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[27] owned transmission capacity and related transmission constraints. In the Western Interconnection, Tri-State Merchant is a network transmission customer of the following Transmission Providers:

- Tri-State Generation & Transmission Association (Tri-State Transmission)
- PSCo
- PNM
- PRPA
- WAPA Rocky Mountain Region Loveland Area Projects (LAPT)
- BHCT

[27] Tri-State Merchant is the marketing arm of Tri-State Generation and Transmission Association that is responsible for planning and resource acquisitions in regards to energy, capacity and transmission necessary to serve Utility Member system load along with related dispatch, scheduling and settlements activity.

- PAC

Additionally, Tri-State Merchant is a Point-to-Point (PTP) transmission customer of many TPs in the Western Interconnection. Tri-State Merchant uses these network and PTP transmission rights within Western Electricity Coordinating Council (WECC) TOT[28] capacity limits and other system constraints to schedule power from resources to loads on a day ahead and hourly basis to serve Utility Member System loads. The "Tri-State owned capacity" arrows in Figure 15 represent Tri-State transmission rights between modeling regions.

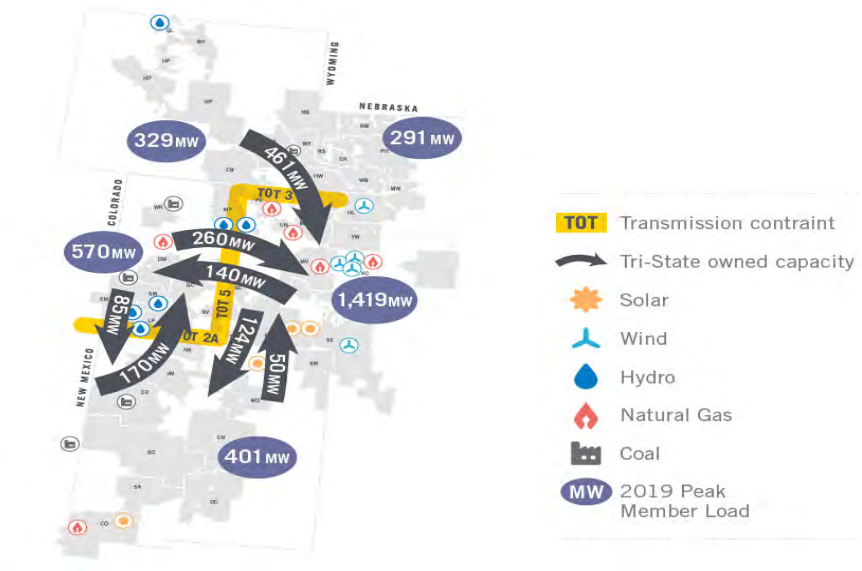

Figure 15: Tri-State System Major Transmission Paths

Table 49 represents Tri-State's major transmission reservations for moving power between regions across Tri-State's system. This is a reflection of the transmission modeling within the modeling systems for resource planning but does not represent a complete list of transmission rights including those within regions necessary to tag load in day-to-day operations.

Table 49: Tri-State's Major Transmission Network Paths

Transmission Capacity *(MW)*	**TOT**	**Path Flow Direction**	**TP/Type**	**Comments**
85	2a	NM to CO	TSGT Network	Path is often significantly reduced.
100	2a	NM to CO	CRCM PTP	
70	2a	CO to NM	TSGT Network	Path is often significantly reduced.
124	-	CO to NM	TSGT Network	Requires additional PTP leg to serve TS network load in PNM.

[28] A collection of transmission paths with a total operating limit that is often lower than the total of the underlying path reservations.

Transmission Capacity *(MW)*	**TOT**	**Path Flow Direction**	**TP/Type**	**Comments**
50	-	NM to CO	TSGT Network	Requires additional PTP leg to serve TS network load in PSCO.
461	3	WY to CO/CO to WY	TSGT MBPP[29]	Multiple reservation paths but total scheduled cannot exceed TOT limit.
260	5	West CO to East CO	TSGT Network	Additional PTP rights exist related to WAPA federal hydro contracts and other long-term firm PTP reservations.
140	5	East CO to West CO	TSGT Network	Additional 3rd party PTP transmission is available along this path at an additional cost.

In the Western Interconnection, Tri-State is required to deliver and tag power to sinks as configured in the North American Reliability Electric Corporation (NERC) webRegistry and as required by NERC Reliability Standards. Below is a breakdown of major load sinks:

- Nebraska West and Wyoming
  - 2 network sinks[30] in LAPT[31] TP – Western Area Colorado Missouri (WACM) BA and 1 ancillary[32] only sink in WACM BA
  - 3 network sinks in PAC TP and BA
- Colorado
  - 1 network sink in PSCO TP and BA and 3 ancillary only sinks in PSCO BA
  - 1 network sink in BHCT TP - PSCO BA
  - 1 network sink in LAPT TP and WACM BA
  - 3 ancillary only sinks in WACM BA
- New Mexico
  - 1 network sink in PNM TP and BA

There are specific Points of Delivery (POD) within each sink to which power can be delivered in order to supply Tri-State Utility Member System load. These PODs are similar to transaction points where purchases and sales occur. Tri-State may purchase power or move owned or contracted resources to these points, within applicable transmission rights, to serve load at the specific sinks.

WEIS/WEIM Transmission Impact:

[29] Transmission rights related to MBPP. However, use of this transmission is not limited to LRS.
[30] A network sink represents a subset of network delivery points with a third party TP where Tri-State has a network transmission integrated service agreement. Tri-State pays for network transmission on a prorata share basis each month based on load levels during the TP's peak.
[31] LAPT represents the transmission lines associated with the Loveland Area Projects federal hydropower
[32] An ancillary sink is a registered load within a Balancing Authority where only Tri-State Transmission is required to serve load.

Upon entry into energy imbalance markets in 2021, transmission and tagging for day ahead and real time activities will mostly remain as-is for load and resources located within WEIS and WEIM. However, the energy imbalance market will also introduce new intra-hour activity driven by the market operator. Intra-hour use of transmission by resources at the market operator's direction will be on a non-firm basis with no related tagging or charges.

RTO Transmission Impact:

Entry into an RTO consists of a common Open Access Transmission Tariff (OATT) and typically a market operator taking on BA responsibilities for the RTO footprint. The following are key changes related to or impacting transmission rights and usage in an RTO:

- One common OATT exists for the market and transmission billing is facilitated through the market operator.
- Congestion and losses are included as components of the Locational Marginal Price (LMP).
    - Resources are offered in at their location and awarded the LMP
    - Load is bid in at its location and pays the associated LMP
- Mitigation of congestion costs is handled through a financial congestion right that is to some extent correlated to transmission reservation rights.
- No tagging occurs within the market footprint; only imports, exports and wheel-thrus are tagged.

Overview of Merchant Ancillary Services

Tri-State meets its ancillary service requirements through Network Integration Transmission Service Agreements and Balancing Authority Ancillary Service Agreements. In the Western Interconnection, Tri-State receives ancillary services from PAC, PSCo, PNM and WAPA. As mentioned previously in this report, Tri-State's electrically east load is served via a full requirements contract with BEPC, which includes ancillary services.

Tri-State currently operates in bilateral energy and ancillary trading markets, and in 2021 will move additional load and resources into energy imbalance markets (WEIS and WEIM). Tri-State does not have load or resources in a full "day-2" organized market (an RTO or ISO) which would allow for both an energy and ancillary market.

Primary Ancillary Services:

The following is a list of primary ancillary services required via applicable TP OATTs and how Tri-State acquires these services, including applicability to any Tri-State resources:

Schedule 1 - Scheduling, System Control & Dispatch: Tri-State pays for this service monthly from appropriate TPs or BAs. Tri-State resources do not have any impact on or relation to this service.

Schedule 2 - Reactive Supply & Voltage Control: Tri-State pays for this service monthly from appropriate TPs or BAs. Tri-State's generating resources do not have any impact on or relation to this service. Tri-State does, however, have several applicable agreements with entities to partially self-supply reactive support via transmission system equipment in exchange for a reduced cost in service. Separately, Tri-

State generation resources are required via NERC Reliability Standards to follow reactive power instructions from Transmission Operators and operate in automatic voltage control mode.

Schedule 3 - Regulation and Frequency Response (includes load following capabilities): Tri-State pays for this service monthly from appropriate TPs or BAs. Applicable Tri-State-owned or contracted resources and Utility Member system distributed resources nameplate capacity are, at times, a factor in determining regulation cost, but Tri-State does not have any obligation to regulate for its own load or resources. Tri-State does, however, have generating resources that have the capability to operate in Automatic Generation Control (AGC) mode and thereby provide regulation as a service for a cost or partially self-supply regulation[33].

Tri-State generating resources that are AGC capable include:

- Craig 1,2,3
- LRS 2
- SPV 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Schedule 4 - Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate TPs or BAs. Beginning in 2021, a significant portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and WEIM. Upon entry, Tri-State will be able to participate with its resources located within the respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Schedule 5 - Operating Reserve Spinning Service: Tri-State self-provides spinning reserves through Southwest Reserve Sharing Group membership and via two sub-entity Reserve Sharing Group Agreements[34]. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- SPV 3
- JM Shafer

[33] See WAPA Regulation Contract for partial self-supply in Section 1 Electric Energy and Demand Forecast under the Energy and Capacity Sales to Other Utilities subsection for an example.

[34] The two sub entity Reserve Sharing Group Agreements are with PSCO and WAPA. PSCO and WAPA are participants of the Northwest Power Pool for reserve sharing as of the fall of 2019. Prior to that time PSCO, WAPA and Tri-State participated in the Rocky Mountain Reserve group for resources in these BAs.

Due to recent changes in operating standards in the Western Interconnection, operating reserves may be fully served via non-spinning supplemental service rather than the previous requirement that operating reserves must include of a minimum of 50% spinning reserves.

Schedule 6 - Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member agreement and two sub-entity Reserve Sharing Group agreements. Tri-State's generating resources with quick start capability, which qualify for supplemental services, include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Schedule 9 - Generator Imbalance Service: Tri-State currently receives and pays for this service monthly from appropriate TPs or BAs. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and the WEIM. Upon entry, Tri-State will be able to participate with its resources located within each respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Schedule 16 - Flex Reserve Service[35]: Tri-State currently takes and pays for this service monthly from appropriate TPs or BAs. This service is calculated based on proportional wind capacity contribution within the footprint as is used by the Balancing Authority to cover the costs of ramping requirements related to wind intermittency. There is no current option to self-supply.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate TPs or BAs or provides physical loss requirement depending on specific contractual arrangements.

Self-Supply Discussion:

Tri-State has the ability to potentially self-supply all or a portion of the following ancillary services as allowed under TP OATTs and related contractual agreements:

- Reactive Supply and Voltage Control
- Regulation and Frequency Response
- Operating Reserves (Spinning or Supplemental)
- Loss Supply

With the transition of Tri-State's load and resources in the PNM-BA and WAPA-BA into WEIM and WEIS respectively Tri-State will also be able to offer in resources to meet intra-hour energy imbalance in these markets.

[35] Currently this ancillary service is only applicable to resources in PSCo.

Forecasting Ancillary Service Charges:

Table 50 provides a description of Tri-State's forecasting methodology for each ancillary service.

Table 50: Forecasting Methodology by Ancillary Service

Ancillary Service	Forecast Method
Scheduling, System Control & Dispatch	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load or tags) to arrive at a forecast.
Reactive Supply & Voltage Control	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load) to arrive at a forecast.
Regulation and Frequency Response	Current charges with adjustments for any known upcoming rate changes are used along with the appropriate forecast quantity (load, generation by type) to arrive at a forecast.
Energy Imbalance	Historical data is used to arrive at a forecast. The operational goal is always to minimize imbalance.
Operating Reserve Service (Spinning and Supplemental)	Tri-State models for self-supply of operating reserves on Pyramid and Burlington resources. Potential sales or purchases related to Reserve Sharing Group are forecast based on recent history. Contracts for specific sale of operating reserves as a service are forecast separately.
Generator Imbalance	Historical data is used to arrive at a forecast.
Flex Reserve Service	Financial forecast based on applicable resources and OATT rate. Included in Regulation forecast.
Loss Supply Service	Average of TP Provider's loss rate (5%) is applied to forecast load. Losses are included as load in the dispatch model.

Historical Ancillary Service Charges:

The following are average historical ancillary service charges from recent years as used to serve load across the Tri-State system in the Western Interconnection.

- Schedule 1 & 2 are recorded for accounting purposes with Network Transmission and Point-to-Point Transmission charges. The history detail for these charges is not readily available.
- Schedule 3 and Schedule 16 average annual regulation total charges for load and resources was $5 Million.
- Schedule 4 Energy Imbalance and Schedule 9 Generator Imbalance average annual purchase price was ~$25/MWh and the average annual sale price was ~$20/MWh.

- Schedule 5 & 6 Operating Reserves[36] average annual purchase price for receiving reserve activation assistance as part of a reserve sharing group or sub entity agreement was ~$40/MWh and average annual sale price was $80/MWh.

Current Ancillary Service Charges:

Table 51 shows current ancillary service rates for network and long-term firm PTP transmission.

[36] Reserve activation transactions occur upon the loss of a resource. The owner of the resource self-supplies replacement power to some extent and then purchases the additional assistance from reserve sharing counterparties.

Table 51 Ancillary Service Charges

ANCILLARY SERVICE CHARGES

Transmission Provider	Effective Date		Schedule 1	Schedule 2	Load Schedule 3	Non-VER Schedule 3	uncommitted VER - Wind Schedule 3	committed VER - Solar Schedule 3	Schedule 5	Schedule 6	Schedule 4	Schedule 9	Flex Reserves - Wind Schedule 16	Attachment R	Transmission Losses
BHTC															
	November 1, 2018	$/MW-month	$76.00	$61.00	$156.00	NA	NA	NA	$307.00	$288.00	See Note 1	See Note 1	NA	NA	1.94%
PAC	June 1, 2020														
		$/MW-hour							$151.00	$151.00					
		$/MW-month	$66.14	$45.83	$177.00	$150.00	$549.00	$469.00					NA	NA	4.45% (46kV +); 3.56% (34.5kV or less)
PNM	June 1, 2020				1.50%				1.50%	1.50%					
		$/MW-month	$30.00	$50.00	$129.00	NA	NA	NA	$140.40	$140.40			NA	See Note 7	2.67%
PSCO	January 1, 2020				1.27%	0.24%	2.07%	2.07%	3.50%	3.50%			12.05%		
		$/MW-month	$59.00	$302.00	$86.66	$16.38	$141.26	$141.26	$239.86	$67.27			$681.07	NA	2.20%-demand; 1.70%-energy
LAPT	October 1, 2020						148.00%	100.00%							
		$/MW-month	$21.14/schedule/day	$79.00	$205.00		$303.40	$205.00	See Note 2	See Note 2			NA	NA	4.50%
CRCM (LTFPTP)	October 1, 2020														
		$/MW-month	$21.14/schedule/day	$79.00	See Note 5	NA	NA	NA	See Note 5	See Note 5	See Note 6	See Note 6	NA	NA	4.50%
PRPA	June 1, 2020														
		$/MW-month	$0.00	$100.87	See Note 3	NA	NA	NA	See Note 4	See Note 4	See Note 3	See Note 5	NA	NA	1.94%
EPE - (Pre-OATT FPTP)	See Note 8	$/MW-month	$70.25	$44.00	See Note 6	NA	NA	NA	See Note 6	See Note 6	See Note 6	See Note 6	NA	NA	4.23%
TEP (LTFPFP)	September 11, 2020	$/MW-month	$41.00	$161.00	See Note 6	NA	NA	NA	See Note 6	See Note 6	See Note 6	See Note 6	NA	NA	3.44%
TSGT	October 1, 2020														
		$/MW-month	$332.00	$90.86	See Note 1	NA	NA	NA	See Note 1	See Note 1	See Note 1	See Note 1	NA	NA	3.378%

NOTES: Settlements
PAC - Schedule 5 & 6 are included in Regulation
PNM - Attachment R is Wheeling Expense
PSCO - Schedule 9 is included in Energy Imbalance
Schedule 16 is Regulation Expense
Schedule 1 & 2 are included as Wheeling Expense
Schedule 3 is Regulation and is Purchase Power Expense
Schedule 4 is Energy Imbalance and is PP Expense/NMS Revenue

Schedule 1 - Scheduling System control and dispatch services
Schedule 2 - Reactive Supply and Voltage Control service
Schedule 3 - Regulation and Frequency response service
Schedule 4 - Energy Imbalance Service
Schedule 5 - Operation Reserve (Spinning Reserve Service)
Schedule 6 - Operating Reserve (Supplemental Reserve Service)
Schedule 9 - Generator Imbalance Service
Schedule 16 - Flex Reserve Service

Note 1:	To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator
Note 2:	Pass Through (purchase price, energy activation, plus administrative fee)
Note 3:	TSGT's Network Load with PRPA - A/S 3 and 4 services supplied by WAPA
Note 4:	Platte River is not a balancing authority, and does not offer this service. Upon written request, Platte River will assist in arranging for the local balancing authority operator
Note 5:	Joint Dispatch Transmission Service ($0.00/MW-month)
Note 6:	A/S is not a required service for LTFPTP transmission service
Note 7:	Reliability Redispatch Costs and Methodology (details in PNM's OATT)
Note 8:	A/S Schedules 1 and 2 are not applicable with pre-OATT FPTP transmission service

Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black & Veatch to perform an analysis of cost and performance of existing owned and contracted resources as compared to generic resources. The scope of this benchmarking analysis was limited to the following:

- Thermal and renewable utility scale resources that are:
  - Commercially operational, and
  - Located in the state of Colorado, or
  - Located outside of the state of Colorado but capable of serving Colorado load at any time.
- Basin Western Interconnection and Basin Electrically East contracts

Alta Luna and Cimarron renewable resources located in New Mexico are included in the benchmarking process but have never been scheduled to Colorado load.

Resources excluded from the benchmarking process include:

- Federal hydro contracts of LAP and CRSP as these long term, cost-based contracts for delivery of firm, renewable, quasi-dispatchable power with certain transmission and ancillary service benefits do not have a reasonable comparison within the generic resource pool.
- Other small contract purchases, small hydro power producer contracts

The full methodology, results and insights from the B&V benchmarking process are located in Attachment Vol II 5-5 B&V Benchmarking Study. This attachment was filed previously in the August 3, 2020 revised filing.

UPDATE: Tri-State is waiting for the Commission Order related to guidance in Proceeding No. 20M-0218E. Once this order is published, Tri-State will reengage B&V to revise this benchmarking study to meet Commission expectations. The revised study will be provided as soon as is reasonably possible.

The benchmarking process is informative to the overall resource planning process but does not take the place of scenario modeling required to arrive at least cost, reliable resources plans within transmission and environmental constraints.

Retirement Analysis

Tri-State allowed the expansion plan model to retire resources in the following scenarios:

- 80pct CR V1, V2, V3 and V4 – coal resources allowed to retire in 2025 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)
  - Results: LRS 3 retires early 2030s; SPV3 retires late 2030s
- Low Load 80 pct CR V1 and V2 – coal resources allowed to retire in 2026 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)
  - Results: LRS 3 retires late 2020s; SPV3 retires late 2030s
- Social Cost of Carbon – coal and gas resources allowed to retire in 2025 except SPV3 which was allowed to retire after the end of the SRP sales contract (mid-year 2036)

- Results: Craig 3, LRS 2 and LRS 3 retire in 2026; SPV3 retires in late 2030s; Various gas resources retired in late 2020s or early 2030s

In the 80pct CR V1, V2, V3 and V4 scenarios and Low Load CR V1, and V2 scenarios the expansion plan model chose to keep Craig 2 and 3 online until announced retirement dates. SPV3 was not allowed to retire prior to the end of the SRP contract associated with this resource in any scenario, because the current expansion plan model setup cannot appropriately consider the lost revenue of the SRP contract associated with SPV3 when making a retirement decision.

While the CE model is retiring LRS3 and SPV3 at varying times during the scenarios including in the preferred plan, Tri-State will need to work with the MBPP joint owners of Laramie River Station to determine the best retirement schedule for either LRS resource for all participants. In regards to SPV3 Tri-State will need to resolve the modeling issue mentioned above and work with other joint owners of common facilities at the Springerville station to arrive at the best retirement schedule for SPV3.

4 Transmission System & Planning

Overview – Transmission System

Tri-State owns (wholly or jointly) more than 5,500 miles of transmission lines in Colorado, Nebraska, New Mexico and Wyoming. Tri-State continues to support regional transmission study efforts. Tri-State continues to make transmission investments to serve growing loads, increase reliability, ensure system stability, and support additional generation development.

Transmission Planning

Tri-State transfer capability limitations on its transmission network are generally based on facility ratings. Tri-State's facility ratings equal the most limiting applicable Equipment Rating of the individual equipment associated with that facility. An overall transmission line rating factors in both the conductor rating and the associated terminal equipment ratings. Facility ratings commonly limit and affect the future siting of resources. See Attachment Vol II 4-1 Tri-State Facility Rating Report for additional detail.

The following Tri-State transmission projects have been identified in Tri-State's 10-year transmission plan filed pursuant to Rule 3627 included as Attachment Vol II 4-2 Tri-State 10-year Transmission Plan. Note, while these transmission projects were categorized as Planned in the filing, most are still in the developing stages. In Tri-State's experience, many of the planned transmission projects in the Rule 3627 report are ultimately modified or cancelled as the result of changing drivers and future needs.

- Burlington-Burlington (KCEA) 115kV Line Re-build
  - Tri-State will re-build the existing Burlington-Burlington KCEA line to increase the thermal rating of the line.
- Del Camino-Slater 115kV Line Uprate
  - This project will replace all the remaining spans of 397.5 ACSR conductor on the Del-Camino Slater line with 477 ACSR conductor.
- Falcon-Midway 115kV Line Uprate
  - This project involves raising, moving, or rebuilding structures along the Falcon-Midway 115kV line to increase the overall line rating to 145 MVA.

- Falcon-Paddock-Calhan 115kV Line
  - The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop.
- Lost Canyon – Main Switch 115kV Line
  - This project will add a new 115kV line between Lost Canyon and Main Switch.
- Sisson Delivery Point Project
  - This project will add approximately 20 miles of new 115 kV transmission to radially serve the new Sisson substation radially north from the existing Keota substation.
- Vollmer Delivery Point Project
  - This project will tap the existing Jackson Fuller-Black Squirrel 115kV line and add approximately 2 miles of 115 kV transmission to serve the new Vollmer substation.
- Western Colorado Transmission Upgrade Project (re-build of Montrose-Nucla-Cahone 115kV line)
  - This project will rebuild the existing Montrose-Nucla-Cahone 115kV with 1272 ACSR conductor and be capable of future 230kV operation. Additionally, the line will be sectionalized at the new Maverick substation, rather than Nucla, which is located between Nucla and Norwood substations.

Project information for each transmission line or facility identified in 3605 (d)(II) can be found in Appendix E of the most recent Rule 3627 Report. See Attachment Vol II 4-3 Tri-State Transmission Project Information for a reduced copy of Appendix E showing the requested information for the identified projects.

Response to C20-0661-I Related to Transmission Impacts on the ERP Process

In the November 12, 2020 Commission weekly meeting the Commission gave guidance in regards to Proceeding No. 20M-0218E. Tri-State interpreted this guidance as the Commission requiring Tri-State to respond to the joint transmission proposal submitted by participants in Proceeding No. 19R-0096E. Tri-State first notes that it submitted comments in that proceeding pursuant to Decision No. C20-0661-I (the "Interim Decision") regarding the transmission-related rule proposals (the "Rule Proposals"). Tri-State's present position with respect to those proposals is the same as what it described in those earlier comments. Namely, while Tri-State agrees that some of the Rule Proposals have merit, there simply was not enough time remaining before Tri-State's ERP filing was due for Tri-State to incorporate any new requirements coming out of the 19R-0096E rulemaking process. Tri- State explains its position in more detail below, consistent with its earlier comments.

The rules governing this ERP filing were finalized in Proceeding No. 19R-0408E and became effective on July 15, 2020. These rules include Rule 3605(d), requiring Tri-State to submit an assessment of transmission resources, which will require Tri-State to provide extensive information regarding its current and planned transmission systems. This information includes Tri-State's transmission capabilities and future needs during the planning period for facilities of 115 kilovolts and above, the location and extent of transfer capability limitations on Tri-State's transmission network that may affect the future siting of resources, and a description of the transmission lines and facilities appearing in Tri-State's 2020 Rule 3627 Report that, as identified in that report, could reasonably be placed into service during the RAP. For each transmission line or facility that could reasonably be placed into service during the RAP, Tri-State must

include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

- length and location;
- estimated in-service date;
- injection capacity;
- estimated costs;
- terminal points; and
- voltage and megawatt rating.

In addition to providing this information, Tri-State must consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria. And it also must describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

Tri-State has included this required information in Section 4 Transmission System & Planning and in other sections throughout this report as identified in the Transmission Summary subsection of Section 4.

The Rule Proposals in the Interim Decision would modify Commission Rules 3608, 3614, and 3615. These rules do not apply to Tri-State, nor should they be extended to do so. As was explained in Decision No. C20-0155 in Proceeding No. 19R-0408E, "given the structure and contents of Rule 3605 . . . the following ERP Rules being reviewed in Proceeding No. 19R-0096E are not intended to apply to Tri-State: . . . Existing/Proposed Rule 3608 Transmission Resources . . . Proposed Rule 3614. Phase I; and Proposed Rule 3615. Phase II." It would be contrary to this clear statement if the Rule Proposals in this proceeding were extended to modify the final rules adopted in Proceeding No. 19R-0408E.

Although Tri-State has not expressly incorporated any of the Rule Proposals into this ERP, it does agree in principle with some of the Initial Comments and Rule Proposals in the 19R-0096E proceeding. At a high level, Tri-State believes it will be important for the ERP process to account for transmission projects that are likely to come online during the resource acquisition period and recognizes that new transmission will be needed to meet Colorado's emissions-reduction goals. As such, Tri-State provides the following comments on some of the Rule Proposals or comments submitted in this proceeding.

Rule 3627 Information

Tri-State has no objection to the Commission taking administrative notice of the 2020 Rule 3627 filings in this ERP. While not all of the Rule 3627 information will be relevant to Tri-State's ERP, these filings nevertheless provide useful context regarding the transmission system and Tri-State believes they are appropriate to include in the ERP process. Indeed, under Rule 3605(d), Tri-State has already included information on those transmission resources in its Rule 3627 filing that could reasonably be placed into service during the resource acquisition period.

Planned Transmission Facilities

Tri-State agrees with the principle that transmission facilities under construction or for which a CPCN has been filed with the Commission at the time this ERP is being filed are in most cases facilities "that could

reasonably be placed into service during the resource acquisition period" under Rule 3605(d)(II). Tri-State has included such facilities in this ERP and intends to accept bids into these facilities as appropriate.

More generally, Tri-State notes that the RFP process for this ERP allows bidders to bid into developing transmission projects that are not yet in service, even where those facilities are not yet under construction and may be altered significantly or even cancelled. In general, this includes transmission projects that have been identified in Tri-State's 10-year transmission plan filed pursuant to Rule 3627.

While Tri-State intends to continue to accept such bids going forward, it urges the Commission to be cautious about adopting future rules that would encourage bids into projects that are still in the developing stages. In Tri-State's experience, many of the planned transmission projects in the Rule 3627 report are modified significantly or cancelled as the result of changing future needs. As an example, of the 16 new transmission line projects included in Tri-State's 3627 filings since 2014, only 2 have been constructed (the Burlington – Wray 230 kV line, and the Southwest Weld Expansion Project). This reflects the reality that Tri-State's long-term transmission planning reports are snapshots in time that rely heavily on forecasts of future drivers (oil and gas loads, for example) that change based on factors largely outside of Tri-State's control.

Tri-State further notes that it has network load that is served via other utilities' transmission systems and that it must coordinate with these utilities and conduct joint studies in some instances in order to accommodate new generation projects. This required coordination can add another layer of complexity and uncertainty with respect to some projects.

While bidders can bid into future, uncertain transmission projects, such bids are contingent on the continued need for the project. Where, as is often the case, the transmission project becomes unnecessary or dramatically changes, the economics of the bids relying on the project often become untenable.

Transmission Related Costs in Portfolios

Tri-State also agrees in principle with OCC that all transmission-related costs related to a particular generator bid should be included for purposes of bid evaluation.

Tri-State's ERP generally seeks to account for all such costs in order to ensure that it is securing the most cost effective generation for its Members. Tri-State notes that it is currently in the process of seeking FERC approval of certain reforms to its generator interconnection queue process that will allow it to better account for transmission costs associated with new generation through a cluster study process, rather than the sequential process it currently uses pursuant to the FERC Pro Forma Large Generator Interconnection Procedures.

Tri-State appreciates the Commission's consideration of these important transmission-related issues. Although the Commission should not adopt new requirements for Tri-State, Tri-State agrees with some of the Rule Proposals and comments in principle as discussed above. Tri-State recognizes the importance of these transmission-related items and is addressing some of them in this ERP filing.

Transmission Summary

In addition to the Transmission System & Planning section of this report transmission information related to Tri-State's system is available as follow:

- Volume I Section 8 Base case and Alternative Scenario Results contains specific transmission assumptions and transmission capital expenses by scenario.
- Volume I Section 11 Resource Acquisition Period – Action Plan contains transmission information related to the Phase II process.
- Volume II Section 3 Assessment of Resources contains a section on merchant transmission.
- Volume II Section 5 Phase 1 Modeling Details contains modeling constraints and assumptions related to transmission modeling.

5 Phase I Modeling Details

Model Description

Overview

Tri-State uses various industry standard software to perform resource planning including the following:

Table 52: Summary of Software Used in Tri-State Resource Planning

System	Purpose
SAS	Load forecasting by region for use in CE & PO and by member for use in Hyperion and UIPlanner.
Hitachi ABB Capacity Expansion (CE)	Develops expansion plans including resource acquisitions and retirements.
Hitachi ABB Portfolio Optimization (PO)	Hourly least cost dispatch within environmental and transmission constraints.
Transmission Siemens PSEE (PSEE)	Evaluates interconnection and network upgrade costs for new resources.
Hyperion	Receives load data from SAS and dispatch data from PO and incorporates this data along with capacity, energy, wheeling, transport and related expenses and revenues for transfer to UIPlanner.
Utilities International Planner (UIPlanner)	Financial model used to calculate PVRR for scenarios incorporating all expense and revenue data while adhering to Tri-State financial goals.

Tri-State's process for scenario analysis includes determining an expansion plan using CE, running an hourly dispatch for the 20-year planning period in PO, and gathering dispatch, plan and load data along with other capacity, energy and wheeling expenses and revenue in Hyperion. The CE plan for each scenario is sent to Tri-State's Transmission Planning group for an evaluation of transmission capital expenditures based on resource additions and retirements in each scenario. All analysis in CE, PO, Hyperion and Transmission are performed in real (2020) dollars without inflation. Final data is sent to UIPlanner for PVRR analysis for each scenario. UIPlanner inflates expense and revenues into nominal dollars.

The diagram below shows the succession through the primary software systems:

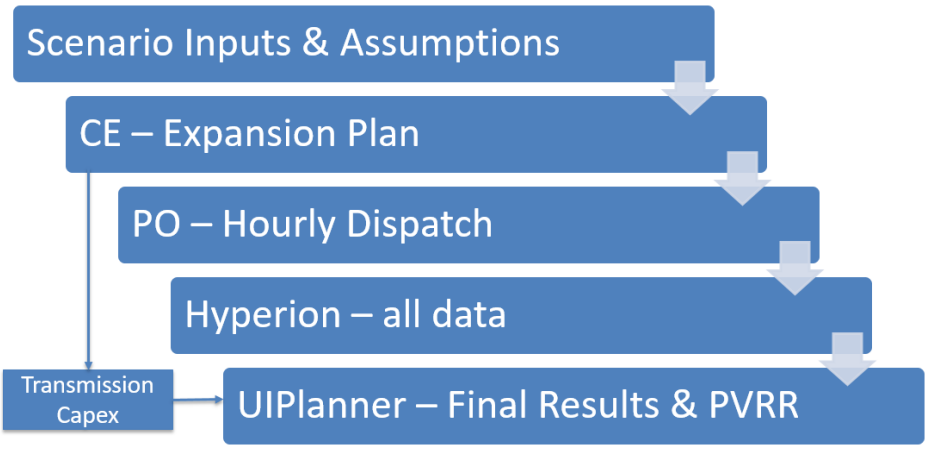

Figure 16: Scenario Modeling Process Overview

CE and PO

CE is a resource expansion planning model used to deliver an optimal expansion plan including timing, technology and size of potential resources. The plan respects a set planning reserve margin and adheres to transmission and emission constraints. For expansion planning, technologies are identified for use in the generic resource dataset. Emerging technologies are evaluated in regards to maturity and availability of reliable pricing and are included or excluded accordingly. Generic resources are set up as build, build transfers or power purchase agreements within the model. Characteristics and pricing of technologies included in the generic resource dataset can be found in the Section 5 Phase 1 Modeling Details under the Generic Resource Cost, Performance Emissions data subsection of this report.

CE uses a number of key inputs necessary for determining an ideal expansion plan from the perspective of cost, technology and timing within the planning horizon. Figure 17 lists inputs required for the system to define the expansion plan.

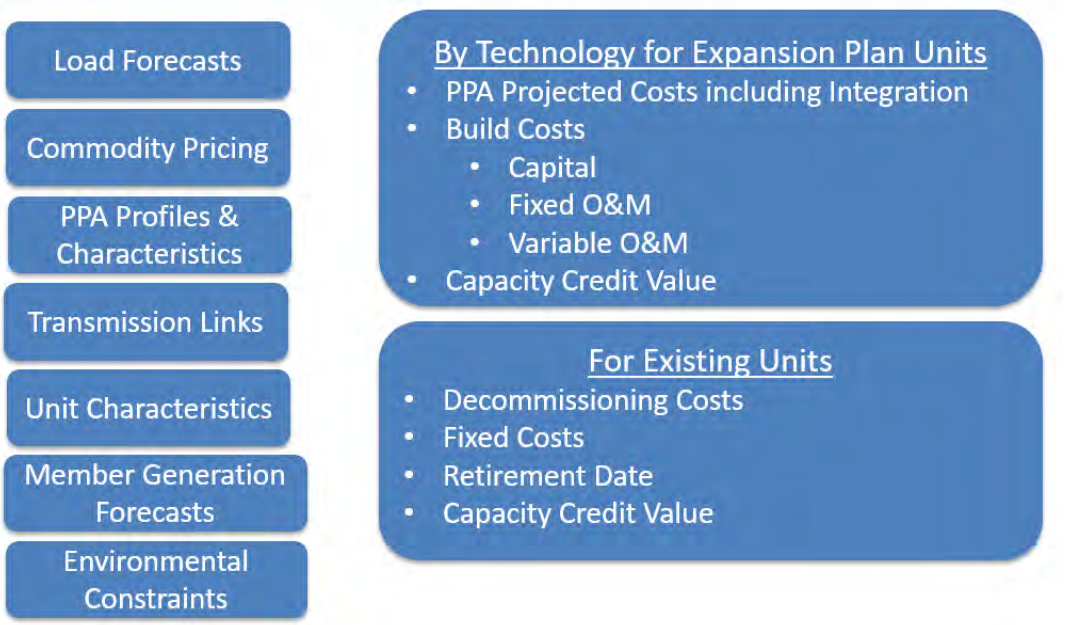

Figure 17: System Inputs for Expansion Plan Scenario Modeling

CE results include the size, timing, location, technology, and characteristics of each new unit.

Figure 18: Capacity Expansion (CE) Plan Results

The final expansion plan is then moved into the hourly dispatch model, PO.

PO is a production cost model used to determine a least-cost hourly dispatch plan based on unit operating characteristics, market prices, transmission constraints, regional load forecasts, and Power Purchase Agreements. Existing resources including any early retirements and generic resources additions identified in the expansion plan are modeled in PO for each scenario. Resources include thermals, renewables, energy storage, distributed generation, and demand-side-management, as

well as contracts with hourly and monthly energy limits. Final PO hourly output for the planning period is reviewed to ensure that all contract, environmental and dispatch limits are followed.

Dump Energy and Energy not Served:

As PO is modeling a dispatch over a 20-year period on an hourly basis, PO uses two methods to allow the model to complete within a reasonable timeframe. These methods are "dump energy" and "energy not served". "Dump energy" allows for an additional market outside of normal market depth limits where energy can be sold at an extremely low price. It is also a reasonable reference to potential curtailments in the plan driven by excess energy. "Energy not served" allows energy in a given hour that cannot be served by the existing and generic resources or existing market to be served at an extremely high market price. If the PO algorithm is having difficulty solving in a particular hour of the 20-year planning period with too much or too little energy, it can fall back on one of these methods to complete the overall dispatch. For each scenario, annual "dump energy" and "energy not served" are reviewed and kept within reasonable bounds. During the RAP, the threshold for "dump energy" is less than 25GWh in any given year, and the threshold for "energy not served" is less than .5GWh in any given year of a study.

Modeling Region/Transmission Area Setup:

PO and CE are setup with up to eight different Transmission Areas (TA) depending on the scenario. These are modeling regions that represent high-level operations of the Tri-State system footprint and allow for the modeling of known transmission limitations via links with set transmission capacity. TAs are not specific to any one TP. Load, resources and markets are assigned to these TAs for modeling purposes.

Table 53: Transmission Areas for CE and PO

TA	Geographical Location	BAs	Transmission Location
WACM_Eastern Colorado	Eastern Colorado	WACM, PSCo	East of TOT 5; South of TOT 3
WACM Wyoming	Wyoming & Nebraska West	WACM, PAC	North of TOT 3
WACM Wyoming Green[37]	Wyoming & Nebraska West	WACM	North of TOT 3
West_Colorado	Western Colorado	WACM	West of TOT 5
New Mexico	New Mexico	PNM	South of TOT 2
Springerville	Arizona	PNM[38]	PTP transmission to PNM
Mt. Elbert	Colorado	WACM	Shares LAP Hydro transmission
Nebraska	Nebraska East and Northeast Colorado	SPP	Eastern Interconnection

[37] This TA is used to allow TOT 3 transmission capacity to be assigned to renewable generic resources located in Wyoming while restricting the use of TOT 3 transmission capacity by thermal resources in the WACM Wyoming TA. The result is to allow more green power to flow from Wyoming to Colorado for CO_2 reduction.

[38] This resource transitioned to a pseudo-tie into PNM instead of WACM in 2020 due to planned entry into WEIM in 2021.

In the model, the Nebraska TA is setup so that load is met entirely by the Basin Electrically East purchase and no flow is allowed from Nebraska into any of the other TA's.

For the other TA's links are used to simulate transmission flow or the ability to flow from one TA to another. Maximum capacities are used to set the boundaries of the amount of energy that can flow from one TA to another. These link capacities are found in Section 5 Phase 1 Modeling Details under the Modeling Assumptions subsection of this report.

Transmission Capex Process

Planning level cost estimates for transmission facilities associated with generation expansion plan resources were developed by Tri-State's Transmission Planning department for the base case and each alternative scenario. For each resource in the expansion plan, a specific Point of Interconnection (POI) on Tri-State's transmission system was assumed within the given region (Eastern Colorado, Western Colorado, Wyoming, and New Mexico). These locations were chosen based on previous requests received as part of Tri-State's Large Generation Interconnection Process (LGIP) Queue, neighboring entities' LGIP studies, and/or locations known to be able to accommodate generation injection from coordinated planning efforts. Each unit was then assigned required upgrades at the POI, which typically consisted of a new switching station or additional breaker bays at an existing substation needed to tie in the generator.

For units assumed to be owned by Tri-State an additional interconnection facilities cost was assigned, which includes costs for generator tie line termination equipment and metering. These interconnection facilities costs were not included for generators assumed to be included in the expansion plan via a PPA as those costs would be borne by the generator owner, consistent with Tri-State's LGIP.

The bulk of the transmission costs are associated with additional Network Upgrades (beyond the POI facilities) that would be required to accommodate the aggregate levels of injection and maintain the reliability of the transmission system. These costs do not include costs for projects in Tri-State's 10-year transmission plan. Similarly, the expansion plan was only evaluated for transmission reliability impacts and transmission service for the additional resources was not in the scope of this analysis. The reliability impacts and necessary upgrades were identified by powerflow contingency analysis using Siemens' PSSE software and WECC approved powerflow models. In general, the costs were primarily associated with new transmission lines and/or transformers needed to mitigate thermal overloads associated with single contingencies.

To the extent possible, results from previous studies were leveraged to determine injection limits and identify Network Upgrades. Primarily, results from the Colorado Coordinated Planning Group's (CCPG) Lamar Front Range Task Force studies, Tri-State's LGIP System Impact Studies, and other internal Tri-State studies were utilized. Where needed, additional powerflow contingency analysis was performed by heavily dispatching the local existing resources consistent with LGIP study methodology. Due to the highly interconnected nature of Tri-State's transmission system, future changes made by other entities can greatly affect the results. As such, the provided cost estimates have a higher degree of uncertainty than is associated with typical planning level cost estimates. This is especially true for resources added beyond the ten-year horizon, as WECC does not build base cases beyond this

timeframe. Additionally, since it was assumed that a regional transmission organization (RTO) will be needed beyond the ten- year horizon, impacts to WECC Rated Paths were not considered.

Financial Analysis Process

Hyperion:

Data from the PO dispatch including the CE expansion plan resources and retirements along with hourly dispatch for resources, markets and contracts is loaded into Hyperion. Additionally, load forecasts and member distributed generation forecasts from SAS are loaded into Hyperion. Finally, manual forecast inputs including wheeling expense and revenue, ancillary service expense and revenue, capacity expense and revenue and fixed charges are entered into Hyperion. This data is compiled and sent to UIPlanner for final financial analysis.

UIPlanner:

Financial forecasting is completed within UIPlanner, resulting in a final value for PVRR for each scenario. UIPlanner is a financial forecasting model specifically designed for, and widely utilized in, the utility industry. Tri-State continuously maintains the functionality of the model, and on a periodic basis throughout the year, updates inputs and assumptions. Key rates used in ERP analysis include:

- Inflation rate of 1.7% in 2021 and 2022 and 2.0% 2023 to 2040
- Discount rate of 4.15%
- A discount rate of 3.00% per Commission guidance was also used for separate analysis of the SCC scenario

The model provides long-term financial forecast results such as Class A member rates, pro forma financial statements and financial ratios.

The expansion plan and hourly dispatch data from the CE and PO, along with the load forecast are extracted by Hyperion and files are prepared for import into UIPlanner. Transmission capital expenditures related to the expansion plan are prepared by Transmission Planning and imported into UI Planner. Along with Near-term operating and capital budgets and forecasts, UIPlanner forecasts capital expenditures, and operating and non-operating revenues and expenses. Financial assumptions and Board approved financial goals, including minimum equity to total capitalization ratios, debt service requirements, liquidity levels and net margins, are also input into UIPlanner. Given those parameters, UIPlanner solves for the minimum Class A revenue requirement to achieve those financial goals for each year of the study period. UIPlanner calculates the PVRR from the monthly revenue requirement over the study period.

For purposes of the base case and alternative scenarios, thermal retirements were handled as follows:

- Net book values impaired and amortized over original accounting life.
- Severance, community assistance and decommissioning cost estimates deferred and amortized over original accounting lives.
- Colowyo depletion accelerated to early retirement date.
- 50% of allocated G&A expense eliminated after an entity's retirement.

Modeling Constraints

As Tri-State progressed through its 2020 ERP process, some modeling issues were identified. The following identifies these issues, their impact to scenarios and plans for resolution.

Tri-State upgraded to its current version of CE and PO in early 2019. Despite robust functionality within the models themselves, some limitations were observed given new modeling requirements and workarounds were used to meet scenario requirements. These issues included the following items:

- The model does not allow a limit on emissions for transmission links. This created difficulties in limiting emissions within a particular state while considering imports. To work around this, Tri-State used an iterative process, which included placing emissions limits on resources where possible, manually checking emissions of final dispatch results and adjusting emission limits and re-running the dispatch as necessary to achieve appropriate emissions limits in a given state inclusive of imports.
- Tri-State's contractual share of Mt. Elbert, a pump storage resource associated with the LAP federal hydro contract, was modeled and functioning properly in initial scenarios. However, a software issue related to Mt. Elbert was encountered during successive scenario modeling which was unable to be resolved for a significant period of time. For impacted scenarios, Tri-State turned Mt. Elbert off and marked assumptions accordingly.
- Transmission capital expenditure analysis related to interconnection costs and network upgrade costs occur outside of CE and PO and typically occur after a CE plan for a given scenario is complete. It is difficult to incorporate into CE the cost of potential network upgrades. Tri-State works around this issue in the current model through the following methods:
    - Restricted early years of the model (prior to 2028) to allow limited generic resources from which the model could select. These restrictions were based on technology type and region depending upon available transmission interconnection and timing to accommodate network upgrades. For example, 200 MW of Wyoming and 100 MW of ECO interconnection capacity are available prior to 2028 without requiring additional significant network upgrades. Tri-State could not reasonably construct additional significant network upgrades in those regions prior to 2028. In such cases, priority for the interconnection capacity was given to renewable resources.
    - Applied a $600/KW transmission adder to the build cost of gas resources in eastern Colorado, where network upgrades are more likely to occur upon the addition of generic resources.
- DSM and EE were modeled as supply-side resources to compete with utility scale resources in CE and PO. While program costs were accounted for within CE, the lost member revenue from reduced load was not. This component of the analysis occurred in the financial models, Hyperion and UIPlanner.
- In scenarios where SPV3 was allowed to retire, the potential retirement date of the resource was limited to any time after the end of the related SRP contract (midyear 2036), as the model setup does not account for the impact of the revenue loss from the SRP contract.
- PO is an hourly least-cost dispatch tool and is unable to perform sub-hourly modeling in the current setup.

In 2021 Tri-State plans to revisit its current modeling setup, assess the current modeling tools, investigate other potential modeling tools and takes steps to close the above gaps from a system perspective without workarounds.

Modeling Assumptions

Table 54 identifies base modeling assumptions used in the 2020 ERP process.

Table 54: Modeling Assumptions used in 2020 ERP Base Case

Assumption Item	Description
Load Forecast	2020 Annual Long Term Forecast
Electric Price Forecast	May 2020 Spring Reset Long Term Forecast
Gas Price Forecast	May 2020 Spring Reset Long Term Forecast
Coal Price Forecast	May 2020
Announced Coal Retirements	• Escalante by 12/31/2020 • Craig 1 12/31/2025 • Craig 2 9/30/2028 • Craig 3 12/31/2029
Forced Outage Factors	• All Coal = 4% • Existing CC's = 3% • Existing CT's = 0% • Proposed CC's = 0% • Proposed CT's 0%
Thermal Resource Status: **Econ** - Model can turn resource on and off but resource has a 168-hour on-line minimum. **Must Run** - Model can choose the level at which resource is run but cannot dispatch lower than the resource minimum operating level.	• *Must Run 2021 - 2040*[39] : Craig 1, Craig 2, Craig 3, LRS 2, LRS 3, and SPV • *Econ 2021 - 2040*: Burlington 1, Burlington 2, Knutson 1&2, Limon 1&2, Pyramid 1-4, Rifle, and JM Shafer
Build Limits – represents the capacity allowed to be built by Transmission Area/Modeling Region or technology.	• Max RPP – East Colorado 1200 MW • Max RPP – New Mexico 400 MW • Max RPP – Storage 400 MW • Max RPP – Thermal 300 MW • Max RPP – Wyoming 600 MW • Max Annual – Renewable 500 MW
Water limits	JM Shafer capacity factor limited to 47% due to current water contracts. Ability to purchase additional water exists.
Emission limits[40]	NOX Limits: • Craig 1 annual capacity factor limited to 80% or less

[39] Through 2040 or announced retirement data as applicable.

[40] A modeling error in 80pct CR V1 and 80pct CR V2 caused Craig 1 to run slightly above the allowed 80% capacity factor set by the Regional Haze agreement. Based on the correction in similar scenarios, the correction of the capacity factor to 80% results in movement of the dispatch generation to Craig 3 and Colorado gas resources. Tri-State did not rerun these two scenarios with this correction.

Assumption Item	Description
	• Pyramid annual capacity factor limited to 30%
EE & DR DSM Level	Low and Aggressive Energy Efficiency (EE) Allowed Low Demand Response (DR) allowed for all Regions.
RES/RPS Levels	Must meet or exceed current RES for Colorado and RPS for New Mexico.
CO_2 Reduction in Colorado	No forced CO_2 reductions or restrictions applied in base assumptions.
Contracts/Power Purchase Agreements	Allowed to expire on terms.
Mt Elbert	On and available to dispatch within contract parameters.
Member Distributed Generation	Treated as renewed upon contract expiration at a proxy price by technology: $25/MWh Wind, $44/MWh Solar, $55/MWh Biomass, hydro and other.
Transmission Links	See Table 55 for detail.
Capacity Credits	See Table 56 for detail.
Market Depths	See Table 57-58 for detail.

Transmission Constraints:

The following constraints were implemented from 2021 to 2027 in the model due to current interconnection limitations and time needed to accomplish significant network upgrades. It was assumed additional significant network upgrades are possible by 2028.

- From 2025 to 2027: New Mexico 0 MW, Wyoming 200 MW, Eastern Colorado 100 MW
- Until 2026 Western Colorado 0 MW interconnection, afterwards interconnection MW amount equal to Craig 1 capacity

Transmission Links:

Table 55: Transmission Links in Base Case

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-E_CO>NM	WACM_Eastern_Colorado	New Mexico	124	0	2021 - 2040
LK-LAP>E_CO	Mt_ Elbert	WACM_Eastern_Colorado	107	139	2021 - 2040
LK-SPRV>NM	Springerville	New Mexico	317	0	2021 - 2040
LK-W_CO>E_CO	West_Colorado	WACM_Eastern_Colorado	457	150	2021 - 2040

Link Name	From Transmission Area	To Transmission Area	Forward Capacity *(MW)*	Backward Capacity *(MW)*	Dates
LK-W_CO>NM	West_Colorado	New Mexico	0	170	2021 - 2024
LK-W_CO>NM	West_Colorado	New Mexico	50	170	2025 - 2040
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	400	400	2021
LK-WY>E_CO	WACM_Wyoming	WACM_Eastern_Colorado	550	400	2022 - 2040

Capacity Credit Values:

For both solar and wind resources, an analysis was performed to determine an appropriate capacity credit value using a modified ELCC method[41]. In later years as more solar resources are added, the time of net system peak load is shifted to later in the day when the sun is setting (or has already set). Therefore, solar capacity credit is decreased. The capacity credit for wind is relatively consistent across all years of the various scenarios. Below are capacity credit values applied to base case scenario modeling.

Table 56: Capacity Credit Values

Resource Technology	Capacity Credit *(% of Nameplate)*
Thermal – existing and generic resources	100%
Standalone Batteries	100%
Existing Solar (Commercial & Under Contract)	35%
Existing Wind (Commercial & Under Contract) & Wind Generic Resources	30%
Solar Generic Resources	15%
Solar + 25 MW Battery Generic Resources	15% Solar; 100% for Battery
Wind + 25 MW Battery Generic Resources	30% for Wind; 100% for battery

Market Depths:

Tri-State has modeled several markets that represent typical locations of power transactions.

Sales Markets

- MS-4 Corner-N_NM – New Mexico
- MS-WEIM – New Mexico
- MS-Ault-E_CO – Eastern Colorado
- MS-Craig-NW_CO – Western Colorado
- MS-LRS-WY - Wyoming
- MS-WEIS - Eastern Colorado

[41] See Attachment Vol II 5-2 B&V Modified Effective Load Carrying Capability Study.

Purchase Markets

- MP-4 Corner-N_NM – New Mexico
- MP-WEIM – New Mexico
- MP-Ault-E_CO – Eastern Colorado
- MP-Craig-NW_CO – Western Colorado
- MP-LRS-WY - Wyoming
- MP-WEIS – Eastern Colorado

Tables 57 and 58 show the hourly market depths associated with each market for sales and purchases respectively, as applied to base case modeling. Market Depths are adjusted from base in alternative scenarios as necessary to accommodate for an evolving grid with higher quantities of intermittent resources and reducing levels of dispatchable resources. This is representative of the long-term need for an organized market to facilitate the addition of intermittent renewables. Changes to assumptions are identified in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Table 57: Market Sales (Hourly Capacity)

Dates	**MS-4 Corner-N_NM** *(MW)* [42]	**MS-WEIM** *(MW)*
Jan 2021 - Mar 2021	20-OFF / 75-ON	0
Apr 2021 - 2024	0-OFF / 20-ON	25-OFF / 60-ON
2025-2040	150	0

Dates	**MS-Ault-E_CO** *(MW)*	**MS-Craig-NW_CO** *(MW)*	**MS-LRS-WY** *(MW)*	**MS-WEIS** *(MW)*
Jan 2021	0-OFF / 50-ON	15-OFF / 100-ON	0	0
Feb 2021 - 2024	0-OFF / 25-ON	0-OFF / 25-ON	0	25-OFF / 125-ON
2025-2029	150	150	0	0
2030-2040	50	50	200	0

Table 58: Market Purchases (Hourly Capacity)

Dates	**MP-4 Corner-N_NM** *(MW)*	**MP-WEIM** *(MW)*
Jan 2021 - Mar 2021	100	0
Apr 2021 - 2024	85	15
2025-2040	200	0

[42] "OFF" and "ON" references off peak and on peak hours respectively.

Dates	MP-Ault-E_CO *(MW)*	MP-Craig-NW_CO *(MW)*	MP-LRS-WY *(MW)*	MP-WEIS *(MW)*
Jan 2021	200	125	75	0
Feb 2021 - 2024	150	100	75	75
2025-2040	200	200	200	0

Generic Resource Cost, Performance and Emissions Data

Cost and technology characteristics for generic resources including renewables, gas resources, and energy storage were verified by B&V. Below highlights key aspects of this review by resource type:

Thermal Resources: Working from Tri-State's original generic resource data set, which primarily consisted of gas resource cost and characteristics data from EPRI TAGWeb Version 3.52 software, B&V utilized in house subject matter experts to compare existing data for generic resources to B&V's independent check-estimates developed using a combination of past project estimates, Thermoflow's GTPRO/GTMASTER modeling software, and Original Equipment Manufacturer (OEM) online performance tools. Key data assessed included capital cost, net heat rate, ability to cycle and load follow, availability, emissions and operation and maintenance expense. Resulting recommended changes included additions or removal of existing gas generic resources in the data set as well as changes to underlying cost and performance data.

Renewable (including renewable plus batteries) Build Transfers: Tri-State was relying on National Renewable Energy Laboratories (NREL), EIA, EPRI and other industry resources to develop costs and characteristics for renewables modeled as build transfers. B&V in house subject matter experts reviewed capital expenses, O&M expenses and net capacity factors for build transfer renewables and provided recommendations.

Renewable (including renewable plus batteries) PPAs*:* B&V utilized its power project data for capital costs, O&M costs and expected production, and its in-house subject matter expertise to forecast PPA prices for generic renewable energy resources, including solar, solar + storage, wind, and wind + storage resources, within the Tri-State operating area. The renewable resources were assumed to have a 35-year life. Net energy output was calculated as follows:

Table 59: Renewable Resource Capacity and Energy Calculations

Resource Type	Net Capacity Factor *(%)*	Year 1 Net Energy Production *(MWh)*
Solar PV	30.0%	262,800
Solar PV + Storage	28.0%	245,192
Wind	43.0%	376,680
Wind + Storage	40.1%	351,442

Solar energy output was assumed to degrade at a rate of .32% per year.

The expiration of tax credits were taken into consideration, and prices were forecast by technology type and region.

Storage Builds: Tri-State was relying on NREL, EIA, EPRI and other industry resources to develop costs and characteristics for standalone energy storage, specifically Li-ion 4 hour batteries. B&V in house subject matter experts reviewed capital expenses, O&M expenses and efficiencies for energy storage builds and provided recommendations. Additionally, Tri-State utilized a proposed pumped storage project in New Mexico as the basis for pumped storage costs and characteristics.

Final costs and characteristics for generic resources as modeled in Tri-State's 2020 ERP process based on recommendations by B&V are as follows. All costs are in real (2020) dollars.

Table 60: Costs for Thermal Build Resources

Resource	Technology	Location[43]	Build Cost *($/kW)*	Fixed Cost *($ Annual)*	VOM *($/MWh)*	Startup Costs *($ per start)*
112_18x6RICE_eco	Recip Engine	Eastern CO	$1,881	$2,332,224	$7.42	$50
112_18x6RICE_nnm	Recip Engine	New Mexico	$1,281	$2,332,224	$7.42	$50
300_1x1_7FA05_eco	Combined Cycle	Eastern CO	$2,163	$4,000,000	$3.00	$500
300_1x1_7FA05_nnm	Combined Cycle	New Mexico	$1,563	$4,000,000	$3.00	$500
300_1x1_7FA05_swco	Combined Cycle	Western CO	$1,563	$4,000,000	$3.00	$500
300_1x1_7FA05_wyo	Combined Cycle	Wyoming	$1,563	$4,000,000	$3.00	$500
40_1x40LM6000_eco	Aeroderivative	Eastern CO	$2,247	$1,750,000	$5.94	$25
40_1x40LM6000_nnm	Aeroderivative	New Mexico	$1,647	$1,750,000	$5.94	$25
40_1x40LM6000_swco	Aeroderivative	Western CO	$1,647	$1,750,000	$5.94	$25
357_1x1_7HA01_nwco	Recip Engine	Western CO	$1,488	$4,603,200	$3.86	$600
46_9x5RICE_eco	Recip Engine	Eastern CO	$2,125	$1,024,398	$7.00	$50
46_9x5RICE_nnm	Recip Engine	New Mexico	$1,525	$1,024,398	$7.00	$50
46_9x5RICE_swco	Recip Engine	Western CO	$1,525	$1,024,398	$7.00	$50
545_1x1_7HA03_nwco	Combined Cycle	Western CO	$1,188	$5,899,500	$3.67	$600
81_2x40LM6000_eco	Aeroderivative	Eastern CO	$2,003	$2,250,000	$5.80	$50
81_2x40LM6000_wyo	Aeroderivative	Wyoming	$1,403	$2,250,000	$5.80	$50
93_1x100_LMS100_nnm	Aeroderivative	New Mexico	$1,525	$1,444,354	$5.00	$50
200_1x235_7FA05_eco	Combustion Turbine	Eastern CO	$1,271	$1,553,481	$1.00	$14,000
200_1x235_7FA05_nnm	Combustion Turbine	New Mexico	$671	$1,553,481	$1.00	$14,000
200_1x235_7FA05_swco	Combustion Turbine	Western CO	$671	$1,553,481	$1.00	$14,000

Table 61: Performance Characteristics for Thermal Build Resources

Resource	Rated Capacity *(MW)*	Average Heat Rate *(btu/kWh)*	Marginal Heat Rate *(btu/kWh)*	Minimum Operation *(MW)*	Ancillary Services
112_18x6RICE_eco	112	8250	8250	28	Reserves, Regulation
112_18x6RICE_nnm	112	8250	8250	28	Reserves, Regulation
300_1x1_7FA05_eco	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_nnm	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_swco	300	6530	6530	150	Reserves, Regulation
300_1x1_7FA05_wyo	300	6530	6530	150	Reserves, Regulation
40_1x40LM6000_eco	40	9300	9300	20	Reserves, Regulation

[43] Eastern Colorado Gas builds have a $600/KW adder for transmission network upgrade expense.

Resource	Rated Capacity *(MW)*	Average Heat Rate *(btu/kWh)*	Marginal Heat Rate *(btu/kWh)*	Minimum Operation *(MW)*	Ancillary Services
40_1x40LM6000_nnm	40	9300	9300	20	Reserves, Regulation
40_1x40LM6000_swco	40	9300	9300	20	Reserves, Regulation
357_1x1_7HA01_nwco	357	6280	6280	110	Reserves, Regulation
46_9x5RICE_eco	46	8400	8400	12	Reserves, Regulation
46_9x5RICE_nnm	46	8400	8400	12	Reserves, Regulation
46_9x5RICE_swco	46	8400	8400	12	Reserves, Regulation
545_1x1_7HA03_nwco	545	6170	6170	207	Reserves, Regulation
81_2x40LM6000_eco	81	9300	9300	40	Reserves, Regulation
81_2x40LM6000_wyo	81	9300	9300	40	Reserves, Regulation
93_1x100_LMS100_nnm	93	8900	8900	14	Reserves, Regulation
200_1x235_7FA05_eco	200	9800	9800	84	Reserves, Regulation
200_1x235_7FA05_nnm	200	9800	9800	84	Reserves, Regulation
200_1x235_7FA05_swco	200	9800	9800	84	Reserves, Regulation

Table 62: Emissions & Water Usage for Thermal Builds (pounds per MWh)

Resource	CO_2	SO_2	NOx	HG	PM	Water
112_18x6RICE_eco	949	0	0.15	N/A	0	0
112_18x6RICE_nnm	949	0	0.15	N/A	0	0
300_1x1_7FA05_eco	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_nnm	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_swco	751	0.0078	0.747	N/A	0.0804	348
300_1x1_7FA05_wyo	751	0.0078	0.747	N/A	0.0804	348
40_1x40LM6000_eco	1,070	0.012	1.223	N/A	0.07	120
40_1x40LM6000_nnm	1,070	0.012	1.223	N/A	0.07	120
40_1x40LM6000_swco	1,070	0.012	1.223	N/A	0.07	120
357_1x1_7HA01_nwco	722	0.0078	0.747	N/A	0.0804	348
46_9x5RICE_eco	966	0	0.15	N/A	0	0
46_9x5RICE_nnm	966	0	0.15	N/A	0	0
46_9x5RICE_swco	966	0	0.15	N/A	0	0
545_1x1_7HA03_nwco	710	0.0078	0.747	N/A	0.0804	348
81_2x40LM6000_eco	1,070	0.012	1.223	N/A	0.07	120
81_2x40LM6000_wyo	1,070	0.012	1.223	N/A	0.07	120
93_1x100_LMS100_nnm	1,127	0.008575	0.360	N/A	0.0929	57
200_1x235_7FA05_eco	1,127	0.008	0.378	N/A	0.0621	57
200_1x235_7FA05_nnm	1,127	0.008	0.378	N/A	0.0621	57
200_1x235_7FA05_swco	1,127	0.008	0.378	N/A	0.0621	57

Table 63: Costs for Solar and Wind Build-Transfers

Resource	Technology	Location	Build Cost in 2021 *($/kW)*[44]	Fixed Cost *(Annual $)*	VOM *($/MWh)*	Startup Costs *($ per start)*
PS-1x100PV_eco	Solar	Eastern Colorado	[redacted]		n/a	n/a
PS-1x100PV_nnm	Solar	New Mexico			n/a	n/a
PS-1x100PV_wco	Solar	Western Colorado			n/a	n/a
PS-1x100Wind_eco	Wind	Eastern Colorado			n/a	n/a
PS-1x100Wind_nnm	Wind	New Mexico			n/a	n/a
PS-1x100Wind_wyo	Wind	Wyoming			n/a	n/a

[redacted]

Table 64: Storage Costs

Resource	Technology	Location	Build Cost in 2021 *($/kW)*[45]	Fixed Cost *(Annual $)*	VOM *($/MWh)*	Startup Costs *($ per start)*
100MW Li-Ion Battery_eco	Li-ion Battery	Eastern Colorado	$1,270	$1,000,000	n/a	n/a
100MW Li-Ion Battery_wco	Li-ion Battery	New Mexico	$1,270	$1,000,000	n/a	n/a
100MW Li-Ion Battery_nnm	Li-ion Battery	Western Colorado	$1,270	$1,000,000	n/a	n/a
25MW Li-Ion Battery_eco	Li-ion Battery	Eastern Colorado	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_nnm	Li-ion Battery	New Mexico	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_wco	Li-ion Battery	Western Colorado	$1,359	$250,000	n/a	n/a
25MW Li-Ion Battery_wyo	Li-ion Battery	Wyoming	$1,359	$250,000	n/a	n/a
300 MW Pumped Storage	Pumped Storage	New Mexico	$2,200	$5,100,000	n/a	n/a

[44] For solar resources build costs decline over time at an average of ~4% per year during the RAP and remain steady thereafter. For wind resources build costs decline over time at an average of ~1.75% per year over the RPP.
[45] Battery build costs are projected to decline by 6% per year through the RAP.

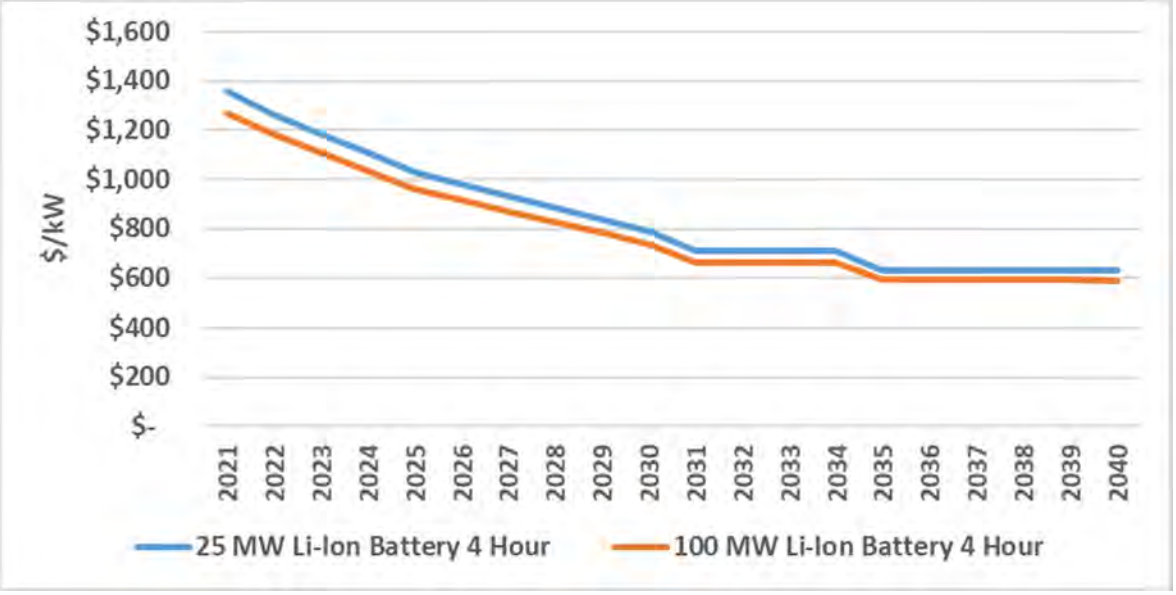

Figure 20: Li-Ion Battery Build Cost Curve

Table 65: Solar and Wind PPA Costs

Resource	Technology	Location	Capacity *(MW)*	Capacity Factor	Costs in 2021 *($/MWh)*
PS-1x100-PV_eco	Solar PV	Eastern Colorado	100	30%	
PS-1x100-PV_nnm	Solar PV	New Mexico	100	30%	
PS-1x100-PV_swco	Solar PV	Western	100	30%	
PS-1x50-PV_swco	Solar PV	Western	50	30%	
PS-1x100-PVBatt_eco	Solar PV + Battery	Eastern Colorado	100	28%	
PS-1x100-PVBatt_nnm	Solar PV + Battery	New Mexico	100	28%	
PS-1x100-PVBatt_swco	Solar PV + Battery	Western	100	28%	
PS-1x100-Wind_eco	Wind	Eastern Colorado	100	43%	
PS-1x100-Wind_nnm	Wind	New Mexico	100	43%	
PS-1x100-Wind_wyo	Wind	Wyoming	100	43%	
PS-1x100-WindBatt_eco	Wind + Battery	Eastern Colorado	100	40%	
PS-1x100-WindBatt_nnm	Wind + Battery	New Mexico	100	40%	
PS-1x100-WindBatt_wyo	Wind + Battery	Wyoming	100	40%	

Figure 21: Solar and Wind PPA Pricing

Figure 22: Solar + Battery and Wind + Battery PPA Pricing

Table 66: Performance Characteristics of Solar, Wind, and Storage Resources[46]

Resource	Rated Capacity *(MW)*	Average Heat Rate	Marginal Heat Rate	Minimum Operation
PS-1x100PV_eco	100	n/a	n/a	n/a
PS-1x100PV_nnm	100	n/a	n/a	n/a
PS-1x100PV_wco	100	n/a	n/a	n/a
PS-1x50PV_wco	50	n/a	n/a	n/a
PS-1x100-PVBatt_eco	100	n/a	n/a	n/a
PS-1x100-PVBatt_nnm	100	n/a	n/a	n/a
PS-1x100-PVBatt_wco	100	n/a	n/a	n/a
PS-1x100Wind_eco	100	n/a	n/a	n/a
PS-1x100Wind_nnm	100	n/a	n/a	n/a
PS-1x100Wind_wyo	100	n/a	n/a	n/a
PS-1x100WindBatt_eco	100	n/a	n/a	n/a
PS-1x100WindBatt_nnm	100	n/a	n/a	n/a
PS-1x100WindBatt_wyo	100	n/a	n/a	n/a
100MW Li-Ion Battery_eco	100	n/a	n/a	n/a
100MW Li-Ion Battery_wco	100	n/a	n/a	n/a
100MW Li-Ion Battery_nnm	100	n/a	n/a	n/a
25MW Li-Ion Battery_eco	25	n/a	n/a	n/a
25MW Li-Ion Battery_nnm	25	n/a	n/a	n/a
25MW Li-Ion Battery_wco	25	n/a	n/a	n/a
25MW Li-Ion Battery_wyo	25	n/a	n/a	n/a
300 MW Pumped Storage_NM	300	n/a	n/a	0

Table 67: Solar, Solar + Storage, Wind, & Wind + Storage Emissions & Water Usage (pounds per MWh)[47]

Resource	CO_2	SO_2	NOx	HG	PM	Water
PS-1x100PV_eco	0	0	0	0	0	0
PS-1x100PV_nnm	0	0	0	0	0	0
PS-1x100PV_wco	0	0	0	0	0	0
PS-1x50PV_wco	0	0	0	0	0	0
PS-1x100-PVBatt_eco	0	0	0	0	0	0
PS-1x100-PVBatt_nnm	0	0	0	0	0	0
PS-1x100-PVBatt_wco	0	0	0	0	0	0
PS-1x100Wind_eco	0	0	0	0	0	0
PS-1x100Wind_nnm	0	0	0	0	0	0
PS-1x100Wind_wyo	0	0	0	0	0	0
PS-1x100WindBatt_eco	0	0	0	0	0	0
PS-1x100WindBatt_nnm	0	0	0	0	0	0
PS-1x100WindBatt_wyo	0	0	0	0	0	0

[46] These resources were not modeled to provide ancillary services (i.e. regulation up, regulation down or contingency reserves).

[47] For wind plus battery and solar plus battery resources, the batteries are modeled as charged from the related renewable resource.

Table 68: Storage Emissions & Water Usage (pounds per MWh)[48]

Resource	CO_2	SO_2	NOx	HG	PM	Water
100MW Li-Ion Battery_eco	1280	0.40	0.70	-	-	-
100MW Li-Ion Battery_wco	1280	0.40	0.70	-	-	-
100MW Li-Ion Battery_nnm	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_eco	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_nnm	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_wco	1280	0.40	0.70	-	-	-
25MW Li-Ion Battery_wyo	1280	0.40	0.70	-	-	-
300 MW Pumped Storage	1280	0.40	0.70	-	-	-

Modeled life of resources are as follows:

- Wind, Solar, Wind plus battery, and Solar plus battery PPA – 20 years
- Wind and Solar Build transfer – 20 years
- Energy Storage Li-Ion Batteries – 15 years
- Energy Storage Pumped Storage Hydro – 30 years
- Gas Resources – 30 years

DSM & EE Generic Resources:

DSM & EE are modeled as supply side generic resources. This modeling is discussed in Section 5 Phase I Modeling Details under the Modeling Assumptions & Analytical Methodology subsection.

Consideration for Clean Energy and Energy Efficient Technologies

Tri-State includes clean energy and energy efficient technologies in its resource mix of available technologies for expansion planning. In regards to clean energy, available technologies included in expansion planning are solar, solar plus battery, wind and wind plus battery installations. Renewable resources are available in the generic resource dataset in each modeling region/TA in sufficient quantities to influence the environmental impact of the overall resource plan for a given scenario. Additionally, energy storage options in the form of stand-alone batteries as well as batteries coupled with solar and wind installations are made available in the generic resource data set to support the addition of renewable resources within the scenarios.

Tri-State also includes in the generic resource dataset for use in expansion planning demand side resource options including energy efficiency and demand response. These represent programs that Tri-State could develop with the consensus of and for use by Tri-State's Utility Member Systems. Forecast data for energy efficiency and demand response generic resource is based on the results of the 2020 DSM & EE Potential study, which can be found in Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study. Forecast energy efficiency and demand response are selectable resources in scenarios

[48] Standalone batteries are modeled as charged from market purchases. Above rates, reflect expected market purchase emission rates based on egrid RMPA values for 2018 as available.

allowing the model to consider these resources on an economic basis. In select scenarios, the energy efficiency or demand response generic resources are forced. Further detail can be found in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Including renewable resources as well as demand side management and energy efficiency helps to continue to diversify Tri-State's fleet including increasing fuel diversity, which insulates the overall cost of power from technology specific fuel price increases. Diversity also incorporates different types of technology with varying generating patterns to more reliably serve Utility Member System load. Finally, diversity in resource planning by incorporating clean energy and energy efficient technologies into scenarios allows for a clear method of measuring environmental impact while respecting reliability.

Assessment of Costs and Benefits of Integration of Intermittent Resources

Tri-State 2020 ERP scenarios include the integration of significant quantities of intermittent renewable energy. The expansion plan for the base case alone, which does not include GHG/CO_2 restrictions as an assumption within the model, has ~2500 MW of wind and solar generic resources. Alternative scenarios with CO_2 restrictions related to the state of Colorado incorporate between ~2,700 MW and ~4,100 MW of wind and solar generic resources. Tri-State currently has ~467MW of commercially operational wind and solar across its system and an additional ~1000 MW under contract and expected to be commercially operational by 2024. As Tri-State looks to integrate a substantial amount of intermittent energy over the RPP, an assessment of the costs and benefits is necessary.

Costs related to integrating larger quantity of intermittent renewable resources include impacts to dispatchable resources, economic impacts, and the need to maintain reliability within an evolving grid. Currently, Tri-State uses thermal resources, coal and gas, to handle ramping needs to meet load requirements when renewable resources are not available. Coal resources that were primarily intended for base loading incur additional cycling costs of less than ~$0.15/MWh. This cost is due to the additional wear and tear on the resource, and specific cycling costs for Tri-State coal resources are identified in Section 3 Assessment of Resources under the subsection of Overview of Thermal Resources in this report. Gas resources are built to be flexible resources, and Tri-State has not determined a similar cycling cost impact to existing gas resources in Tri-State's fleet.

Related to this cycling requirement is the potential to curtail renewable resources in the event sufficient dispatchable generation is not available to move down in a low load, high renewable situation. Tri-State's current contracted and operational renewable resources are via PPAs, and specifically, the associated tax credit for wind resources can exacerbate the economic impact of curtailments. The addition of energy storage to accommodate power that would otherwise be curtailed is a potential solution. Tri-State's scenario modeling shows the need for energy storage to accommodate the integration of renewable resources. From a cost perspective, an expected decline in energy storage build costs over the next decade is necessary to allow this resource type to be a viable part of a renewable integration solution.

As dispatchable resources are retired and more renewables are brought onto the grid for economic and regulatory compliance reasons, the ability to have sufficient capacity to meet planning reserve margins and ramping requirements is critical. Related to this, Tri-State engaged Black & Veatch to perform a modified ELCC study based on the expected significant increase of renewable resources and decrease of dispatchable resources on Tri-State's system over the RPP. Details of the impact of the modified ELCC on

capacity credits for intermittent resources can be found in Volume I Section 6 Assessment of Resource Needs of this report. Overall, an evolving grid with less dispatchable resources and an increasing quantity of intermittent resources leads to a need for more ramping capabilities from existing and expansion plan resources. The movement of load and resources into an organized market where a larger set of resources can respond on a sub hourly basis to ramping needs is critical for successful integration of large quantities of intermittent renewable resources.

Benefits related to the integration of larger quantities of intermittent renewable resources include economic impacts, supply diversity and emissions reductions. Intermittent renewable generation projects represent a low cost option for meeting energy needs, and effective, large-scale integration of this resource is necessary to drive down the cost of serving Utility Member System load.

The low cost of renewables was a key driver behind Tri-State's recent RFPs, which resulted in the planned addition of 1 GW of renewables by 2024. Adding renewable resources also brings diversity to Tri-State's resource mix and allows for locating resources in areas where the addition of thermal resources is not a viable option. Another significant benefit of renewables is the resulting reduction in fleet emissions as renewable energy displaces thermal generation. Tri-State's Responsible Energy Plan, state-specific CO2 reduction goals, and Renewable Energy or Portfolio Standards are all intended to reduce the environmental impacts associated with electric power generation.

Modeling Assumptions & Analytical Methodology

Energy Storage

In the current CE and PO models, the value of energy storage is focused on its ability to assist with the integration of intermittent resources. This value includes the ability to smooth delivery of intermittent resources and avoidance of potentially costly renewable curtailments. Tri-State's western interconnection load and resources currently do not have access to full "day-2" organized markets with ancillary service markets, so the value of energy storage as a supplier of ancillary services such as regulation up and regulation down was not evaluated at this time.

Li-Ion Batteries:

Tri-State does not have any existing battery storage facilities, but Tri-State modeled generic Li-Ion battery storage facilities as resource options for expansion planning. The Li-Ion batteries were modeled with four hours of storage and either 100MW (ECO, CO, NM) or 25MW (ECO, WCO, NM, and WY) of capacity. Discharge capability of four hours of energy storage was modeled based on demonstrated projects and proposed projects previously evaluated. The batteries are allowed to have multiple cycles per day, but a 4% annual forced outage factor is applied. Batteries were modeled with a 90% efficiency. 100% of the capacity is assumed to be available to meet planning reserve requirements at the peak hour. Given that the generation expansion planning module can build multiple units of the same generic resource it can in theory build multiple four-hour resources to simulate an eight-hour or larger resource. The model is designed to dispatch the charge and discharge to most economically serve Utility Member System load. Specific cost and modeling data can be found in Section 5 Phase I Modeling Details under the Generic Resource Cost, Performance and Emissions Data subsection of this report.

Li-Ion Batteries combined with Solar and Wind:

Hybrid renewable-battery storage plants were modeled based on the existing 100MW wind and solar profiles paired with a 25MW/100MWh lithium-ion battery system. The hybrid facilities offer advantages in pricing due to the availability of Investment Tax Credits for hybrid solar facilities as well as efficiencies related to using a single inverter to reduce balance of plant construction costs. Discharge capability of four hours of energy storage was modeled based on demonstrated projects and proposed projects previously evaluated.

The hybrid facilities are modeled such that all of the power to charge the battery is produced from the associated renewable facility. For Solar-Battery hybrid facilities this resulted in new daily shapes created to maximize load peak shaving by moving energy into the 5 peak hours of the day. For Wind-Battery hybrid facilities the shape is developed to minimize ramping spikes and provide a consistent energy resource throughout the day. Specific cost and modeling data can be found in Section 5 Phase I Modeling Details under the Generic Resource Cost, Performance and Emissions Data subsection of this report.

Pumped Storage Hydro (Mt. Elbert):

The Mt. Elbert pumped storage hydro facility is part of Tri-State's portfolio, modeled within the eastern Colorado transmission area, as a part of its LAP hydro contract purchases. Tri-State does not operate Mt. Elbert, and Tri-State's share of the facility is limited to a daily schedule for pumping and generation and a seasonal amount of the energy and capacity. Per contractual limits, return energy is scheduled between Hour Ending (HE) 23 and HE7 and generation is scheduled between HE8 and HE22. Mt. Elbert is capable of storing up to 1380MWh in the summer season and can receive or generate a capacity of 176MW in a given hour. The "roundtrip" efficiency of the Mt. Elbert facility 68% in that 1.47MWh is required to add 1MWh of energy storage. The market is the source for charging/pump back energy. The total generation capacity of the Mt. Elbert pumped storage and LAP Hydro contract is limited by the capacity of the LAP Hydro contract. Within the limits of the contract and the capability of the facility Mt. Elbert is modeled to dispatch to reduce system costs.

Pumped Storage Generic Resource:

A generic pumped storage resource was modeled as an option for all scenarios. Because of the difficulty of development and siting a pumped storage facility, a single option in Northern New Mexico was identified and modeled. Tri-State's portion of the facility would be limited to 300MW of capacity and 2400MWh of energy or eight hours of storage at full capacity. The efficiency of the facility is assumed to be 80% or 1.25MWh of energy is required to add 1MWh of energy output. The market is the source for charging/pump back energy. The cost of the facility is modeled as $2,200/kW with a 30-year operating and book life. Due to the limited options for pump storage only one unit may be added in the study period and only in 2028 or later.

Renewables

Tri-State models existing, under contract and generic renewable resources as varying 8760 profiles. The methodology to arrive at these profiles utilizes historical generation for existing facilities as recorded by Tri-State's OSIsoft PI historian system. These actual monthly profiles are randomized to create new pseudo-random hourly profiles for the duration of the PPA contract. Up to five years of historical data

was used to develop the hourly profiles and, to the extent possible, the same dates were used across resources to maintain the same daily weather patterns and demonstrate the geographical diversity of the existing generation.

For generic renewable resources, a similar method was employed to develop hourly profiles. Tri-State uses similar existing resources that are most representative of future renewable resources in each geographical area to the extent possible. Western Colorado, eastern Colorado and Wyoming wind profiles for generic resources were developed from the Colorado Highlands wind facility. New Mexico generic resource solar profiles were developed from the Alta Luna solar facility, while the Colorado solar generic resource profiles were developed from the Spanish Peaks solar facility. Table 69 shows this setup and related capacity factors. Individual generation profiles were developed by randomizing the data. This mimics the geographic diversity of the generation. For hybrid wind-battery and solar-battery generic resources, the same renewable profiles were used and a 4 hour 25MW battery is used to maximize peak shaving for solar and limit high ramping hours for wind.

Table 69: Renewable Hourly Forecast Development

Renewable Options	Location(s)	Actual Generation Source	Storage Capacity	Capacity Factor
Tracking PV (PPA)	ECO, WCO	Spanish Peaks	N/A	28%
Tracking PV (Build Transfer)	ECO, WCO	Spanish Peaks	N/A	28%
Tracking PV (PPA)	NM	Alta Luna	N/A	32%
Tracking PV (Build Transfer)	NM	Alta Luna	N/A	32%
Tracking PV with Battery	ECO, WCO, NM	Alta Luna	25MW (4 Hour)	31%
Wind (PPA)	ECO, WCO, WY	Colorado Highlands	N/A	44%
Wind (Build Transfer)	ECO, WCO, WY	Colorado Highlands	N/A	44%
Wind with Battery	ECO, WCO, WY	Colorado Highlands	25MW (4 Hour)	40%

The annual outputs for new and existing generation were compared for reasonableness to the simulated forecast for each resource as created by Ascend Analytics. The complete results of the comparison can be found in Attachment Vol II 5-6 Ascend Analytics Renewables and Ramping Analysis.

Using the method described above for existing and under contract resources, annual energy for individual PPAs may be higher or lower than the forecasted contract energy amount due to the variability of the underlying technology, but the output is representative of previously recorded actual output. While this is to be expected, in the event that the total annual renewable energy was out of the range of contracted PPA energy, the Ascend hourly profiles were used in place of the outlier profiles to better align with the contract energy.

For financial modeling purposes actual contract energy for existing and contracted renewable PPAS is used in Hyperion and forwarded to UIPlanner for calculation of PVRR. The variance between Hyperion contract energy for existing and under contract renewables and the PO randomized 8760 profile annual totals are shown in Figure 23.

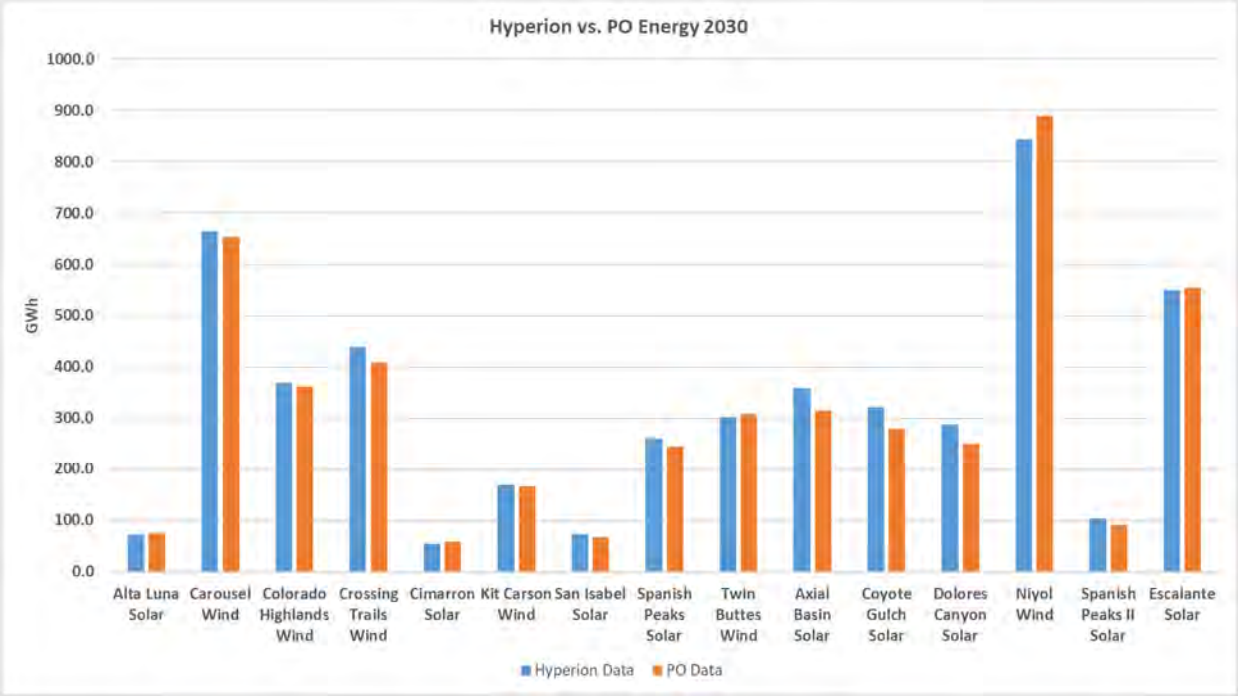

Figure 23: Hyperion versus PO Energy by PPA - Projected 2030

PO Dispatch data for renewables is used for determining GHG/CO_2 reduction.

DSM and EE

Tri-State's current demand side management and energy efficiency programs are described in Volume I Section 6 Assessment of Resource Needs under the subsection of Demand Side Management & Energy Efficiency.

In regards to potential expansion plan resources, Tri-State modeled in the generic resource dataset demand side resource options including energy efficiency and demand response by region.

Tri-State commissioned Mesa Point Energy to perform a DSM and EE potential study in 2019 that was completed in the spring of 2020. The study can be found as Attachment Vol II 5-1 Demand Side Management and Energy Efficiency Potential Study. This analysis was the basis for the modeled energy efficiency and demand response options in the generic resource dataset. The study was performed by load type (HVAC, Lighting, etc.), scenario (low achievable through max achievable), sector (Residential, Commercial, Industrial, Irrigation), and load region.

To model the resources, the individual load types, sectors, and load regions were consolidated to match the modeling regions/TAs used in CE and PO (New Mexico, West Colorado, East Colorado, Wyoming, and Nebraska). Tri-State modeled two levels of EE generic resources: Low Achievable and Aggressive Achievable and modeled one Low Achievable DR program level based on data from the study. For the EE generic resources costs were broken down to a must take $/MWh cost. For the DR generic resources, the associated study costs were represented as an annual fixed cost with a limited energy quantity representing the number of times that the demand response resource was called on as assumed by the DSM & EE Potential Study. It is important to note that the costs associated with DSM and EE are solely related to outgoing expenses related to funding the potential programs through incentives and promotion and does not include the opportunity cost associated with lost billing revenues.

Each EE or DR resource was eligible to be added during the years 2021, 2025, 2030, and 2035 with the same energy, capacity, and cost curves shifted to the start year. This was done to reduce the model size and complexity while allowing EE or DR resources to be introduced later in the study. For EE the model could select either Low or Aggressive Achievable generic resources within a region but not both. Modeled values can be found in Table 70 through Table 75.

Table 70: Energy (MWh) from Demand Response (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	131	43	35	37
2022	218	71	58	62
2023	355	115	95	100
2024	561	182	150	156
2025	850	276	228	235
2026	1,214	393	326	333
2027	1,608	520	432	438
2028	1,931	622	515	525
2029	2,148	689	569	583
2030	2,269	725	598	615
2031	2,331	742	610	630
2032	2,368	751	616	639
2033	2,395	756	620	645
2034	2,418	761	622	650
2035	2,438	765	624	655
2036	2,459	769	626	659
2037	2,480	772	628	663
2038	2,500	776	630	668
2039	2,527	782	634	673
2040	2,554	788	638	679

Table 71: Peak Capacity (MW) from Demand Response (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	2	1	1	1
2022	4	1	1	1
2023	6	2	2	2
2024	9	2	3	3
2025	14	4	5	4
2026	20	5	6	5
2027	26	7	9	7
2028	32	8	10	9
2029	35	9	11	10
2030	37	10	12	10
2031	38	10	12	10
2032	39	10	12	10
2033	39	10	12	11
2034	40	10	12	11
2035	40	10	13	11
2036	40	10	13	11
2037	41	10	13	11
2038	41	10	13	11
2039	41	10	13	11
2040	42	10	13	11

Table 72: Energy (MWh) from Energy Efficiency (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	12,370	7,756	6,093	4,112
2022	27,808	16,914	13,697	8,954
2023	44,834	27,154	22,083	13,978
2024	63,562	38,564	31,305	19,242
2025	84,189	51,077	41,466	24,963
2026	106,912	64,870	52,659	31,161
2027	131,971	80,056	65,002	37,896
2028	162,035	96,497	79,809	45,491
2029	192,962	113,373	95,040	53,327
2030	226,302	131,244	111,462	61,777
2031	261,647	150,039	128,872	70,670
2032	299,015	169,452	147,277	80,104
2033	338,278	189,315	166,616	90,006

Year	East Colorado	New Mexico	West Colorado	Wyoming
2034	379,575	210,071	186,954	100,501
2035	422,779	231,585	208,234	111,527
2036	454,261	242,111	223,740	117,453
2037	486,844	252,945	239,790	123,705
2038	519,974	263,812	256,107	129,965
2039	553,231	274,352	272,488	136,002
2040	586,909	285,037	289,075	142,135

Table 73: Capacity (MW) from Energy Efficiency (Low Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	2	2	1	1
2022	5	4	3	2
2023	9	6	4	3
2024	12	8	6	4
2025	16	11	8	5
2026	21	14	10	6
2027	26	18	13	8
2028	32	21	16	9
2029	39	25	19	11
2030	47	30	23	12
2031	55	34	27	14
2032	63	38	31	16
2033	72	43	35	18
2034	81	48	40	20
2035	90	53	45	23
2036	98	56	48	24
2037	105	58	52	25
2038	113	61	56	27
2039	120	63	59	28
2040	128	65	63	29

Table 74: Energy (MWh) from Energy Efficiency (Aggressive Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	25,522	15,370	12,571	8,315
2022	58,352	34,504	28,741	18,344
2023	95,548	56,809	47,062	29,153
2024	137,648	82,393	67,798	40,627
2025	185,432	110,975	91,334	53,413
2026	239,174	142,587	117,803	67,622
2027	298,593	176,974	147,068	83,279
2028	364,994	212,847	179,773	100,560
2029	432,758	248,988	213,149	118,296
2030	502,940	285,921	247,718	136,953
2031	574,208	323,291	282,817	155,938
2032	646,233	360,727	318,294	175,386
2033	718,589	397,729	353,932	194,926
2034	791,700	435,099	389,942	214,868
2035	865,590	472,673	426,336	235,066
2036	920,430	495,023	453,347	247,270
2037	976,073	517,830	480,753	259,546
2038	1,031,659	539,986	508,128	271,741
2039	1,086,722	560,923	535,251	283,423
2040	1,141,901	581,312	562,430	295,086

Table 75: Peak Capacity (MW) from Energy Efficiency (Aggressive Achievable)

Year	East Colorado	New Mexico	West Colorado	Wyoming
2021	5	3	2	2
2022	11	7	6	4
2023	19	12	9	6
2024	27	18	13	8
2025	36	25	18	11
2026	47	32	23	14
2027	59	40	29	17
2028	74	49	36	21
2029	88	58	44	25
2030	104	67	51	29
2031	120	76	59	33
2032	135	85	66	37
2033	151	94	75	41

Year	East Colorado	New Mexico	West Colorado	Wyoming
2034	168	103	83	45
2035	184	113	91	49
2036	196	118	97	52
2037	209	124	103	54
2038	221	129	109	57
2039	234	134	115	59
2040	245	138	121	61

Distributed Generation

Tri-State models member distributed generation projects, under Board Policy 115 and Board Policy 119, as resources in CE and PO. Energy forecasts of distributed generation projects are based on project history or history for similar technology types. Projects are associated with their appropriate region within the model. Hourly profiles are developed and used in PO dispatch. Projects are added to the model upon Tri-State Board and FERC approval. Additionally, a 2% annual expected growth forecast is included to represent potential future projects. In CE a capacity planning factor of 22% was applied to these resources. This percentile was derived from four years of hourly generation data during typical system peak hours in July and August and ranking them from smallest to largest. Then the generation level at the 15th percentile is selected as the estimated contribution to the system peak. This means that 85% of the time the capacity contribution will be equal to or greater than the estimate. Due to their size, these resources were not incorporated into the modified ELCC study.

GHG & $C0_2$ Reduction Methodology Used in Scenarios

The following is a description of the methodology for calculating Tri-State's CO_2 and GHG emissions baseline, calculating forecasted emissions and determining the resulting emission reductions.

GHG and CO_2 reductions are calculated on all wholesale electricity sales in the state of Colorado by Tri-State. Tri-State only sells electricity at the wholesale level. Wholesale electricity sales include sales to Tri-State's Utility Member Systems and non-member sales to counterparties (other utilities, marketers) at transaction points in Colorado. From a resource perspective, all resources in Colorado including owned thermal generators, renewable PPAs, long-term contracts with delivery points in Colorado, and forecast market purchases at Colorado transaction points are considered to supply wholesale electricity sales in Colorado. Also, Tri-State resources, thermal or renewable, located outside of Colorado that are forecast to be imported to serve wholesale Utility Member System load in Colorado are included in the total emissions calculation. GHG emissions include carbon equivalent (CO_2e) rates for CH_4, N_2O and SF_6.

GHG and CO_2 emissions are also calculated on retail load served in the state of Colorado by Tri-State's Utility Member Systems. To arrive at the forecast retail load the amount of wholesale electricity sales by Tri-State to Utility Member Systems in Colorado excluding transmission losses is reduced by representative distribution losses for a given year.

Calculation of Tri-State's 2005 Baseline of CO_2 & GHG Emission in the state of Colorado:

Colorado Electricity Sales are defined as all wholesale electricity sales including Tri-State sales to Utility Member Systems in Colorado and non-member sales from Colorado generation and/or sold at transaction points in CO. Delta Montrose Electric Association (DMEA) was a member of Tri-State in 2005 but withdrew as a member of Tri-State July 1, 2020. DMEA is included in the initial load calculation in order to arrive at total 2005 emissions, but related emissions for DMEA are then removed to arrive at the final 2005 baseload calculated emissions for Tri-State. Non-Member sales energy is based on Colorado non-member sales as identified in a Tri-State report from 2005, "All revenue by State.xls". All sales are marked up 6.1%, which is the transmission loss value identified in Tri-State's 2005 financial reports.

The following resources are considered to serve wholesale electricity sales in Colorado whether to Utility Member Systems or non-member sales:

- All thermal owned generation in Colorado
- LAP and CRSP hydro contract deliveries at transaction points in Colorado[49]
- Basin Western Interconnection at transaction points in Colorado [50]
- Small renewable contracts located in Colorado
- Any necessary balance required to meet wholesale electricity sales in Colorado was most likely imported from LRS 2 & LRS 3 with potential small contributions from Escalante Generating Station, San Juan 3, or the Pyramid facility.

CO_2 emission methodology and source for each 2005 resource are identified in Table 76:

Table 76: CO_2 Emission Rates – 2005

Resource	Emission Source	Emission Rate *(short tons/MWh)*
Craig 1 & 2[51]	Plant Rate (average of generator rates)	1.17
Craig 3	Generator Rate	1.05
Nucla	Generator Rate	1.30
Rifle	Generator Rate	0.95
Knutson 1 &2	Plant Rate (average of generator rates)	0.75
Limon 1 & 2	Plant Rate (average of generator rates)	0.75
Burlington 1 &2	Plant Rate (average of generator rates)	1.12
CRSP Colorado Deliveries	Federal Hydropower – No GHG/CO_2	0
LAP Colorado Deliveries	Federal Hydropower – No GHG/CO_2	0
Small Power Producers	Hydropower – – No GHG/CO_2	0
Basin Western Interconnect Colorado Deliveries	Plant Rate (average of LRS 2 & LRS 3 rates)	1.15
Market Purchases in Colorado	Based on average of Tri-State coal rates[52]	1.10
Imports from out of state	Plant Rate (average of generator rates)[53]	1.15

[49] Identified in 555XX Purch Pwr by State_2005.xls
[50] Identified in 555XX Purch Pwr by State_2005.xls
[51] Historical data is available as Yampa Project – Craig 1 & 2 combined
[52] No regional published rate available
[53] Average of LRS 2 & LRS 3 emission rates as LRS generation would have been the primary import source.

After determining the amount of wholesale electricity sales in Colorado and the necessary in and out of state resources that supplied those sales, emissions are calculated using rates from Table 76. Total emissions are then calculated. Next, the percentage of energy necessary to serve each of the following is calculated:

- DMEA load including losses
- Tri-State Utility Member Systems load in Colorado including losses (net of DMEA)
- Wholesale electricity sales to non-members including losses

The percentages of energy to supply Utility Member System sales including losses and wholesale electricity sales to non-members including losses are then summed and this percentage is applied to the total calculated emission. The result is Tri-State's 2005 CO_2 emissions baseline for wholesale electricity sales in Colorado, which is 9,180,383 short tons of CO_2 emissions.

GHG emissions for CH_4 and N_2O were calculated based on EPA CO_2e emission factors and fuel used for thermal generation. Additionally, SF_6 GHG emissions were provided by Tri-State's environmental department. Resulting 2005 GHG emissions baseline for wholesale electricity sales in Colorado is 9,257,365 CO_2e short tons of GHG emissions.

To determine CO_2 and GHG emissions in the state of Colorado in 2005 for Tri-State Utility Member System retail sales, Tri-State used Tri-State Utility Member System load net of DMEA and transmission losses and then further reduced the load amount by 7%[54] for distribution losses. Tri-State used two calculation options to arrive at emissions from Utility Member System retail load in Colorado:

Option 1 uses "known" resources serving Colorado load and itemizes the related MWh and emission associated with those resources. The balance of the energy required to serve Colorado Utility Member System retail load after netting the energy supplied from these resources is then given a CO_2 emission rate calculated from an average of Craig and LRS plant emissions and market purchase emissions. The CO_2 emissions from known resources and the calculated emissions for the balance energy are summed to arrive at total CO_2 emissions.

Option 2 calculates CO_2 emission by taking total 2005 CO_2 emissions (emissions caused by sales to Tri-State Utility Member Systems in Colorado including DMEA and non-member sales in Colorado) and multiplying this values times the quotient of Tri-State Utility Member System retail sales in Colorado divided by all Tri-State wholesale electricity sales in Colorado.

For both options the GHG adder (percentage), based on CH_4, N_2O and SF_6 CO_2e emissions divided by total CO_2e emissions, is applied to Utility Member System retail loadCO_2 emissions and used to arrive at total GHG emissions.

Based on option 1, Tri-State's 2005 baseline of CO_2 emissions to serve retail load in Colorado is 6,147,055 short tons. Tri-State's 2005 baseline of total GHG emissions to serve retail load in Colorado is 6,198,172 carbon equivalent short tons.

[54] Representative of average distribution losses at the Utility Member System level in 2005

Based on option 2, Tri-State's 2005 baseline of CO_2 emissions to serve retail load in Colorado is 6,244,171 short tons. Tri-State's 2005 baseline of total GHG emissions to serve retail load in Colorado is 6,296,096 carbon equivalent short tons.

Calculation of Tri-State's Forecasted CO_2 & GHG Emissions in the state of Colorado:

For forecast CO_2 and GHG emissions, the primary focus is emissions in 2030 and related reductions from the 2005 baselines. However, for some scenarios Tri-State calculated a glide path[55] beginning in 2025. Tri-State also monitored reduction levels in 2035 and 2040.

In general, the calculations for forecasted emissions are similar to the 2005 baseline method. Any differences are identified as follows:

- Transmission losses are calculated at 5% instead of 6.1% as this is more representative of current OATT loss factors.
- Distribution losses are calculated at 4%, as this is more representative of an average of Tri-State's Utility Member Systems' distributions losses today.
- Charging load that occurs, as a result of energy storage due to efficiency levels is included in the total load calculation. This includes batteries and pump back hydro serving Colorado wholesale electricity sales.
- In both 2005 and forecast emission calculations, gross load is used. Therefore, Utility Member System distributed generation forecast is used as a resource in serving electricity sales in Colorado for purposes of total emissions calculations.
- Basin Electrically East contract portion serving load in Colorado is pulled out as a separate line item due to Basin Electrically East now being served via an RTO (SPP).

CO_2 emission methodology and source for each forecasted resource are identified in Table 77:

Table 77: CO_2 Emission Rates - Forecasted

Resource	Emission Source	**CO_2 Emission Rate** *(short tons/MWh)*
Craig 1 & 2[56]	Plant Rate (average of generator rates)	1.17
Craig 3	Generator Rate	1.05
Rifle	Generator Rate	0.95
Knutson 1 &2	Plant Rate (average of generator rates)	0.75
Limon 1 & 2	Plant Rate (average of generator rates)	0.75
Burlington 1 &2	Plant Rate (average of generator rates)	1.12
JM Shafer	Generator Rate	0.49
CRSP Colorado Deliveries	Federal Hydropower – No GHG/CO_2 w RECs	0
LAP Colorado Deliveries	Federal Hydropower – No GHG/CO_2 w RECs	0
Small Power Producers	Hydro power – No GHG/CO_2 w RECs	0

[55] The glide path includes measured reductions in emissions beginning in 2025 and continually increasing to reach required emission reduction levels in 2030.
[56] Historical data is available as Yampa Project – Craig 1 & 2 combined.

Resource	Emission Source	CO_2 Emission Rate *(short tons/MWh)*
Basin Western Interconnect Colorado Deliveries	Published Regional rate – egrid RMPA[57]	0.64
Market Purchases in Colorado[58]	Published Regional rate – egrid RMPA	0.64
Kit Carson	Contract Rate - Wind w RECs	0
Carousel	Contract Rate - Wind w RECs	0
Colorado Highlands	Contract Rate - Wind w RECs	0
Crossing Trails	Contract Rate - Wind w RECs	0
Spanish Peaks	Contract Rate - Solar w RECs	0
San Isabel	Contract Rate - Solar w RECs	0
Twin Buttes	Contract Rate - Wind w RECs	0
Niyol	Contract Rate - Wind w RECs	0
Coyote Gulch	Contract Rate - Solar w RECs	0
Dolores Canyon	Contract Rate - Solar w RECs	0
Axial	Contract Rate - Solar w RECs	0
Basin Electrically East (Colorado portion)	Published Regional rate – Egrid MROW[59]	0.62
Colorado Member Generation	Renewables – No GHG w and w/o RECs	0
Imports from LRS 2&3	Plant Rate (average of generator rates)	1.15
Expansion Plan Wind	Contract Rate - Wind w RECs	0
Expansion Plan Solar	Contract Rate - Solar w RECs	0
Expansion Plan Combined Cycle	Generator Rate	0.4
Expansion Plan Combustion Turbine, RICE, Aeroderivative	Generator Rate	0.6

Basin Western Interconnection, Market Purchases in Colorado including energy imbalance and Basin Electrically East use the egrid published 2018 CO_2 emission rates for RMPA or MROW based on location. During the Colorado AQCC Clean Energy Plan Guidance process, discussion around forward emission rates for markets and contracts with unspecified sources included using region wide published numbers such as WECC and SPP. Additionally, the potential for using a trend line to 2030 was discussed. While Tri-State agrees that the market purchase and contracts with unspecified sources emission rates will likely decline between now and 2030, Tri-State has taken a conservative approach in its CO_2 reduction calculation by applying the 2018 emission rate. Also, it is important to note that there is a general movement towards organized markets in WECC, and it is likely that all of Tri-State's load and resources will be located within an RTO by 2030. In an RTO, load and resources are no longer connected in that a utility does not schedule their resource to their load, but instead bid load and offer resources into the market. At that point, the applicable RTO published emission rate may be the more suitable rate to apply to market purchases and contracts with unspecified sources.

[57] Rate is reflective of 2018 published egrid RMPA rate.
[58] Market purchases in Colorado includes energy imbalance forecast purchases.
[59] 2018 Egrid MROW rate

Calculations of total emissions are similar to 2005 method with the exception that there is no need to remove DMEA load as DMEA load is already removed from the load forecast.

CO_2 & GHG Reduction Calculations:

Following are the calculations for CO_2 reduction - forecasted vs 2005 baseline emission:

Colorado CO_2 Reduction:

- Colorado Wholesale Electricity Sales
  - 2005 CO Electricity Sales Baseline CO_2 emissions excluding DMEA minus forecasted 2030 CO Electricity Sales CO_2 emissions divided by 2005 CO Electricity Sales Baseline CO_2 emissions excluding DMEA
- Colorado Utility Member System Retail Sales
  - 2005 CO Member Retail Load Baseline CO_2 emissions excluding DMEA minus forecasted 2030 CO Member Retail Load CO_2 emissions divided by 2005 CO Member retail Load Baseline CO_2 emissions excluding DMEA

GHG Reduction:

- Calculate additional GHG emissions for CH_4, N_2O and SF_6 as CO_2e and add to CO_2 emissions for 2005 baseline and 2030 forecast. Use CO_2 reduction calculation method above to arrive at total GHG reduction

2005 Baseline:

Table 78: 2005 Baseline CO_2 & GHG emissions for Wholesale Electricity Sales in Colorado

Carbon Emission Mass base CO Generation - Electricity Sales in CO				
2005	**Fuel Type**	**Energy MWh**	**Carbon Emission Rate (tons/MWh)**	**Carbon Emissions**
CO Sales to Members		7,347,873		
CO Sales to Members inc Transmission Losses (6.1%)		7,796,093		
Craig 1 & 2	Coal	1,711,570	1.17	1,997,830
Craig 3	Coal	3,011,768	1.05	3,147,297
LRS Imports into CO	Coal	1,626,188	1.15	1,874,181
Nucla	Coal	736,962	1.30	958,051
Rifle	Gas	39,243	0.95	37,281
Knutson 1&2	Gas	22,843	0.75	17,132
Limon 1 & 2	Gas	23,027	0.75	17,270
Burlington 1 & 2	Oil	4,551	1.12	5,097
CRSP East & West (CO)	Federal Hydro	609,330	0.00	0
LAP (CO)	Federal Hydro	513,319	0.00	0
Small Power Producers	Small Hydro	40,396	0.00	0
Basin AU PPA	Coal	859,067	1.15	990,075
Wind PPAs	Wind	0	0.00	0
Gas PPAS	Gas	0	0.00	0
Solar PPAs	Solar	0	0.00	0
CO Market Purchases	Market	672,728	1.10	740,001
CO Market Sales (marked up 6.1% for trans losses)	Market	2,074,897		
	Check	7,796,093		9,784,215
	Check	9,870,990		0.99
Market Sales		2,074,897	21%	2,056,657
DMEA Load plus losses	574,163	609,187	6%	603,832
TS Load plus losses	6,773,710	7,186,906	73%	7,123,727
			Carbon Tons	9,180,383
			GHG Tons	9,257,364

Table 79: 2005 Baseline CO_2 & GHG Emissions for Tri-State Utility Member Systems' Retail Sales

2005 Baseline for TS Utility Member System Retail Sales			
		Option 1	**Option 2**
	MWh	**Carbon Emissions Based on How served**	**Carbon Emissions based on Percentage of Sales**
Retail Load (Member load reduced for distribution & transm	6,299,550	6,147,055	6,244,171
Carbon Rate (Tons/MWh)		0.98	0.99
GHG Emissions		6,198,172	6,296,096
Resources Known to Exclusively Serve Load			
Nucla	736,962	958,051	
Rifle	39,243	37,281	
Limon 1	5757	4317.75	
CRSP East & West (CO)	609,330	0	
LAP (CO)	513,319	0	
Small Power Producers	40,396	0	
Basin AU PPA	859,067	990,075	
Total	2,804,073	1,989,724	
Net After transmission losses	2,633,025	1,868,351	
DMEA Prorata Portion	8%	8%	
Serving Load net of DMEA	2,427,280	1,722,358	
Balance	3,872,270	4,278,704	

Social Cost of Carbon

In Table 80 column "PUC Staff Step 3" represents the values in real dollars for SCoC as applied to resource CO_2 emission rates for use in CE. Rates are applied to thermal resource CO_2 emission rates and added to VOM for use in CE modeling as shown in Table 81 and Table 82.

Table 80 Social Cost of Carbon Annual Values

2007	$/metric ton	$/short ton	Escalated $/short ton	PUC Staff Step 3 $/short ton (Real)	PUC Staff Step 4 $/short ton (Nominal)
2020	$42.00	$38.10	$46.00	$46.60	$46.58
2021	$42.00	$38.10	$46.00	$46.60	$47.51
2022	$43.00	$39.01	$47.10	$47.70	$49.61
2023	$44.00	$39.92	$48.19	$48.80	$51.78
2024	$45.00	$40.82	$49.29	$49.90	$54.02
2025	$46.00	$41.73	$50.38	$51.00	$56.32
2026	$47.00	$42.64	$51.48	$52.10	$58.70
2027	$48.00	$43.54	$52.57	$53.20	$61.15
2028	$49.00	$44.45	$53.67	$54.30	$63.67
2029	$49.00	$44.45	$53.67	$54.30	$64.94
2030	$50.00	$45.36	$54.76	$55.40	$67.59
2031	$51.00	$46.27	$55.86	$56.60	$70.32
2032	$52.00	$47.17	$56.95	$57.70	$73.14
2033	$53.00	$48.08	$58.05	$58.80	$76.03
2034	$54.00	$48.99	$59.14	$59.90	$79.02
2035	$55.00	$49.90	$60.24	$61.00	$82.09
2036	$56.00	$50.80	$61.33	$62.10	$85.25
2037	$57.00	$51.71	$62.43	$63.20	$88.51
2038	$58.00	$52.62	$63.52	$64.30	$91.87
2039	$59.00	$53.52	$64.62	$65.40	$95.32
2040	$60.00	$54.43	$65.71	$66.50	$98.87

Table 81 Social Cost of Carbon Values by Existing Resource (Real $)

	LRS 2	LRS 3	Craig 1	Craig 2	Craig 3	SPV3	Burlington 1	Burlington 2	Pyramid 1	Pyramid 2	Pyramid 3	Pyramid 4	Rifle	Limon 1	Limon 2	Knutson 1	Knutson 2	J. M. Shafer
Carbon Rate (Tons/MWh)	**1.1015**	**1.2035**	**1.1595**	**1.175**	**1.045**	**1.0695**	**1.106**	**1.043**	**0.62**	**0.616**	**0.625**	**0.619**	**0.603**	**0.749**	**0.746**	**0.752**	**0.75**	**0.4905**
2021	$51.33	$56.08	$54.03	$54.76	$48.70	$49.84	$51.54	$48.60	$28.89	$28.71	$29.13	$28.85	$28.10	$34.90	$34.76	$35.04	$34.95	$22.86
2022	$52.54	$57.41	$55.31	$56.05	$49.85	$51.02	$52.76	$49.75	$29.57	$29.38	$29.81	$29.53	$28.76	$35.73	$35.58	$35.87	$35.78	$23.40
2023	$53.75	$58.73	$56.58	$57.34	$51.00	$52.19	$53.97	$50.90	$30.26	$30.06	$30.50	$30.21	$29.43	$36.55	$36.40	$36.70	$36.60	$23.94
2024	$54.96	$60.05	$57.86	$58.63	$52.15	$53.37	$55.19	$52.05	$30.94	$30.74	$31.19	$30.89	$30.09	$37.38	$37.23	$37.52	$37.43	$24.48
2025	$56.18	$61.38	$59.13	$59.93	$53.30	$54.54	$56.41	$53.19	$31.62	$31.42	$31.88	$31.57	$30.75	$38.20	$38.05	$38.35	$38.25	$25.02
2026	$57.39	$62.70	$60.41	$61.22	$54.44	$55.72	$57.62	$54.34	$32.30	$32.09	$32.56	$32.25	$31.42	$39.02	$38.87	$39.18	$39.08	$25.56
2027	$58.60	$64.03	$61.69	$62.51	$55.59	$56.90	$58.84	$55.49	$32.98	$32.77	$33.25	$32.93	$32.08	$39.85	$39.69	$40.01	$39.90	$26.09
2028	$59.81	$65.35	$62.96	$63.80	$56.74	$58.07	$60.06	$56.63	$33.67	$33.45	$33.94	$33.61	$32.74	$40.67	$40.51	$40.83	$40.73	$26.63
2029	$59.81	$65.35	$62.96	$63.80	$56.74	$58.07	$60.06	$56.63	$33.67	$33.45	$33.94	$33.61	$32.74	$40.67	$40.51	$40.83	$40.73	$26.63
2030	$61.02	$66.67	$64.24	$65.10	$57.89	$59.25	$61.27	$57.78	$34.35	$34.13	$34.63	$34.29	$33.41	$41.49	$41.33	$41.66	$41.55	$27.17
2031	$62.34	$68.12	$65.63	$66.51	$59.15	$60.53	$62.60	$59.03	$35.09	$34.87	$35.38	$35.04	$34.13	$42.39	$42.22	$42.56	$42.45	$27.76
2032	$63.56	$69.44	$66.90	$67.80	$60.30	$61.71	$63.82	$60.18	$35.77	$35.54	$36.06	$35.72	$34.79	$43.22	$43.04	$43.39	$43.28	$28.30
2033	$64.77	$70.77	$68.18	$69.09	$61.45	$62.89	$65.03	$61.33	$36.46	$36.22	$36.75	$36.40	$35.46	$44.04	$43.86	$44.22	$44.10	$28.84
2034	$65.98	$72.09	$69.45	$70.38	$62.60	$64.06	$66.25	$62.48	$37.14	$36.90	$37.44	$37.08	$36.12	$44.87	$44.69	$45.04	$44.93	$29.38
2035	$67.19	$73.41	$70.73	$71.68	$63.75	$65.24	$67.47	$63.62	$37.82	$37.58	$38.13	$37.76	$36.78	$45.69	$45.51	$45.87	$45.75	$29.92
2036	$68.40	$74.74	$72.00	$72.97	$64.89	$66.42	$68.68	$64.77	$38.50	$38.25	$38.81	$38.44	$37.45	$46.51	$46.33	$46.70	$46.58	$30.46
2037	$69.61	$76.06	$73.28	$74.26	$66.04	$67.59	$69.90	$65.92	$39.18	$38.93	$39.50	$39.12	$38.11	$47.34	$47.15	$47.53	$47.40	$31.00
2038	$70.83	$77.39	$74.56	$75.55	$67.19	$68.77	$71.12	$67.06	$39.87	$39.61	$40.19	$39.80	$38.77	$48.16	$47.97	$48.35	$48.23	$31.54
2039	$72.04	$78.71	$75.83	$76.85	$68.34	$69.95	$72.33	$68.21	$40.55	$40.29	$40.88	$40.48	$39.44	$48.98	$48.79	$49.18	$49.05	$32.08
2040	$73.25	$80.03	$77.11	$78.14	$69.49	$71.12	$73.55	$69.36	$41.23	$40.96	$41.56	$41.16	$40.10	$49.81	$49.61	$50.01	$49.88	$32.62

Table 82: Social Cost of Carbon Values by Generic Resource (Real $)

	__BM 112_18x6RICE_CO2	__BM 200_1x235_7FA05_CO2	__BM 300_1x1_7FA05_CO2	__BM 357_1x1_7HA01_CO2	__BM 40_1x40LM6000_CO2	__BM 46_9x5RICE_CO2	__BM 545_1x1_7HA03_CO2	__BM 81_2x40LM6000_CO2	__BM 93_1x100_LMS100_CO2
Carbon Rate (Tons/MWh)	**0.6201**	**0.7475**	**0.3755**	**0.62**	**0.40**	**0.63**	**0.36**	**0.40**	**0.52**
2021	$28.90	$34.83	$17.50	$28.89	$18.55	$29.17	$16.54	$18.62	$24.43
2022	$29.58	$35.66	$17.91	$29.57	$18.99	$29.86	$16.93	$19.06	$25.00
2023	$30.26	$36.48	$18.32	$30.26	$19.42	$30.55	$17.32	$19.50	$25.58
2024	$30.94	$37.30	$18.74	$30.94	$19.86	$31.23	$17.71	$19.94	$26.16
2025	$31.63	$38.12	$19.15	$31.62	$20.30	$31.92	$18.11	$20.38	$26.73
2026	$32.31	$38.94	$19.56	$32.30	$20.74	$32.61	$18.50	$20.82	$27.31
2027	$32.99	$39.77	$19.98	$32.98	$21.18	$33.30	$18.89	$21.26	$27.89
2028	$33.67	$40.59	$20.39	$33.67	$21.61	$33.99	$19.28	$21.70	$28.46
2029	$33.67	$40.59	$20.39	$33.67	$21.61	$33.99	$19.28	$21.70	$28.46
2030	$34.35	$41.41	$20.80	$34.35	$22.05	$34.68	$19.67	$22.14	$29.04
2031	$35.10	$42.31	$21.25	$35.09	$22.53	$35.43	$20.09	$22.62	$29.67
2032	$35.78	$43.13	$21.67	$35.77	$22.97	$36.12	$20.48	$23.06	$30.24
2033	$36.46	$43.95	$22.08	$36.46	$23.40	$36.81	$20.87	$23.50	$30.82
2034	$37.14	$44.78	$22.49	$37.14	$23.84	$37.49	$21.26	$23.94	$31.40
2035	$37.83	$45.60	$22.91	$37.82	$24.28	$38.18	$21.66	$24.38	$31.97
2036	$38.51	$46.42	$23.32	$38.50	$24.72	$38.87	$22.05	$24.82	$32.55
2037	$39.19	$47.24	$23.73	$39.18	$25.16	$39.56	$22.44	$25.26	$33.13
2038	$39.87	$48.06	$24.14	$39.87	$25.59	$40.25	$22.83	$25.70	$33.70
2039	$40.55	$48.89	$24.56	$40.55	$26.03	$40.94	$23.22	$26.14	$34.28
2040	$41.24	$49.71	$24.97	$41.23	$26.47	$41.63	$23.61	$26.58	$34.86

In Table 80 column "PUC Staff Step 4" represents the values in nominal dollars for SCoC used in the calculation of PVRR for the SCC scenario. Resulting PVRR for the SCC scenario is identified in Volume I Section 9 Base Case and Alternative Scenario Comparison of this report. PVRR for this scenario is calculated both with and without the social cost of carbon with both Tri-State's discount rate of 4.15% and a discount rate of 3% per Commission guidance.

Additionally, this nominal value for SCoC for each year is applied to annual system CO_2 emissions for each scenario. Total system CO_2 emissions include emissions from energy imbalance, market purchases, thermal owned resources, and Basin contracts. Total SCoC for each scenario is identified in Volume I Section 8 Base Case and Alternative Scenario Results of this report.

Table 83 shows the Appendix 5 to Commission Staff comments from September 2020, which provided direction on values to use for SCoC and a comparison of Tri-State's original methodology.

Table 83 Extraction from PUC Staff Comments Appendix 5

Appendix 5 to Staff's Attachment 1:
Social Cost of Carbon Calculation and Implementation
Proceeding No. 20M-0218E
Page 3 of 6

Comparison of the Calculation of the Social Cost of Carbon for Modeling

Staff's Recommended Methodology:

Year	Step 1 Central Estimate (3% Average) ($2007/metric-ton)	Step 2 Central Estimate (3% Average) ($2007/short-ton)	Step 3 $2020/short-ton ($2007/short-ton)	Step 4 Inflation Factor	Step 4 Nominal $/Short-ton
2020	42	38	46.6	100%	46.58
2021	42	38	46.6	102%	47.51
2022	43	39	47.7	104%	49.61
2023	44	40	48.8	106%	51.78
2024	45	41	49.9	108%	54.02
2025	46	42	51.0	110%	56.32
2026	47	43	52.1	113%	58.70
2027	48	44	53.2	115%	61.15
2028	49	44	54.3	117%	63.67
2029	49	44	54.3	120%	64.94
2030	50	45	55.4	122%	67.59
2031	51	46	56.6	124%	70.32
2032	52	47	57.7	127%	73.14
2033	53	48	58.8	129%	76.03
2034	54	49	59.9	132%	79.02
2035	55	50	61.0	135%	82.09
2036	56	51	62.1	137%	85.25
2037	57	52	63.2	140%	88.51
2038	58	53	64.3	143%	91.87
2039	59	54	65.4	146%	95.32
2040	60	54	66.5	149%	98.87
2041	61	55	67.6	152%	102.53
2042	61	55	67.6	155%	104.58
2043	62	56	68.8	158%	108.42
2044	63	57	69.9	161%	112.37
2045	64	58	71.0	164%	116.44
2046	65	59	72.1	167%	120.63
2047	66	60	73.2	171%	124.93
2048	67	61	74.3	174%	129.36
2049	68	62	75.4	178%	133.92
2050	69	63	76.5	181%	138.60

Tri-State's Methodology

Year	Step 1 Central Estimate (3% Average) ($2007/metric-ton)	Step 2 Central Estimate (3% Average) ($2007/short-ton)	Step 3 Escalated ($2020/short-ton)
2020	42	38	46.0
2021	42	38	46.0
2022	43	39	47.1
2023	44	40	48.2
2024	45	41	49.3
2025	46	42	50.4
2026	47	43	51.5
2027	48	44	52.6
2028	49	44	53.7
2029	49	44	53.7
2030	50	45	54.8
2031	51	46	55.9
2032	52	47	57.0
2033	53	48	58.0
2034	54	49	59.1
2035	55	50	60.2
2036	56	51	61.3
2037	57	52	62.4
2038	58	53	63.5
2039	59	54	64.6
2040	60	54	65.7
2041	61	55	66.8
2042	61	55	66.8
2043	62	56	67.9
2044	63	57	69.0
2045	64	58	70.1
2046	65	59	71.2
2047	66	60	72.3
2048	67	61	73.4
2049	68	62	74.5
2050	69	63	75.6

Summary of Third Party Studies

The following third party studies were completed in support of Tri-State's 2020 ERP.

Table 84: Third Party Study Summaries

Third Party Study	Consultant	Attachment	Description
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	5-1	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.
Loss of Load Probability Study	Black & Veatch	5-2	Evaluates representative plans with varying load and CO_2 reduction statuses to determine the adequacy of the current planning reserve margin.
Modified Effective Load Carrying Capability Study	Black & Veatch	5-3	Determines reasonable capacity credits for wind and solar based on increasing renewable penetration levels.
Report on Assessment of Existing Resources	Black & Veatch	5-4	Assesses key costs and performance metrics of existing resources against industry standards.
Benchmarking Study	Black & Veatch	5-5	Compares existing resources to generic resources in regards to cost and performance.
Renewable & Ramping Analysis	Ascend Analytics	5-6	Assesses the reasonability of Tri-State's hourly renewable profiles for existing and generic resources and evaluates potential ramping needs related to integration of intermittent resources.
Beneficial Electrification Study	Mesa Point Energy	5-7	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.

6 Scenario Results Data

Emissions & Water Usage Data

See Attachment Vol II 6-1 Annual Emissions and Water Usage for a detailed list of annual emissions and water usage data by resource for the base case and alternative scenarios.

RES/RPS Data

See Attachment Vol II 6-2 RES/RPS for a detailed annual list of RECs by resource for the base case and each alternative scenario. Renewable energy under PPAs are shown with contractual annual energy amounts from Hyperion as well as dispatched annual energy amounts from PO.

7 Phase II RFP

See Attachment Vol II 7-1 Phase II All-Source RFP.

See Attachment Vol II 7-2 Bidder Highly Confidential Non-Disclosure Agreement.

For model contracts, see the following attachments:

- Attachment Vol II 7-3 Dispatchable PPA
- Attachment Vol II 7-4 Semi-Dispatchable PPA
- Attachment Vol II 7-5 Renewable PPA

List of Acronyms

ACE	Affordable Clean Energy Rule
APR	Annual Progress Report
ARIMA	Auto Regressive Integrated Moving Average
BA	Balancing Authority
BE	Beneficial Electrification
BEPC	Basin Electric Power Cooperative
BHCE	Black Hills Colorado Electric, Inc.
BHCT	Black Hills Colorado Transmission
B&V	Black & Veatch
CAISO	California Independent System Operator
CE	Capacity Expansion
CO_2	Carbon dioxide
CR	CO_2 Reduction
CRN	Cooperative Research Network
CRSP	Colorado River Storage Project
CSU	Colorado Springs Utility
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
ECO	Eastern Colorado
EE	Energy Efficiency
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERPI	Electric Research Power Institute
ERP	Electric Resource Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
Hg	Mercury
IRP	Integrated Resource Plan
ISO	Independent System Operator
LAP	Loveland Area Projects
LAPT	WAPA Rocky Mountain Region Loveland Area Projects
LCoE	Levelized Cost of Energy
LGIP	Large Generation Interconnection Process
LOLP	Loss of Load Probability
LRS	Laramie River Station

MBPP	Missouri Basin Power Project
MCP	Member Coincident Peak
M-RETS	Midwest Renewable Energy Tracking System
NERC	North American Reliability Corporation
NREL	National Renewable Energy Laboratories
NO_x	Nitrogen Oxides
NRECA	Nation Rural Electric Cooperative Association
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
POI	Point of Interconnection
PM	Particulate Matter
PR	Partial Requirements
PPA	Power Purchase Agreement
PSCo	Public Service of Colorado
PNM	Public Service of New Mexico
PO	Portfolio Optimization
POD	Point of Delivery
PRPA	Platte River Power Authority
PVRR	Prevent Value Revenue Requirement
QRU	Qualifying Retail Utility
QWU	Qualifying Wholesale Utility
RAP	Resource Acquisition Period
REC	Renewable Energy Credit
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposal
RPP	Resource Planning Period
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	Social Cost of Carbon (Scenario)
SCoC	Social Cost of Carbon
SIP	Regional Haze State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SPV 3	Springerville Unit 3
SRP	Salt River Project
SRSG	Southwest Reserve Sharing Group
TA	Transmission Area
TEP	Tucson Electric Power
TP	Transmission Provider
WACM	Western Area Colorado Missouri
WAPA	Western Area Power Administration
WCO	Western Colorado

WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WMPA	Wyoming Municipal Power Agency
WREGIS	Western Renewable Energy General Information System

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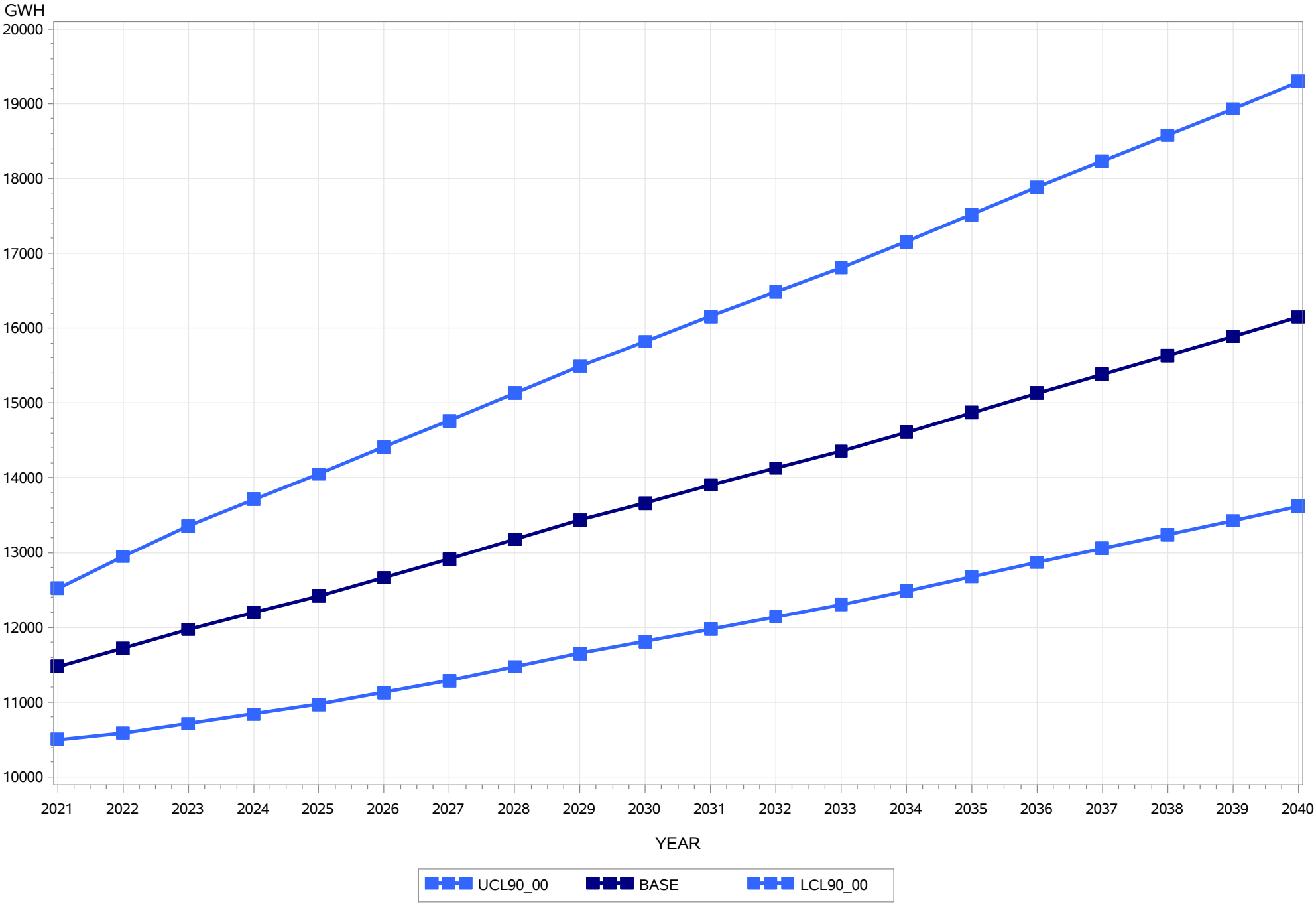
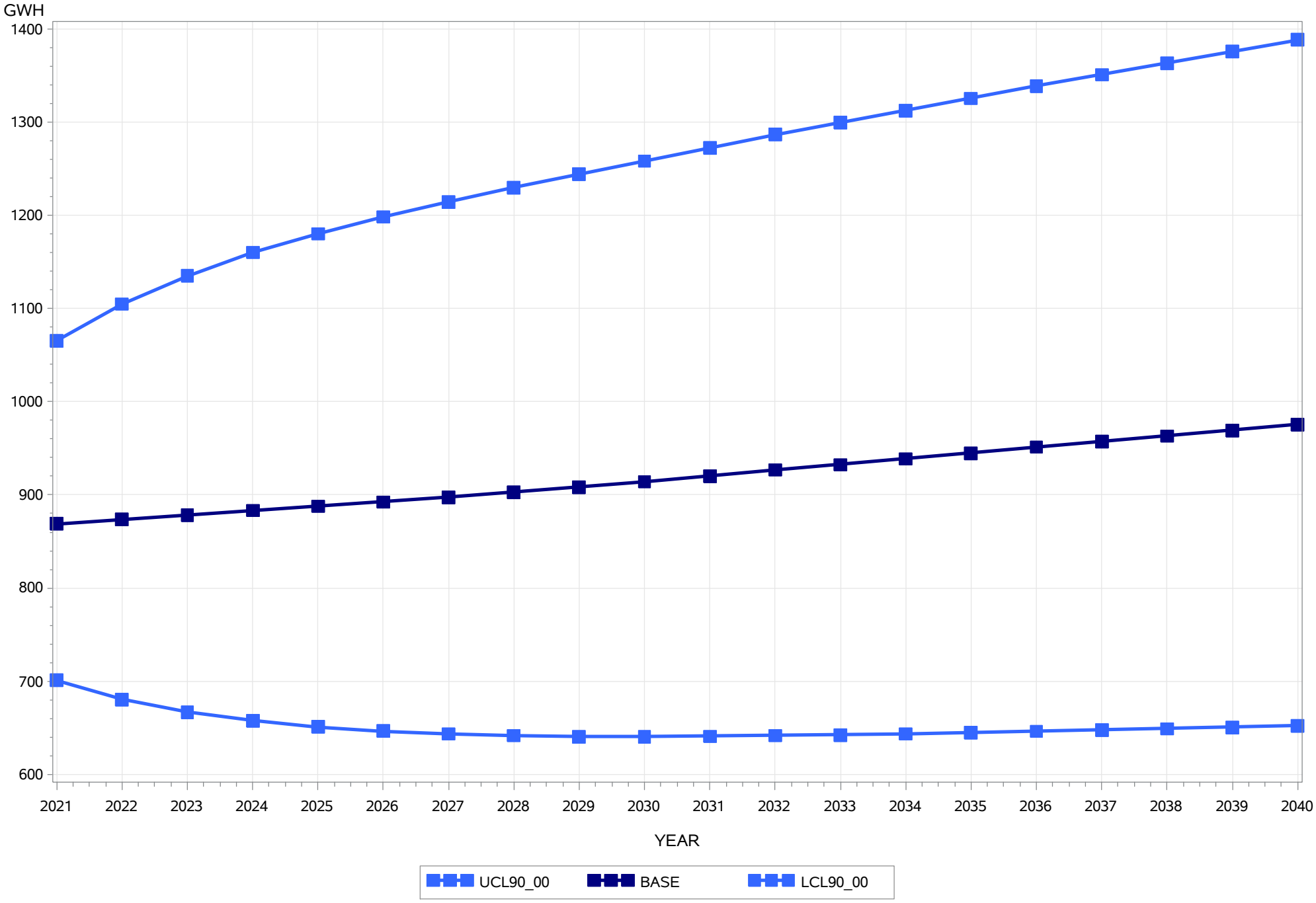
Attachment Vol II 1-1 Tri-State Load Forecasts by State & Member

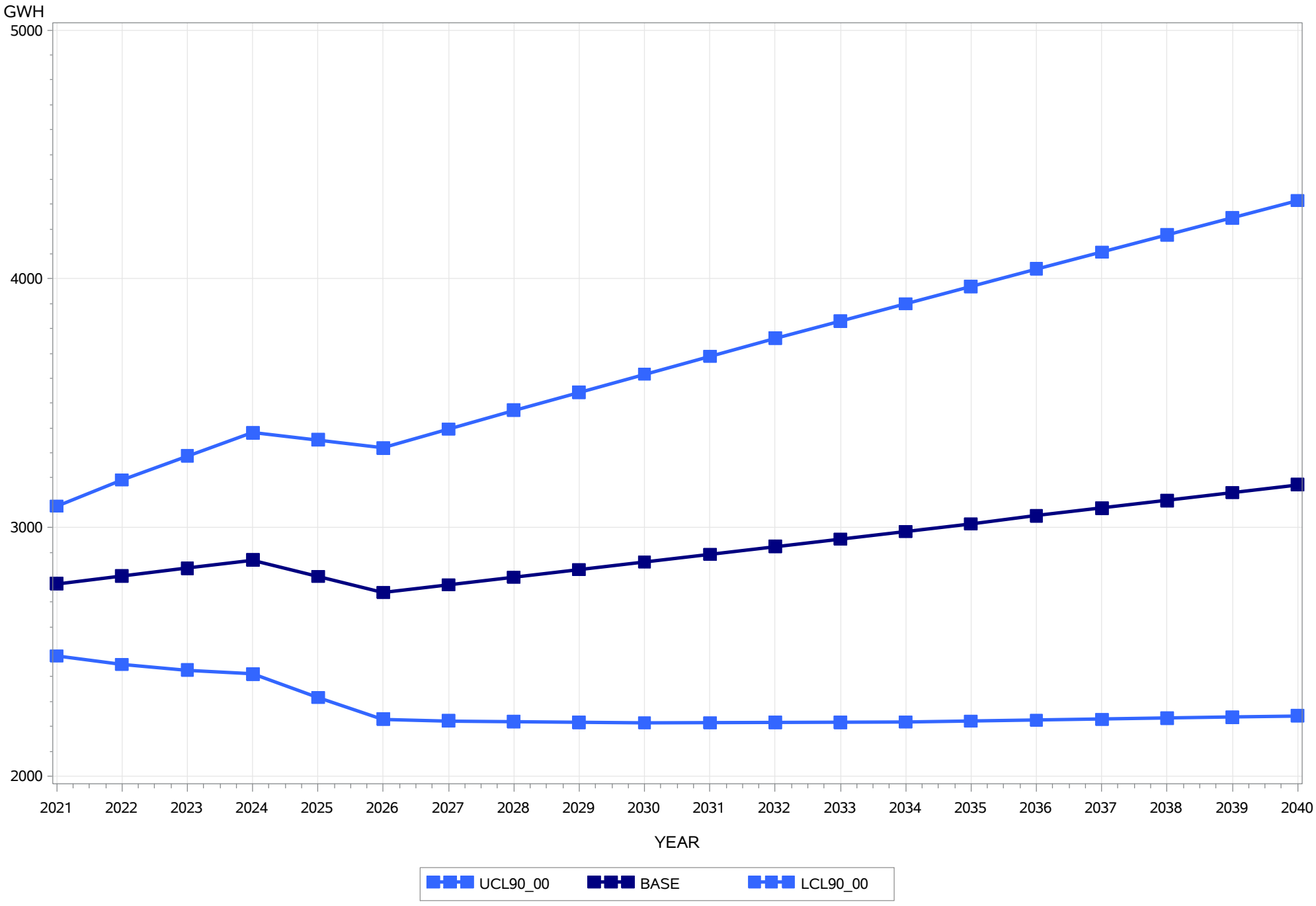
Total Annual Energy Sales
STATE OF COLORADO



Total Annual Energy Sales
STATE OF NEBRASKA



Total Annual Energy Sales
STATE OF NEW MEXICO



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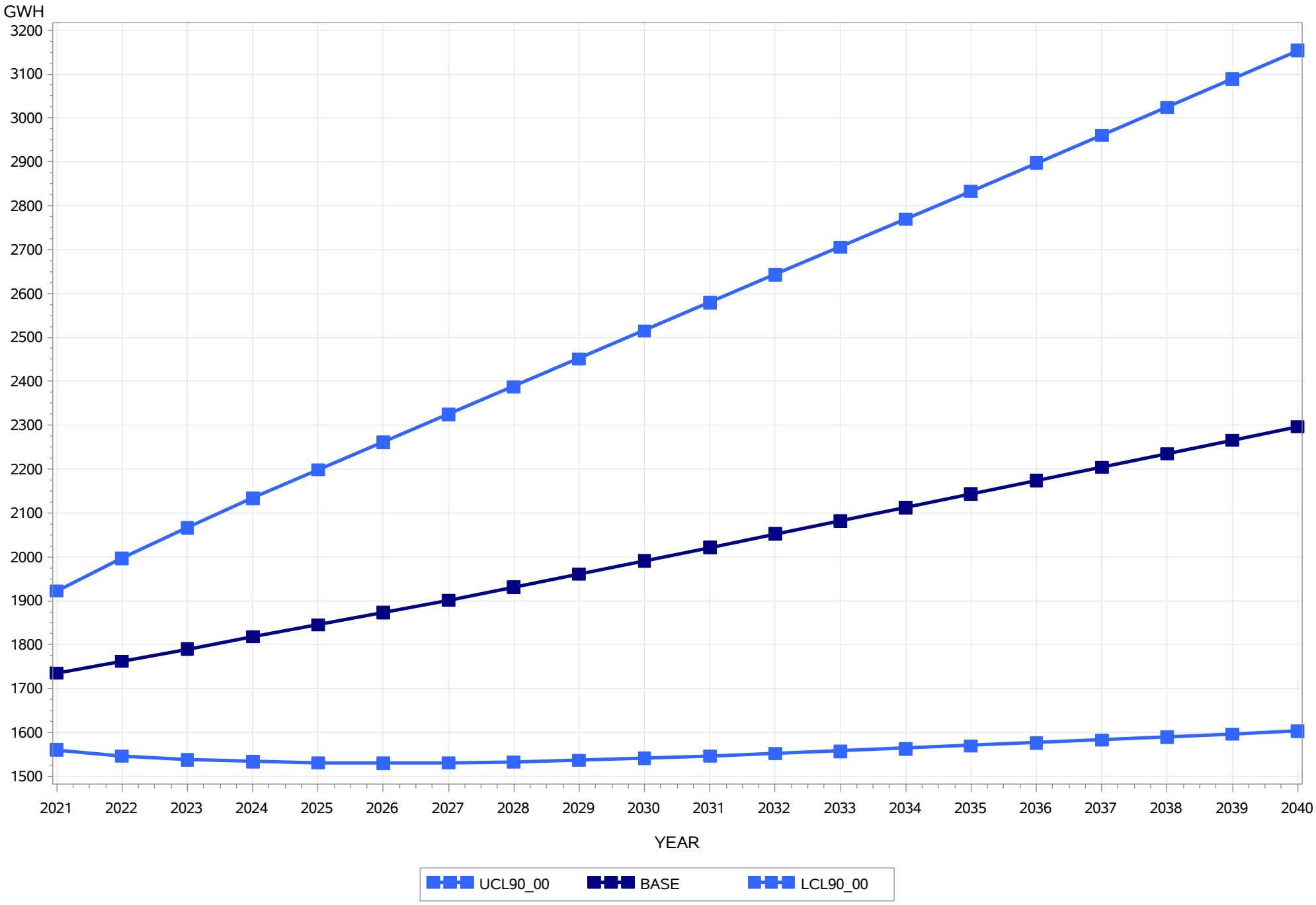
Total Annual Energy Sales
STATE OF WYOMING



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Total Annual Energy Sales
Big Horn Rural Electric Company

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Total Annual Energy Sales
Carbon Power and Light, Inc.

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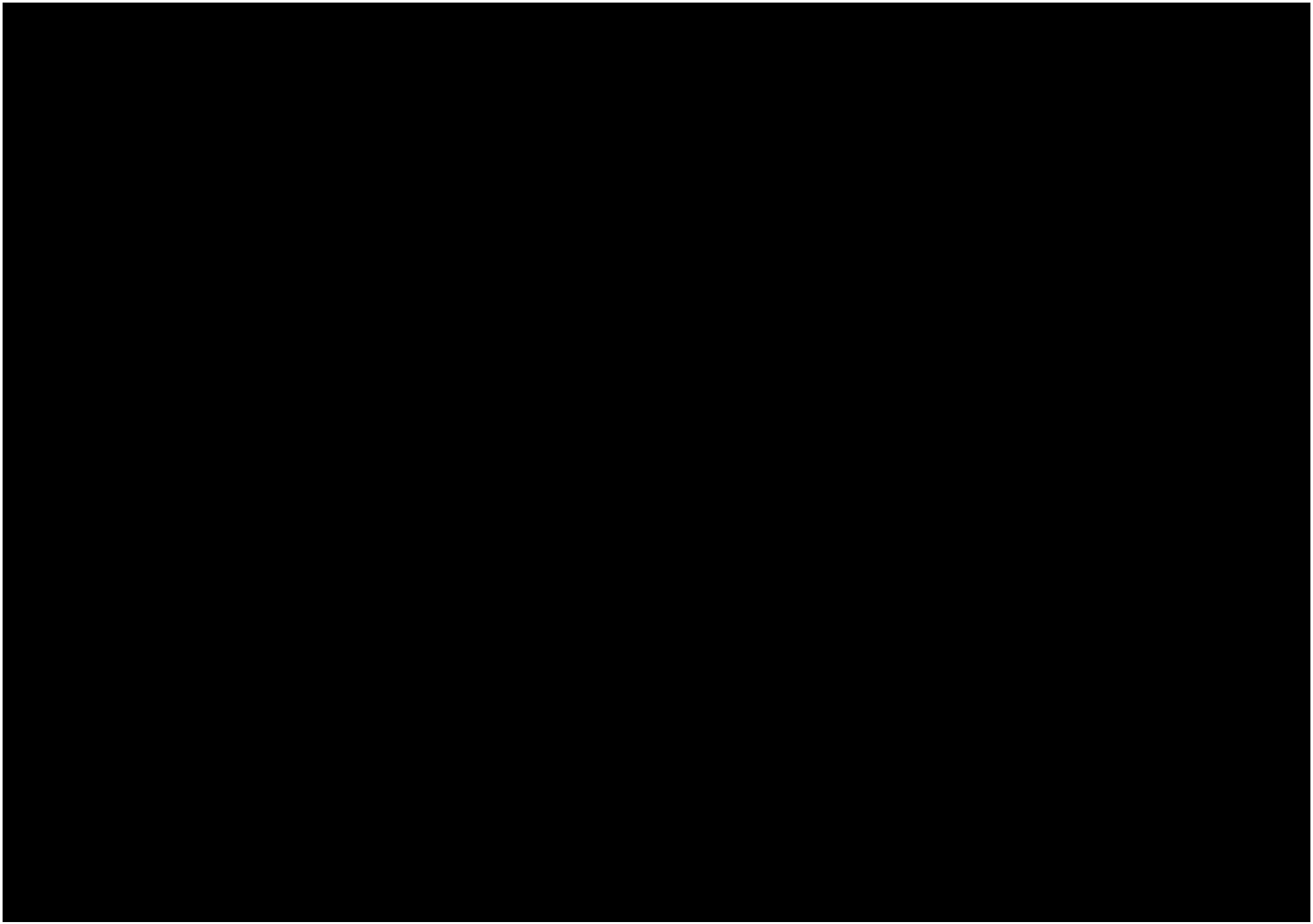
Total Annual Energy Sales

Continental Divide Electric Cooperative, Inc.



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Total Annual Energy Sales
Columbus Electric Cooperative, Inc.

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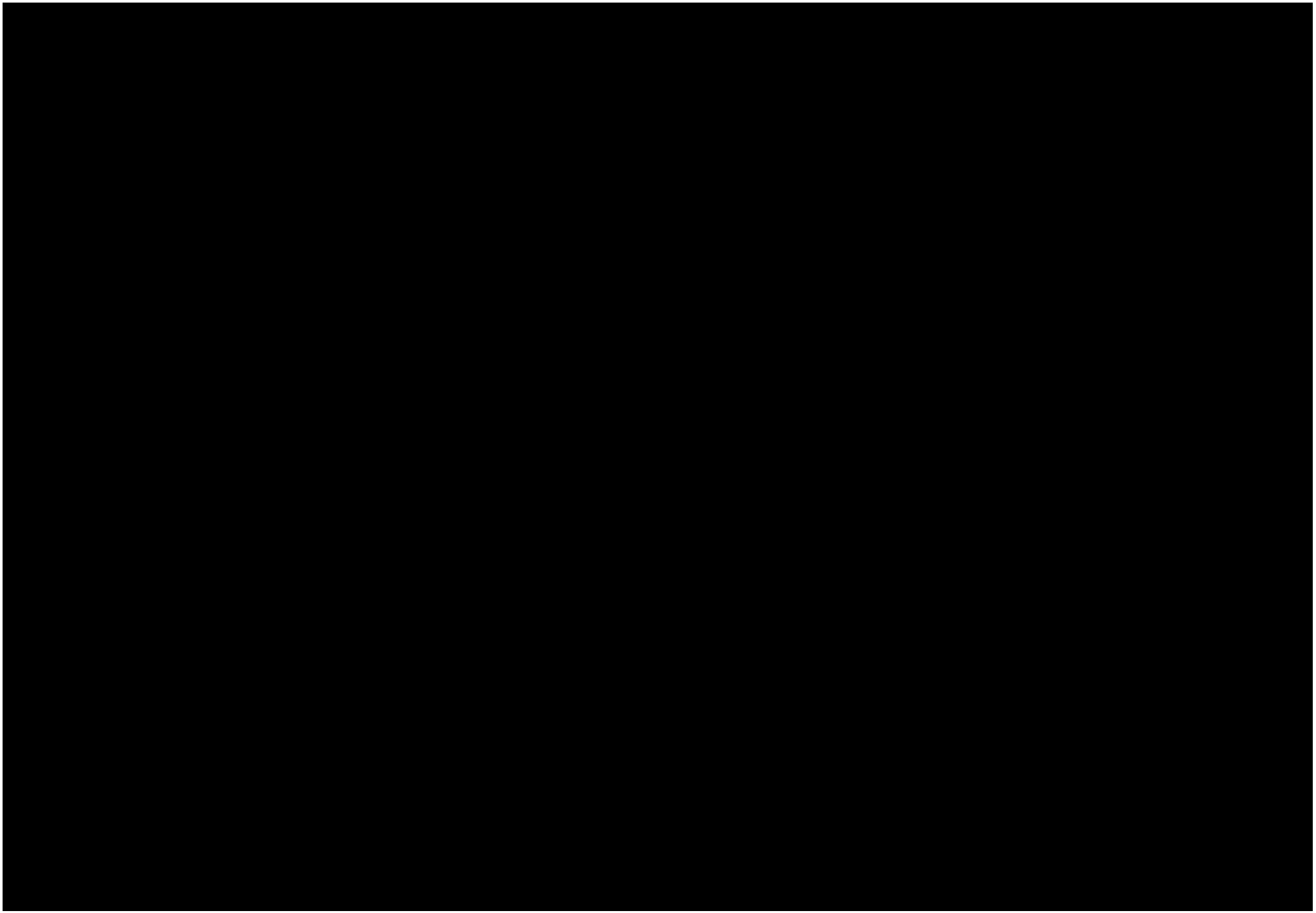
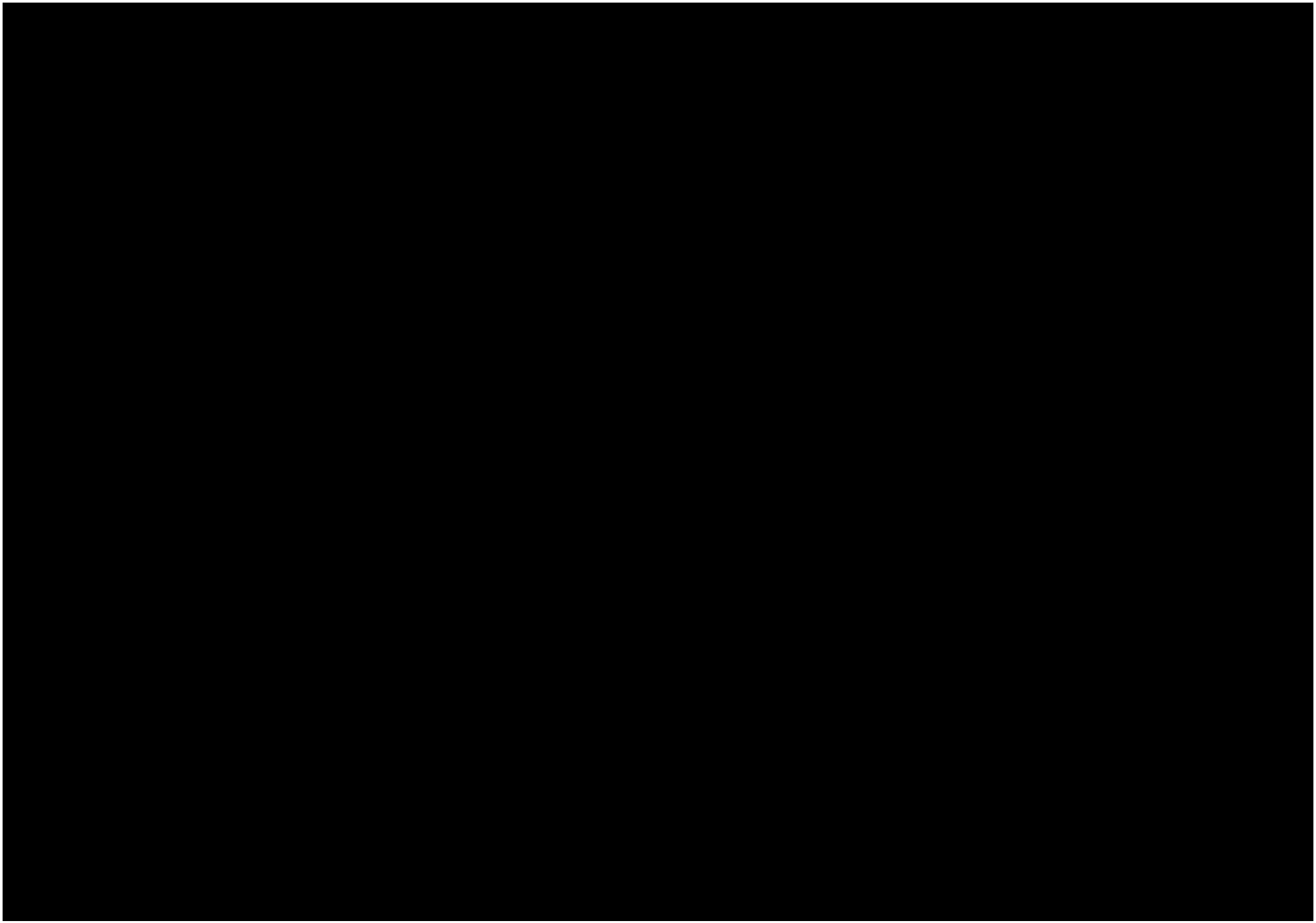
Total Annual Energy Sales

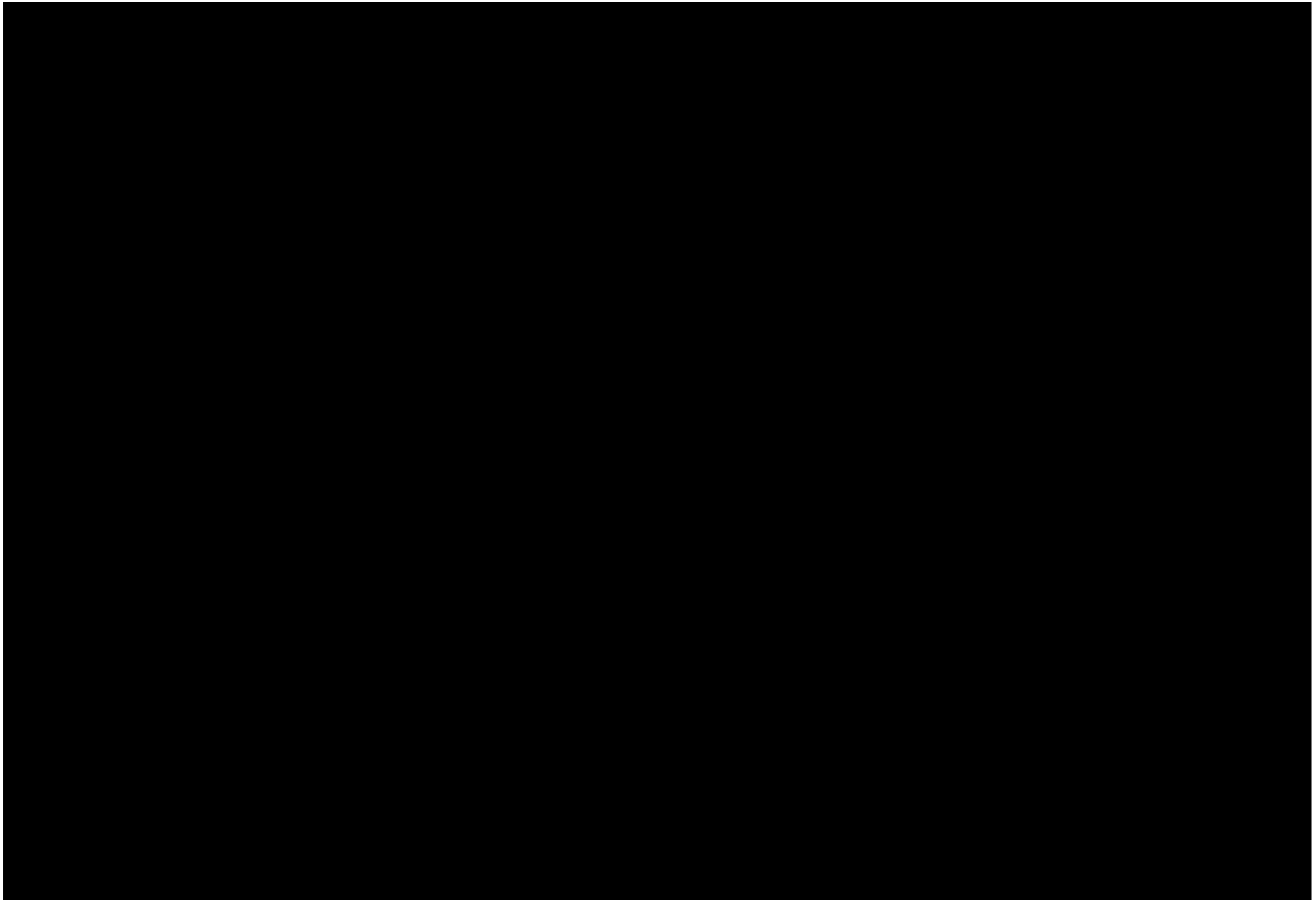
Central New Mexico Electric Cooperative, Inc.



Total Annual Energy Sales
Chimney Rock Public Power District



Total Annual Energy Sales
Empire Electric Association, Inc.



Total Annual Energy Sales
Gunnison County Electric Association, Inc.

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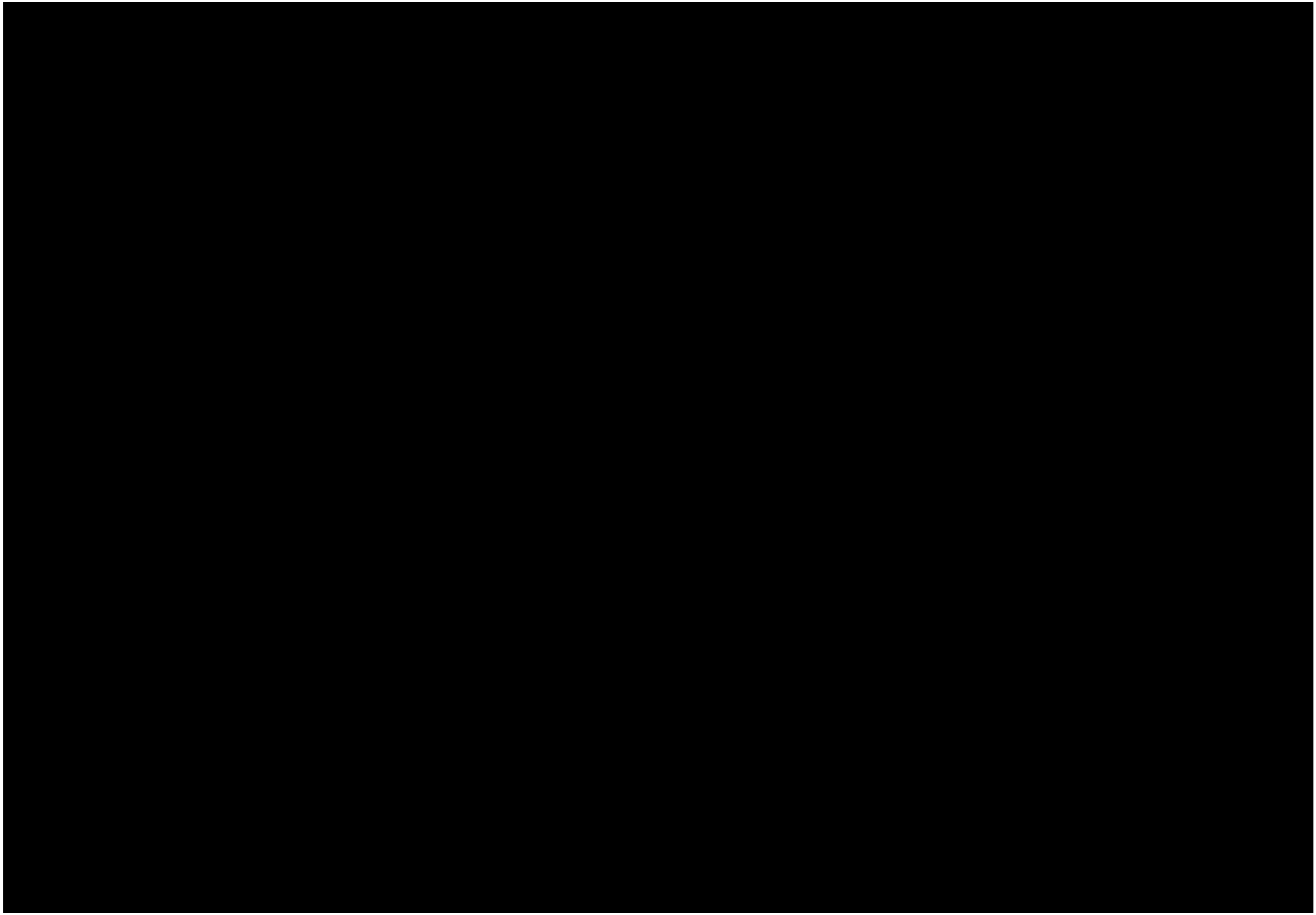
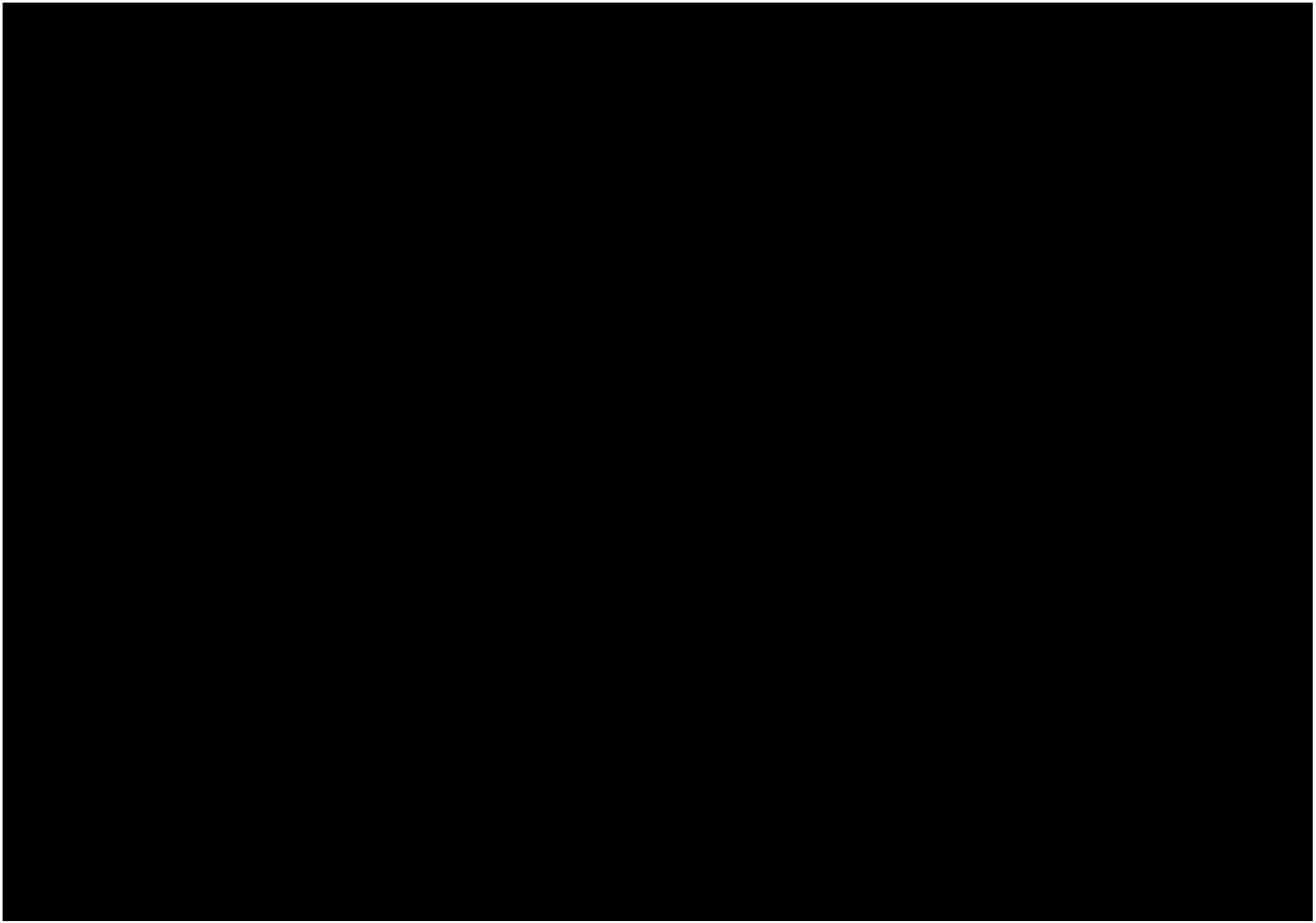
Total Annual Energy Sales
Garland Light and Power Company



Total Annual Energy Sales
Highline Electric Association



Total Annual Energy Sales
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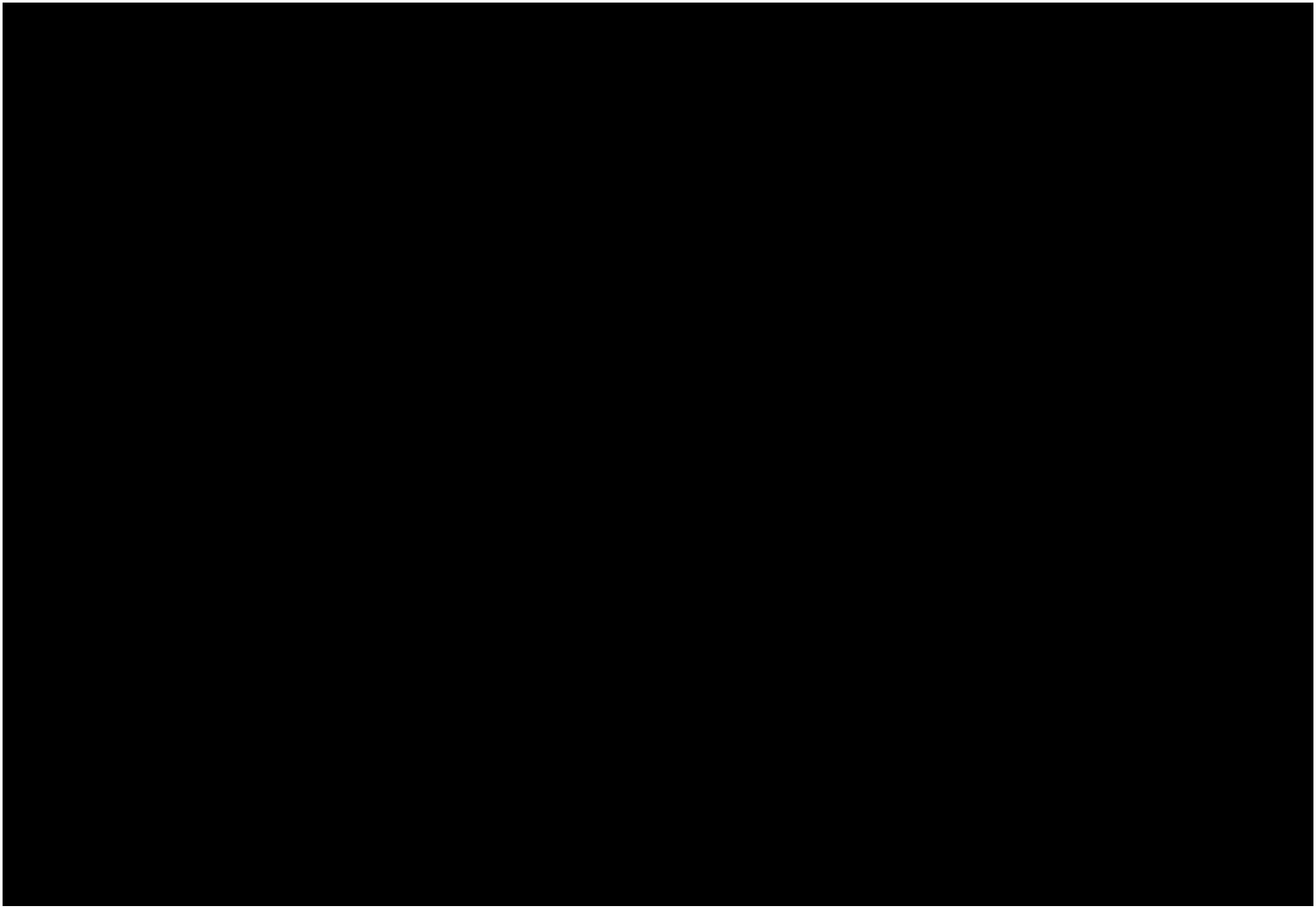
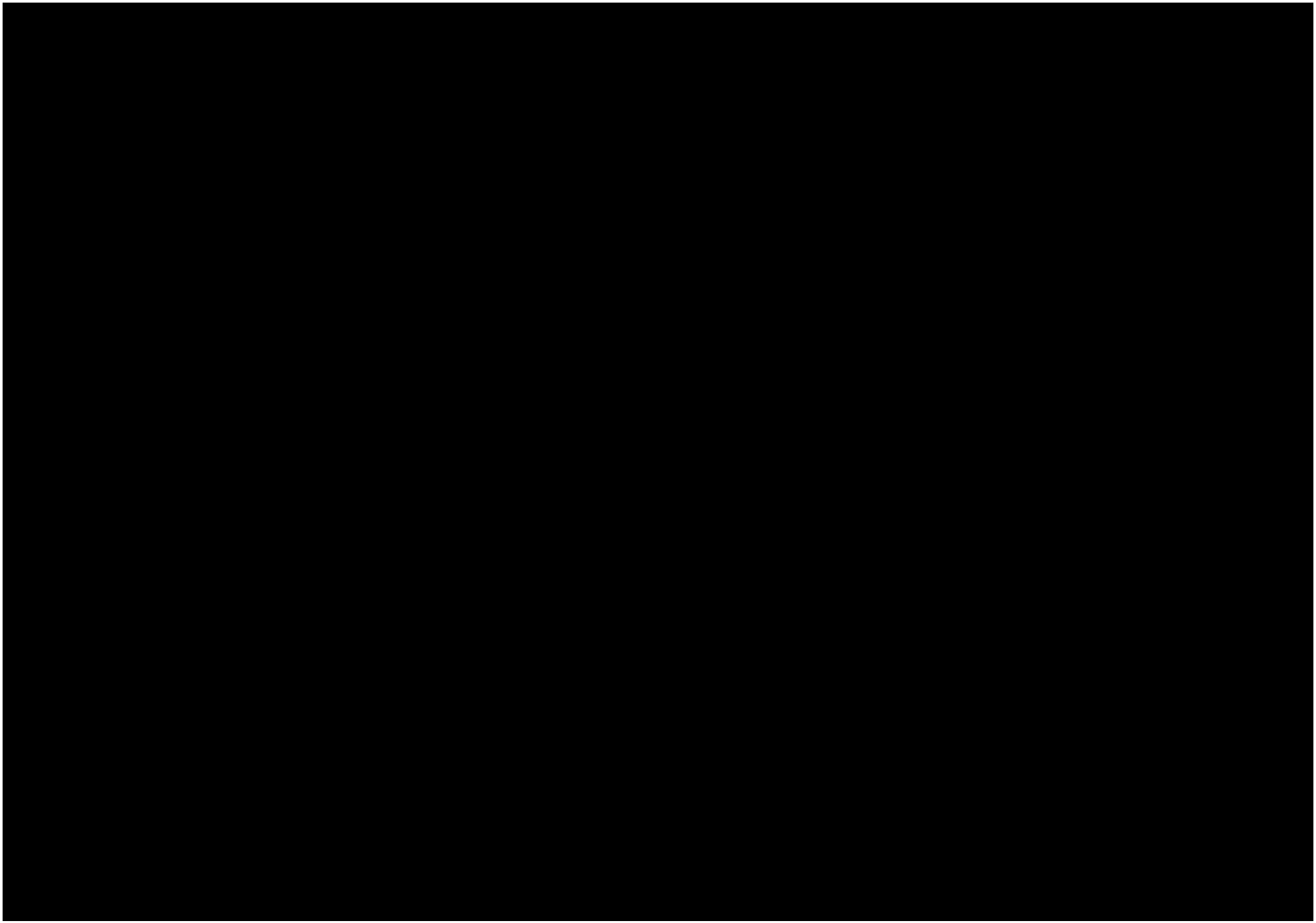
Total Annual Energy Sales
High West Energy, Inc.



Total Annual Energy Sales
Jemez Mountains Electric Cooperative, Inc.



Total Annual Energy Sales
K.C. Electric Association, Inc.

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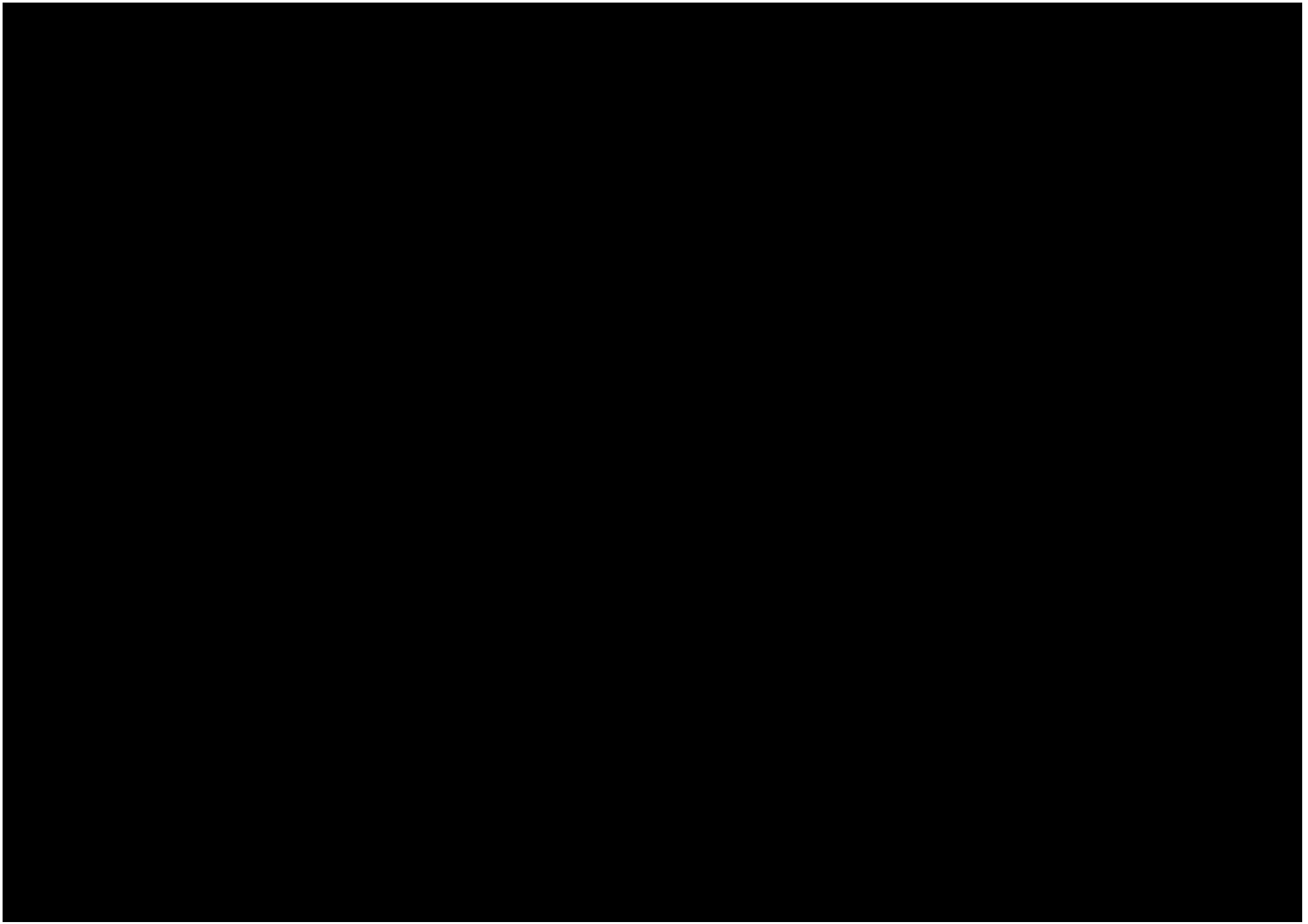
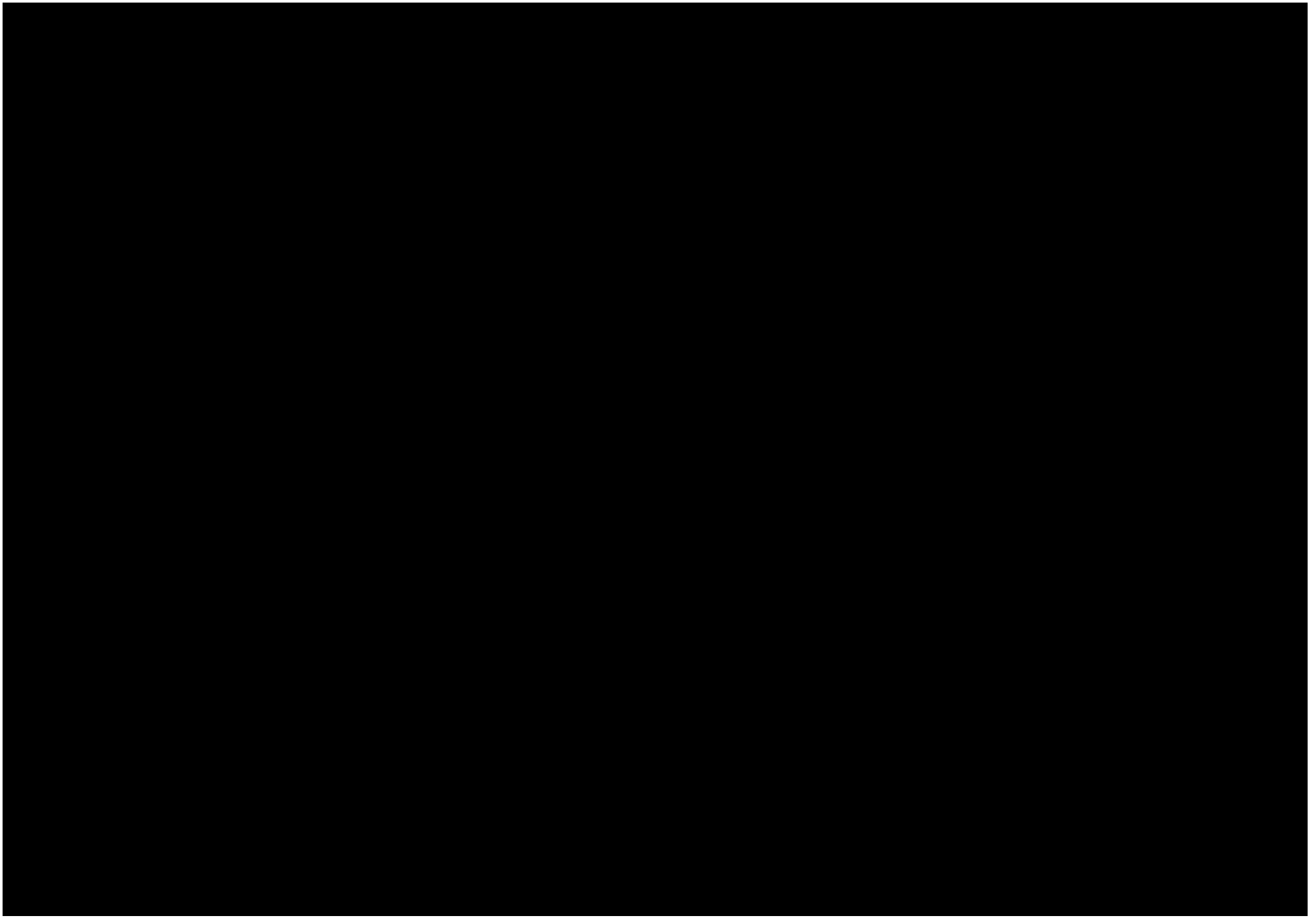
Total Annual Energy Sales
La Plata Electric Association, Inc.



Total Annual Energy Sales
Morgan County Rural Electric Association



Total Annual Energy Sales
Mountain Parks Electric, Inc.

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Total Annual Energy Sales
Mora-San Miguel Electric Cooperative, Inc.

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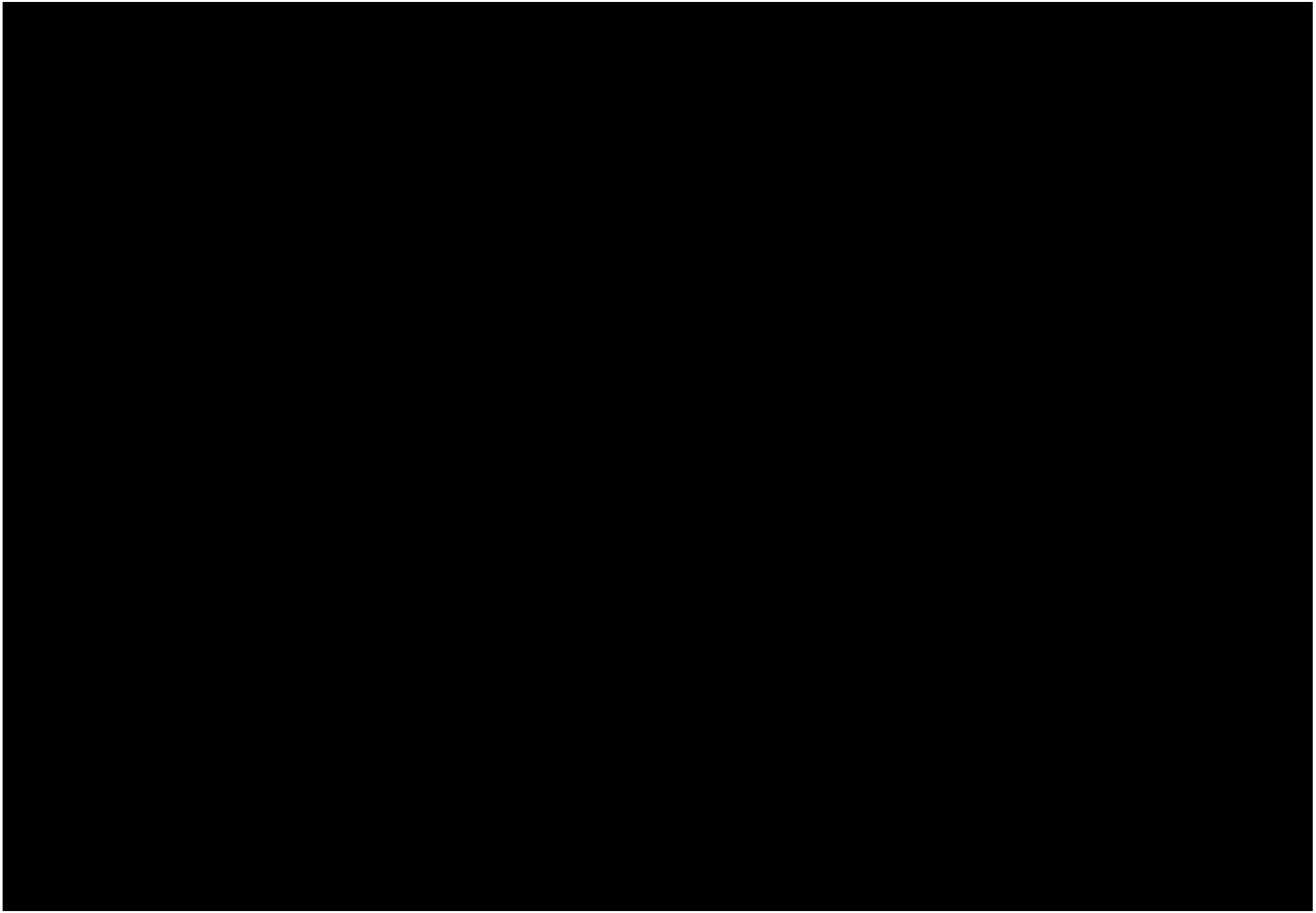
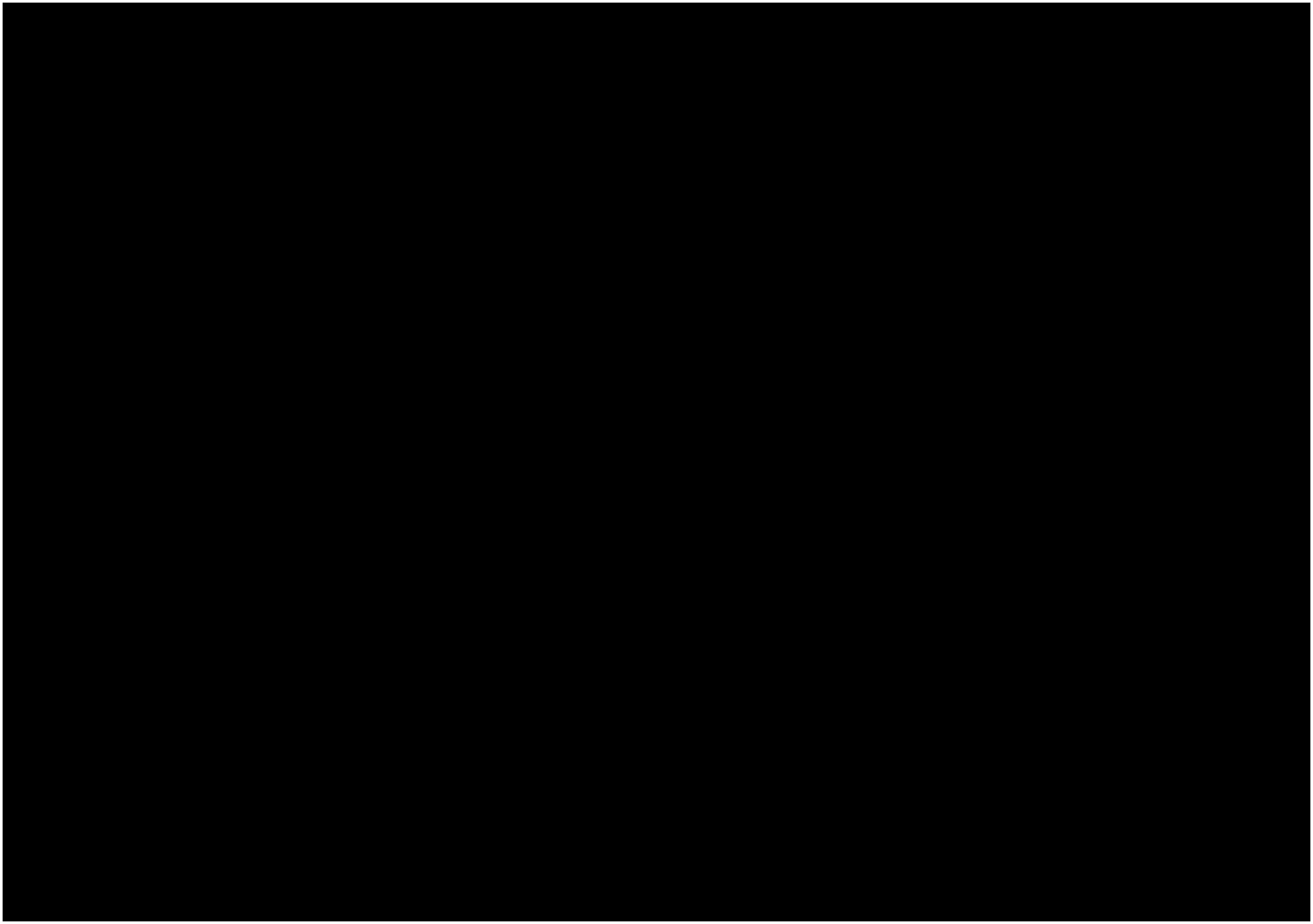
Total Annual Energy Sales
Mountain View Electric Association, Inc.



Total Annual Energy Sales
Midwest Electric Cooperative Corporation



Total Annual Energy Sales
Niobrara Electric Association, Inc.

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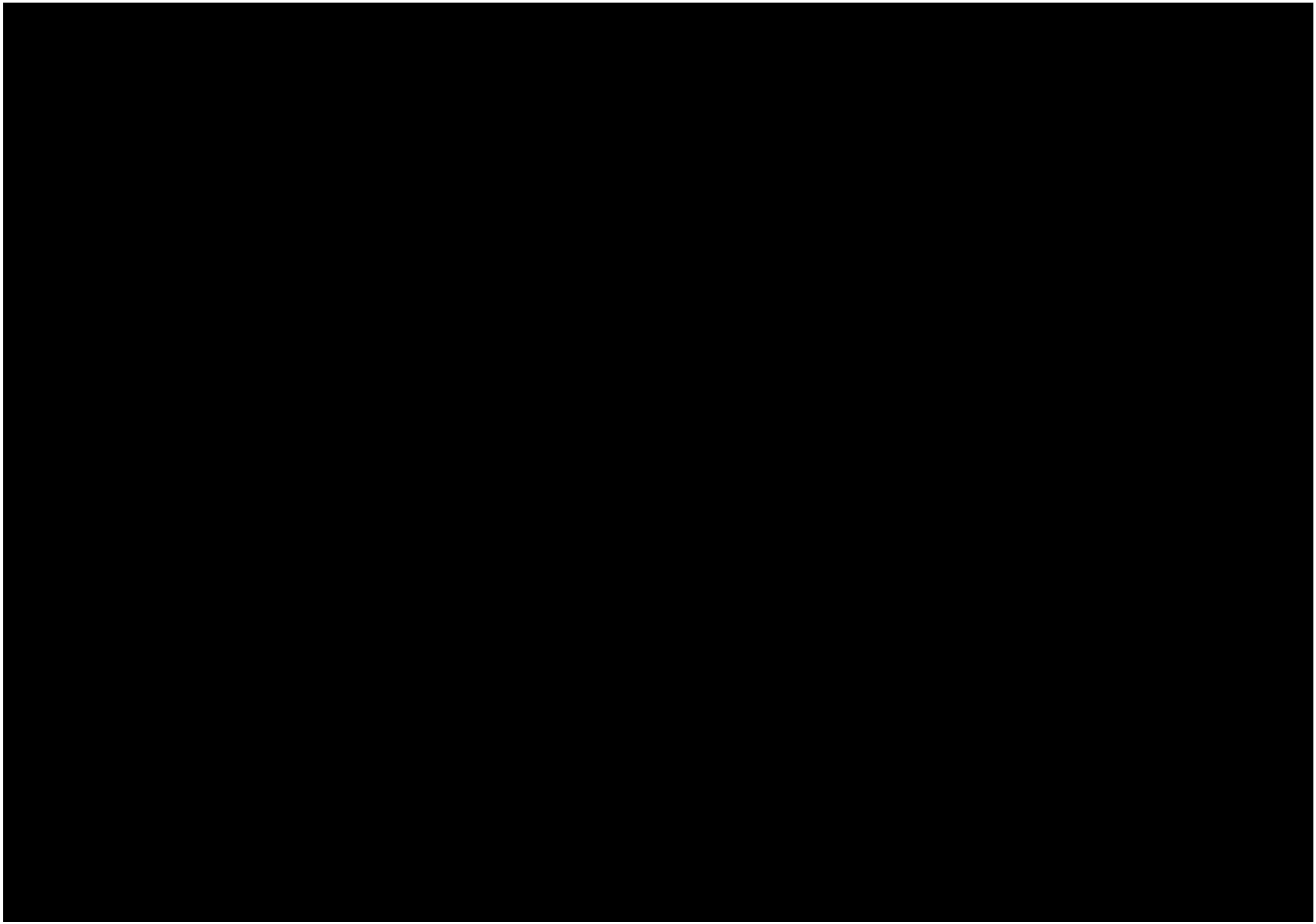
Total Annual Energy Sales
Northwest Rural Public Power District



Total Annual Energy Sales
Otero County Electric Cooperative, Inc.

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Total Annual Energy Sales
Panhandle Rural Electric Membership Association

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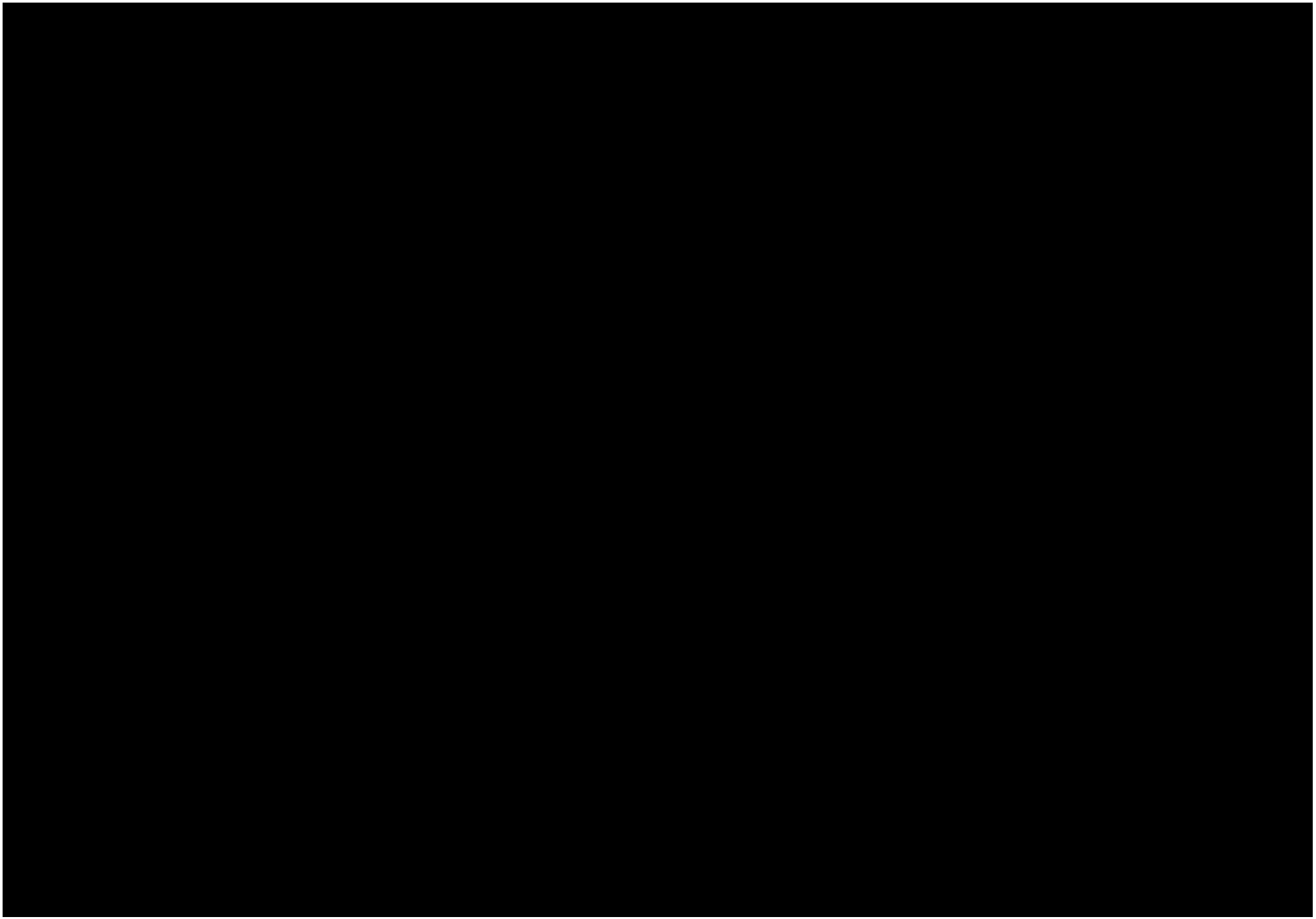
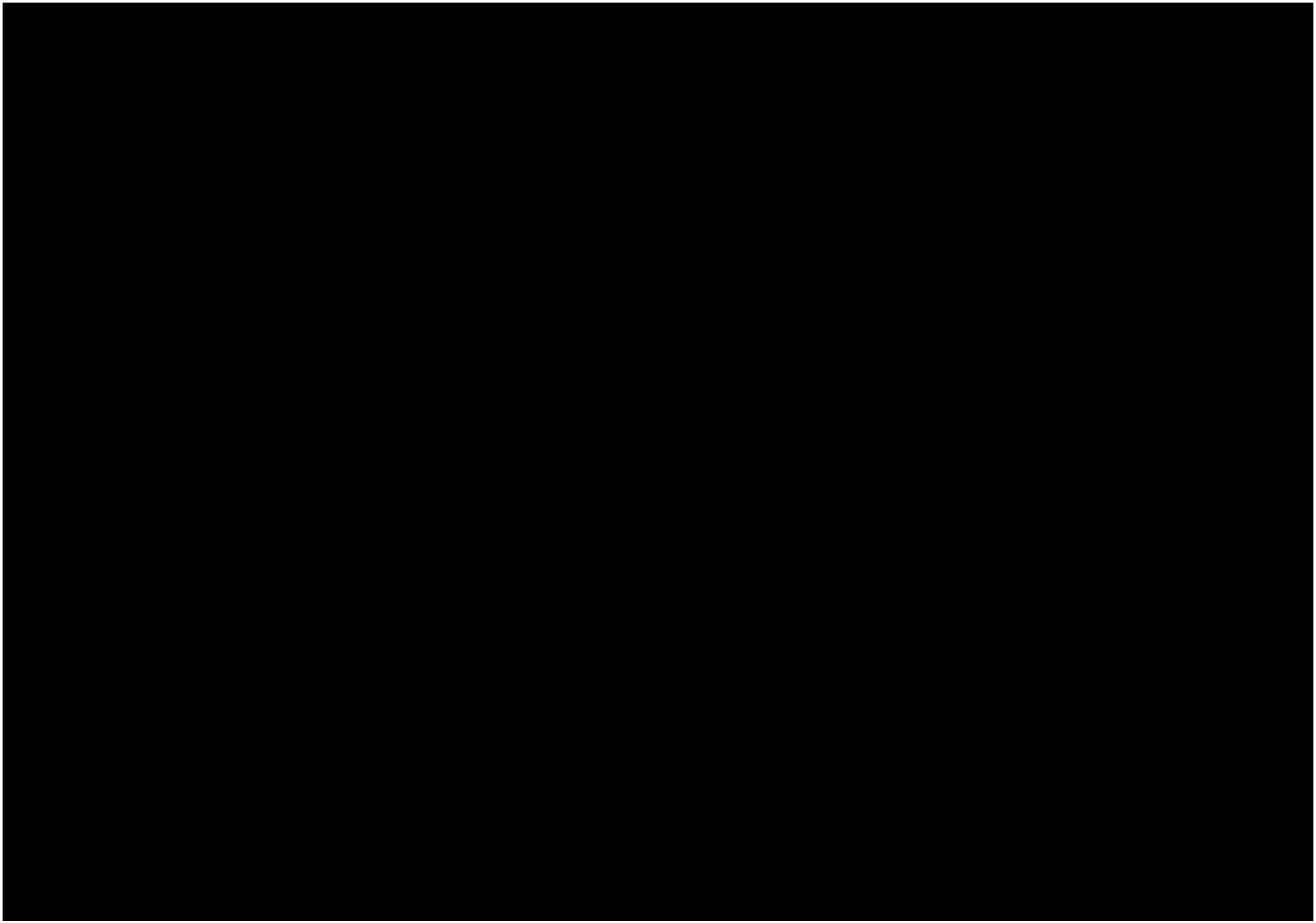
Total Annual Energy Sales
Poudre Valley Electric Association, Inc.



Total Annual Energy Sales
Northern Rio Arriba Electric Cooperative, Inc.



Total Annual Energy Sales
Roosevelt Public Power District

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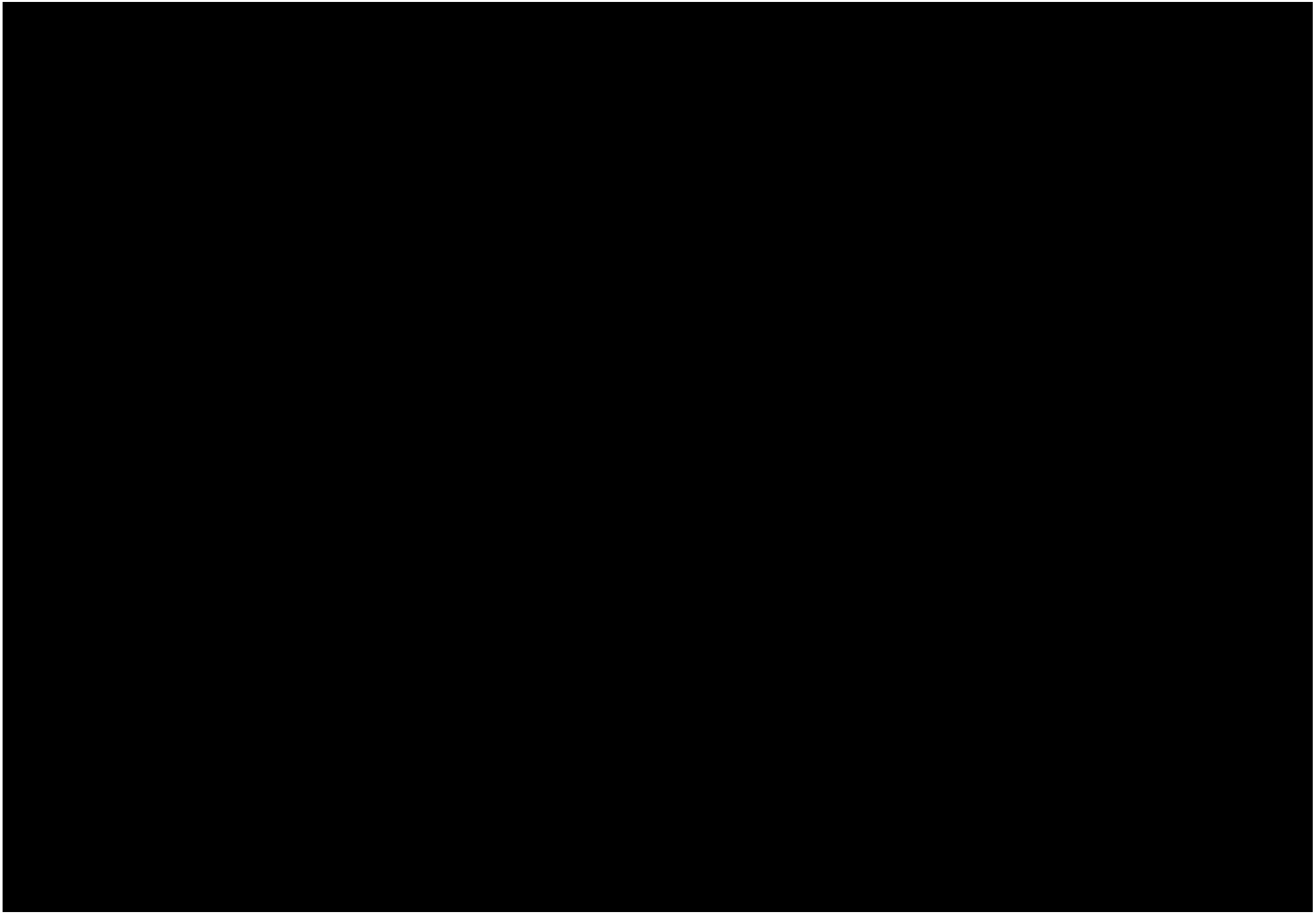
Total Annual Energy Sales
Sierra Electric Cooperative, Inc.



Total Annual Energy Sales
Sangre de Cristo Electric Association, Inc.

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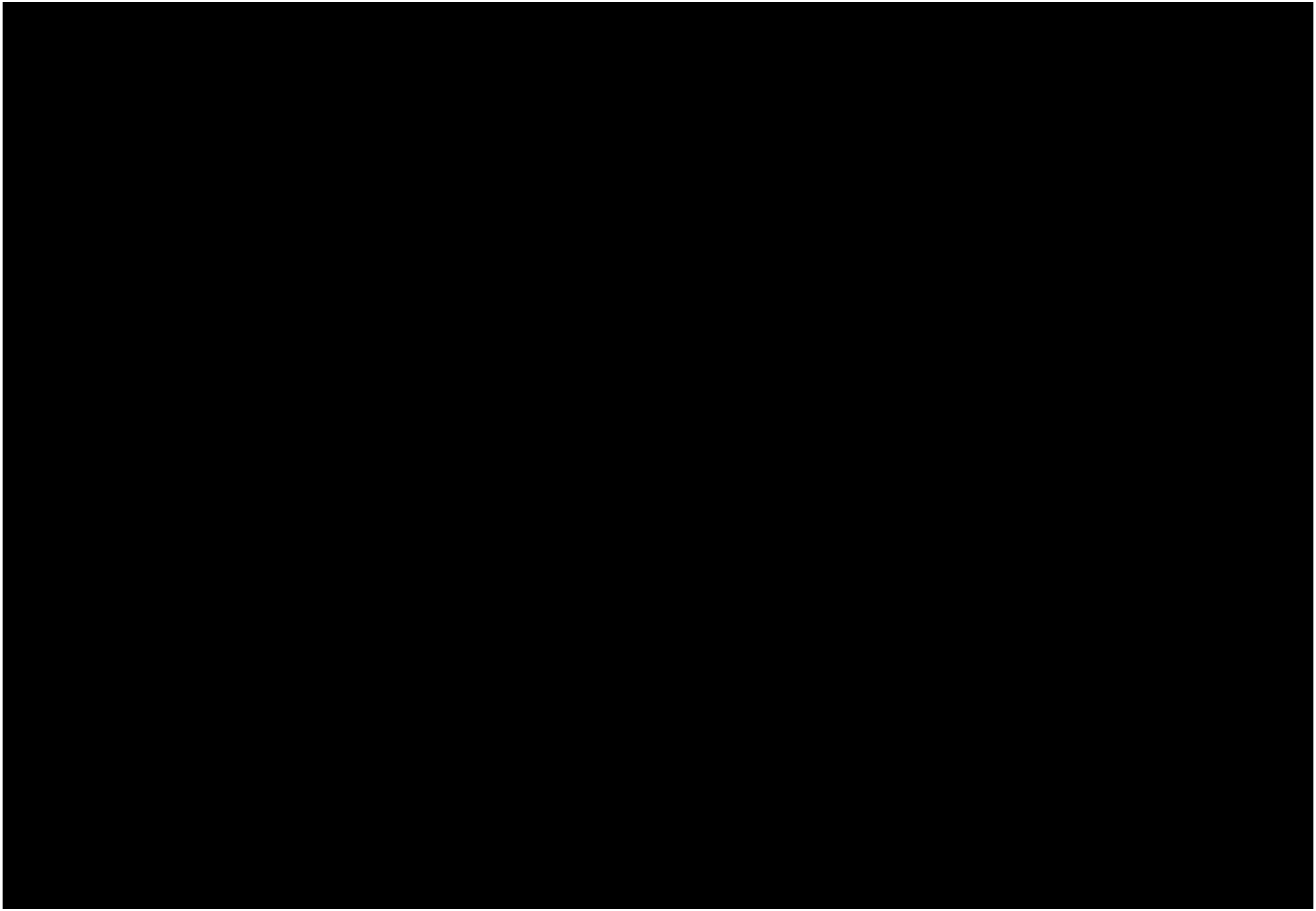
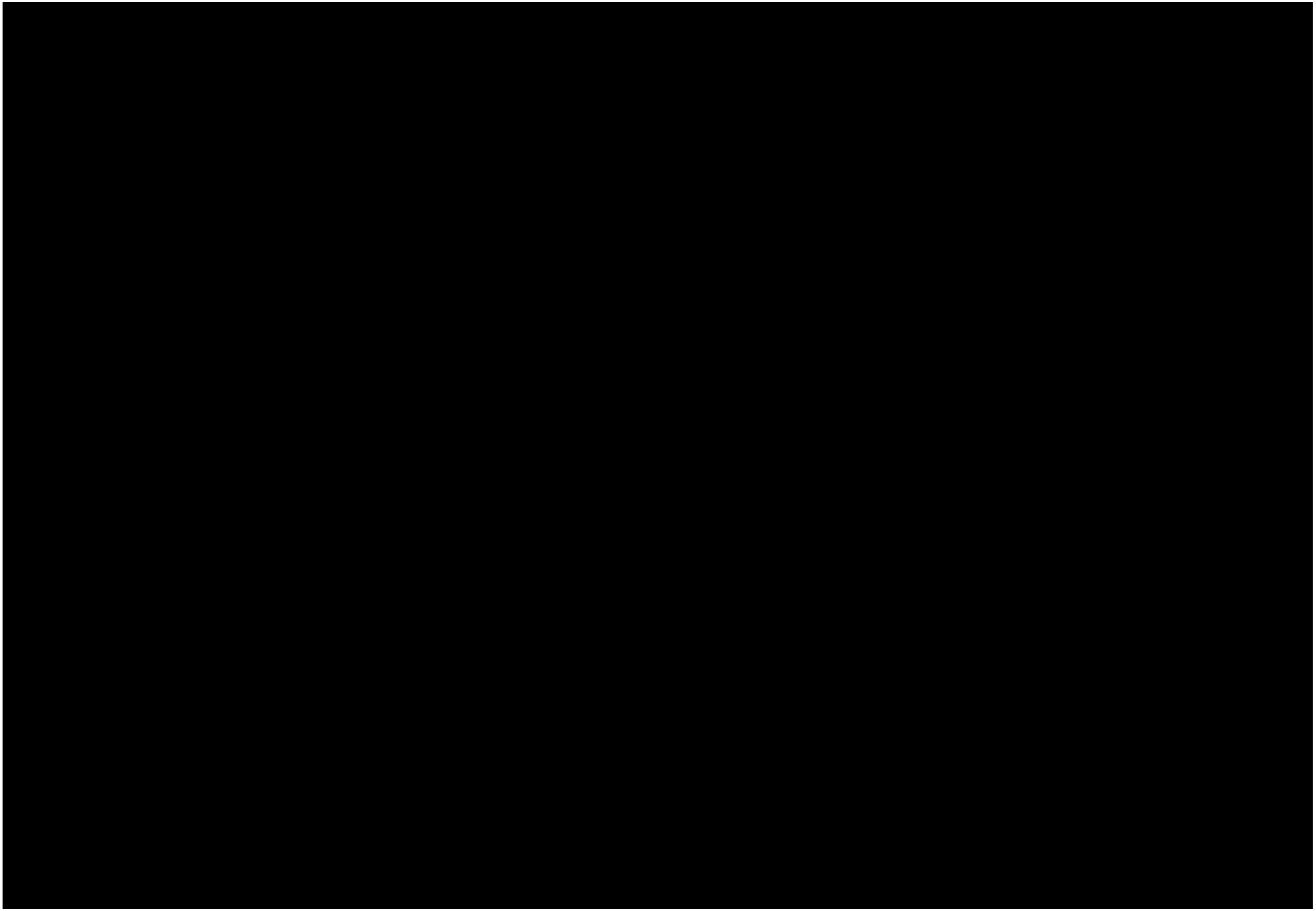
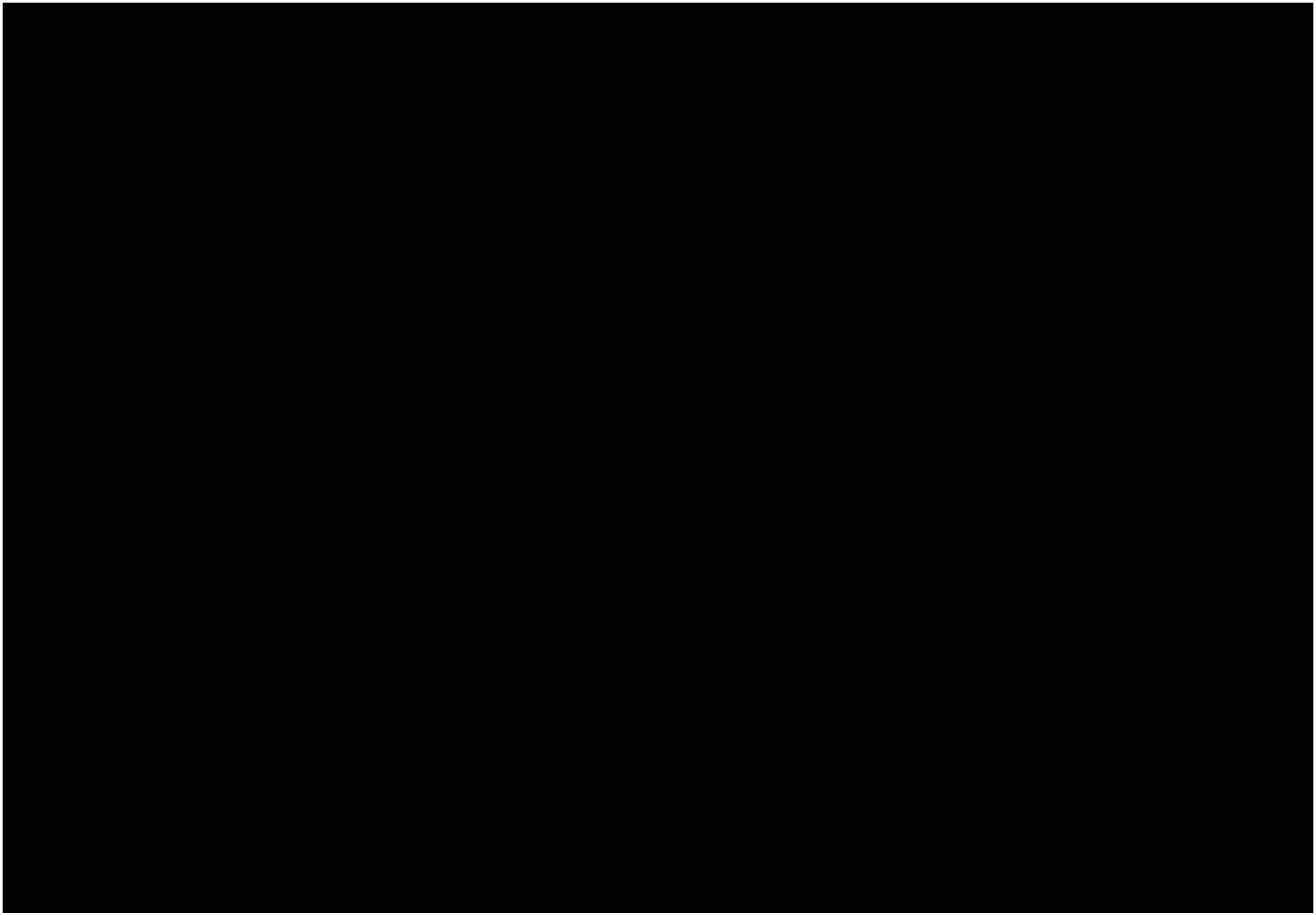
Total Annual Energy Sales
Southeast Colorado Power Association



Total Annual Energy Sales
San Isabel Electric Association, Inc.



Total Annual Energy Sales
San Luis Valley Rural Electric Cooperative, Inc.



Total Annual Energy Sales
San Miguel Power Association, Inc.

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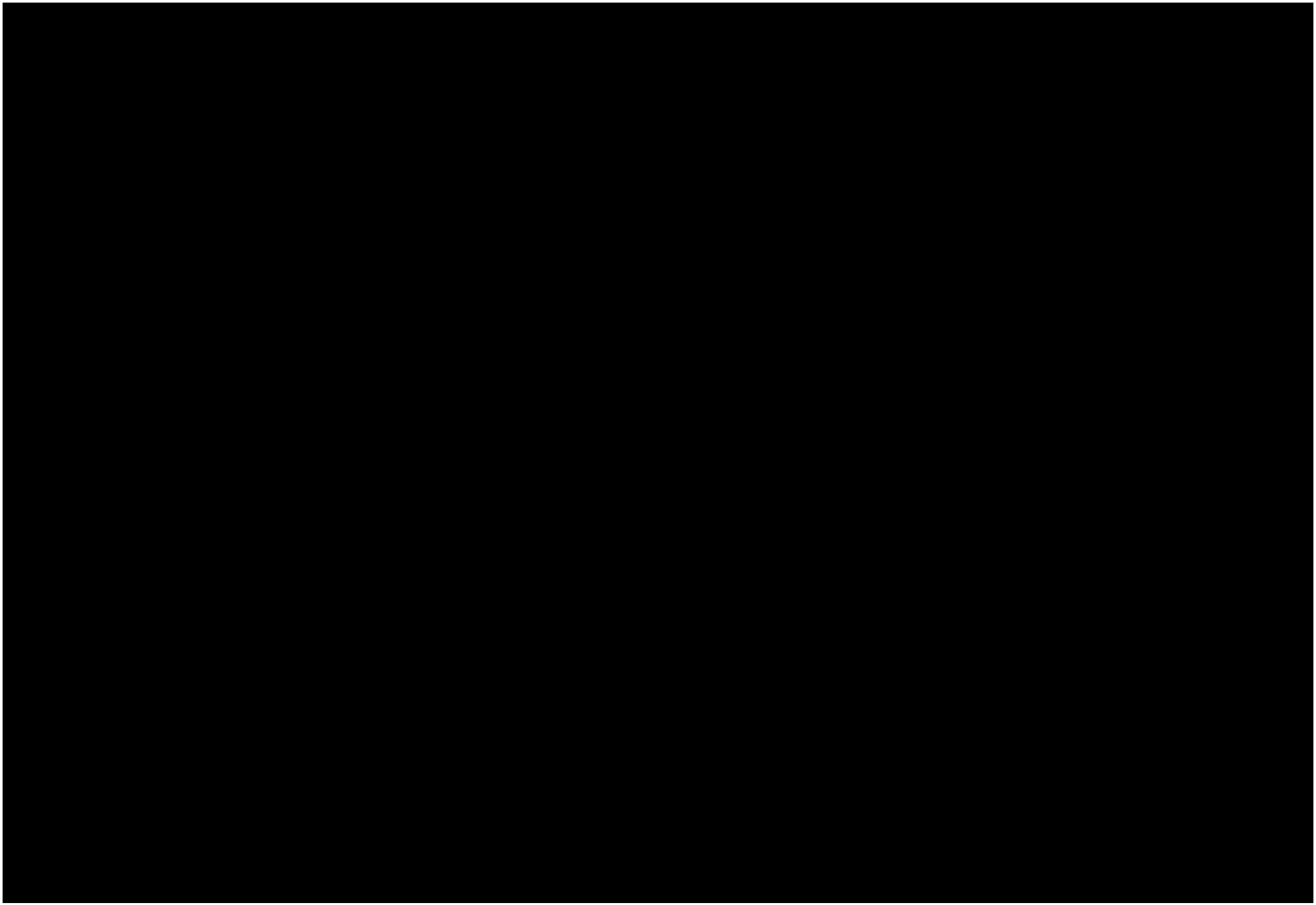
Total Annual Energy Sales
Socorro Electric Cooperative, Inc.



Total Annual Energy Sales
Springer Electric Cooperative, Inc.

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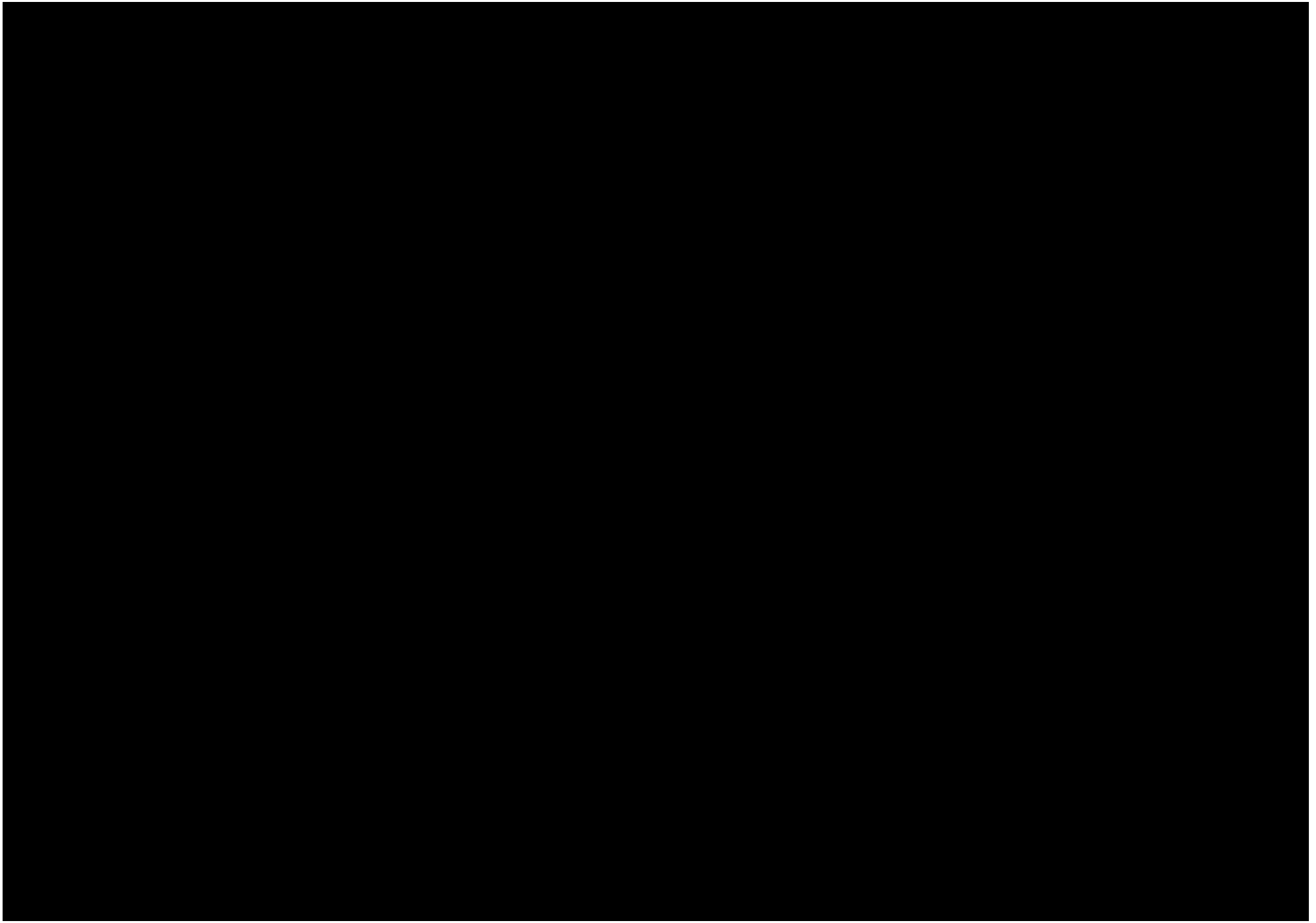
Total Annual Energy Sales
Southwestern Electric Cooperative, Inc.



Total Annual Energy Sales
United Power, Inc.

[redacted]

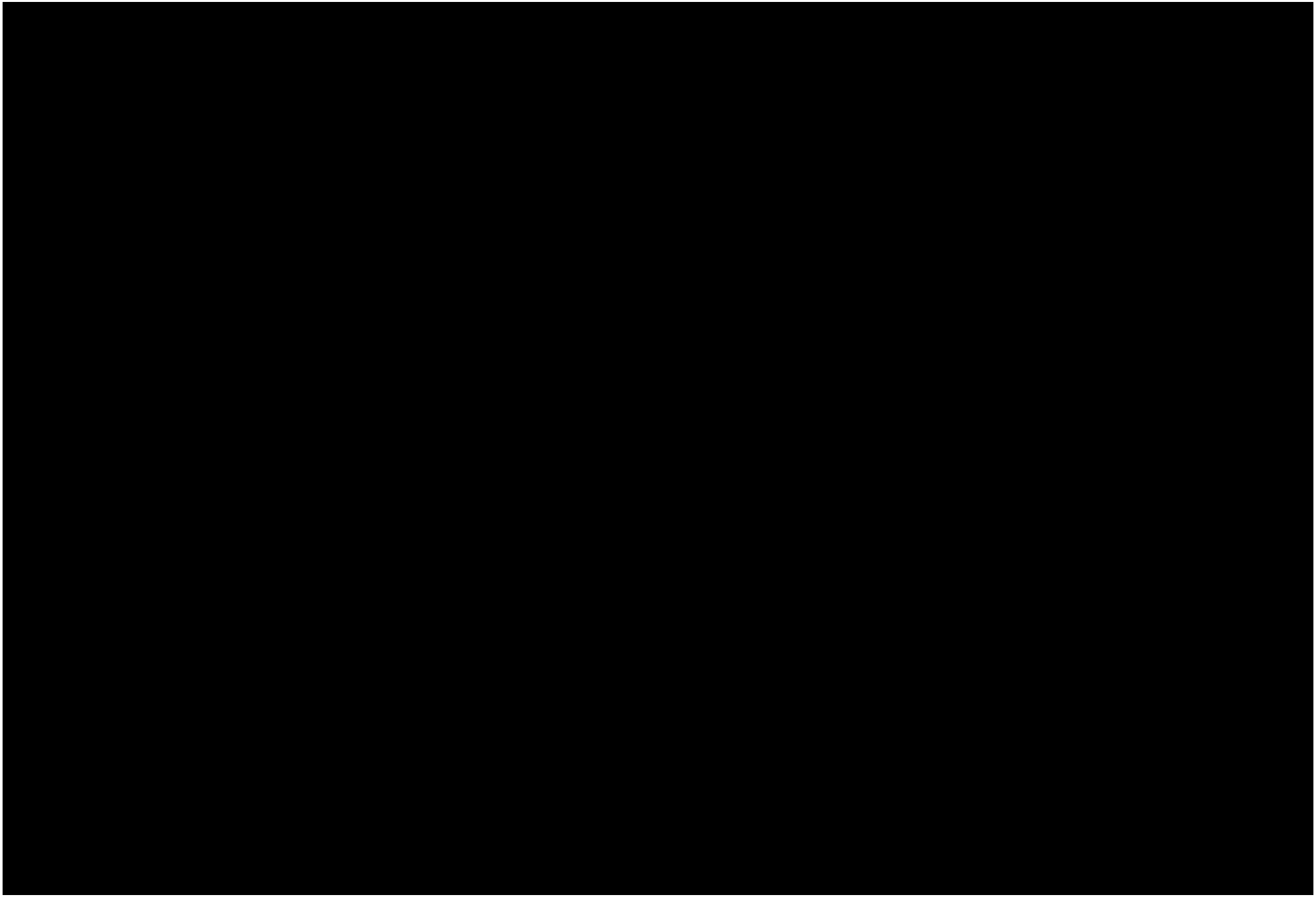
Total Annual Energy Sales
Wheat Belt Public Power District

[redacted]

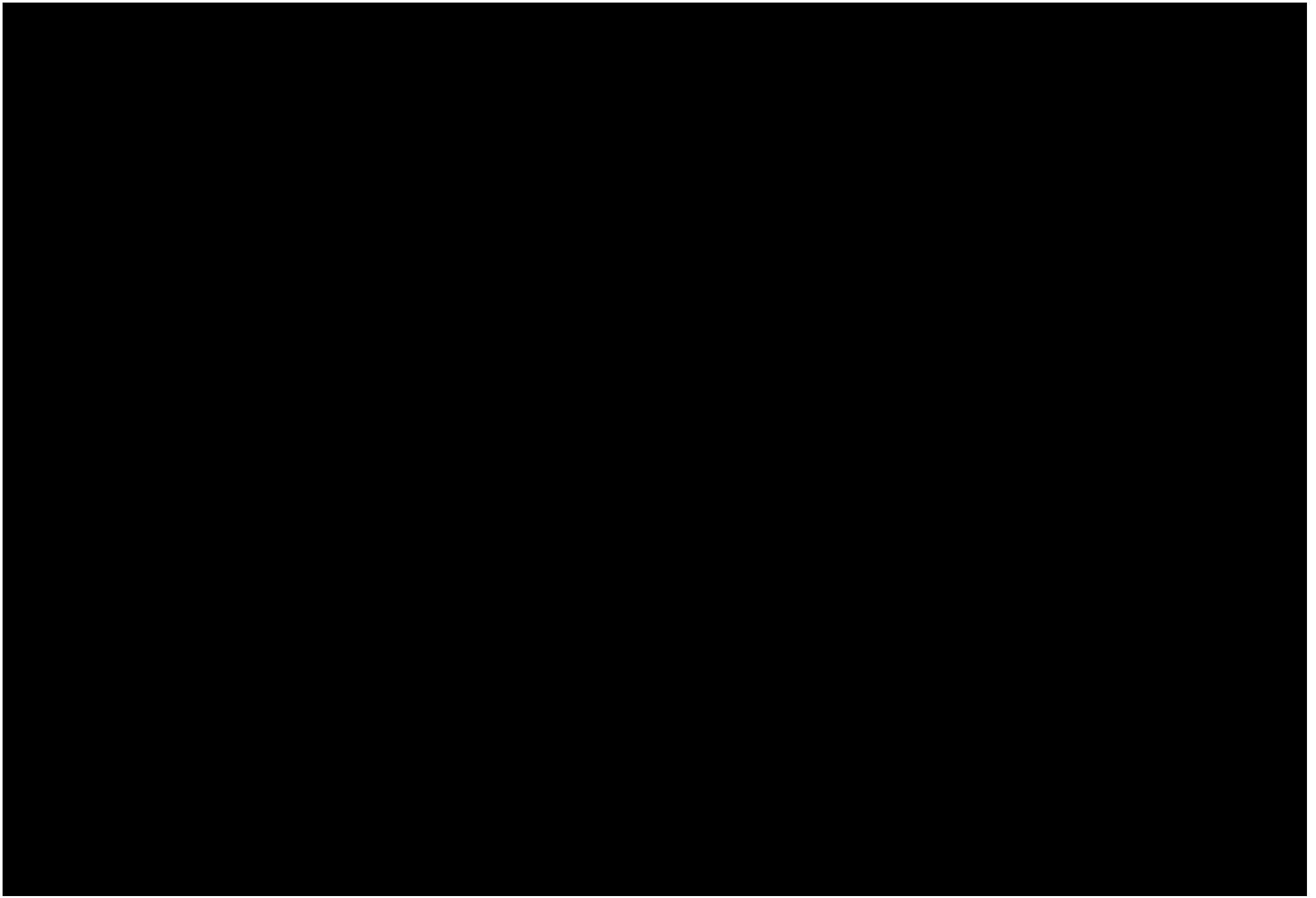
Total Annual Energy Sales
Wheatland Rural Electric Association, Inc.

[redacted]

Total Annual Energy Sales
White River Electric Association, Inc.



Total Annual Energy Sales
Wyrulec Company



Total Annual Energy Sales
Y-W Electric Association, Inc.

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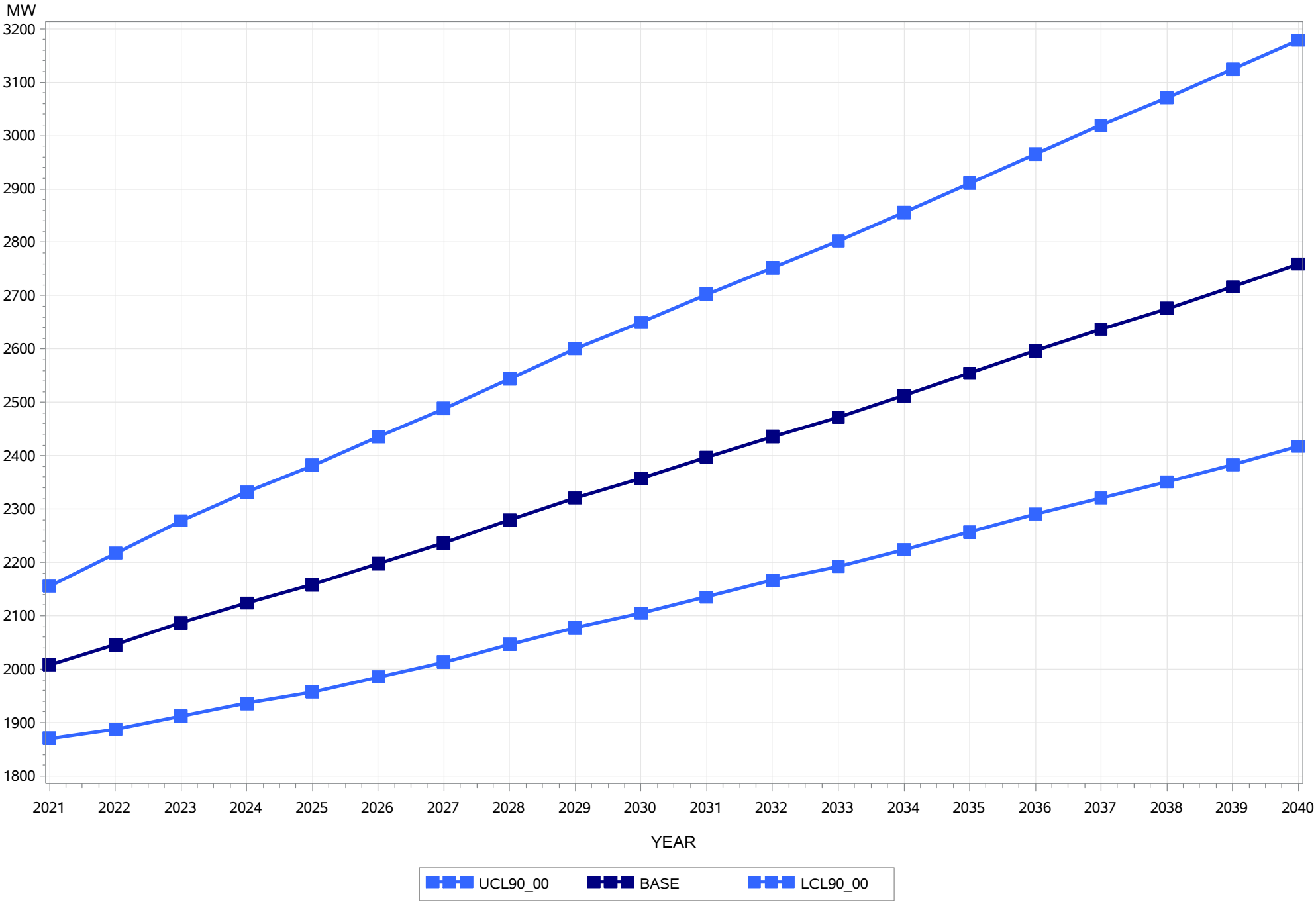
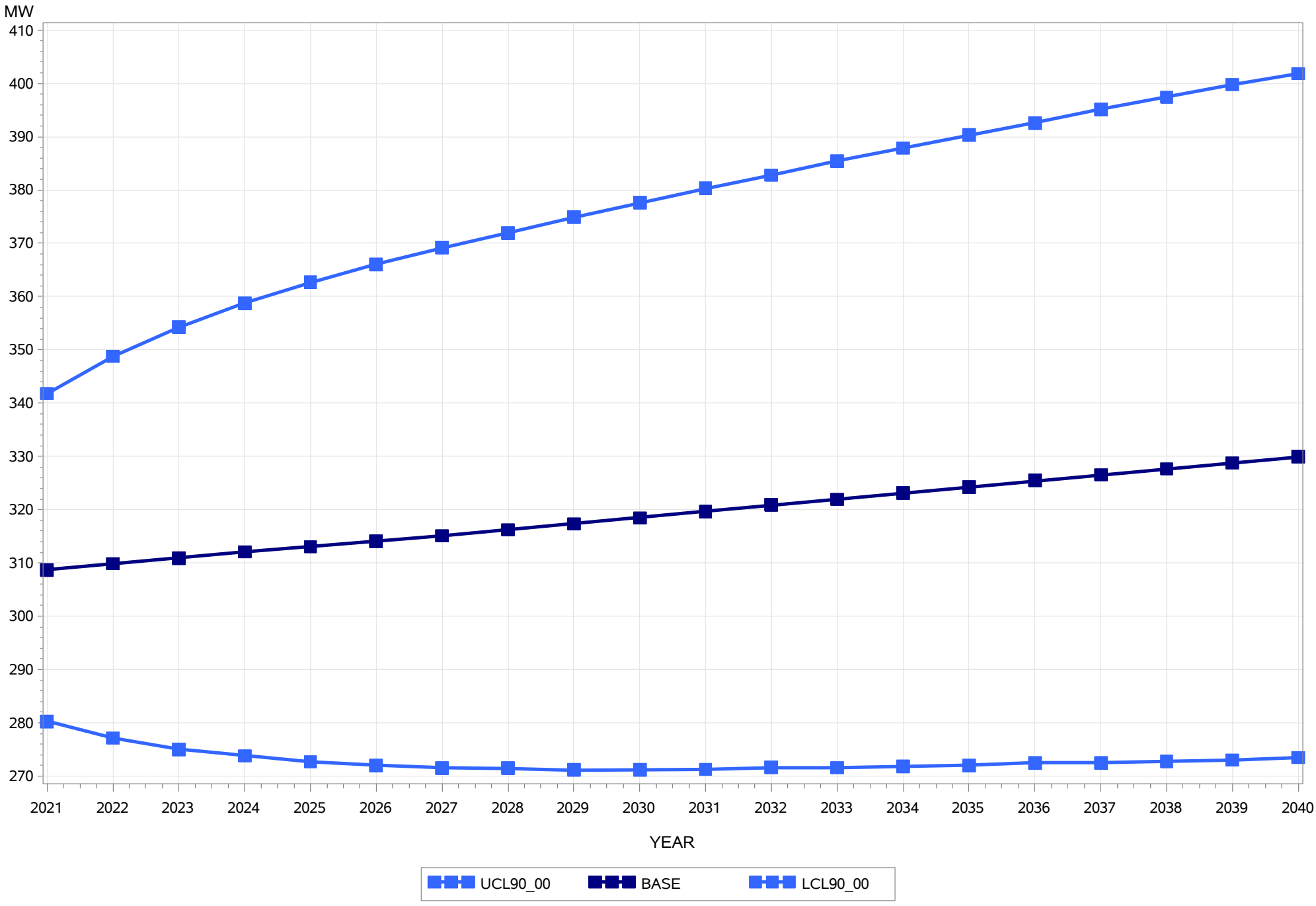
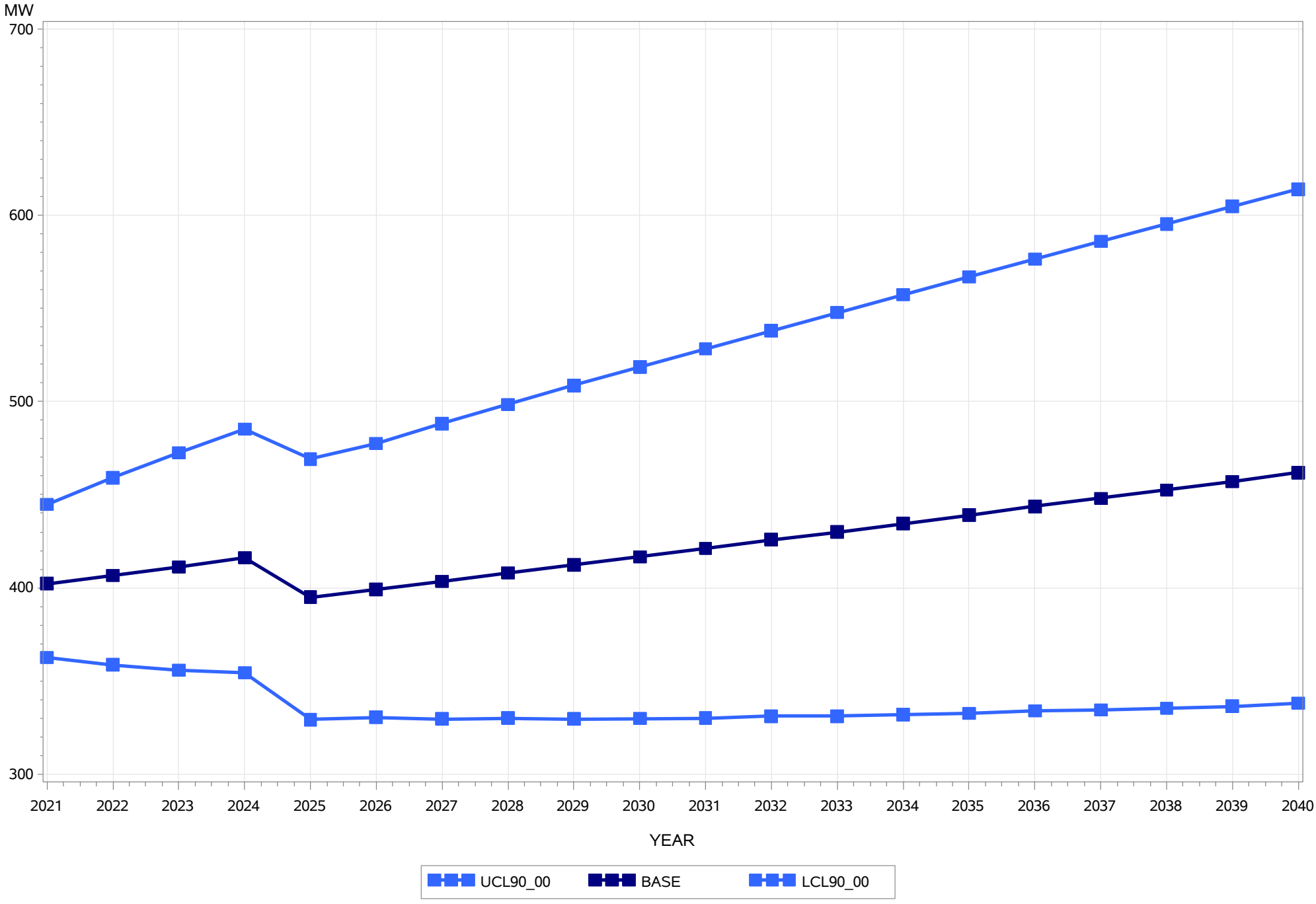
Annual Summer Coincident Peak
STATE OF COLORADO



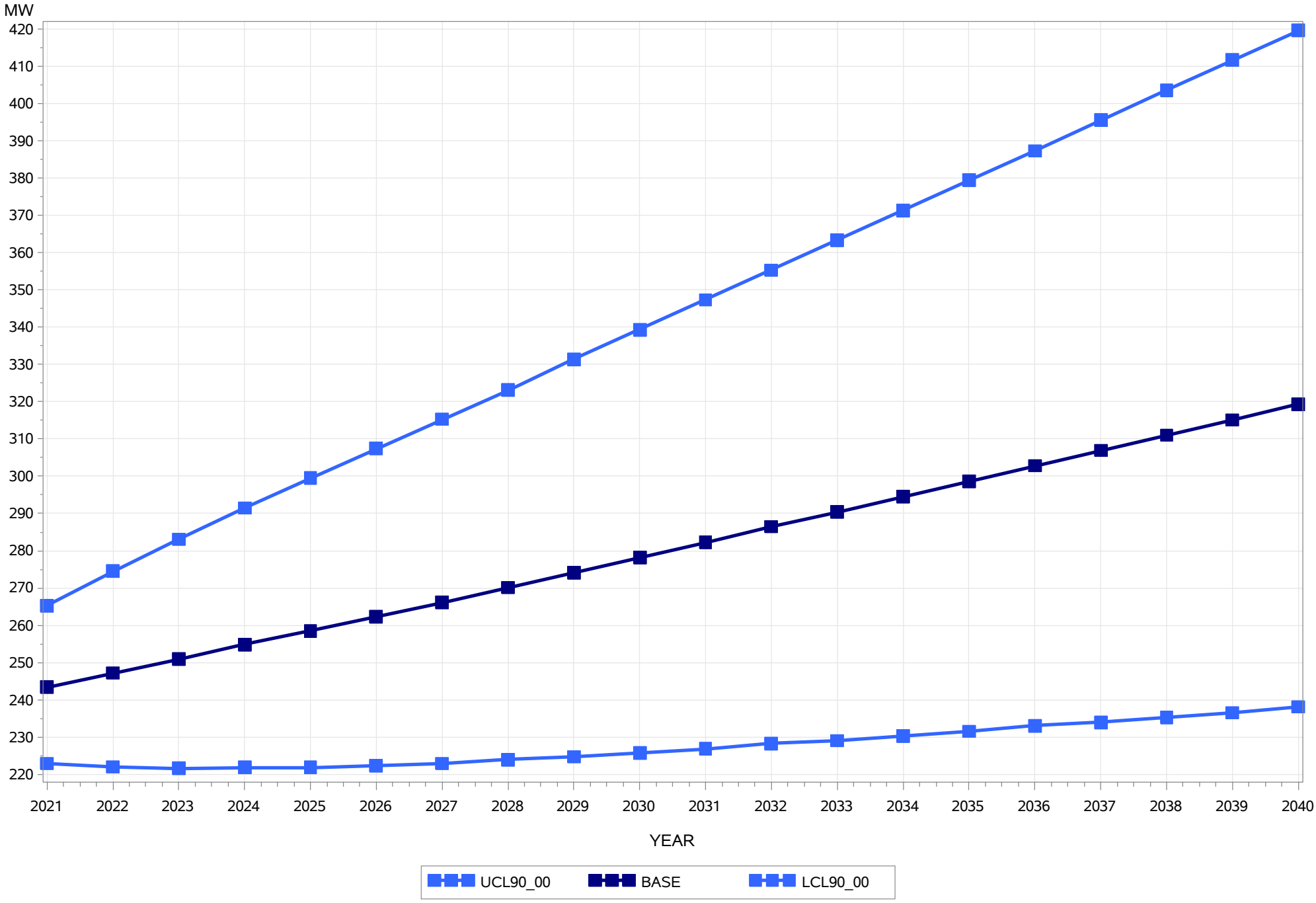
Annual Summer Coincident Peak
STATE OF NEBRASKA



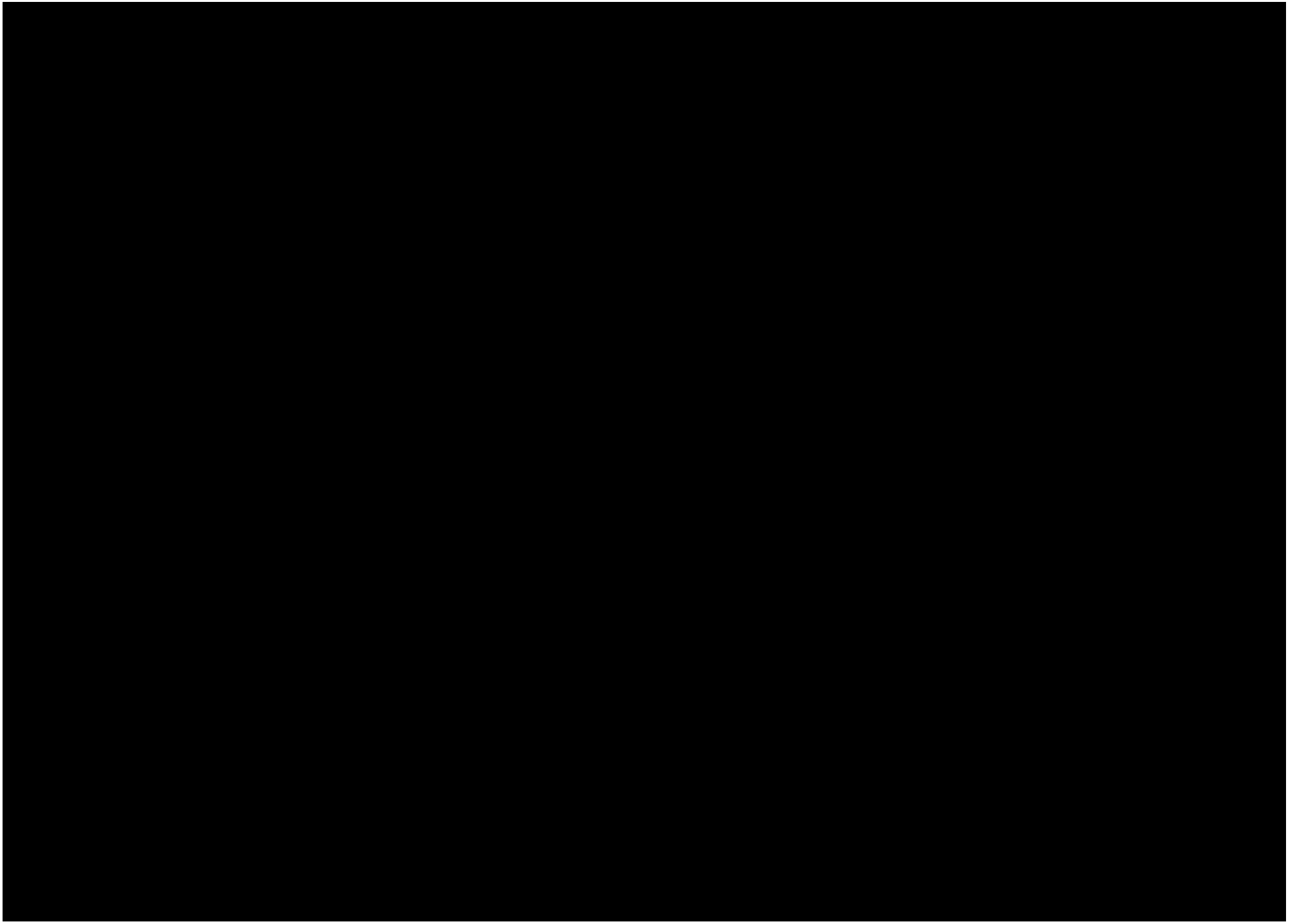
Annual Summer Coincident Peak
STATE OF NEW MEXICO



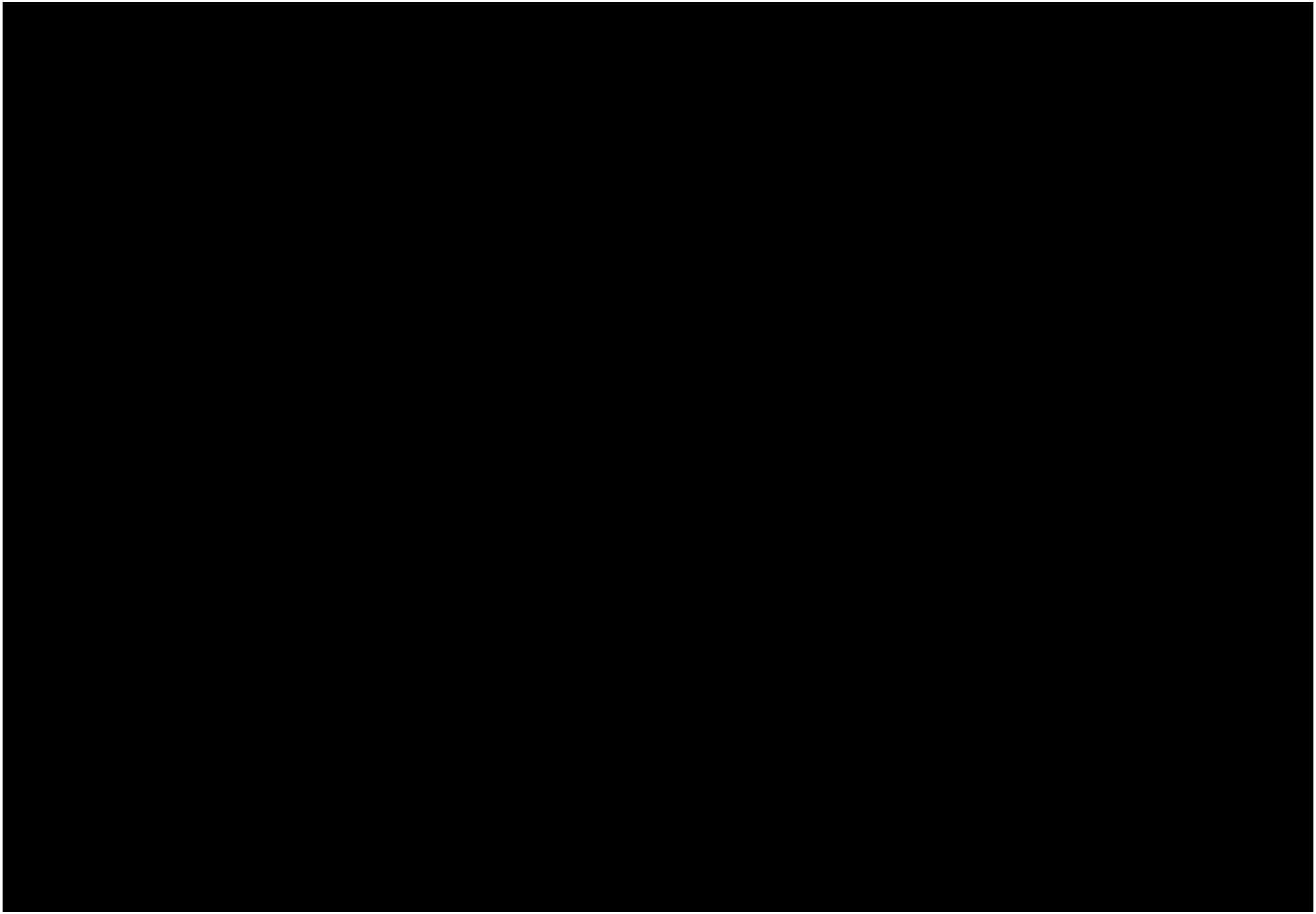
Annual Summer Coincident Peak
STATE OF WYOMING



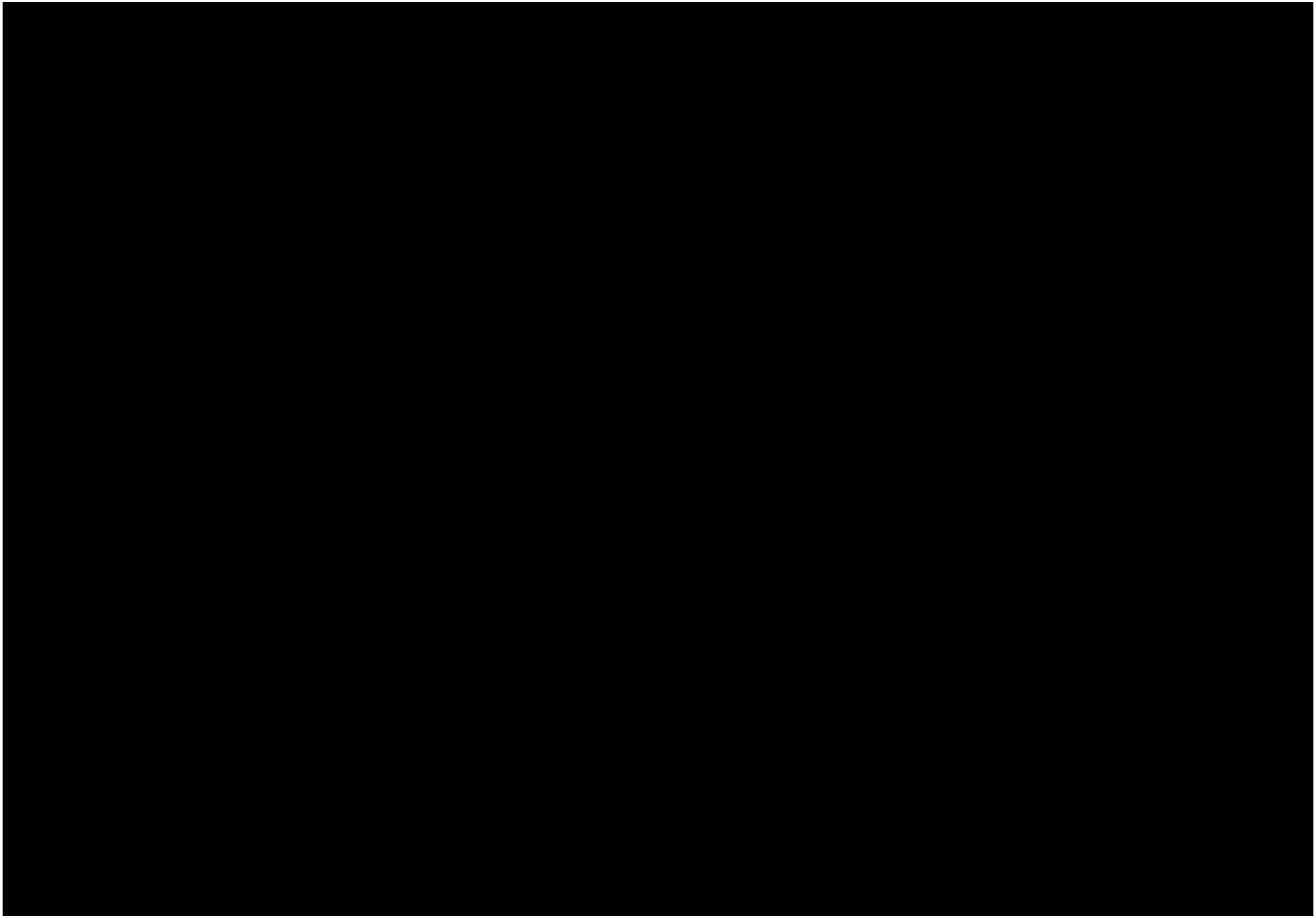
Annual Summer Coincident Peak
Big Horn Rural Electric Company



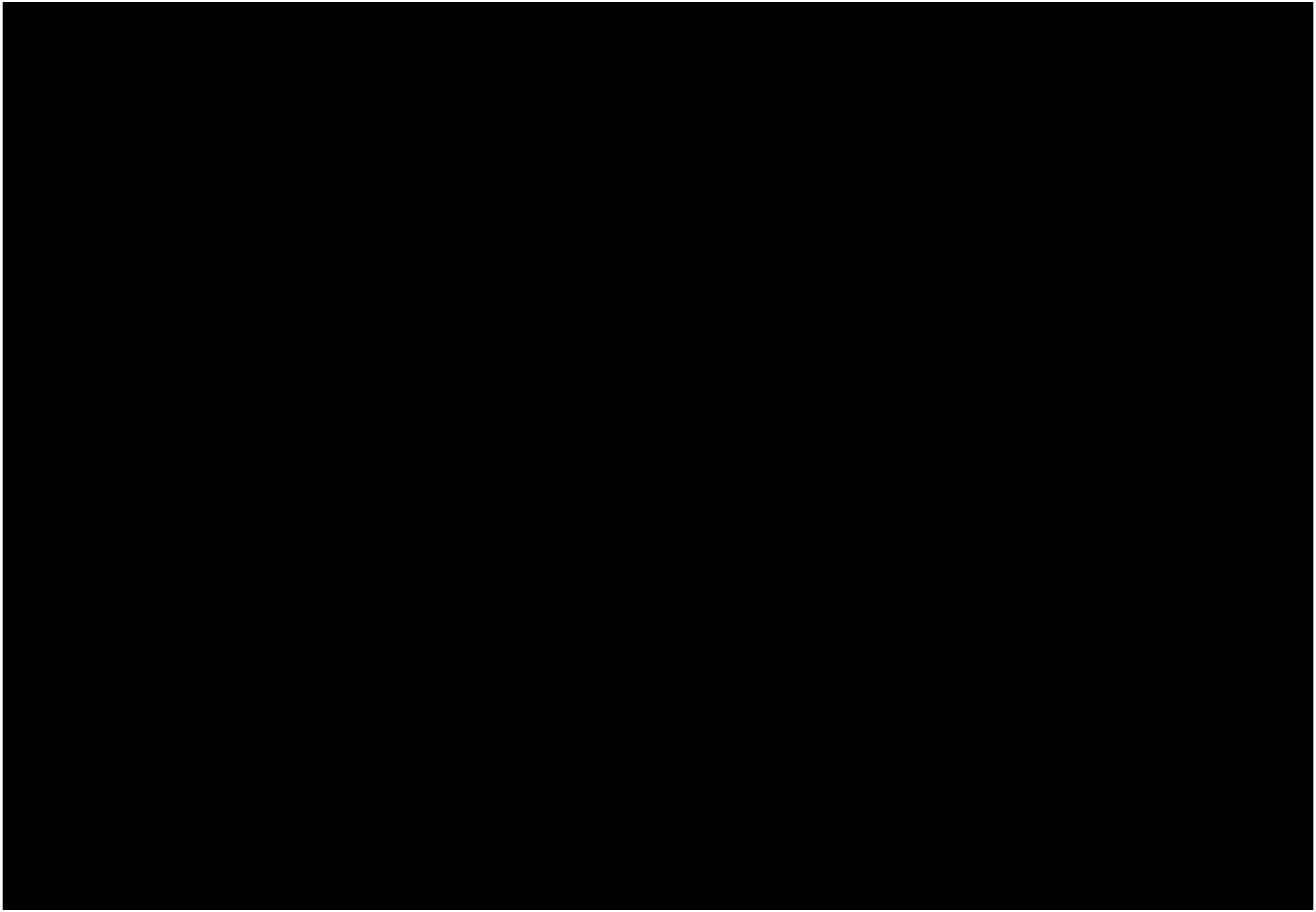
Annual Summer Coincident Peak
Carbon Power and Light, Inc.



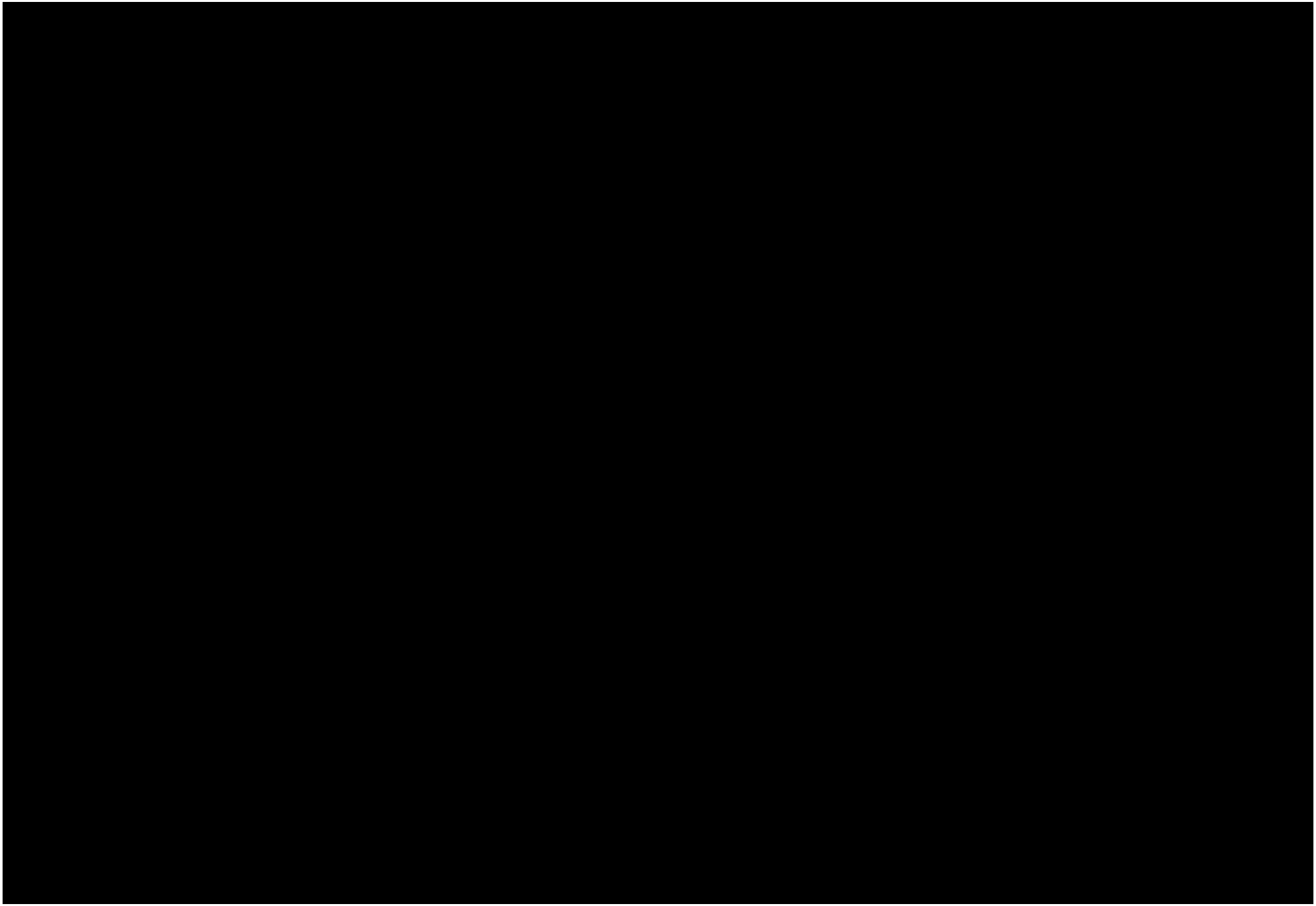
Annual Summer Coincident Peak
Continental Divide Electric Cooperative, Inc.



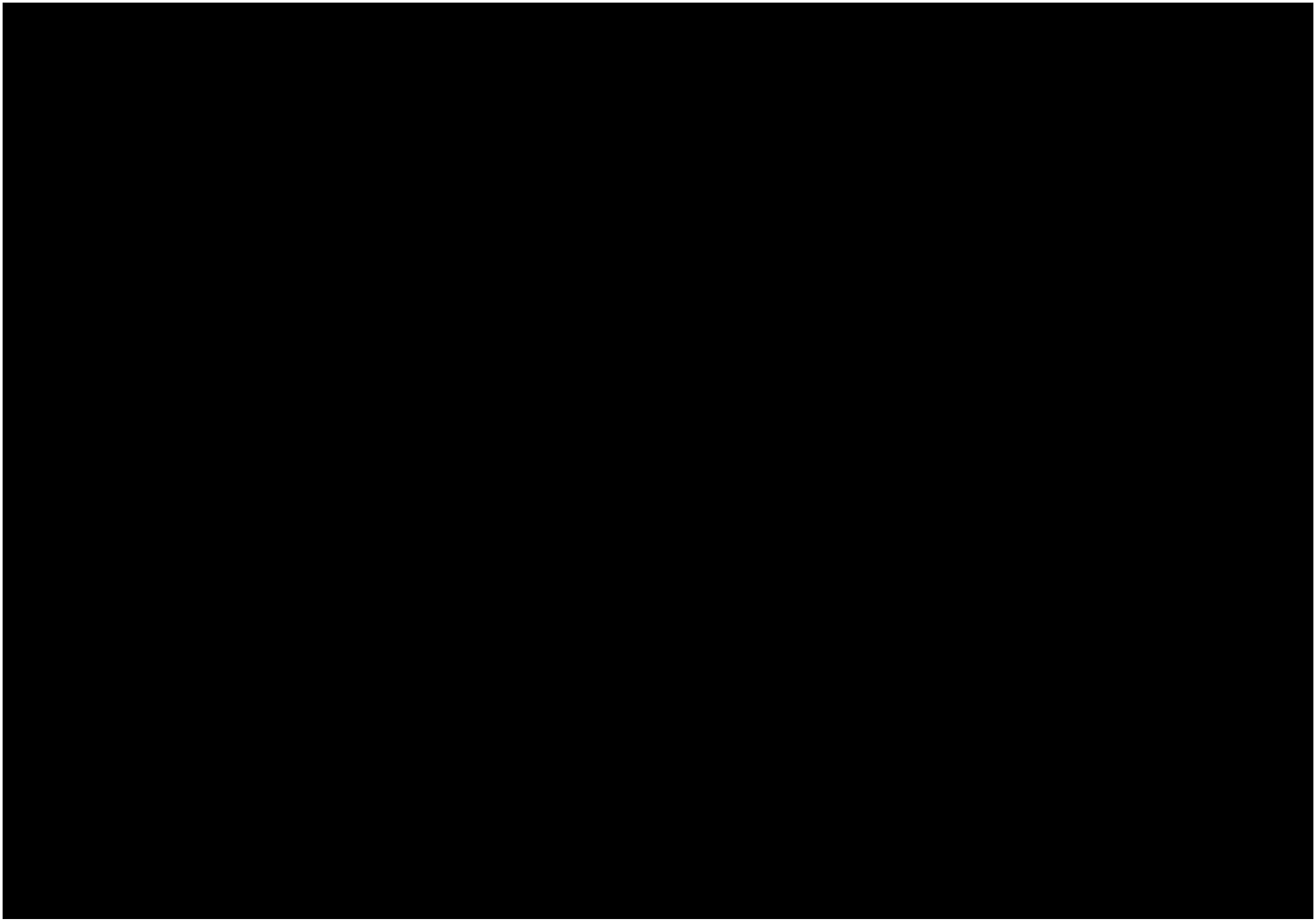
Annual Summer Coincident Peak
Columbus Electric Cooperative, Inc.



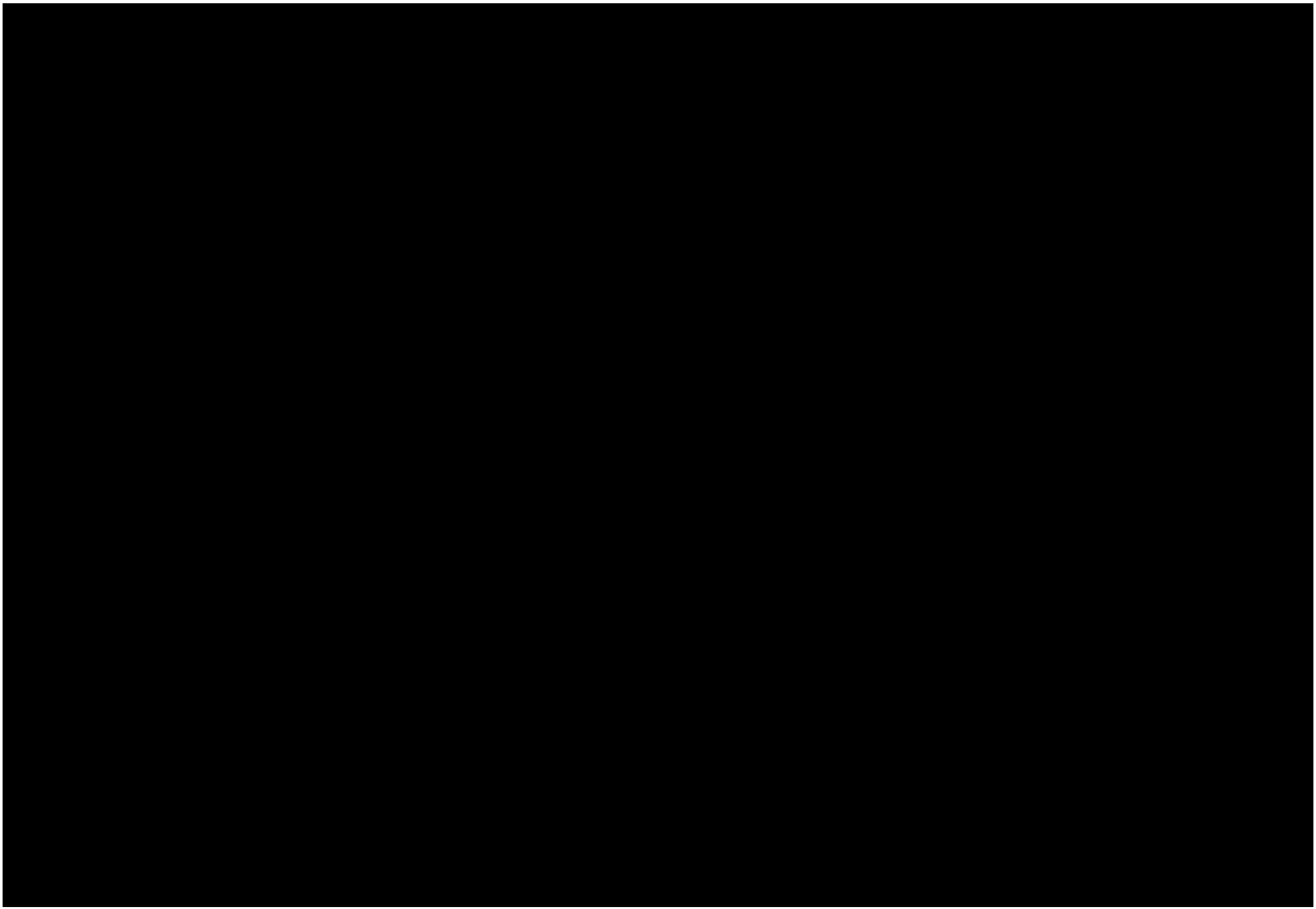
Annual Summer Coincident Peak
Central New Mexico Electric Cooperative, Inc.



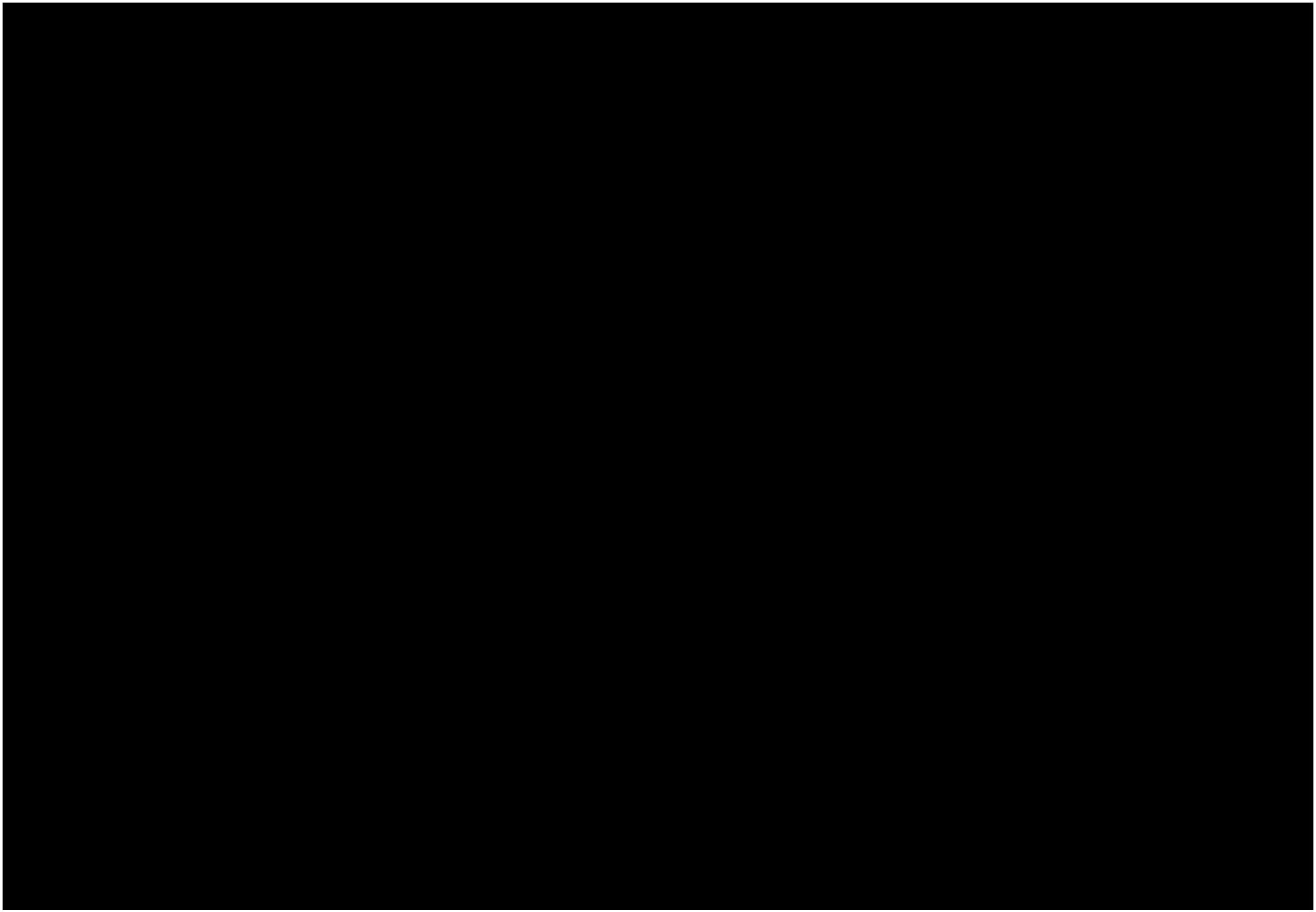
Annual Summer Coincident Peak
Chimney Rock Public Power District



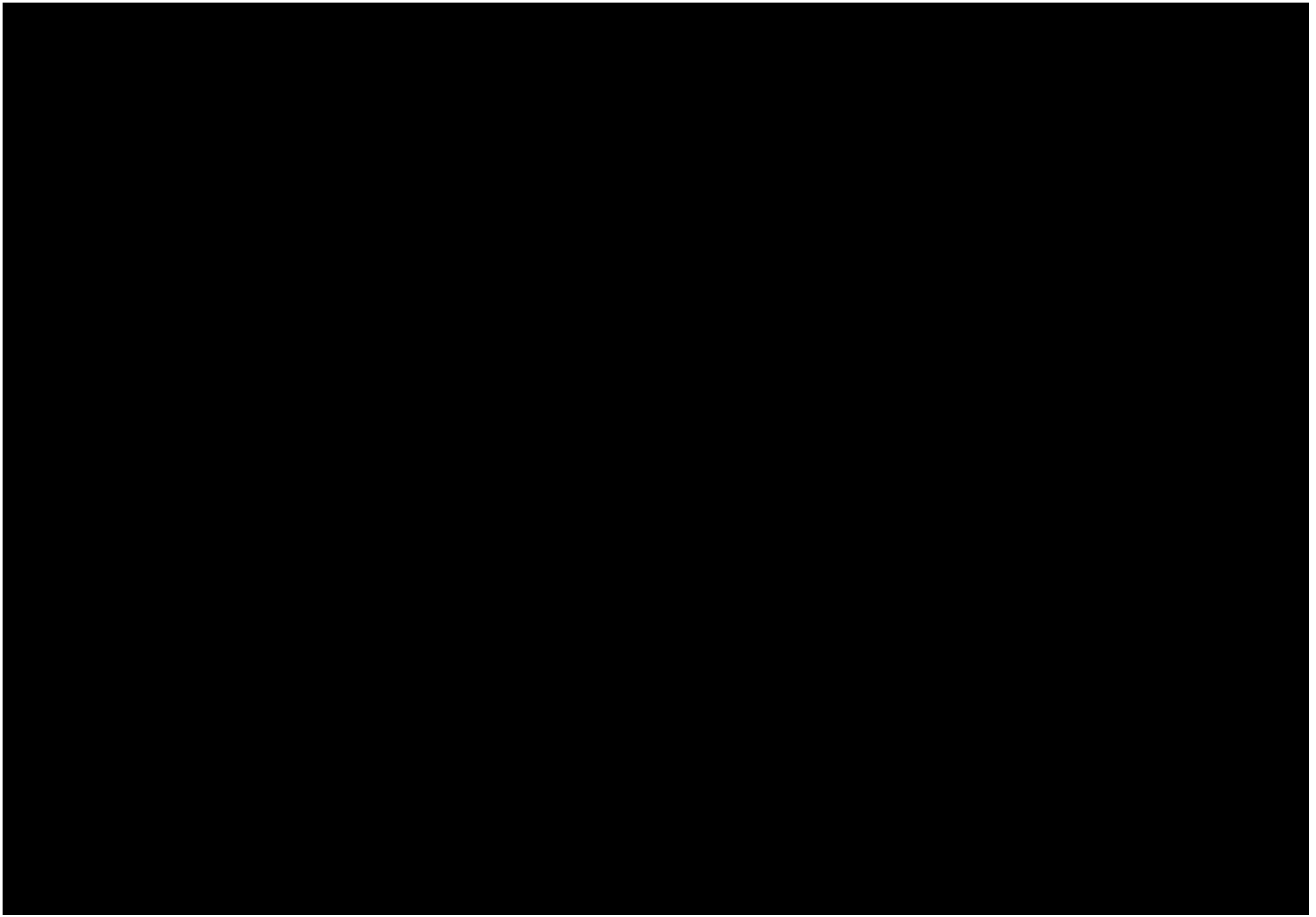
Annual Summer Coincident Peak
Empire Electric Association, Inc.



Annual Summer Coincident Peak
Gunnison County Electric Association, Inc.



Annual Summer Coincident Peak
Garland Light and Power Company



Annual Summer Coincident Peak
Highline Electric Association

[redacted]

Annual Summer Coincident Peak

High Plains Power, Inc.

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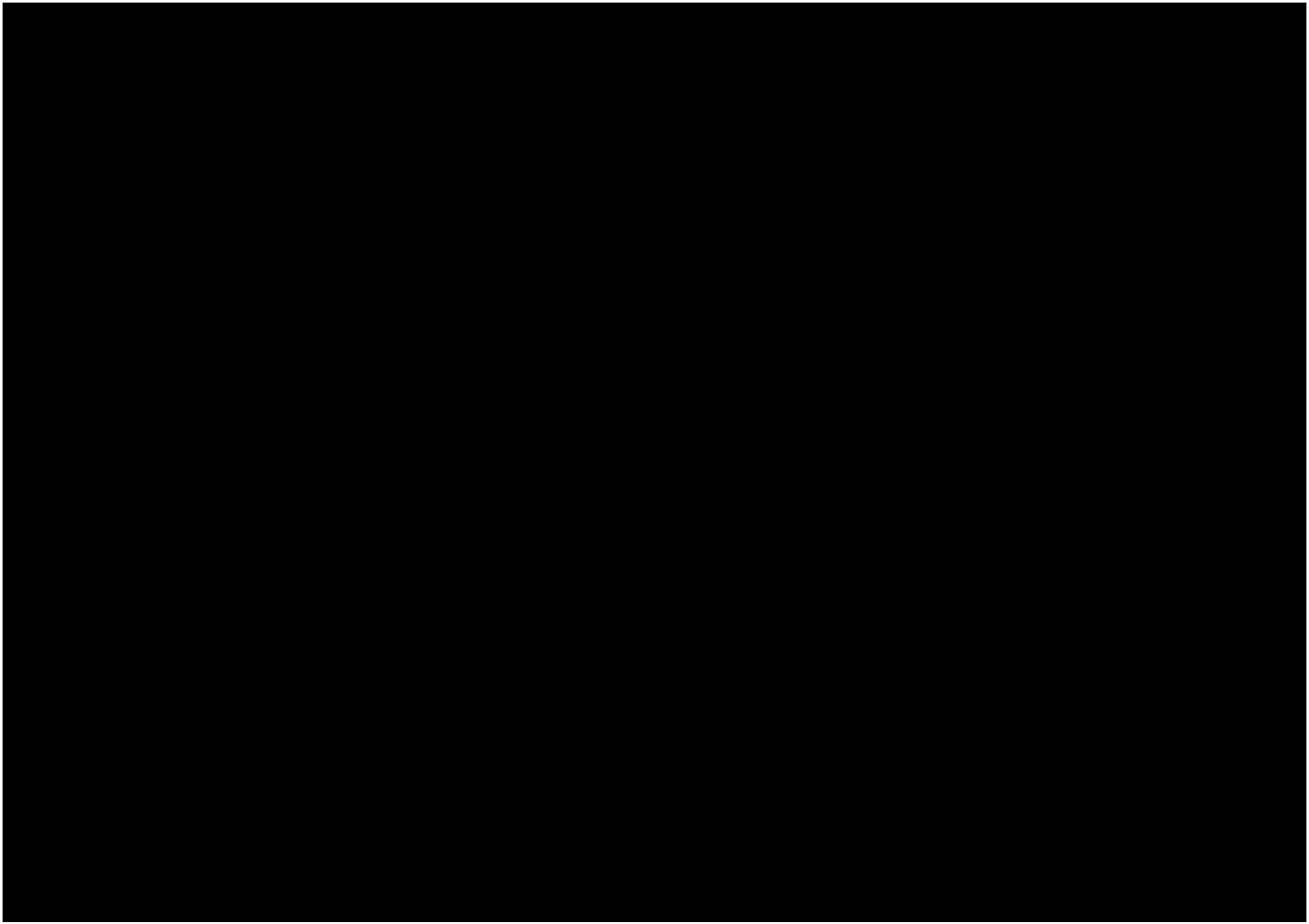
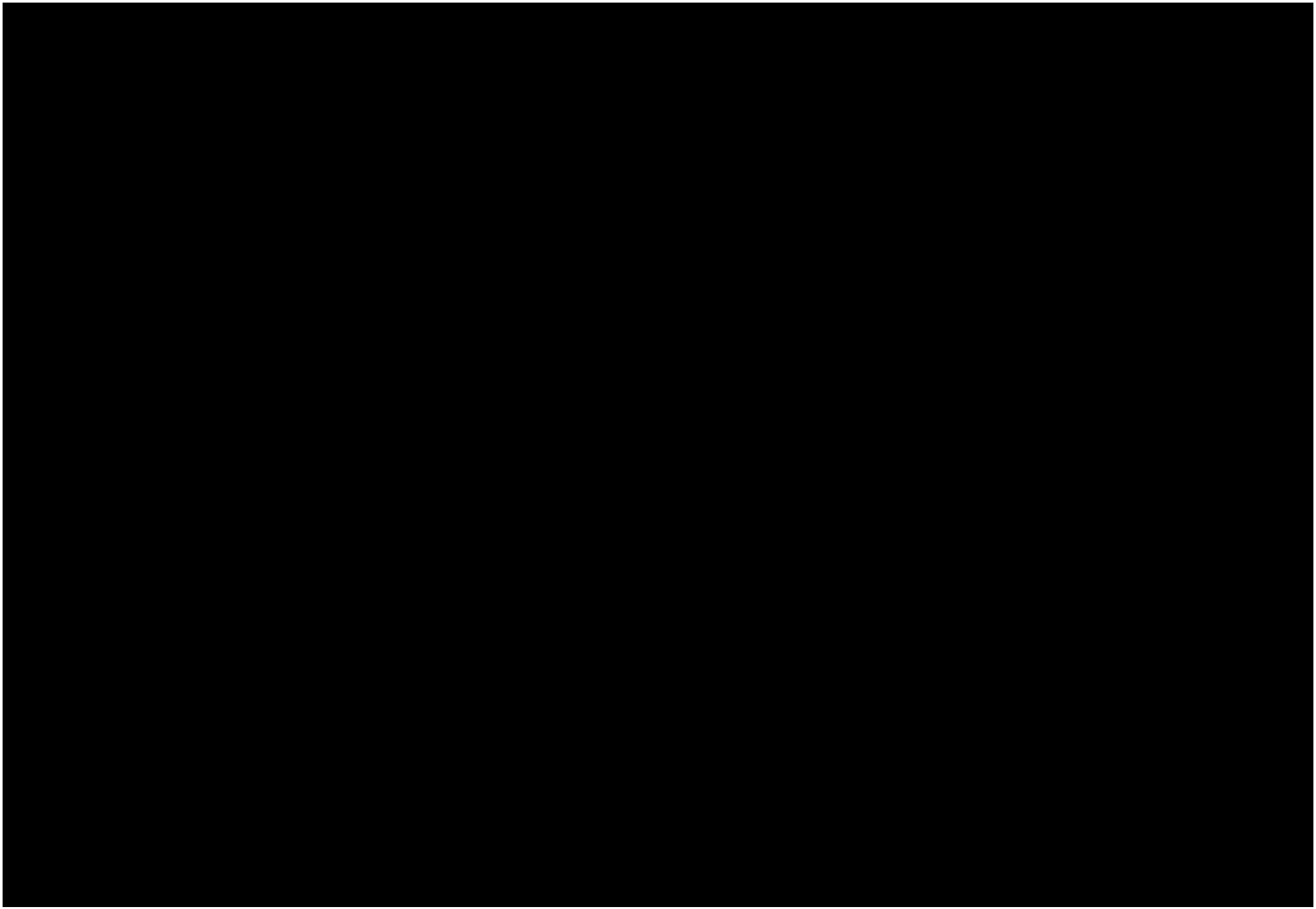
Annual Summer Coincident Peak
High West Energy, Inc.

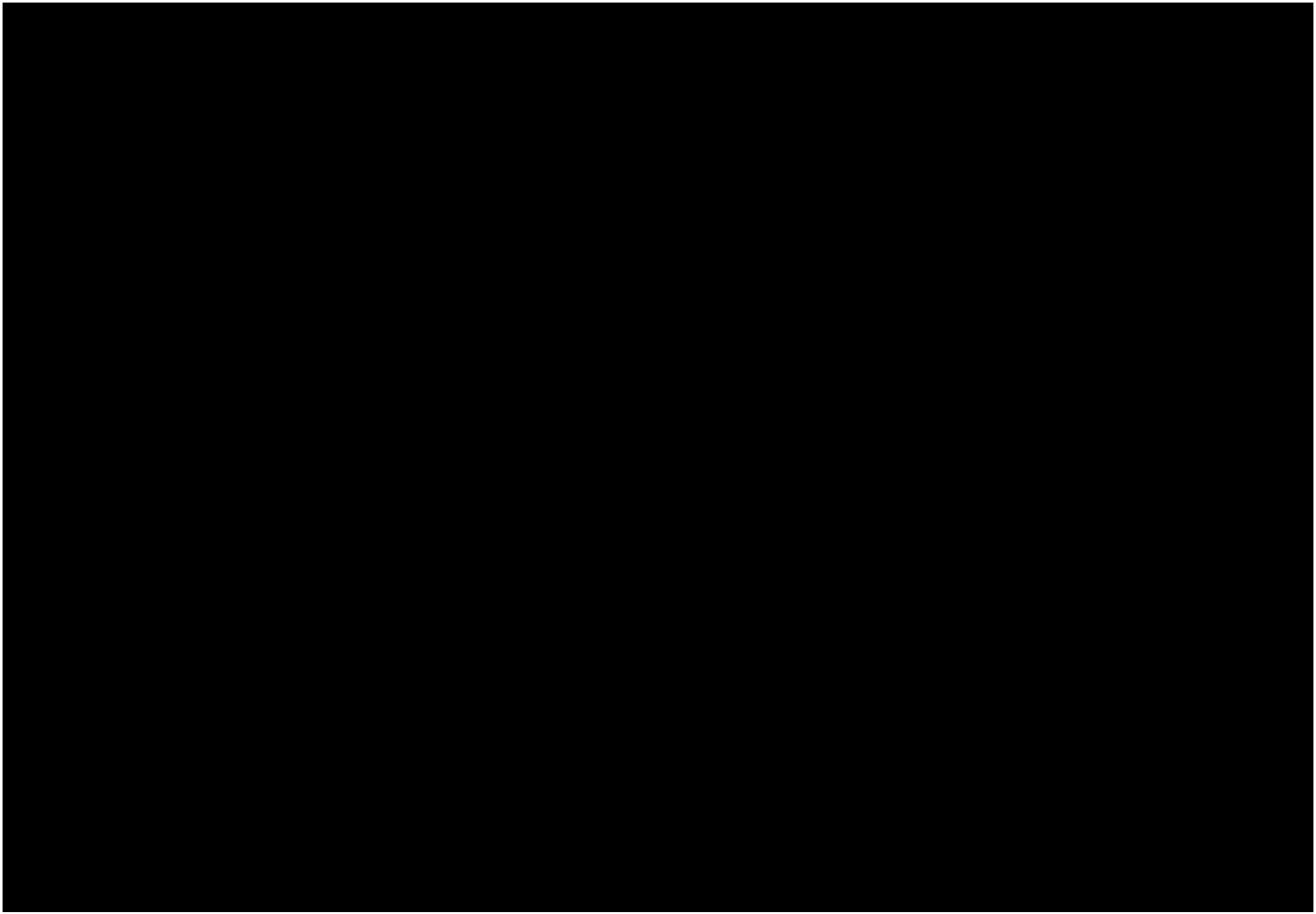


Annual Summer Coincident Peak

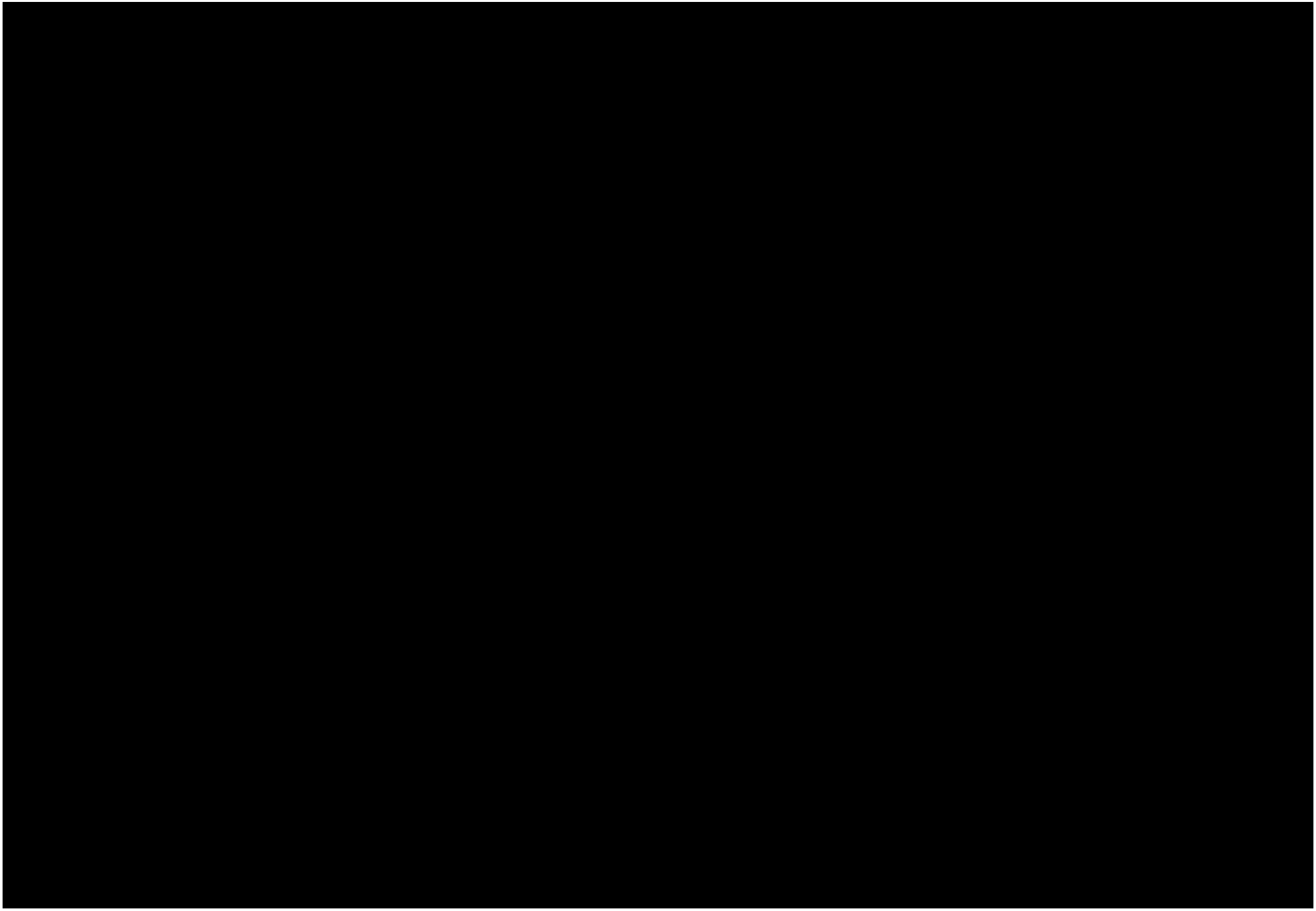
Jemez Mountains Electric Cooperative, Inc.



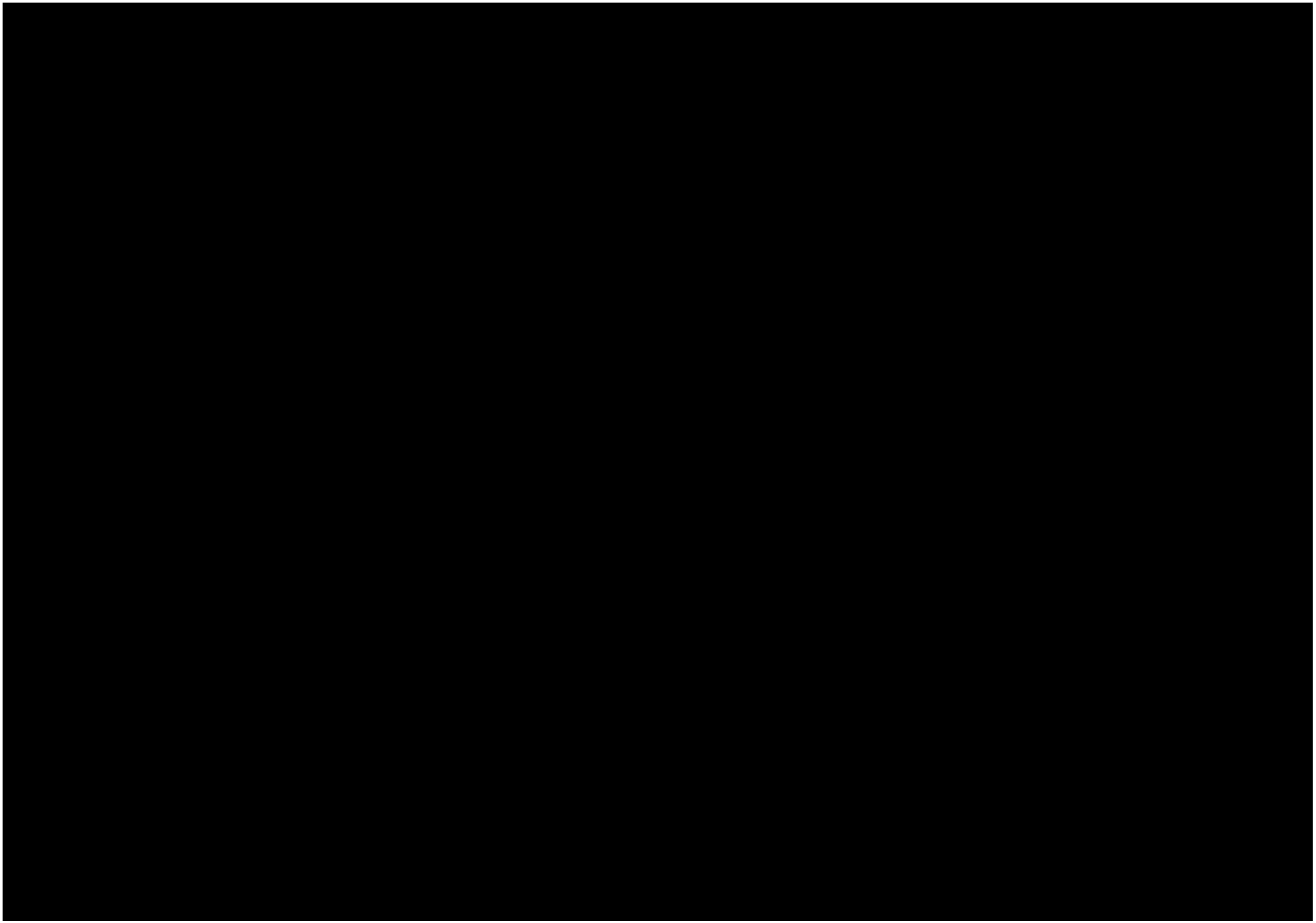
Annual Summer Coincident Peak
K.C. Electric Association, Inc.



Annual Summer Coincident Peak
La Plata Electric Association, Inc.

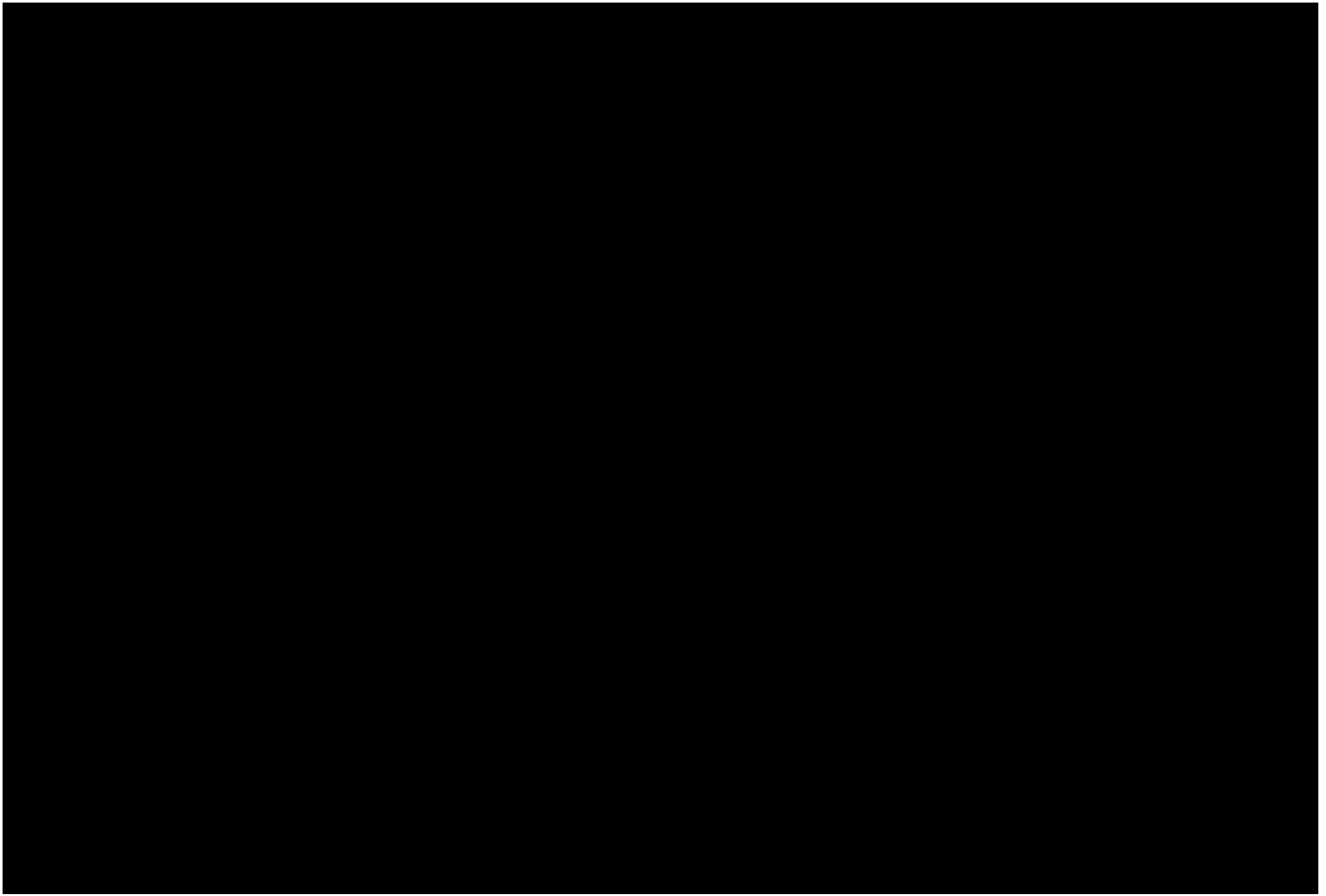


Annual Summer Coincident Peak
Morgan County Rural Electric Association

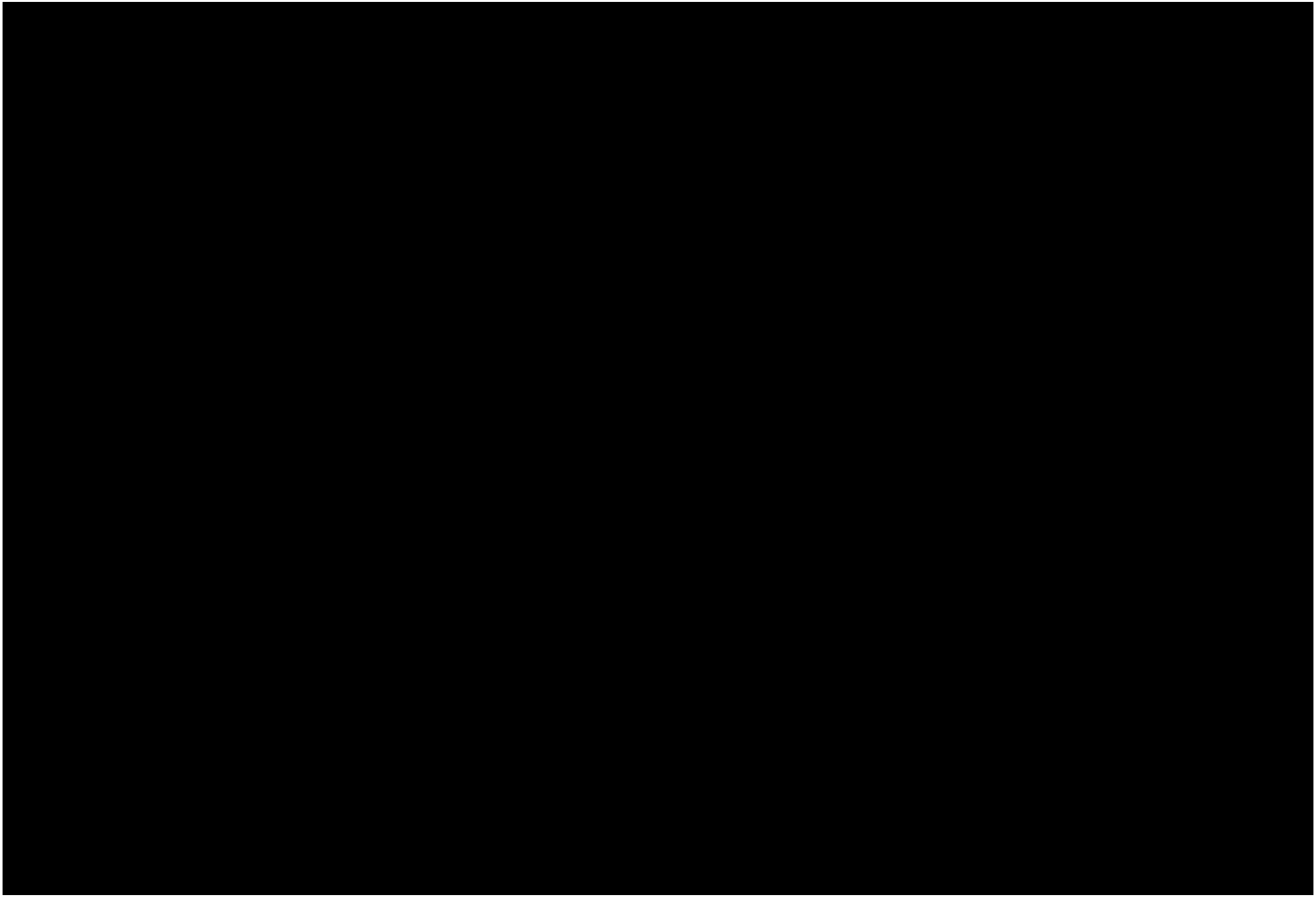


Annual Summer Coincident Peak

Mountain Parks Electric, Inc.



Annual Summer Coincident Peak
Mora-San Miguel Electric Cooperative, Inc.



Annual Summer Coincident Peak
Mountain View Electric Association, Inc.

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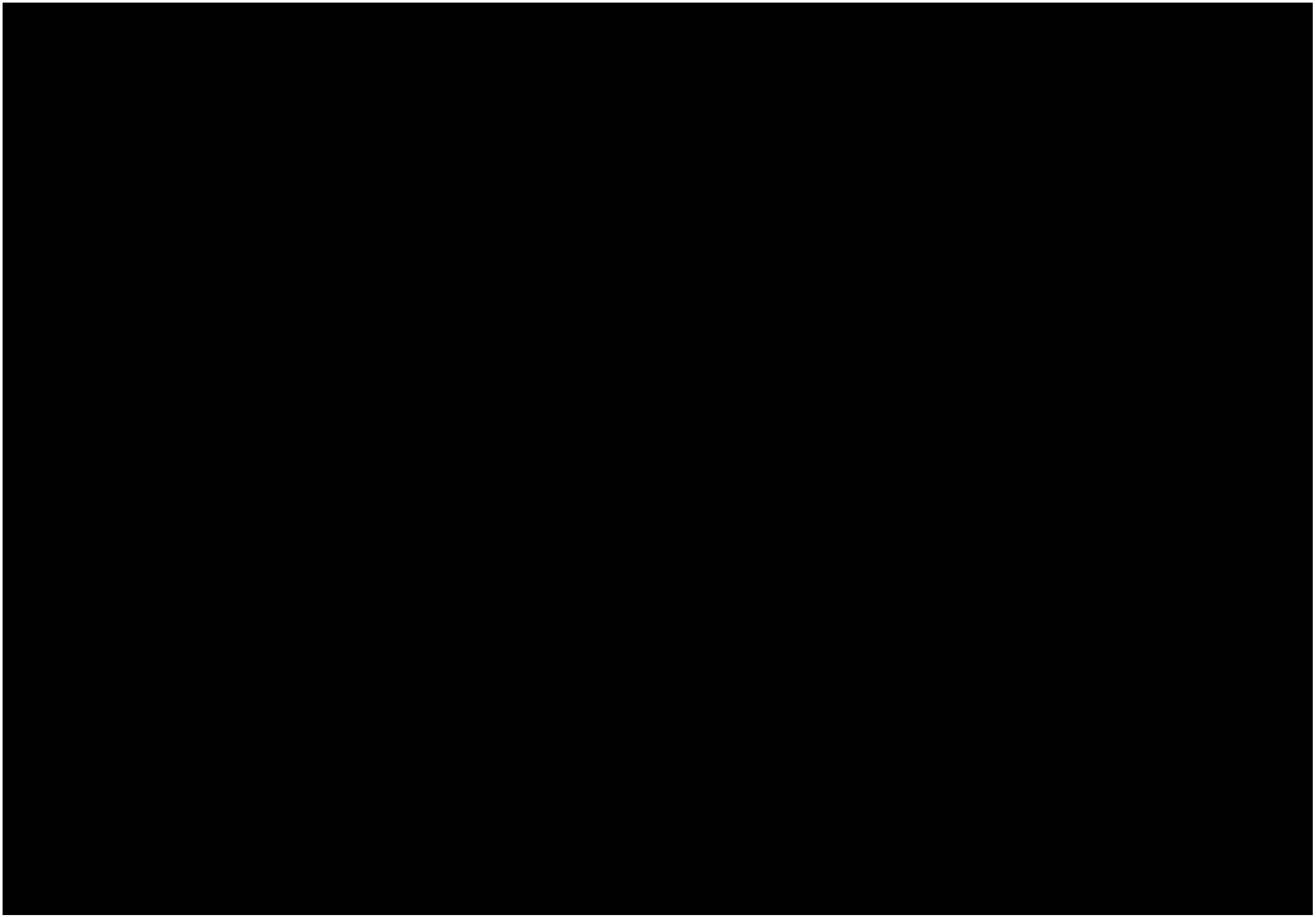
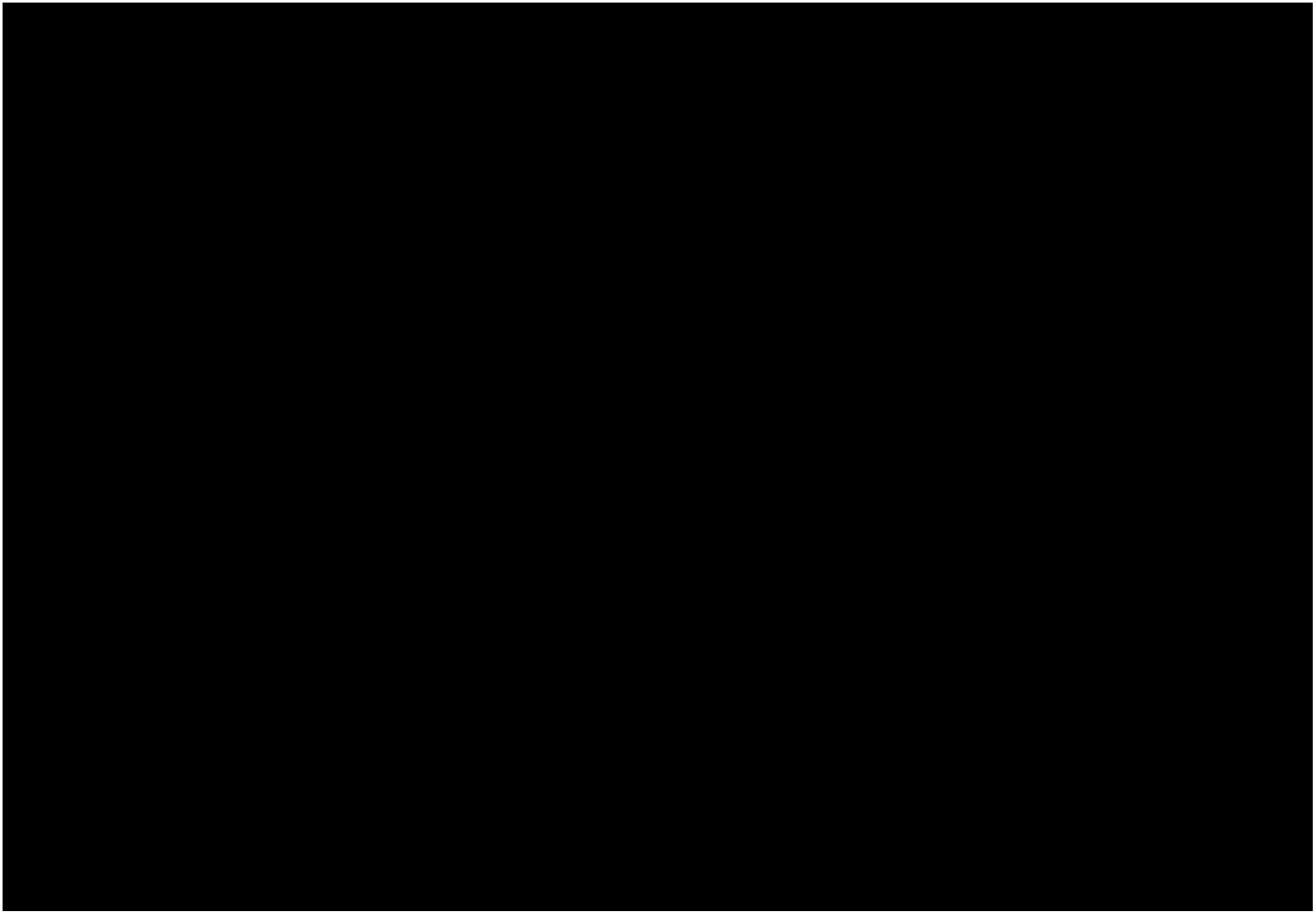
Annual Summer Coincident Peak
Midwest Electric Cooperative Corporation

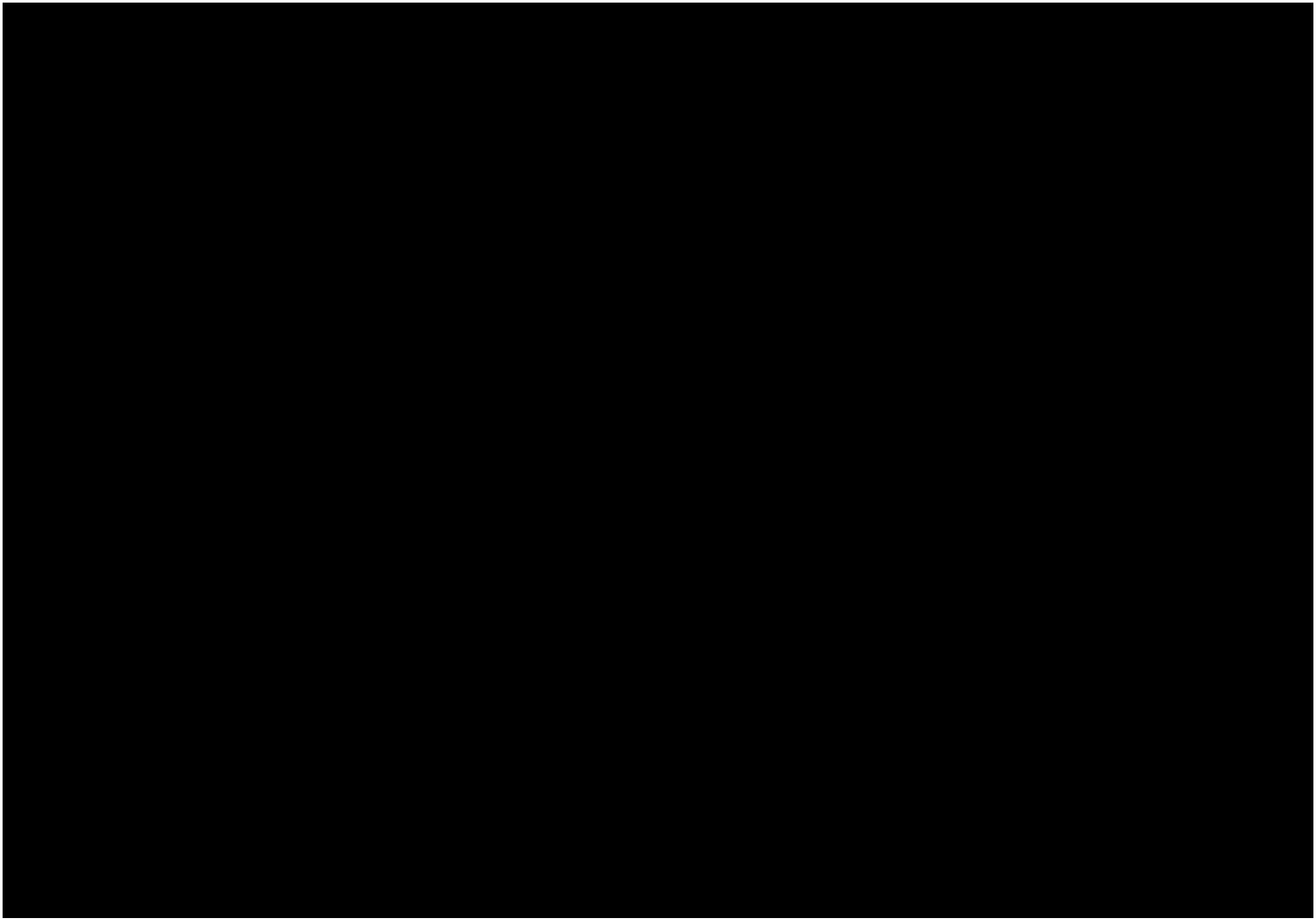


Annual Summer Coincident Peak

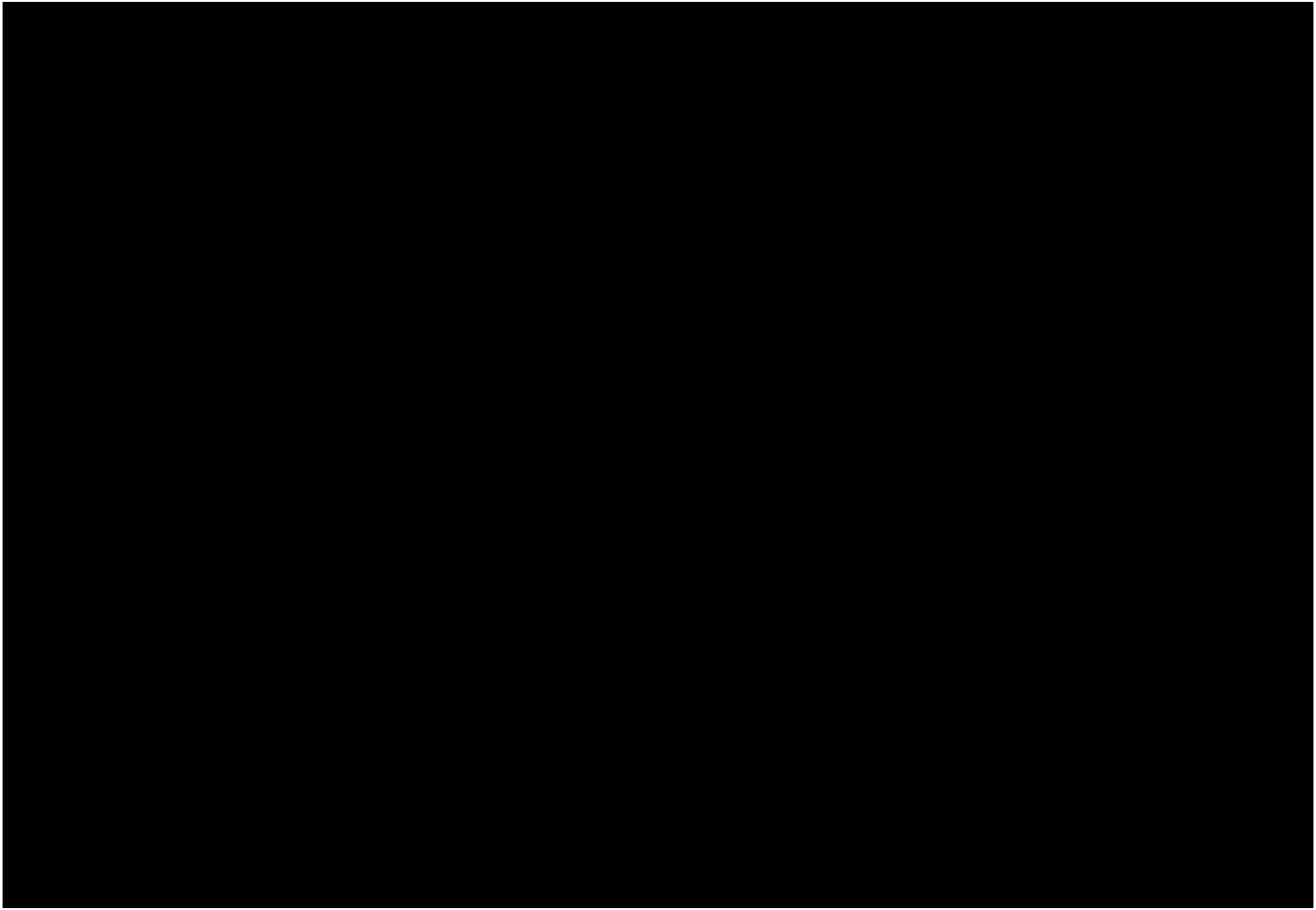
Niobrara Electric Association, Inc.



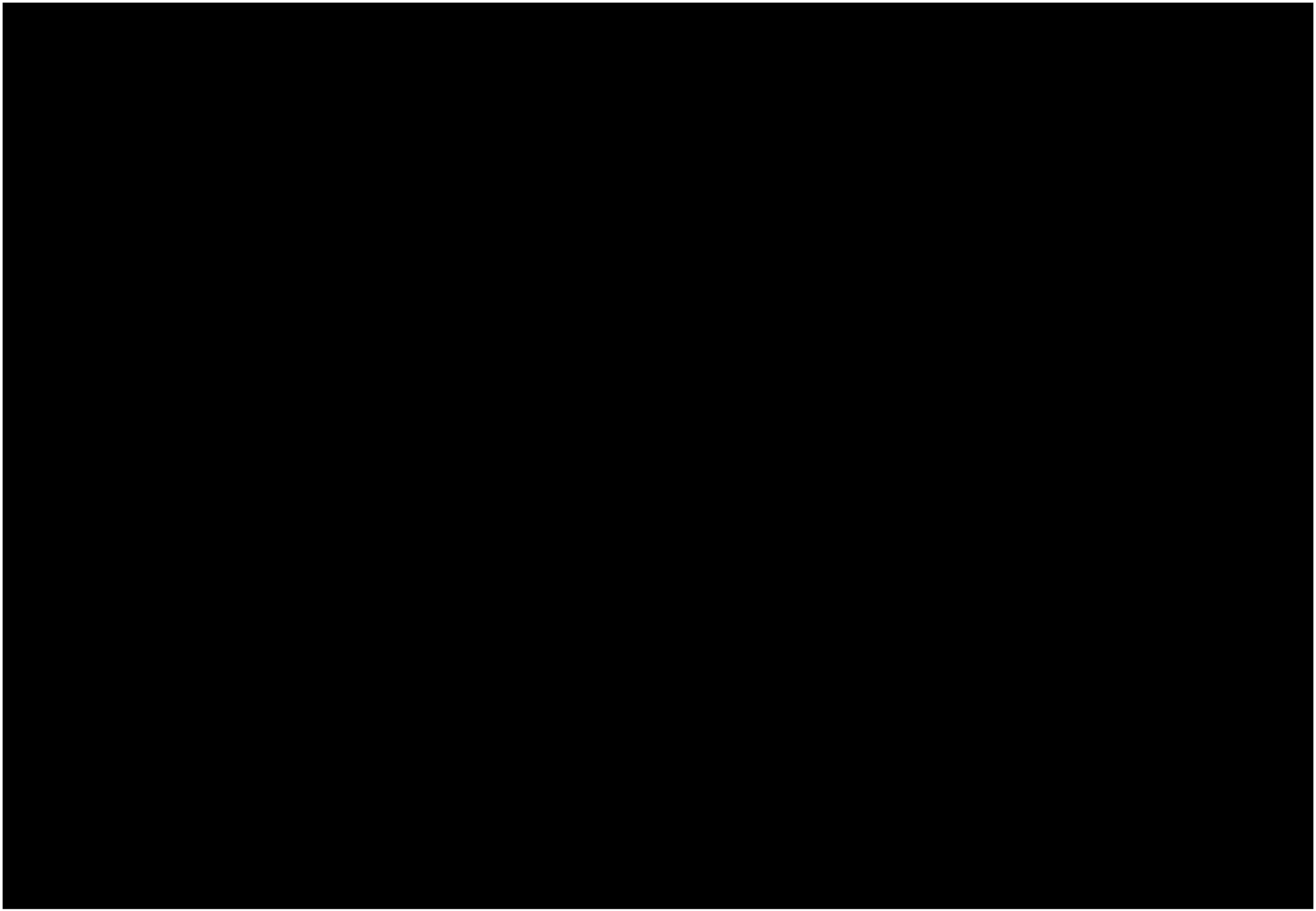
Annual Summer Coincident Peak
Northwest Rural Public Power District



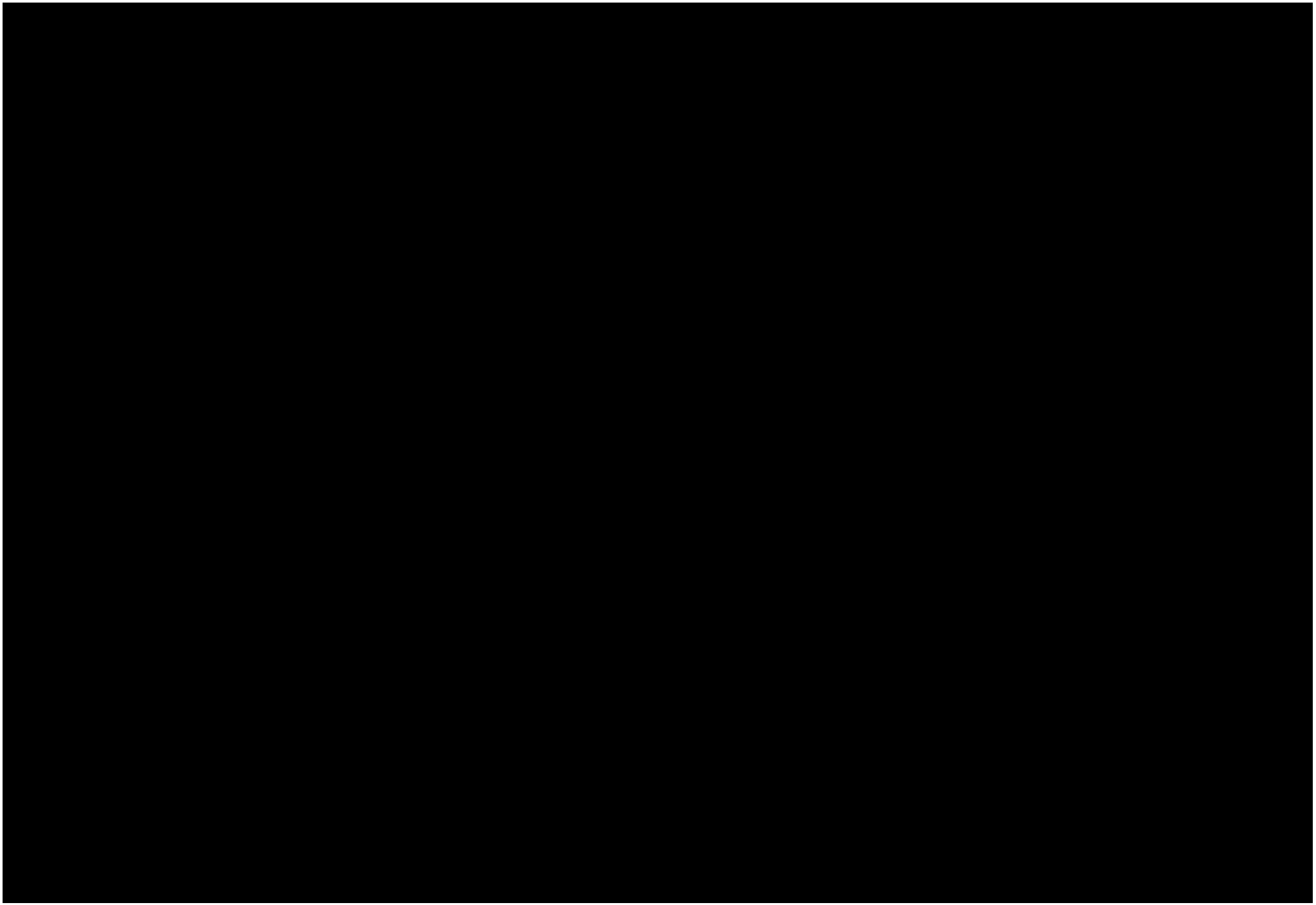
Annual Summer Coincident Peak
Otero County Electric Cooperative, Inc.



Annual Summer Coincident Peak
Panhandle Rural Electric Membership Association

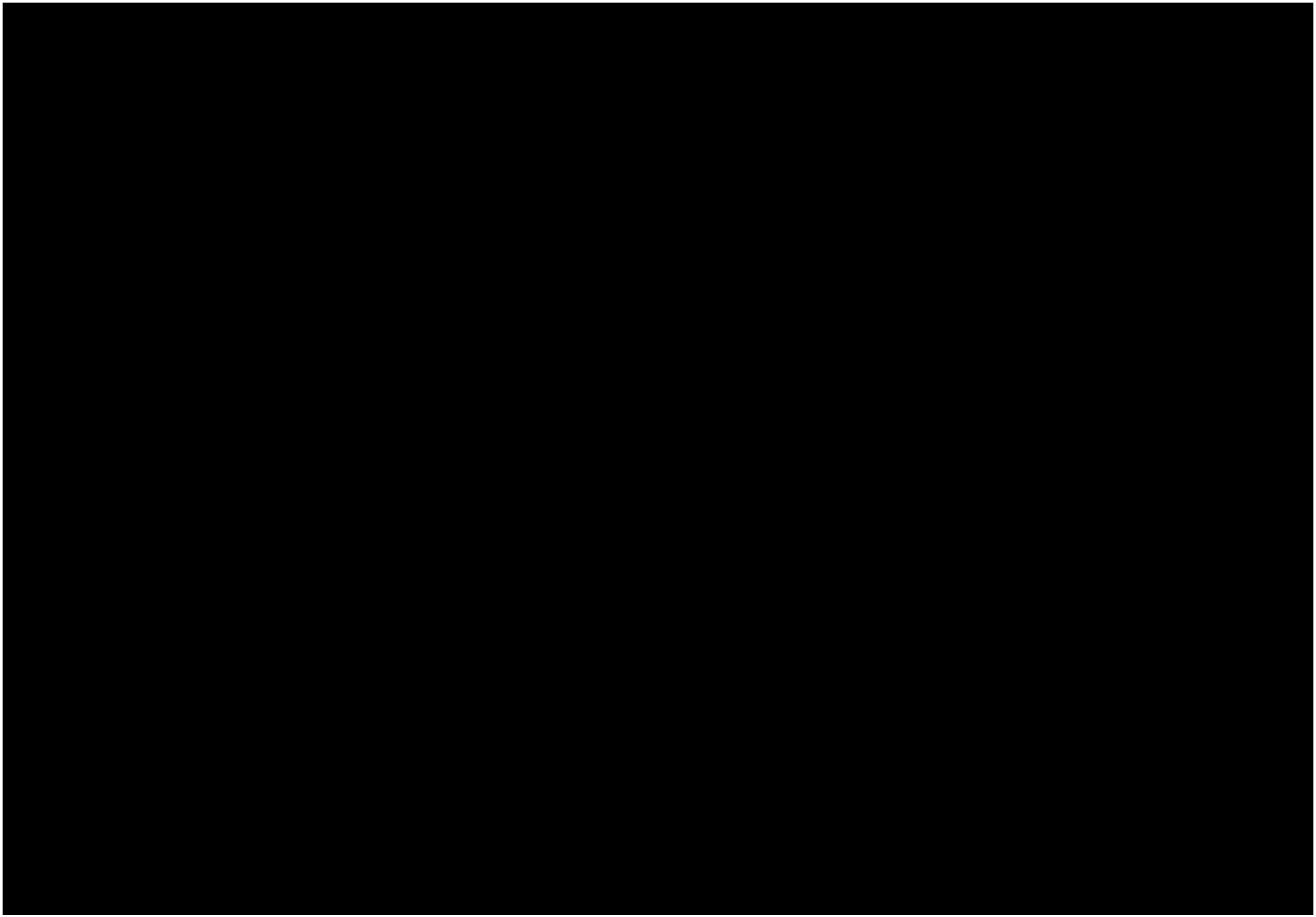


Annual Summer Coincident Peak
Poudre Valley Electric Association, Inc.

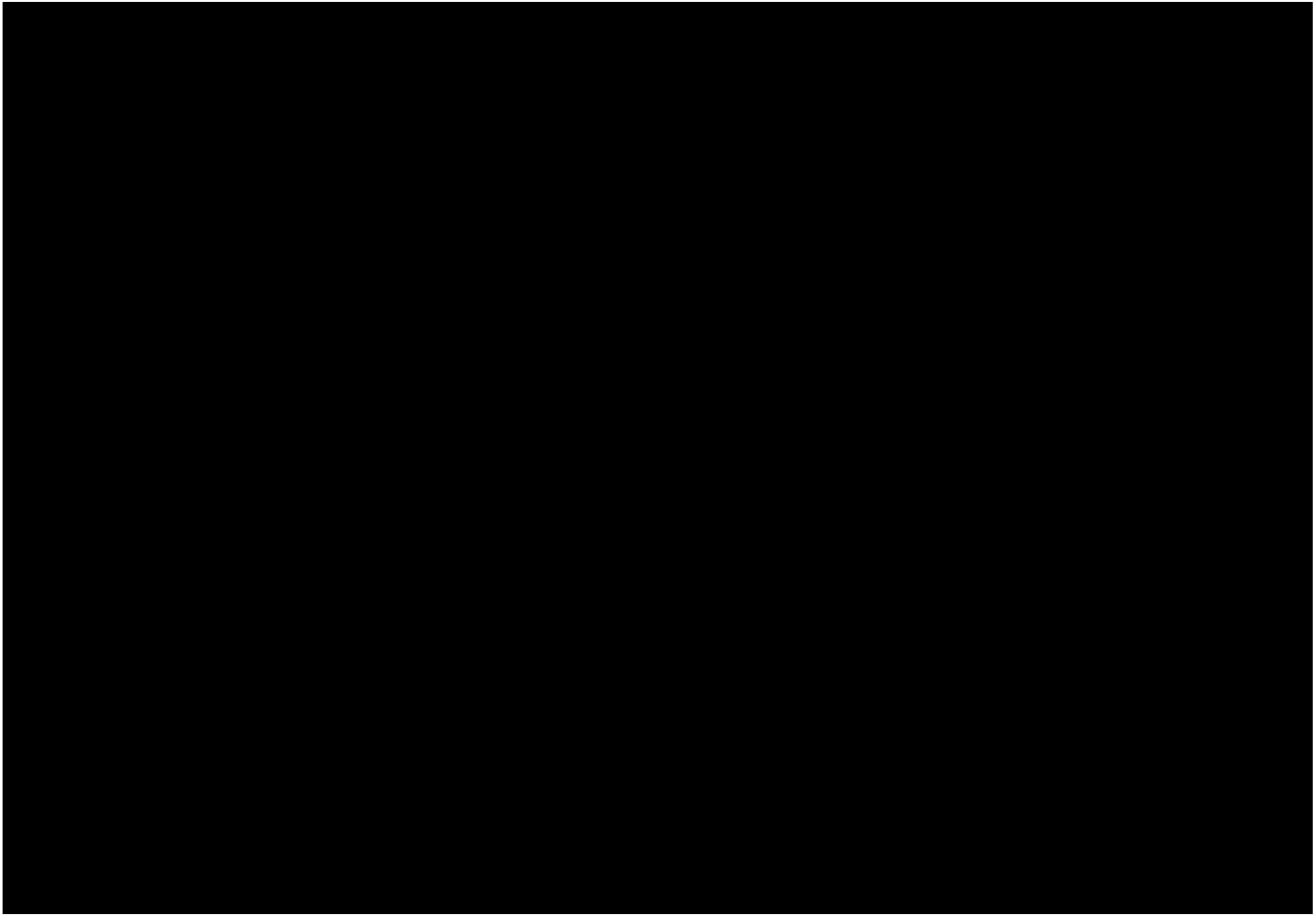


Annual Summer Coincident Peak

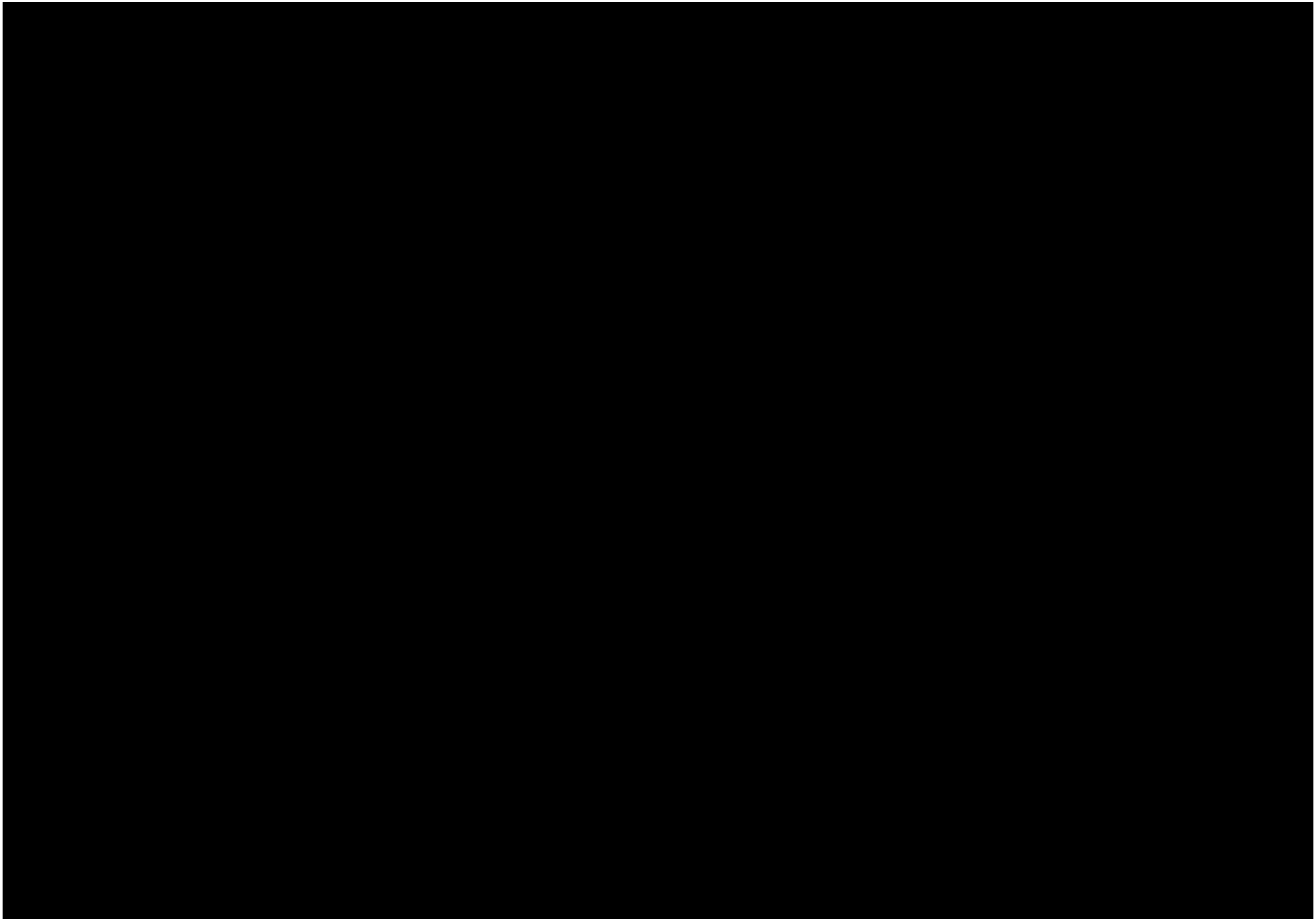
Northern Rio Arriba Electric Cooperative, Inc.



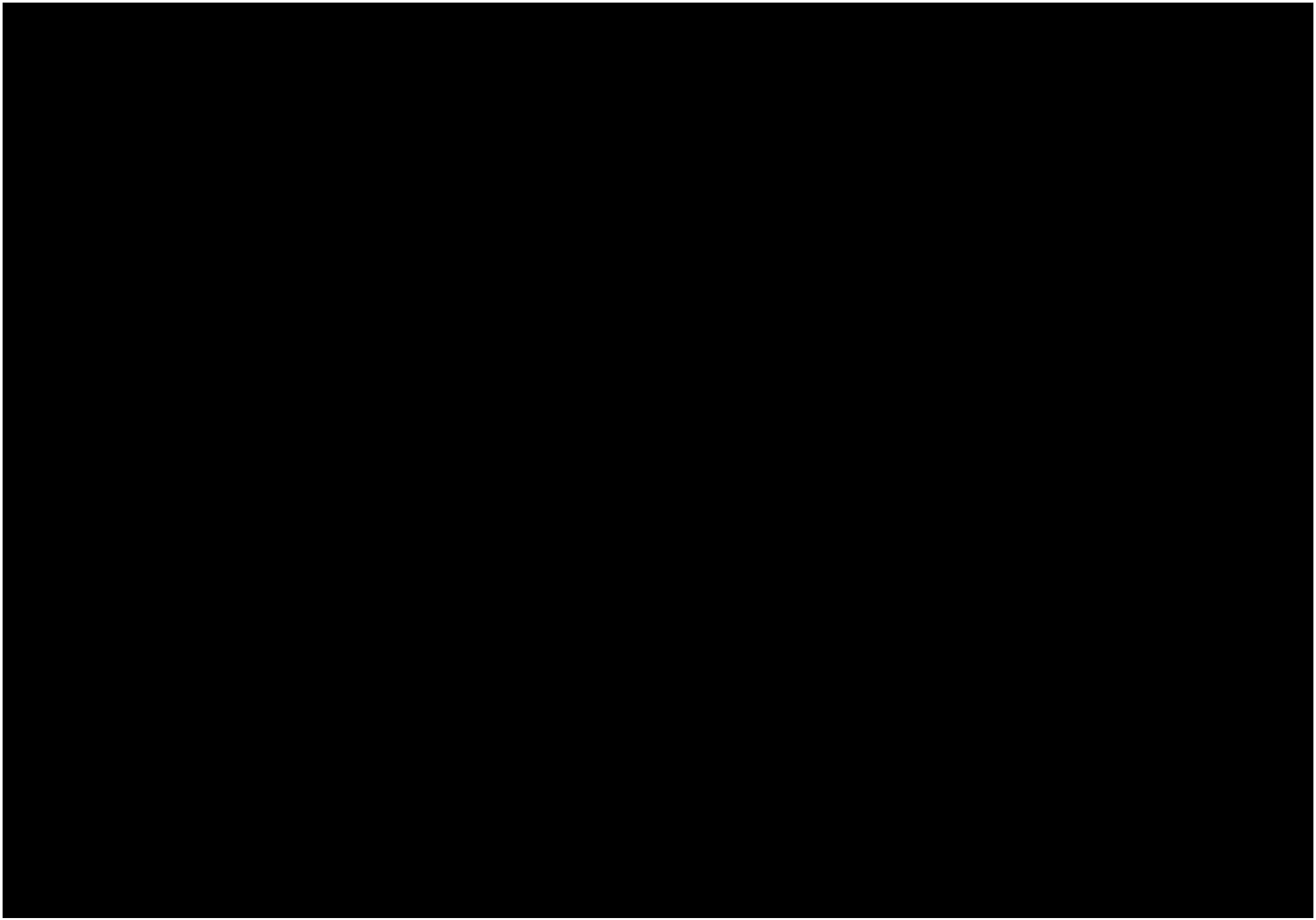
Annual Summer Coincident Peak
Roosevelt Public Power District



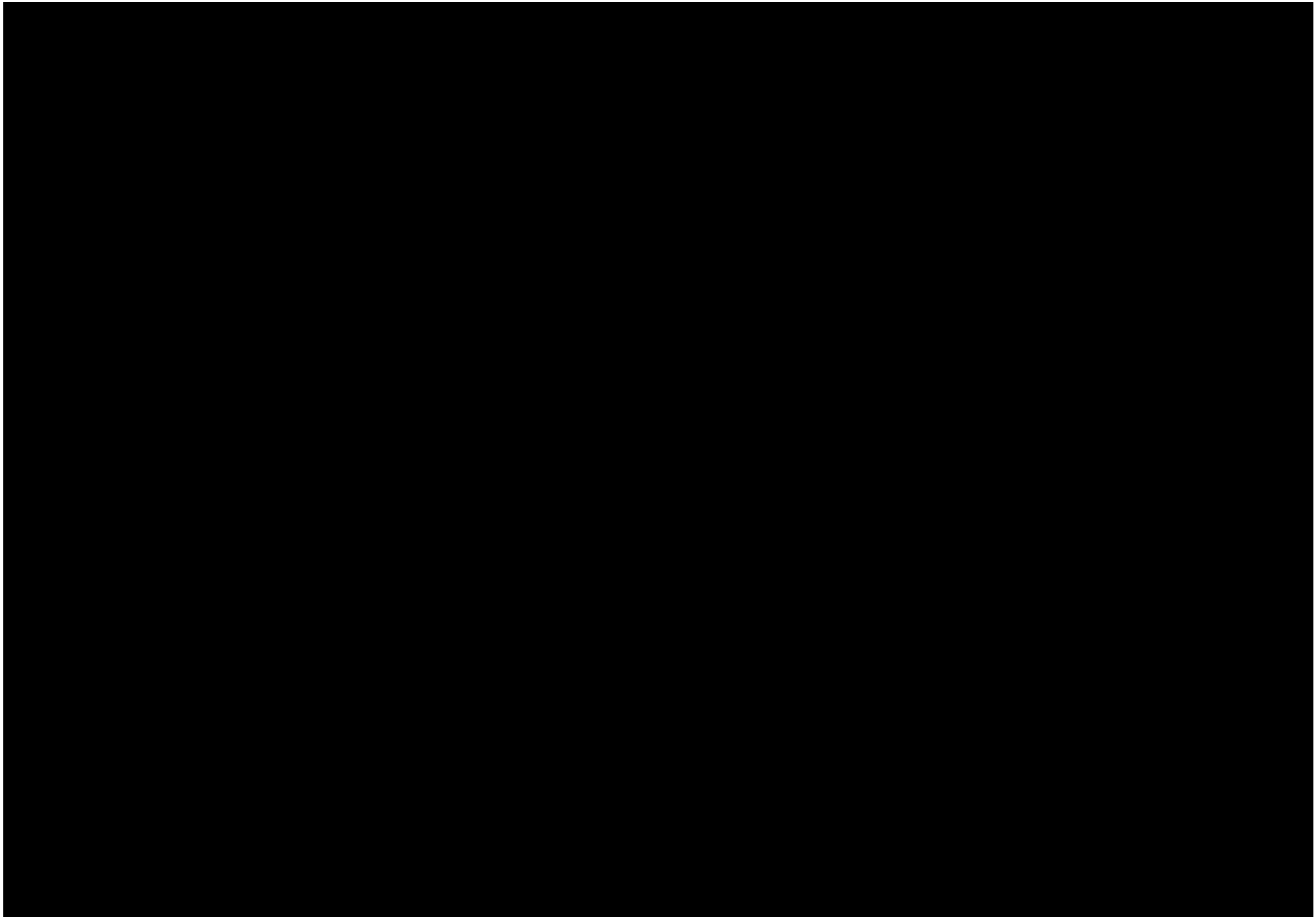
Annual Summer Coincident Peak
Sierra Electric Cooperative, Inc.



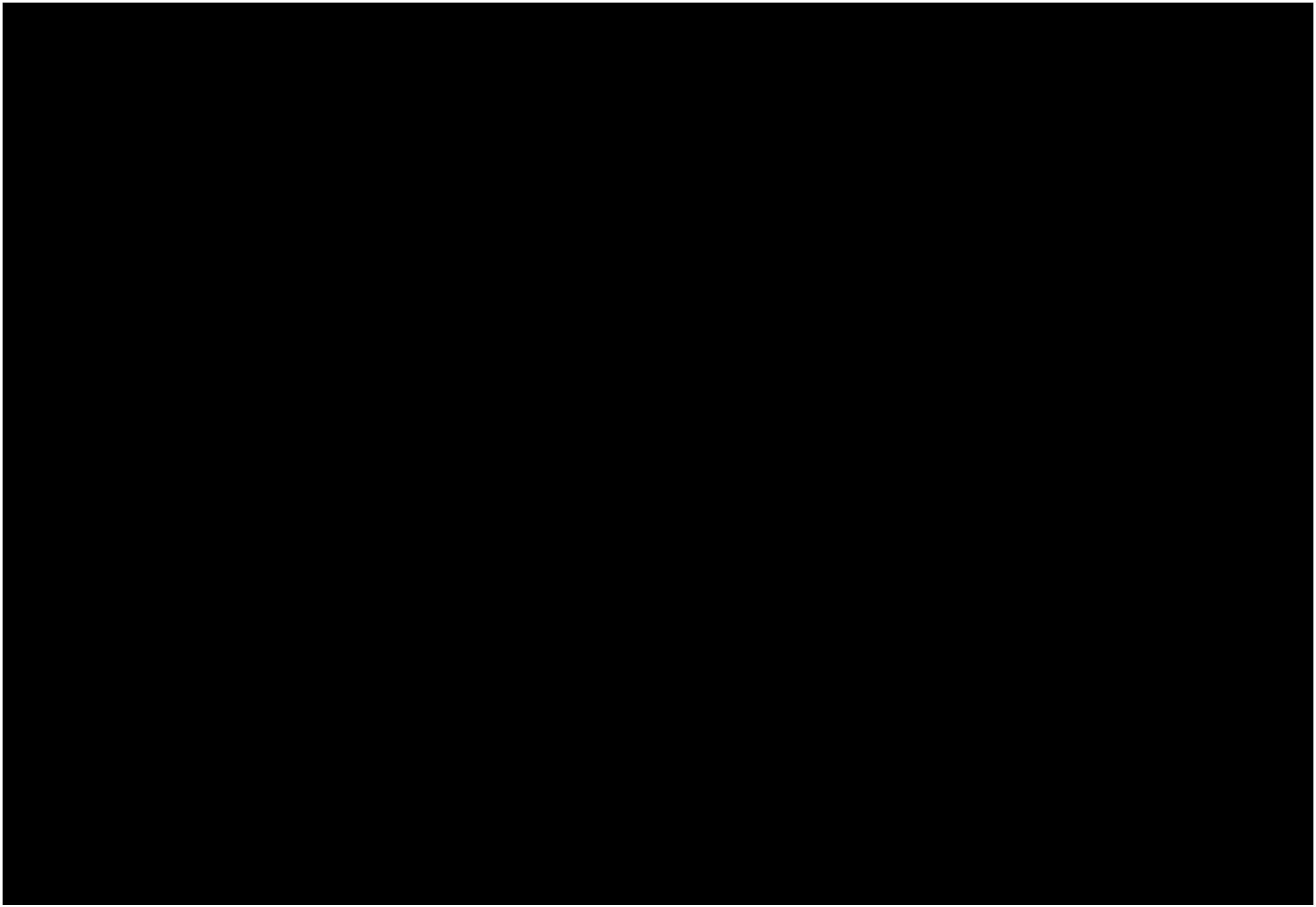
Annual Summer Coincident Peak
Sangre de Cristo Electric Association, Inc.



Annual Summer Coincident Peak
Southeast Colorado Power Association

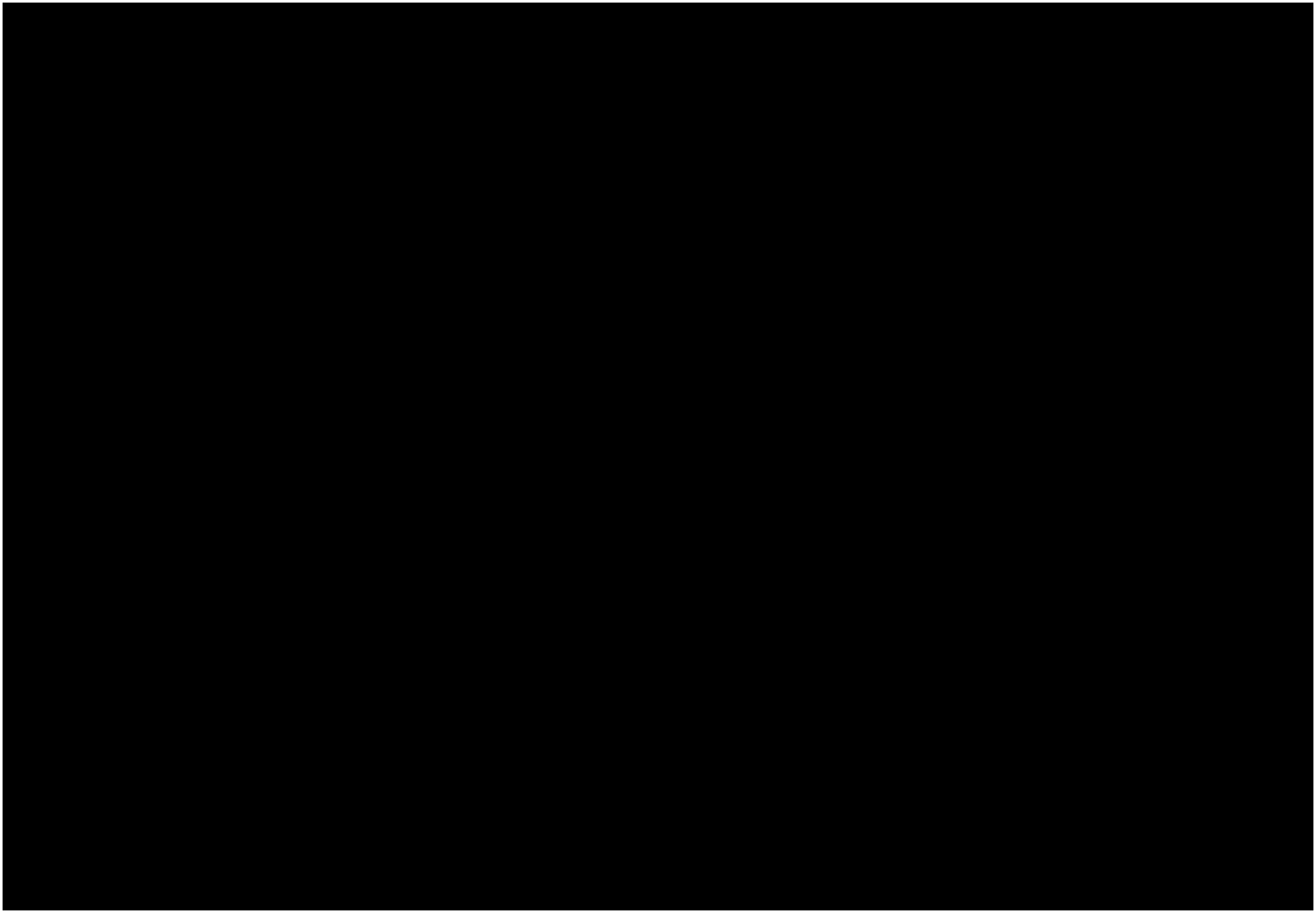


Annual Summer Coincident Peak
San Isabel Electric Association, Inc.



Annual Summer Coincident Peak

San Luis Valley Rural Electric Cooperative, Inc.



Annual Summer Coincident Peak

San Miguel Power Association, Inc.

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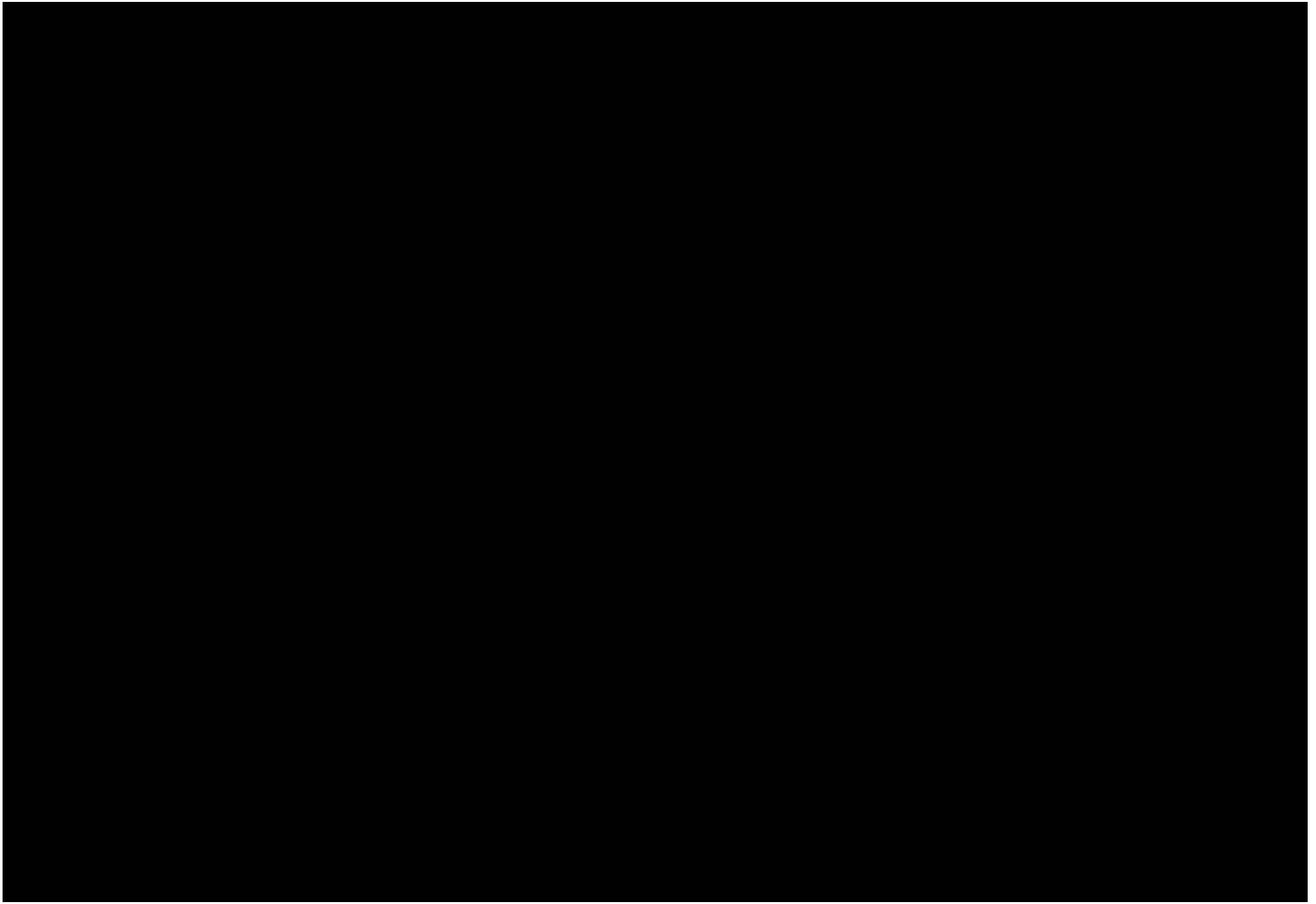
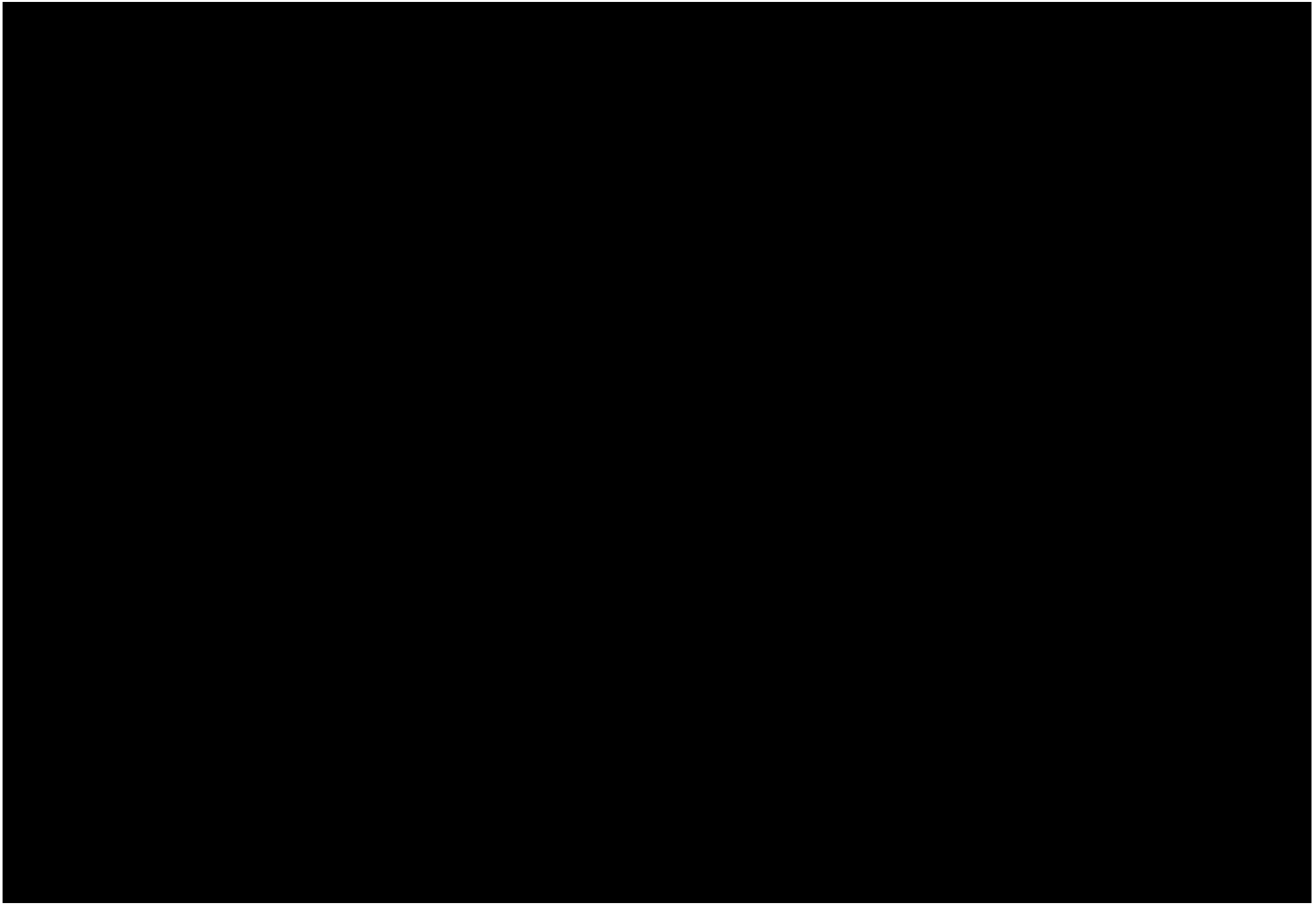
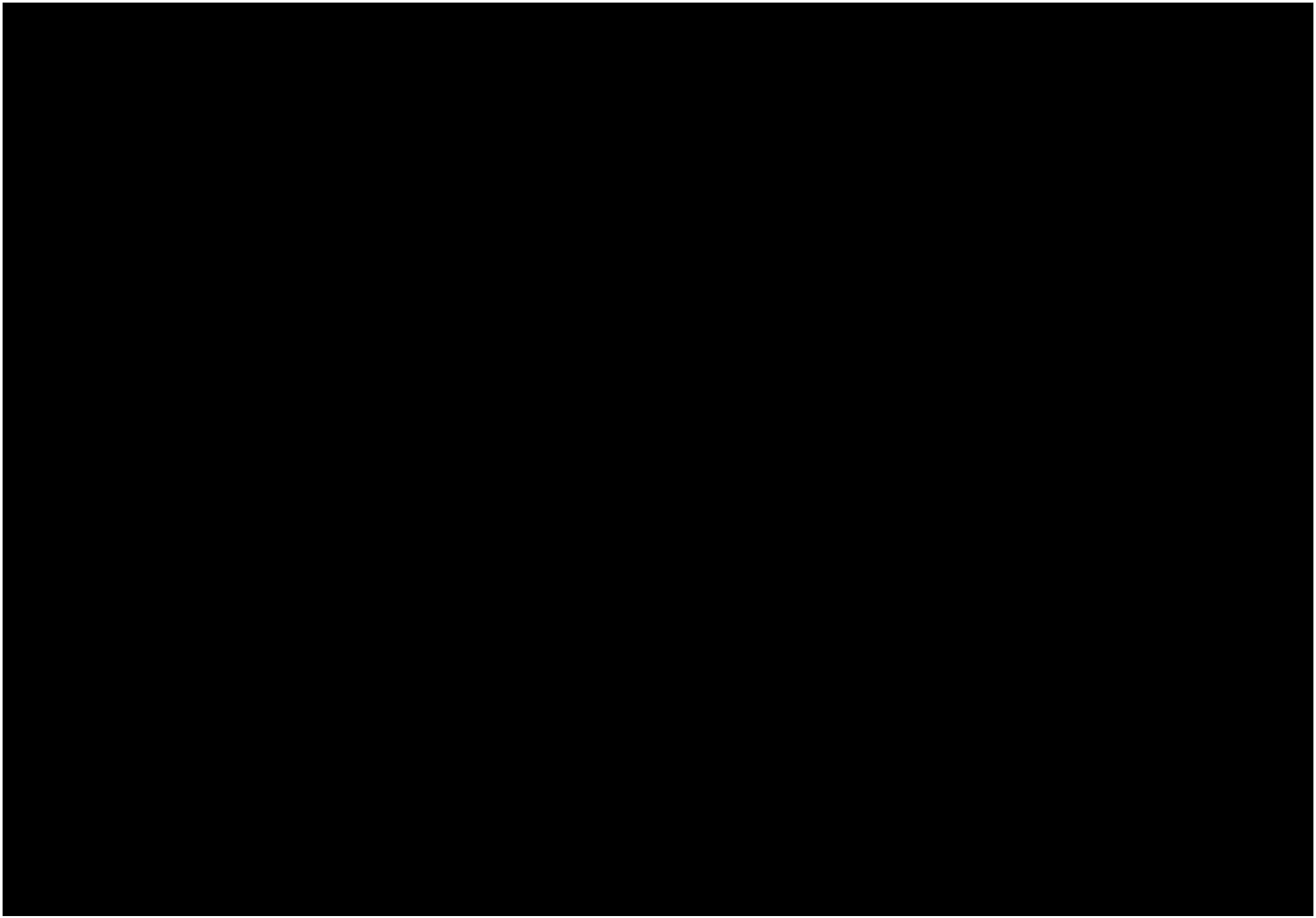
Annual Summer Coincident Peak
Socorro Electric Cooperative, Inc.



Annual Summer Coincident Peak
Springer Electric Cooperative, Inc.

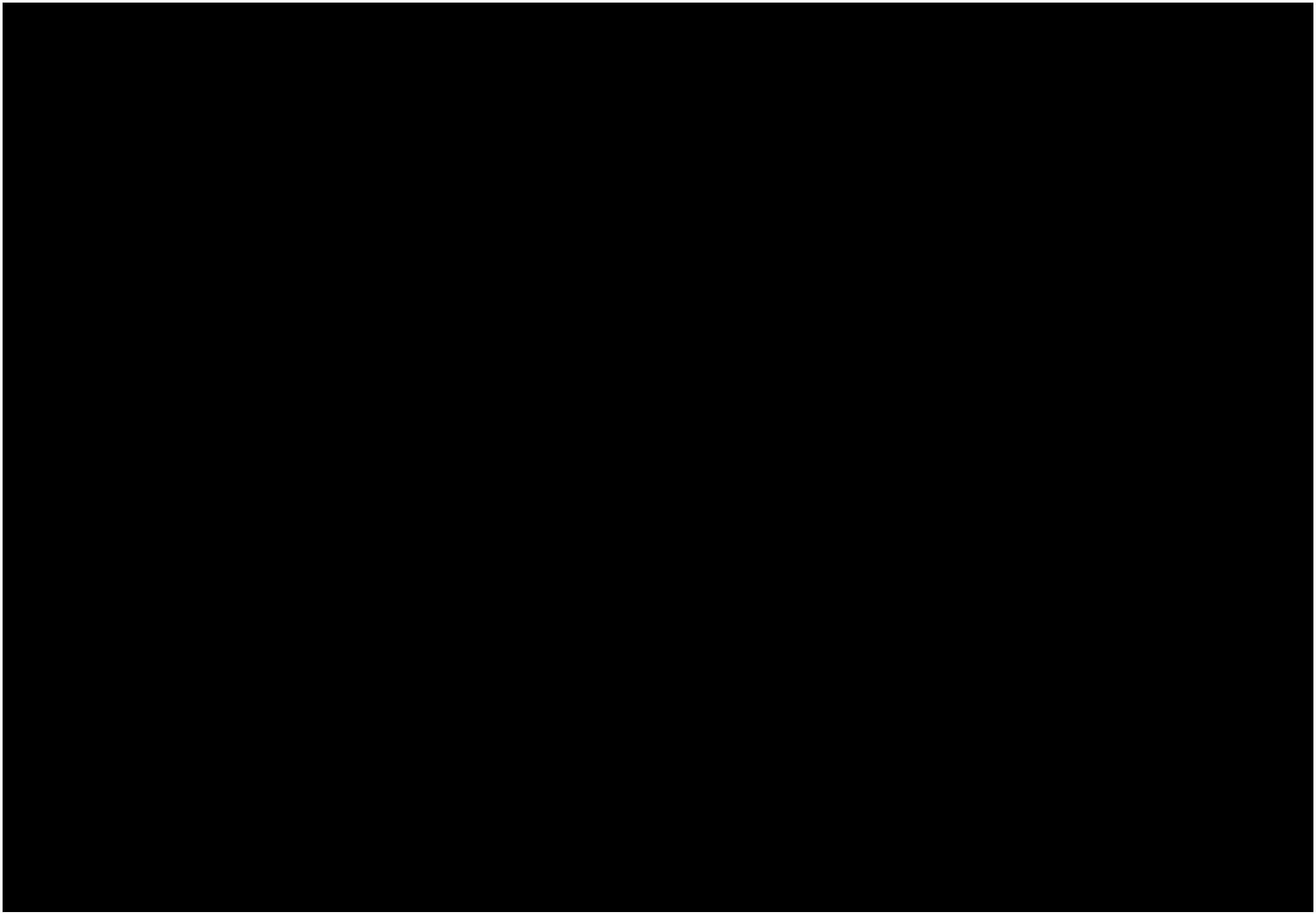


Annual Summer Coincident Peak
Southwestern Electric Cooperative, Inc.



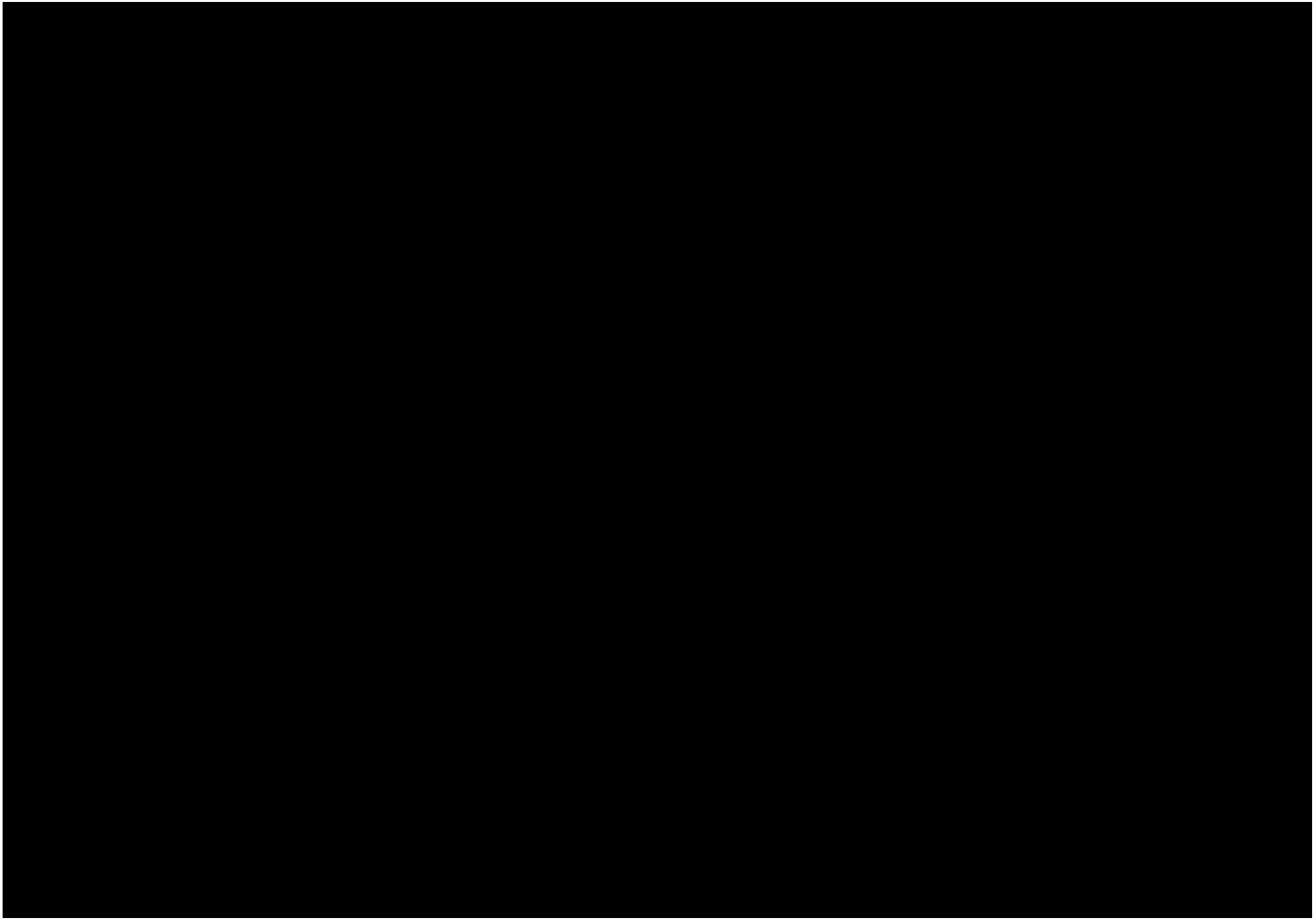
Annual Summer Coincident Peak

United Power, Inc.



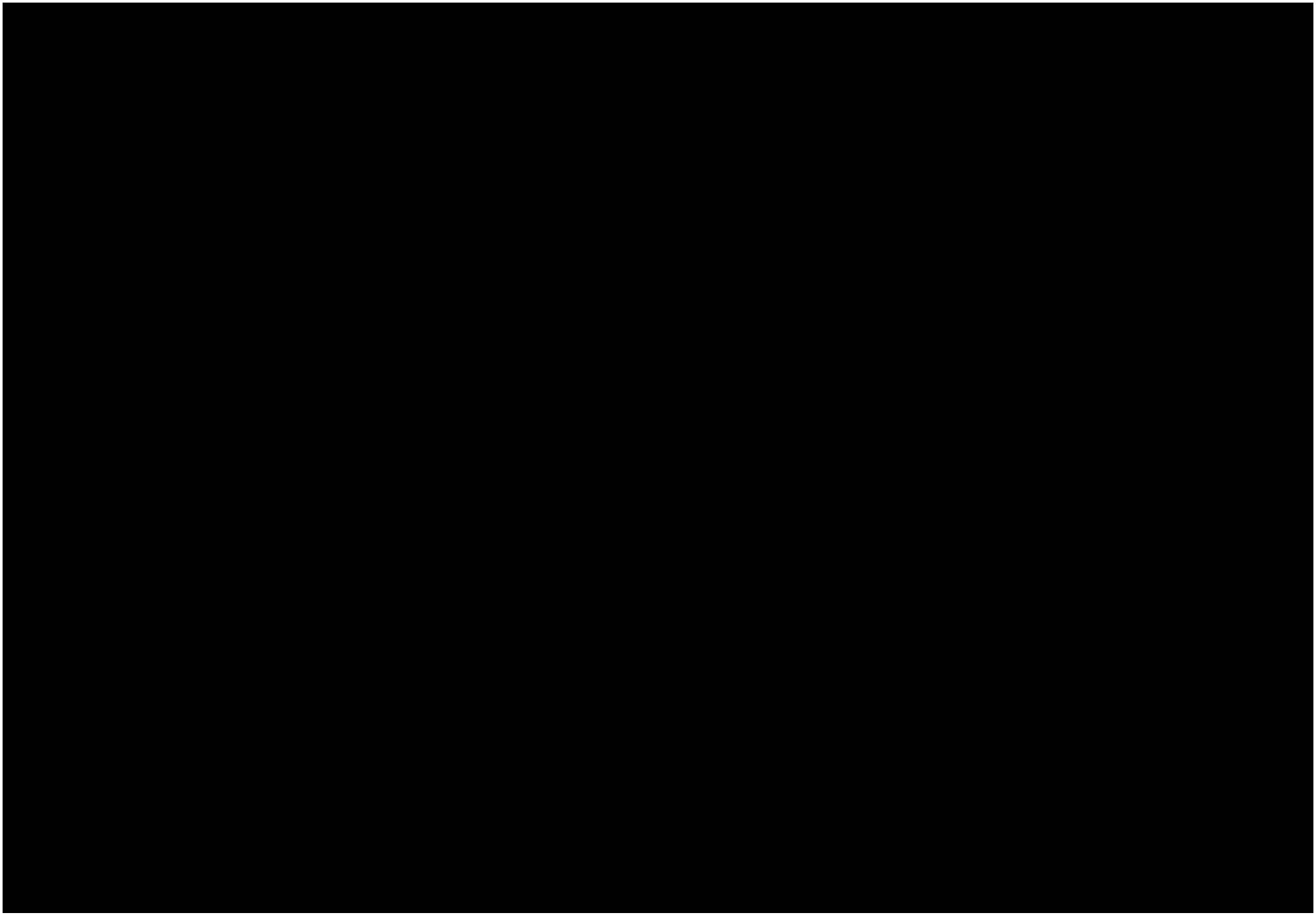
Annual Summer Coincident Peak

Wheat Belt Public Power District



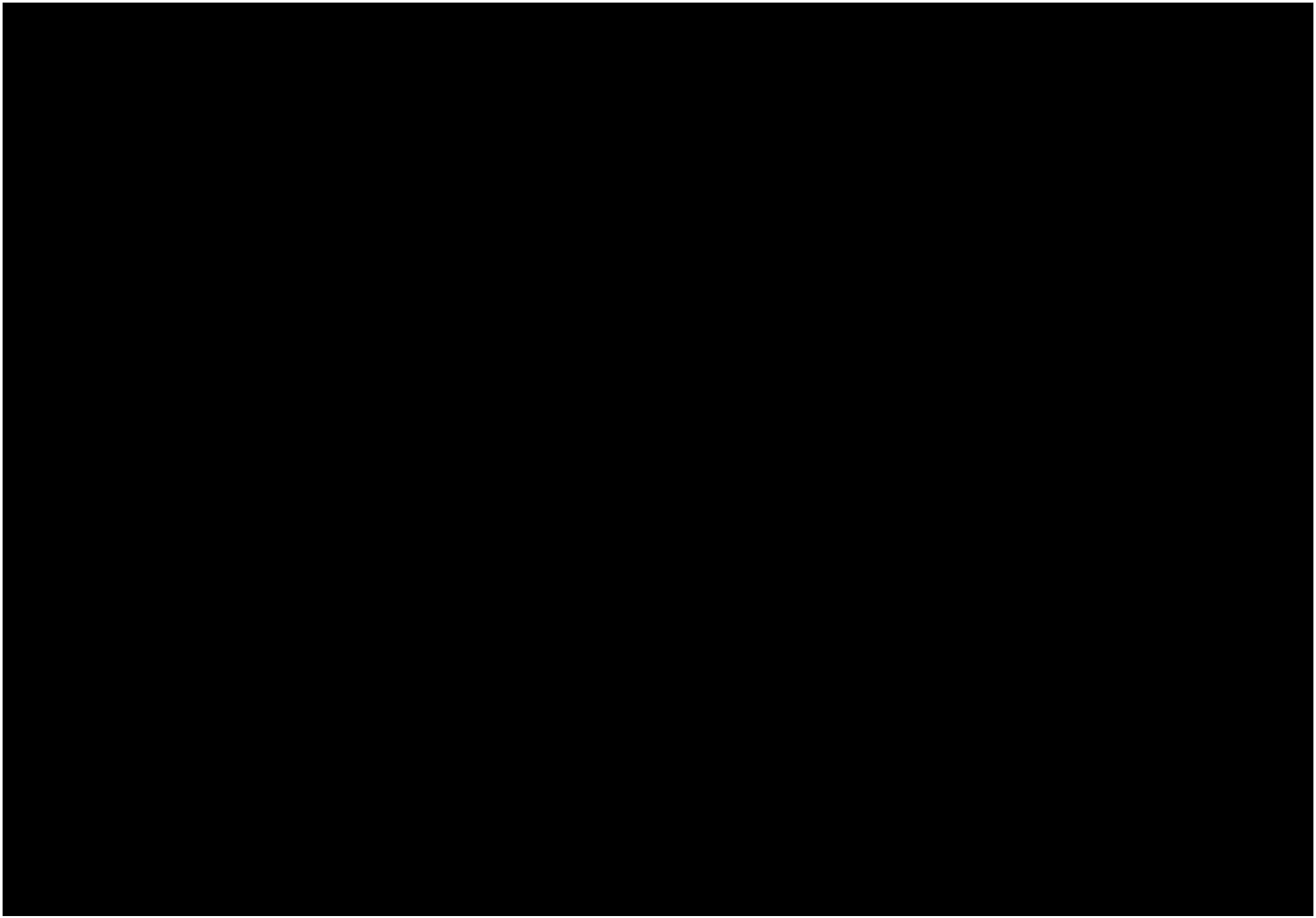
Annual Summer Coincident Peak

Wheatland Rural Electric Association, Inc.

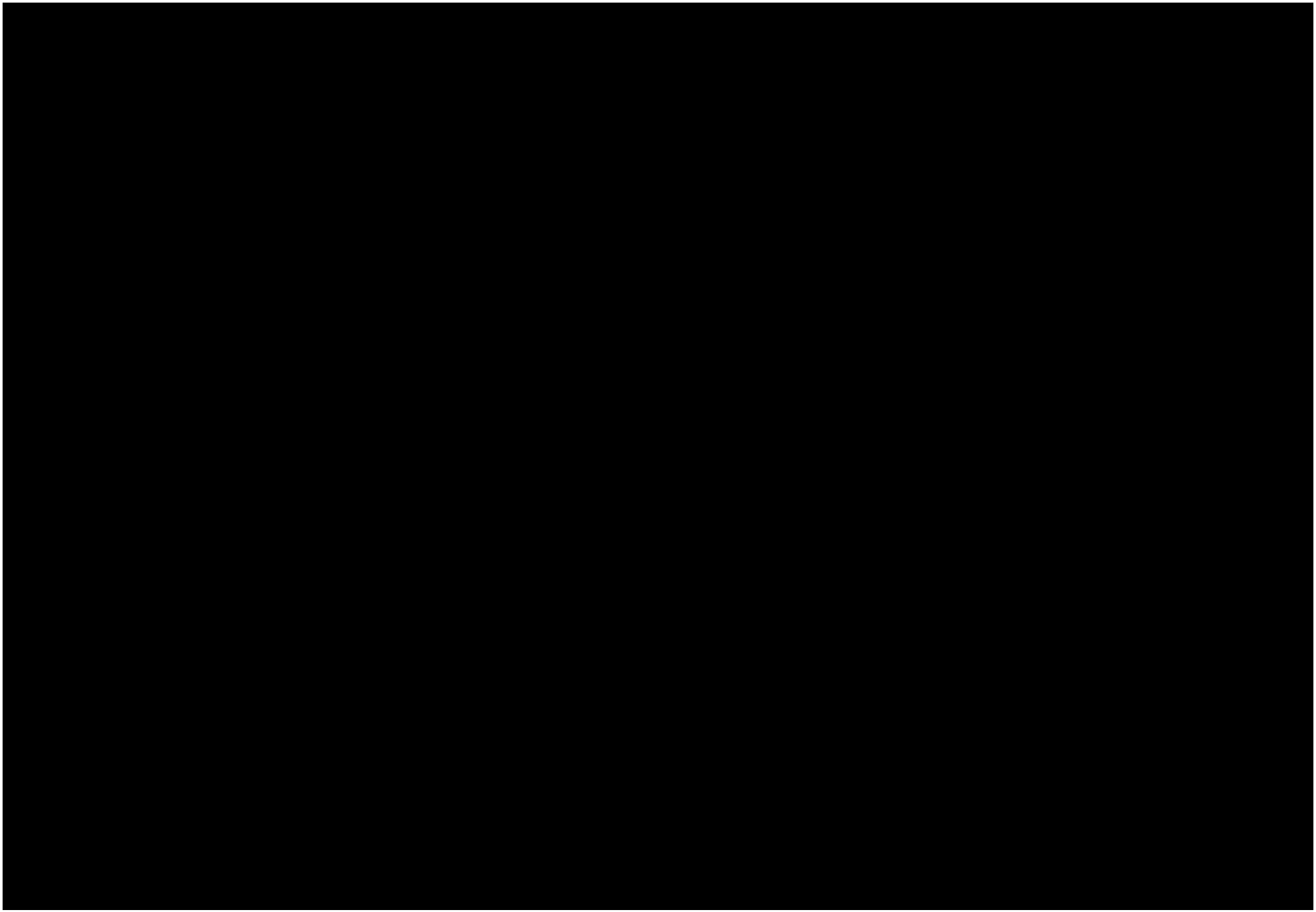


Annual Summer Coincident Peak

White River Electric Association, Inc.



Annual Summer Coincident Peak
Wyrulec Company



Annual Summer Coincident Peak
Y-W Electric Association, Inc.

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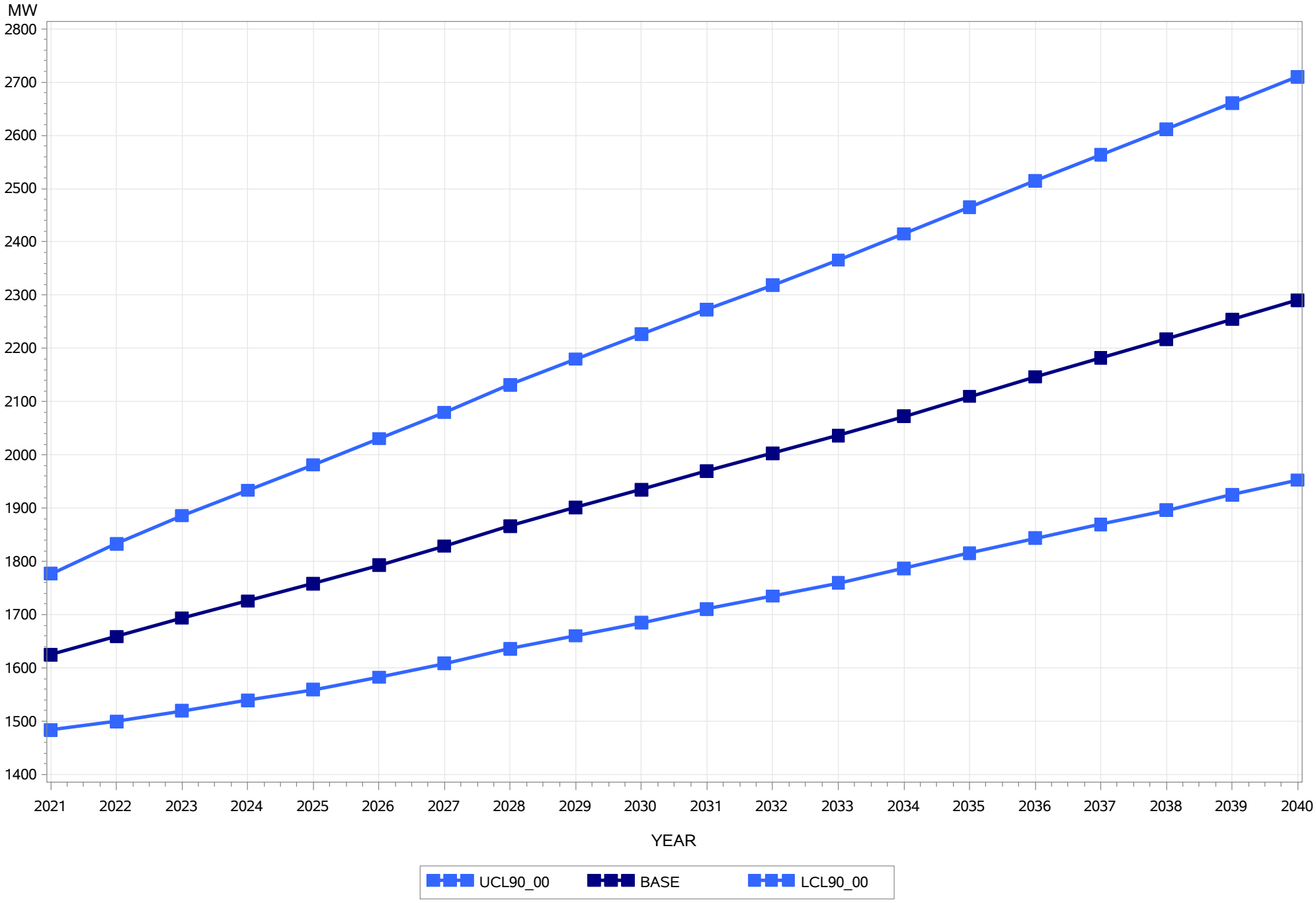
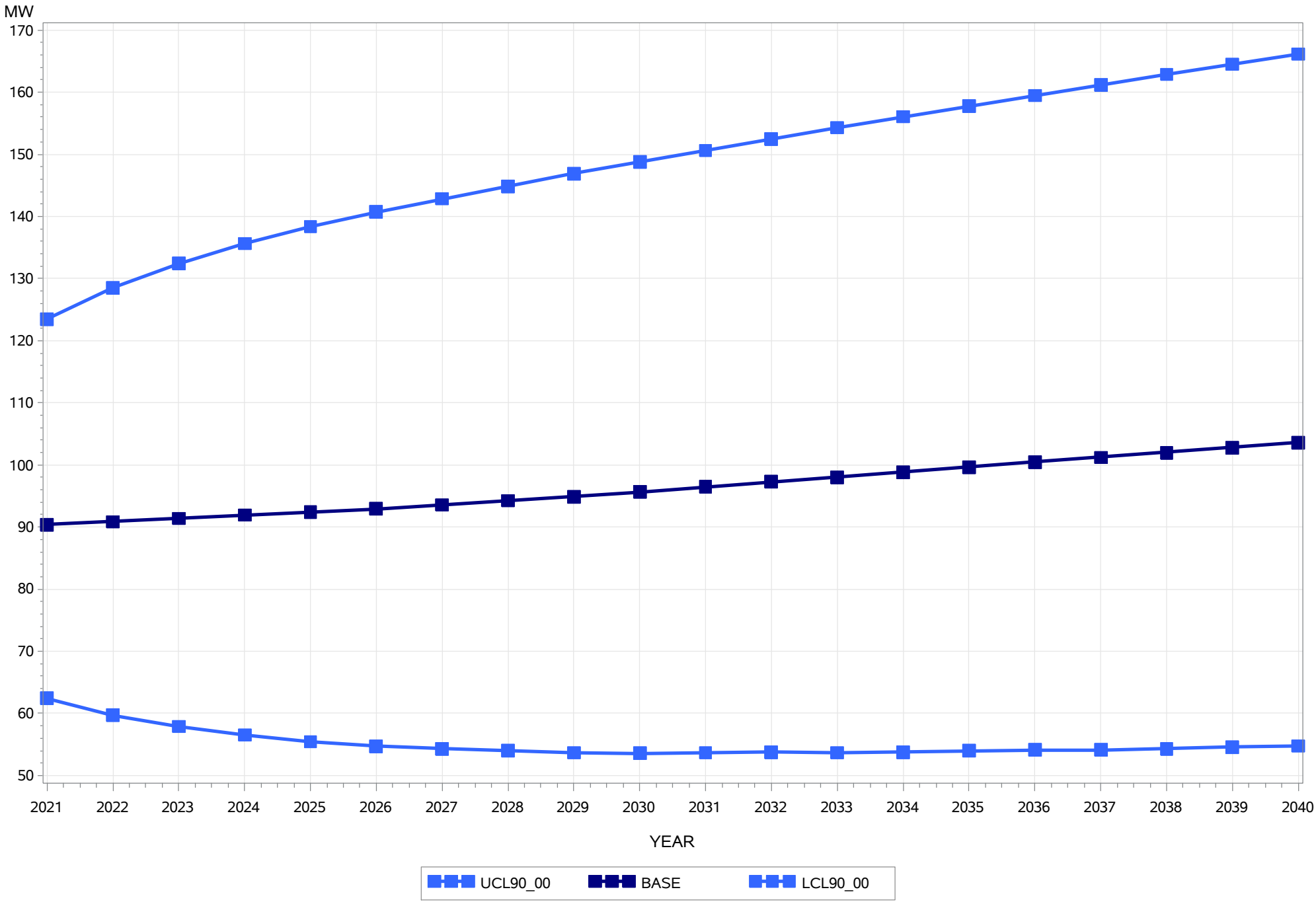
Annual Winter Coincident Peak
STATE OF COLORADO



Annual Winter Coincident Peak
STATE OF NEBRASKA



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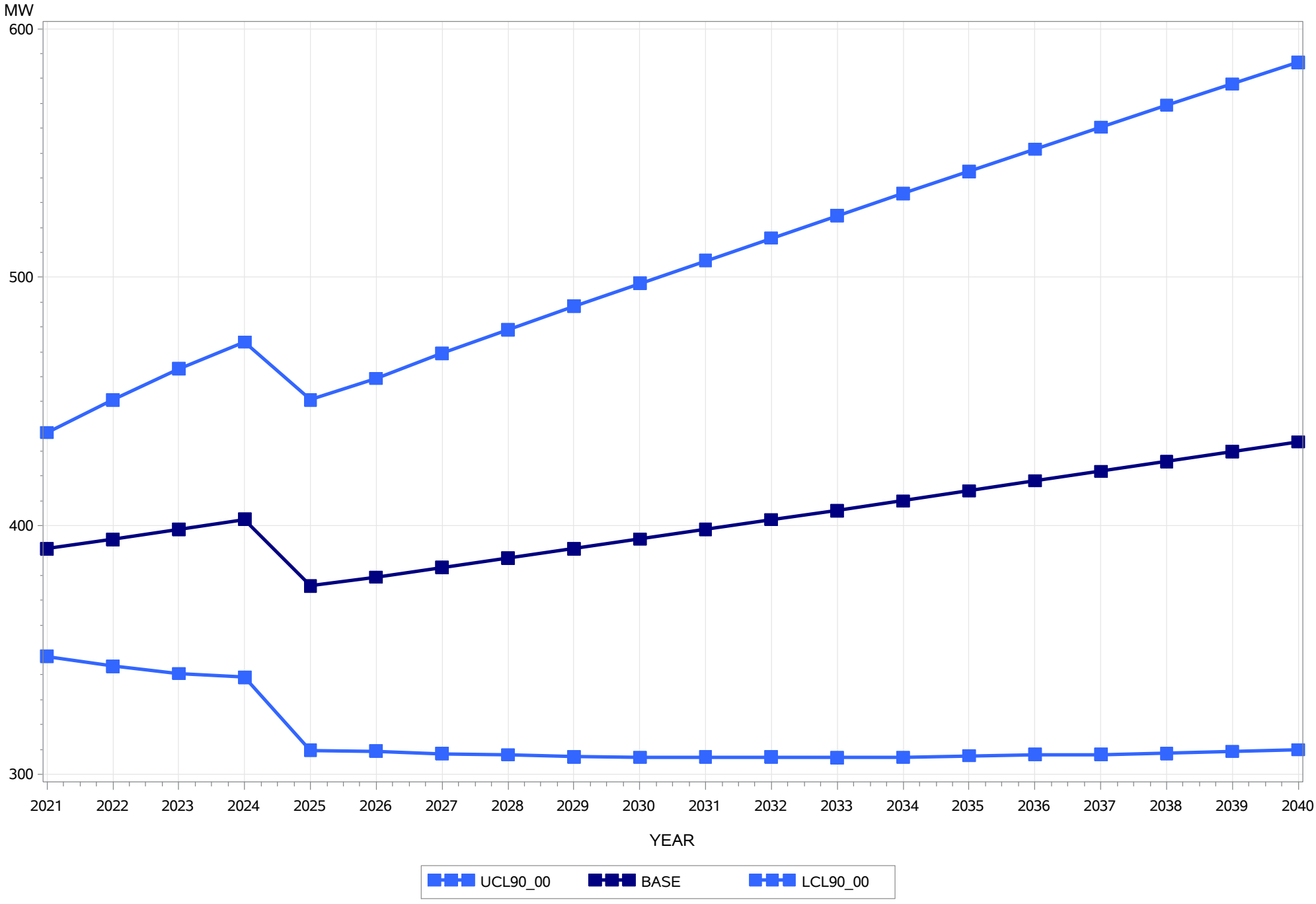
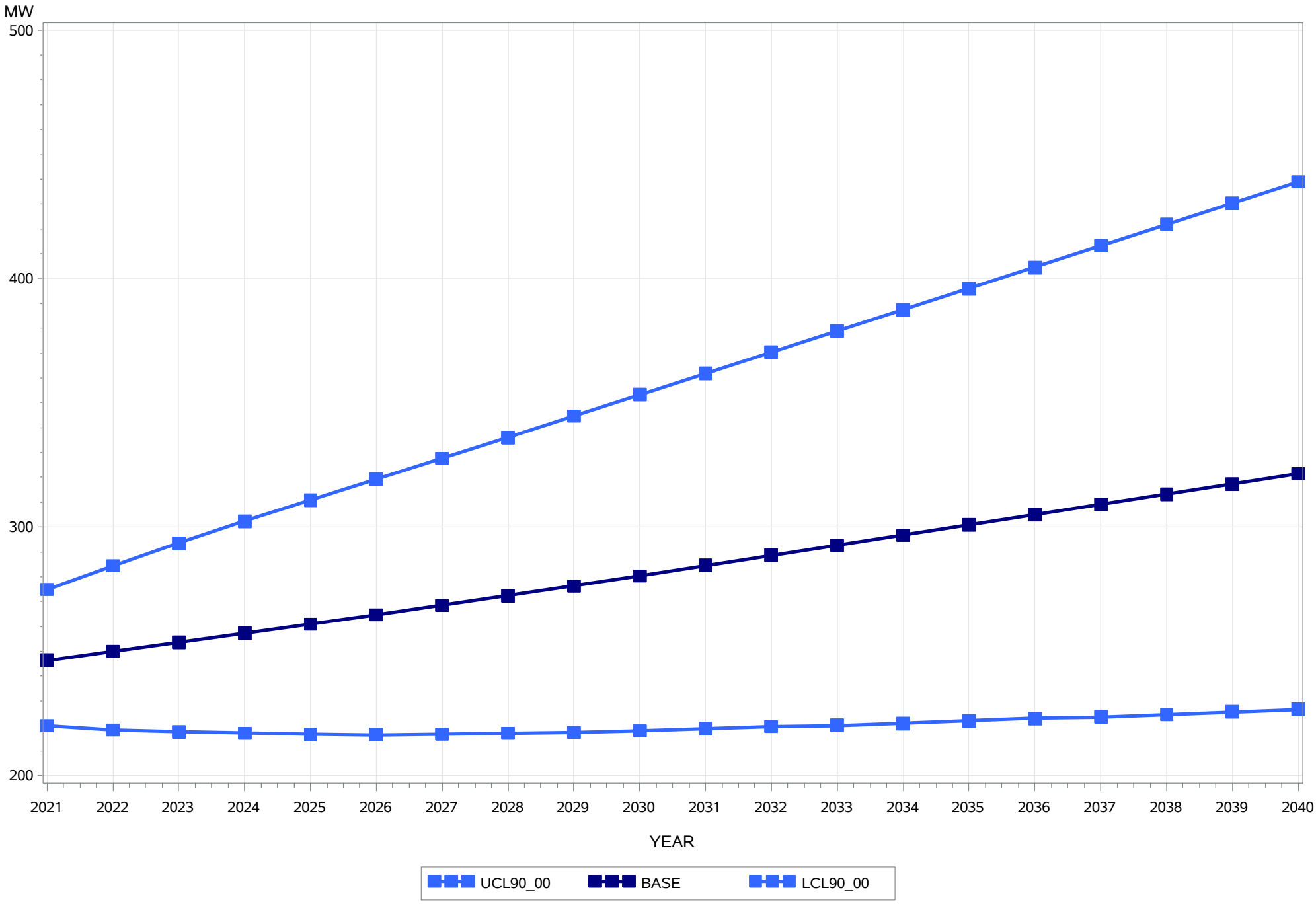
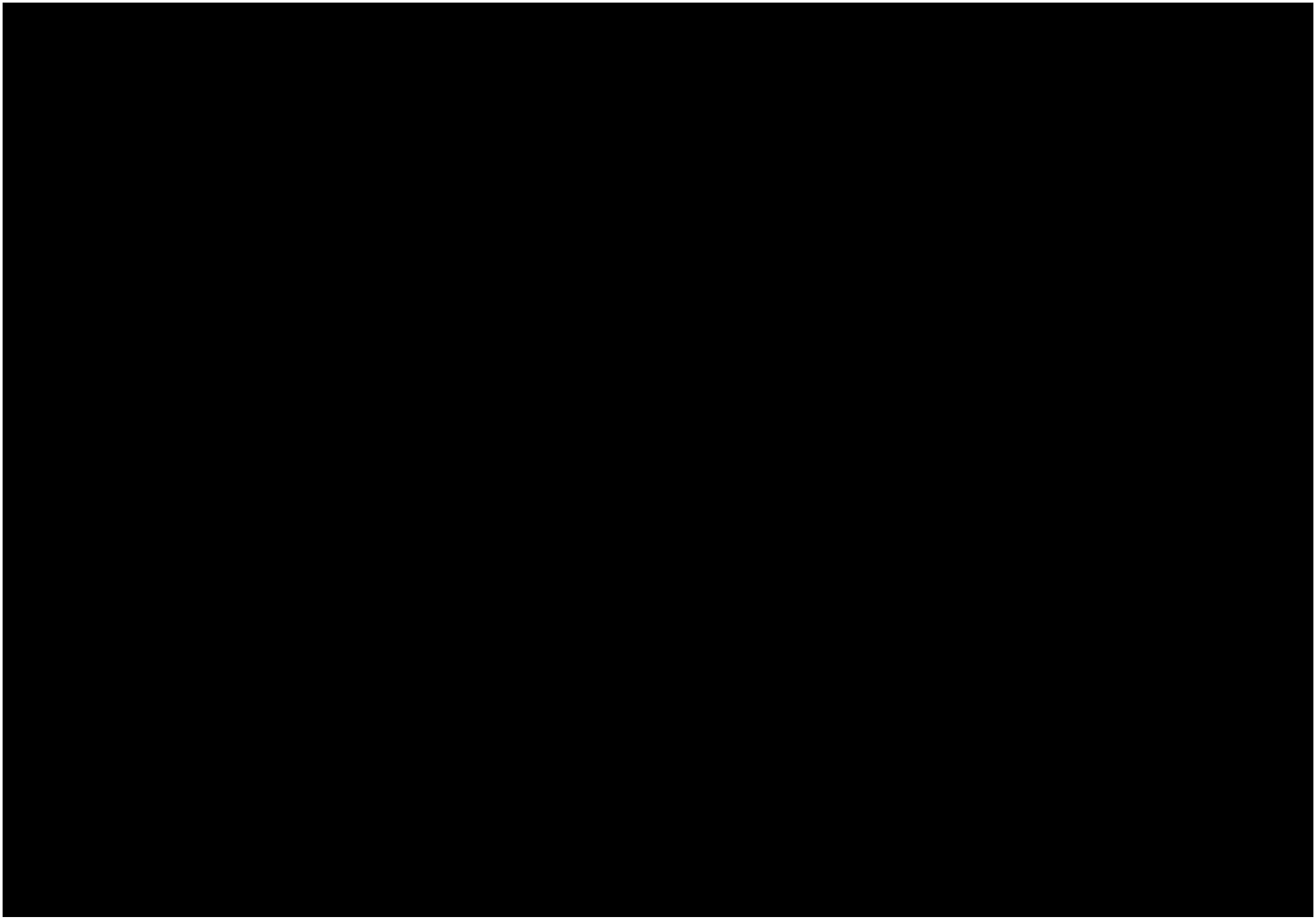
Annual Winter Coincident Peak
STATE OF NEW MEXICO



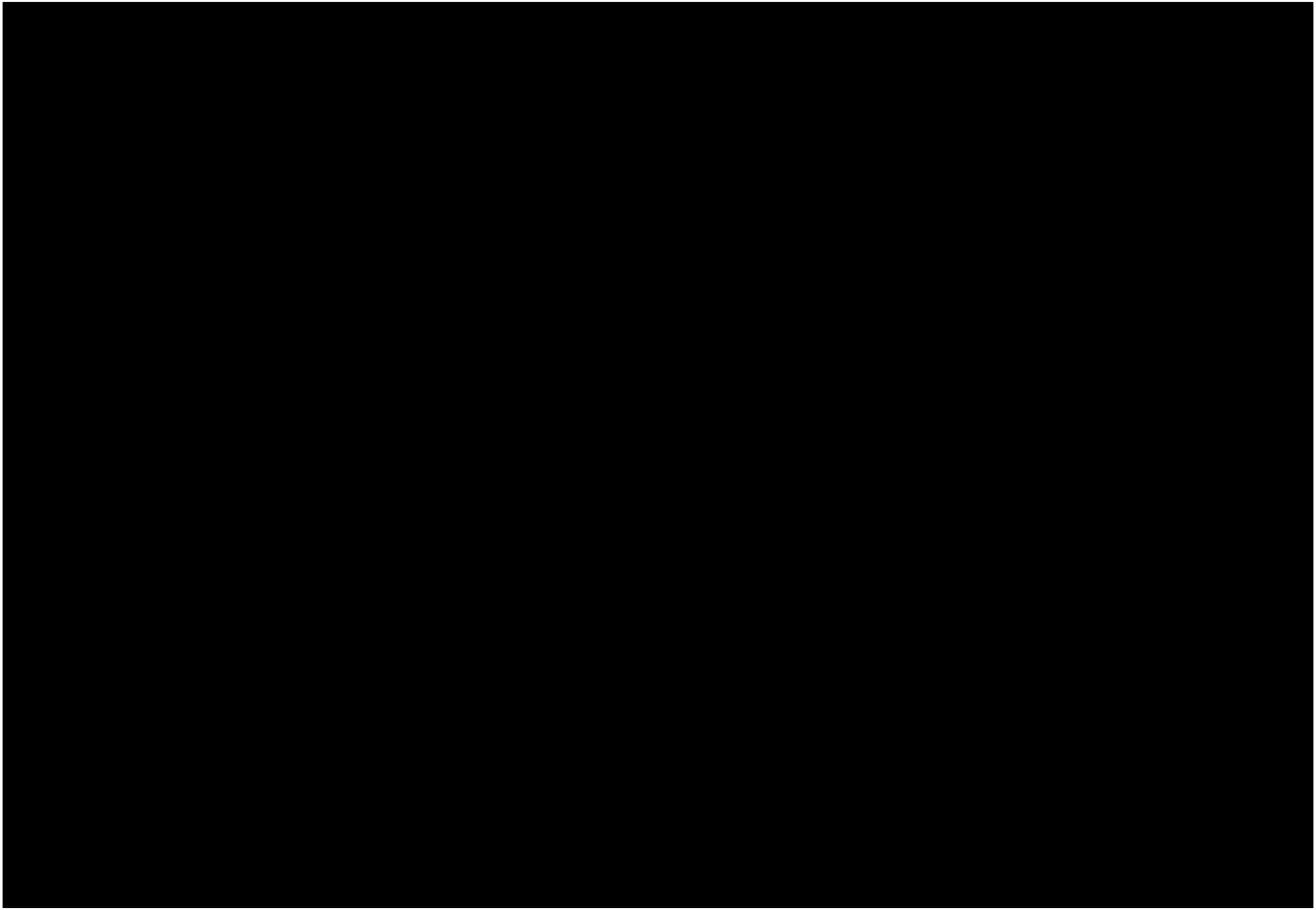
Annual Winter Coincident Peak
STATE OF WYOMING



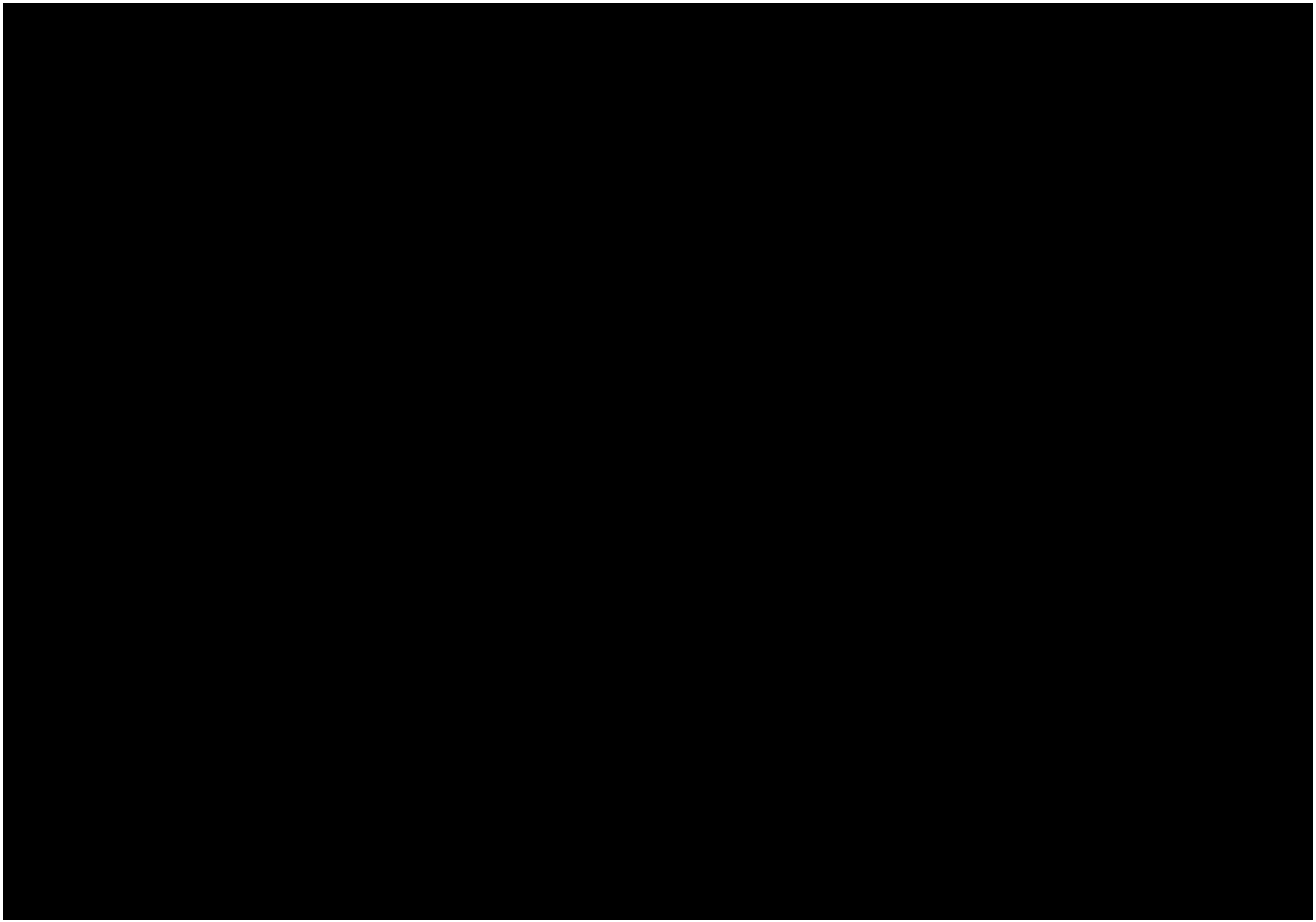
Annual Winter Coincident Peak
Big Horn Rural Electric Company



Annual Winter Coincident Peak
Carbon Power and Light, Inc.



Annual Winter Coincident Peak
Continental Divide Electric Cooperative, Inc.



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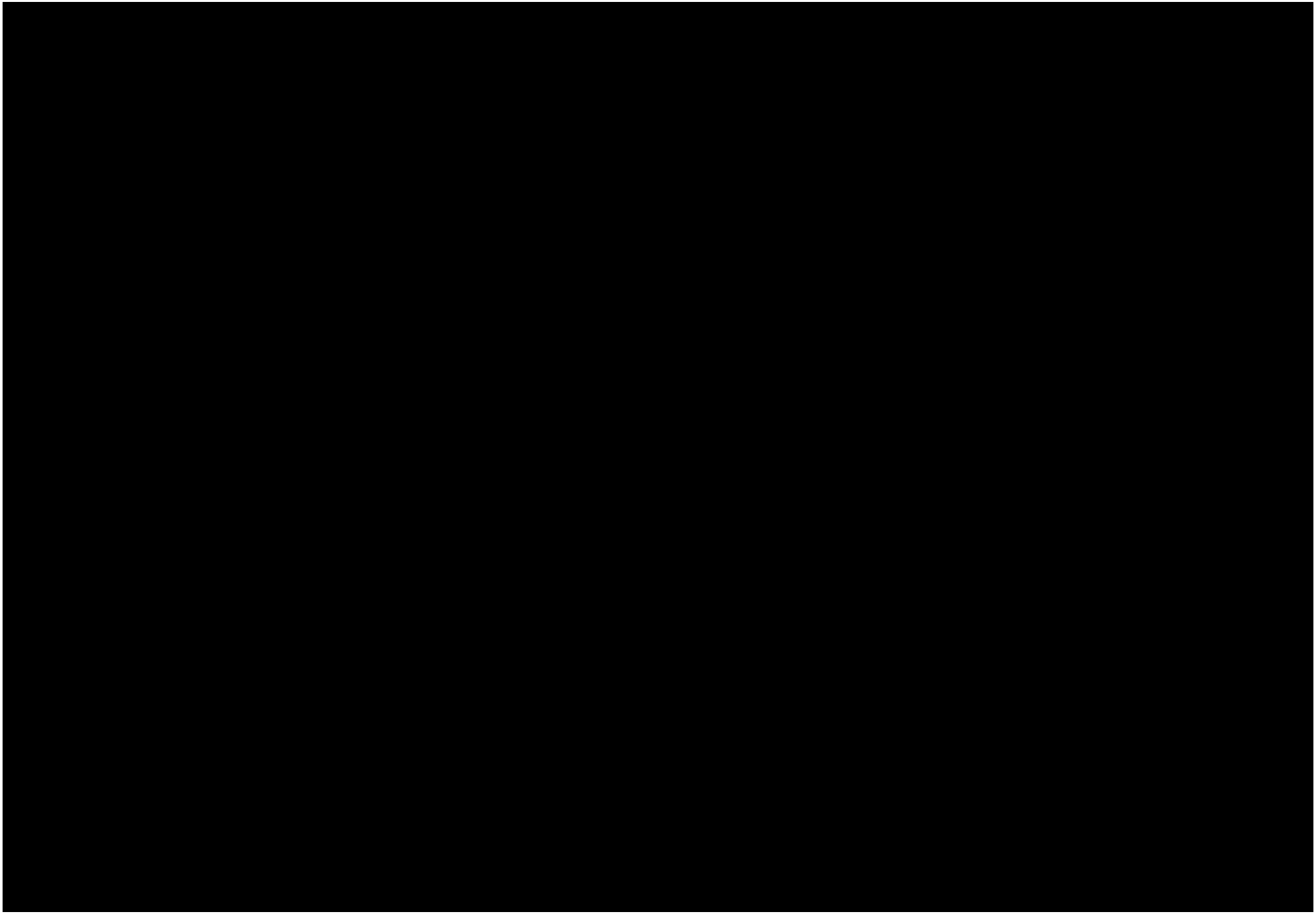
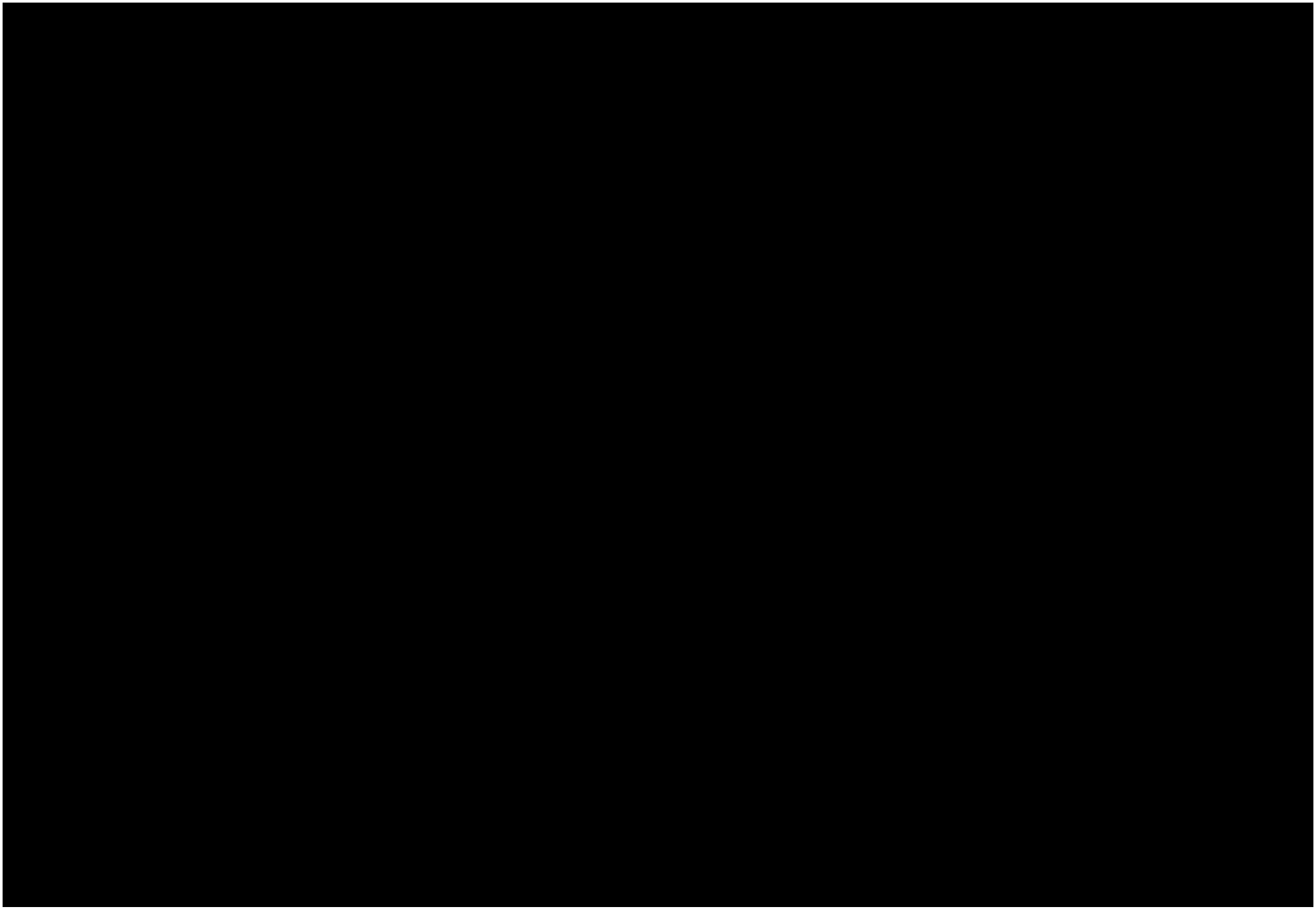
Annual Winter Coincident Peak

Columbus Electric Cooperative, Inc.

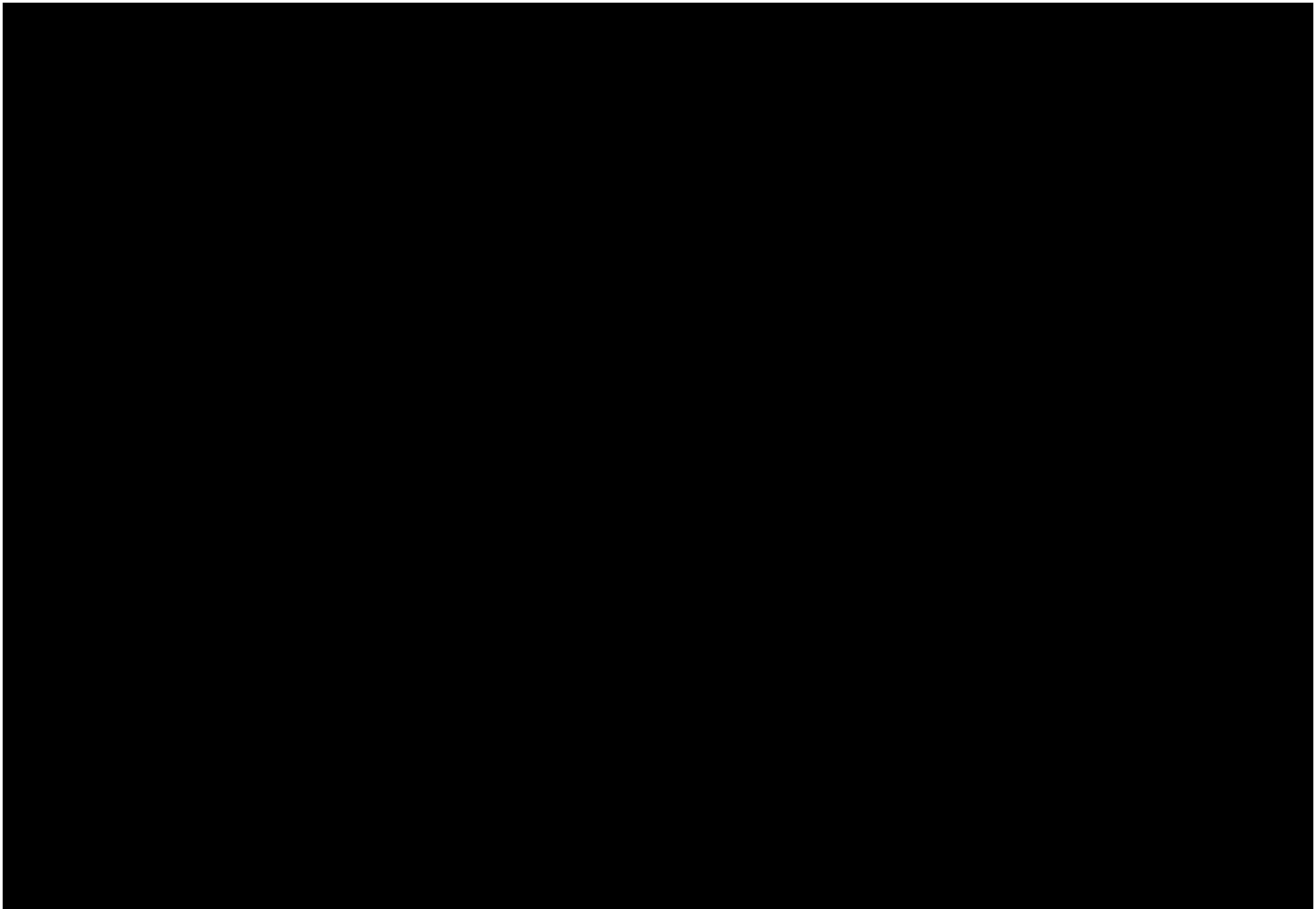


Annual Winter Coincident Peak

Central New Mexico Electric Cooperative, Inc.



Annual Winter Coincident Peak
Chimney Rock Public Power District



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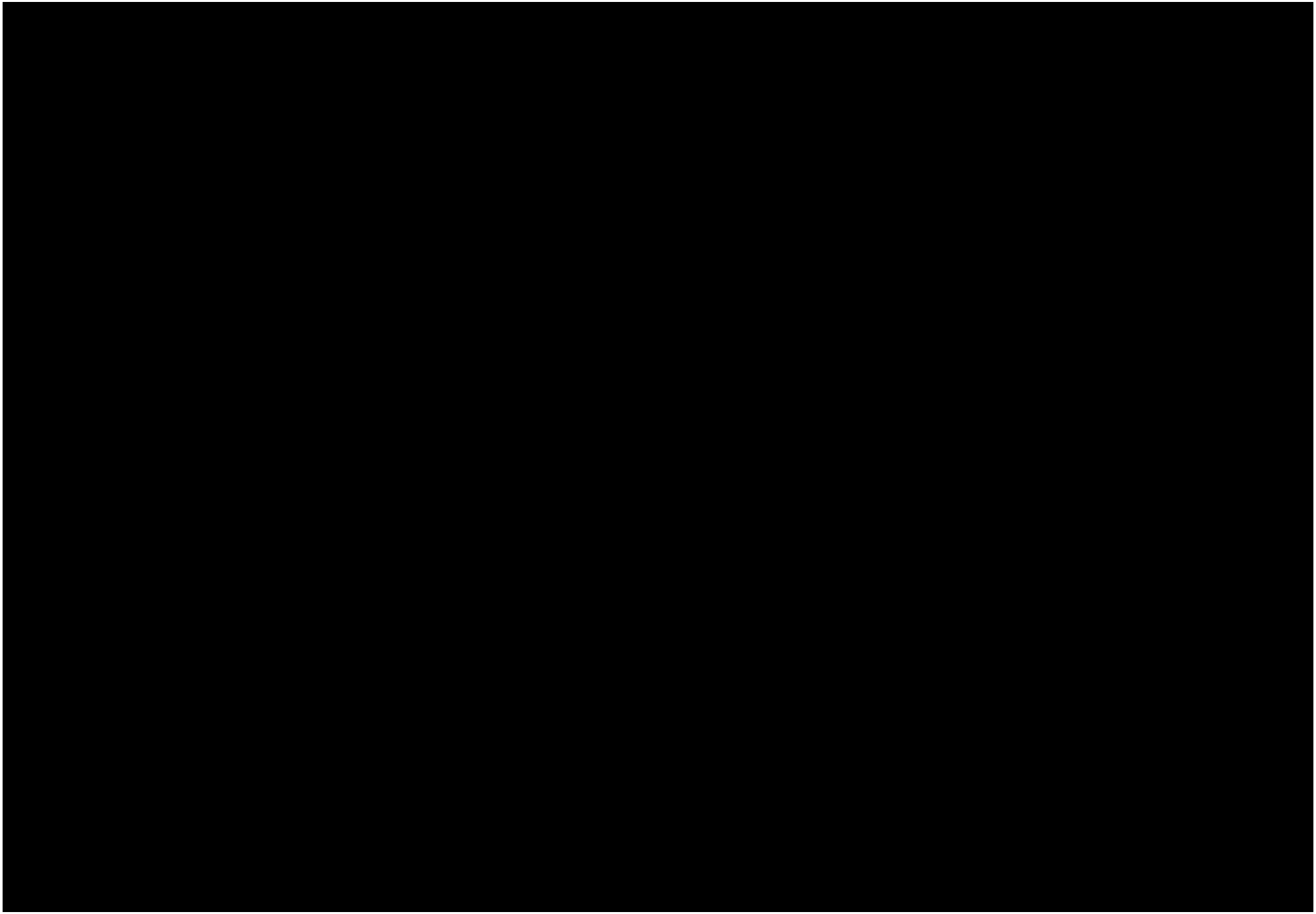
Annual Winter Coincident Peak

Empire Electric Association, Inc.



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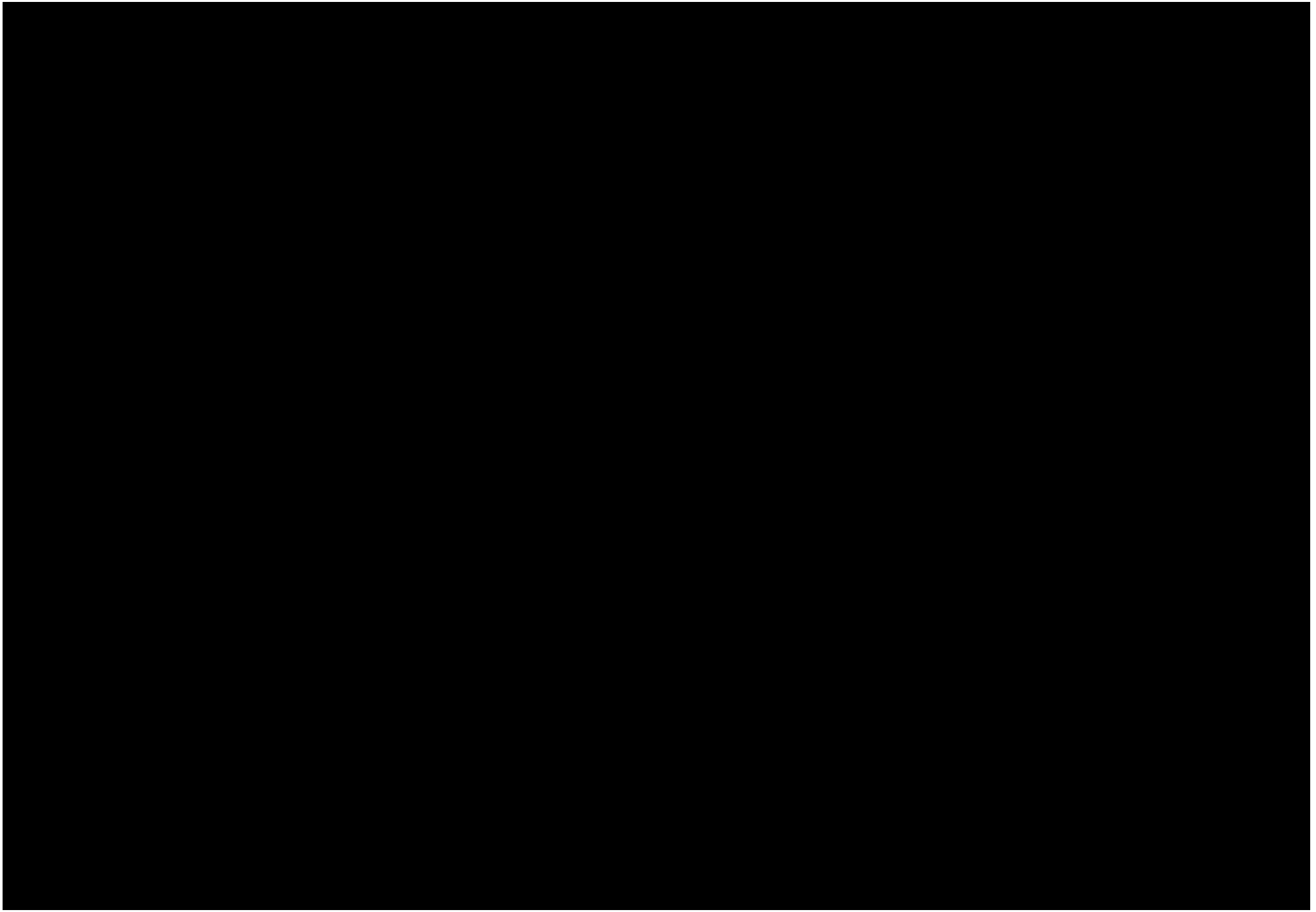
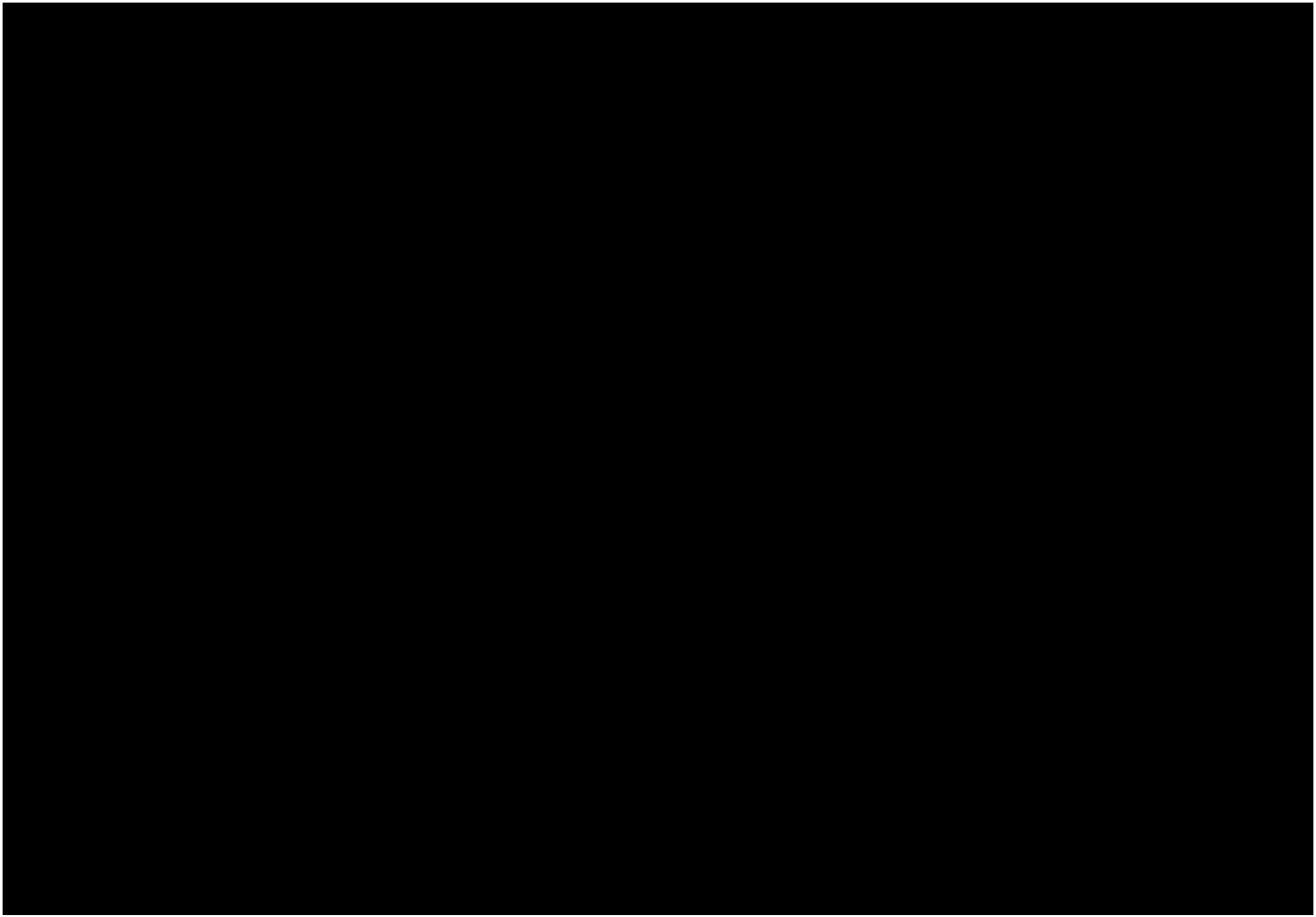
Annual Winter Coincident Peak

Gunnison County Electric Association, Inc.



Annual Winter Coincident Peak
Garland Light and Power Company



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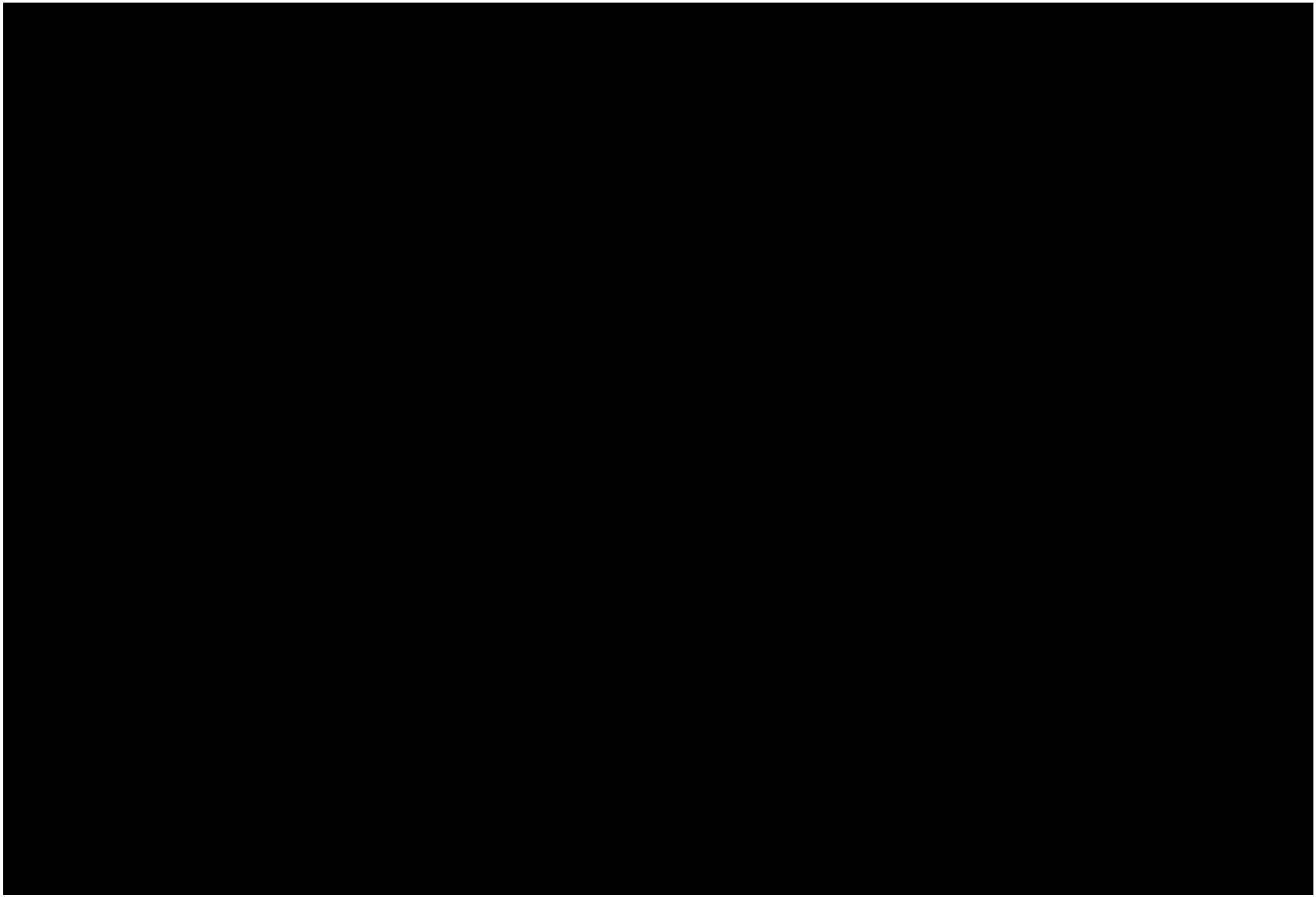
Annual Winter Coincident Peak

Highline Electric Association



Annual Winter Coincident Peak
High Plains Power, Inc.

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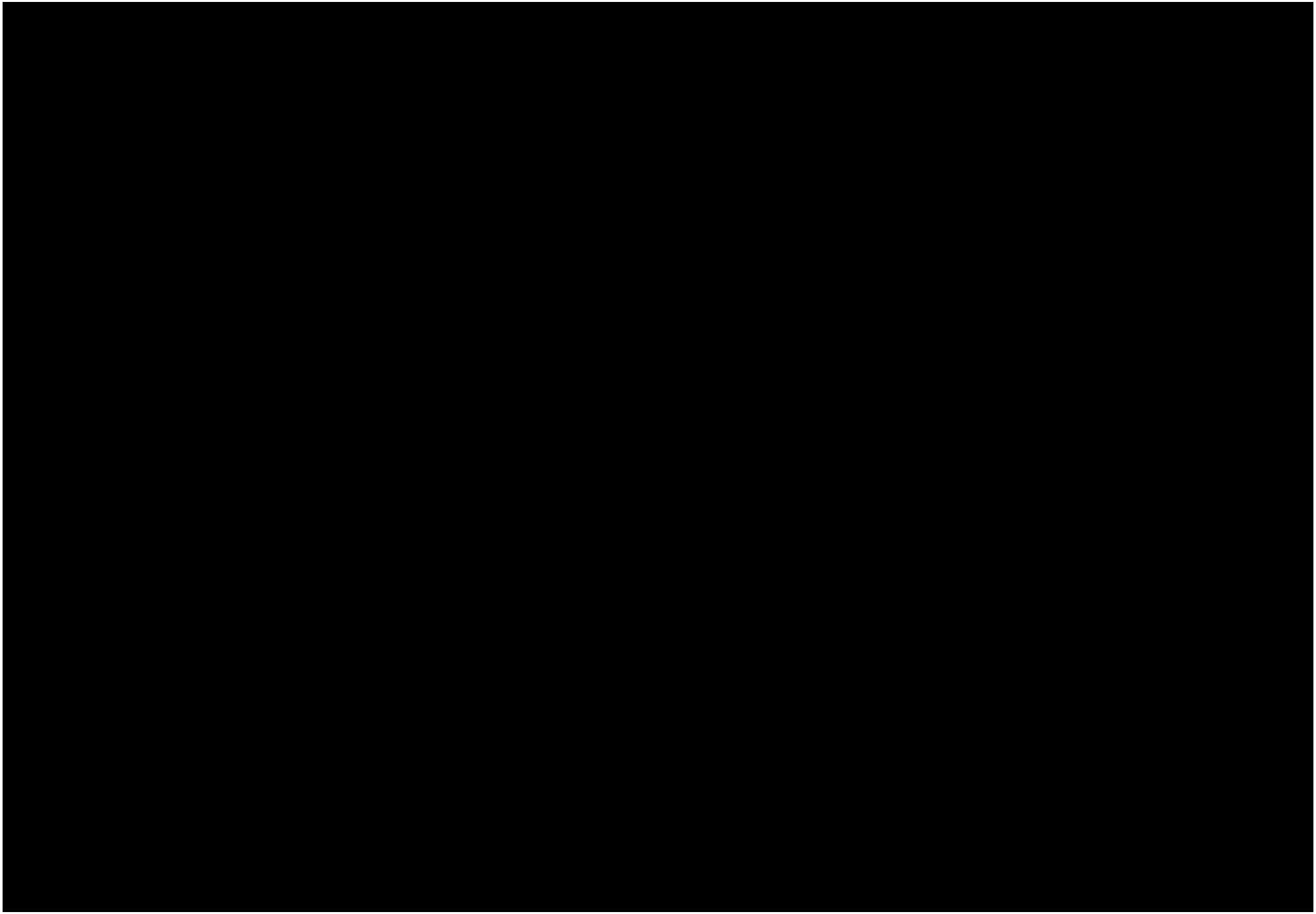
Annual Winter Coincident Peak

High West Energy, Inc.



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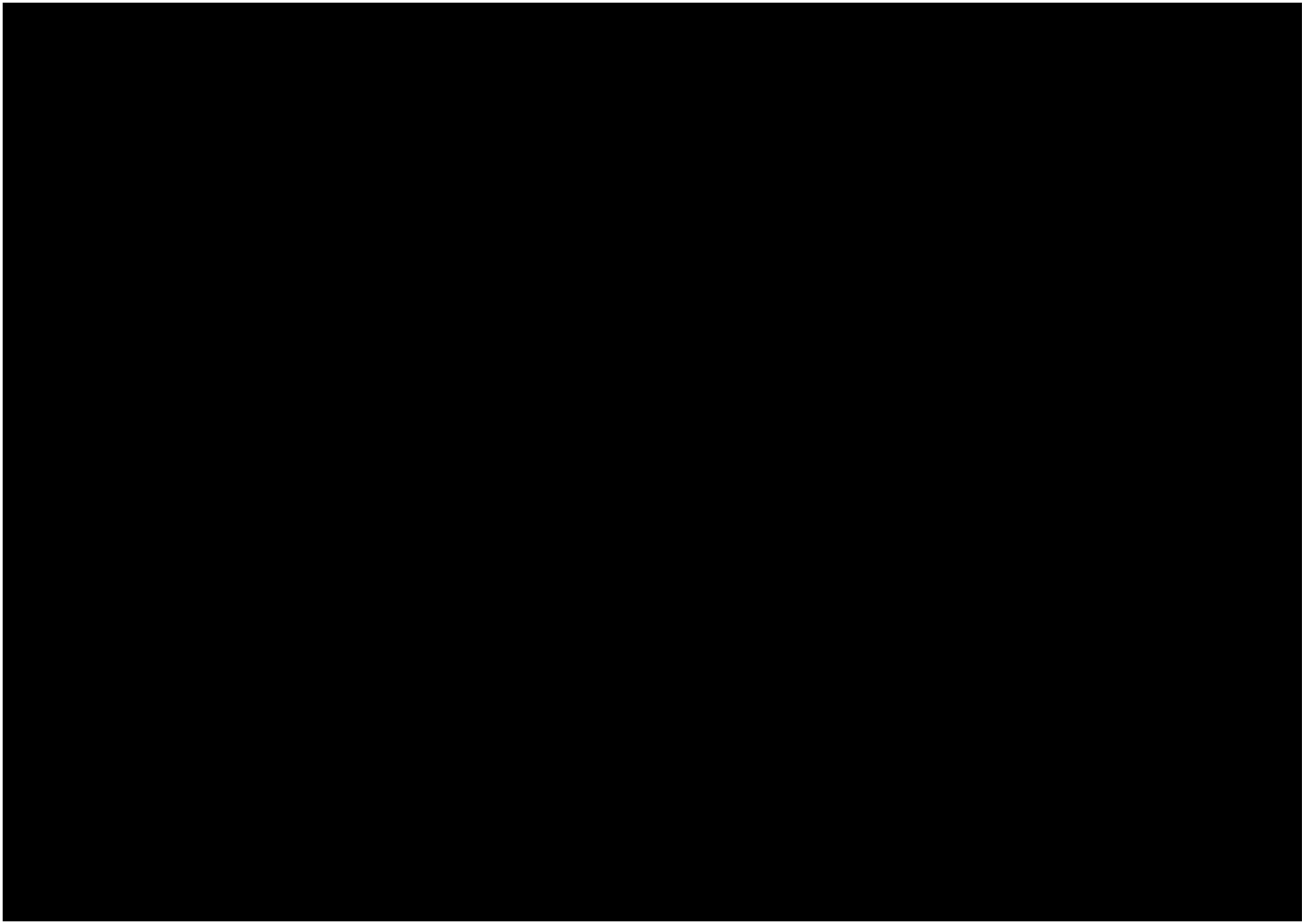
Annual Winter Coincident Peak

Jemez Mountains Electric Cooperative, Inc.



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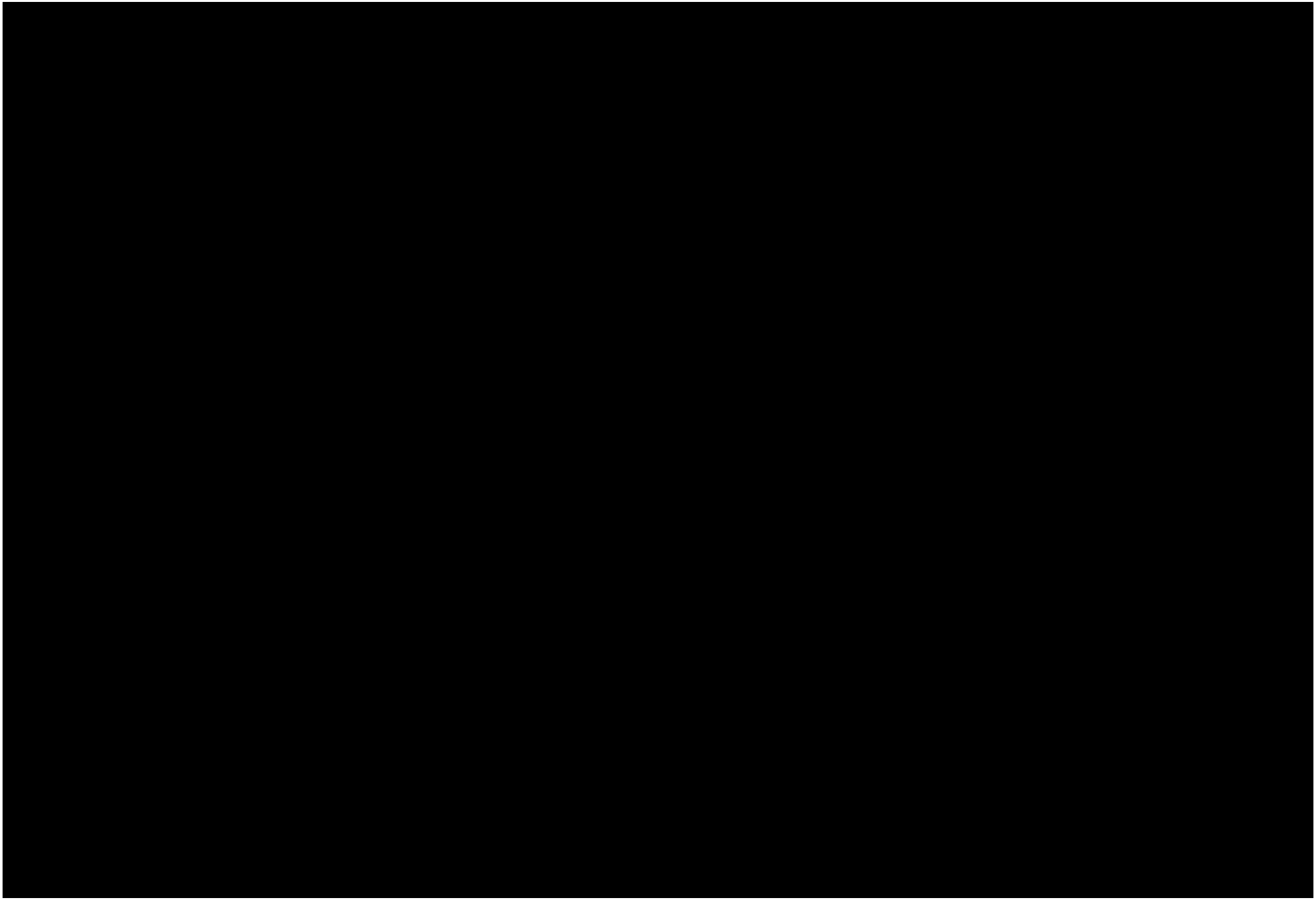
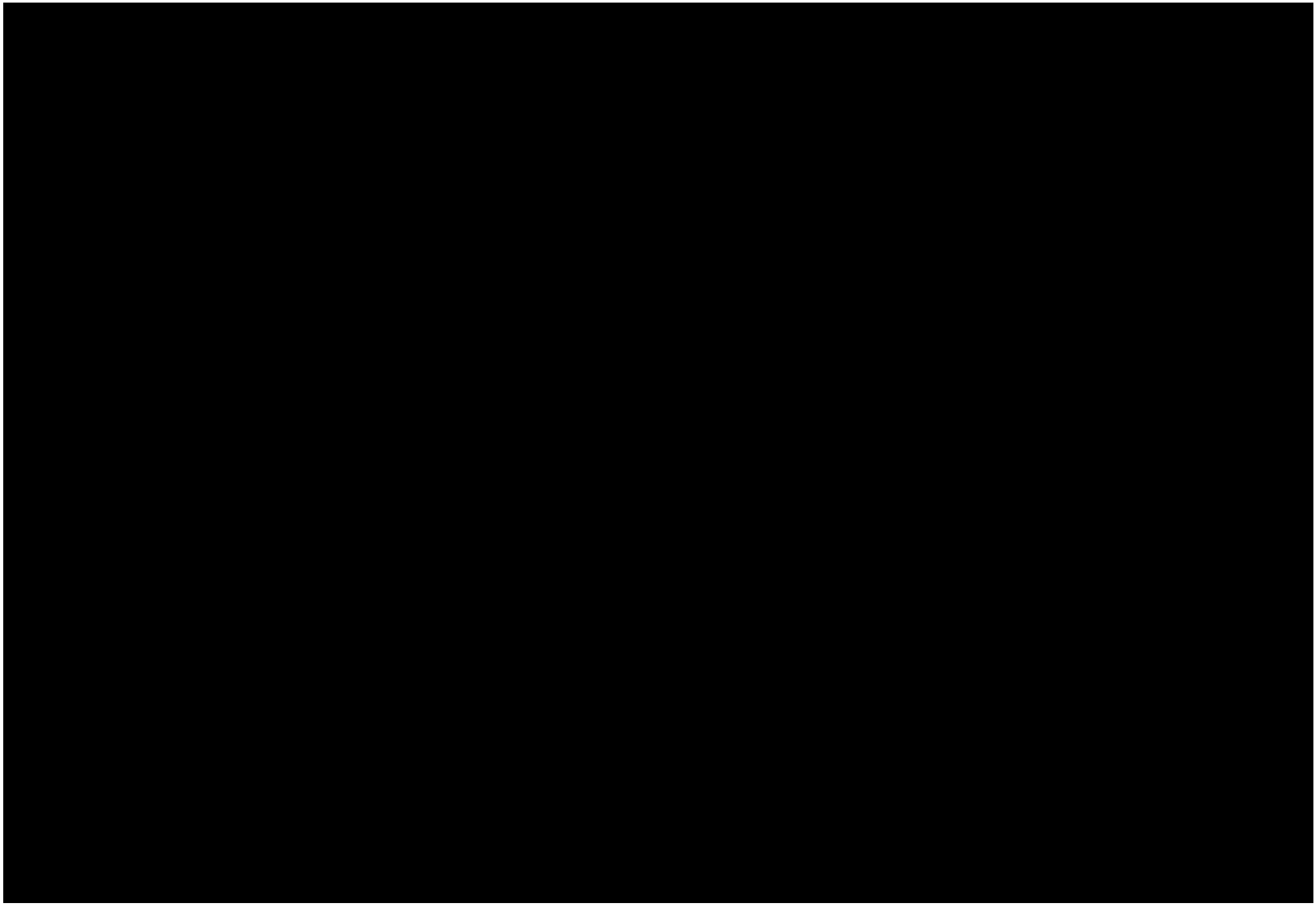
Annual Winter Coincident Peak
K.C. Electric Association, Inc.



Annual Winter Coincident Peak
La Plata Electric Association, Inc.



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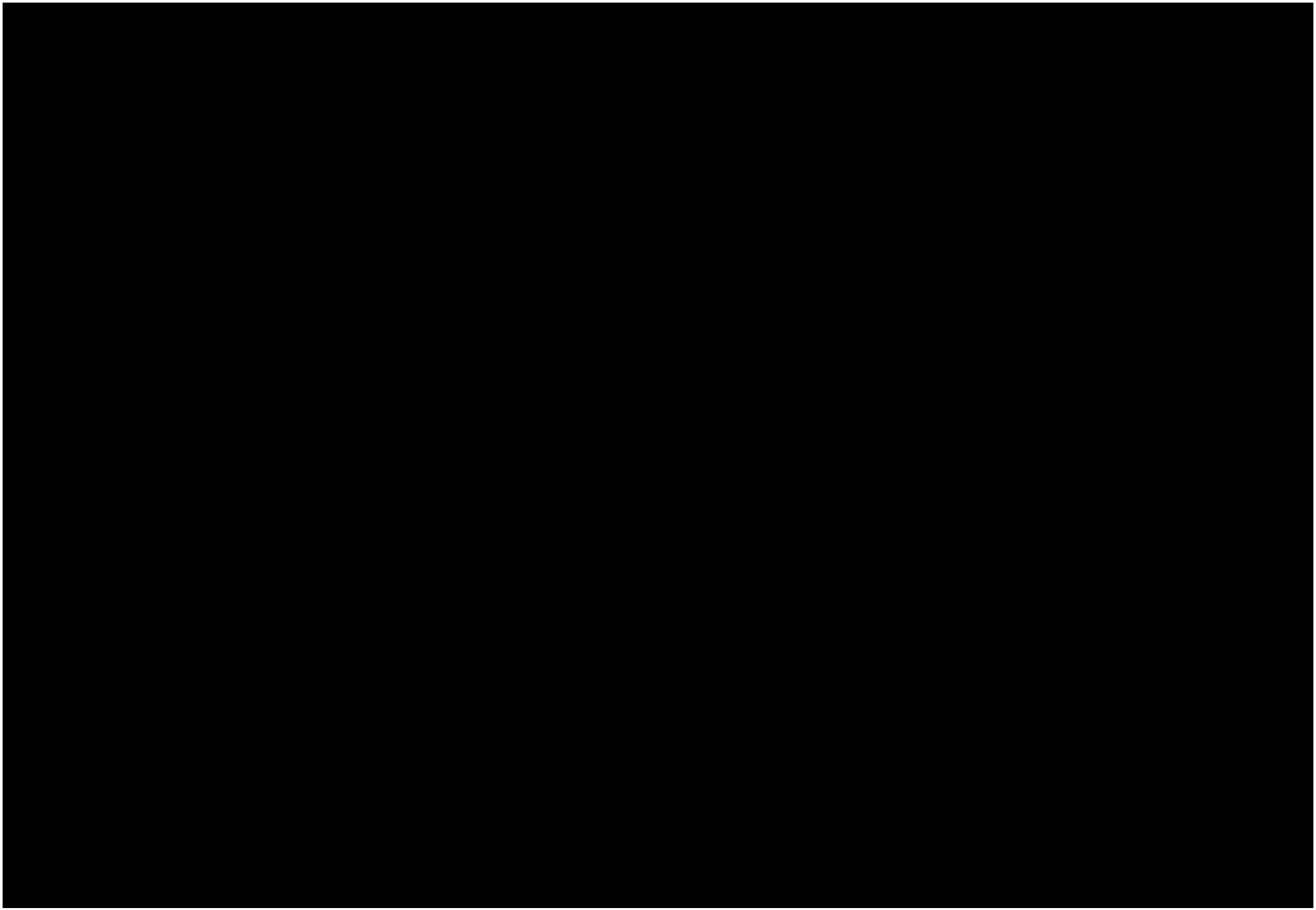
Annual Winter Coincident Peak

Morgan County Rural Electric Association



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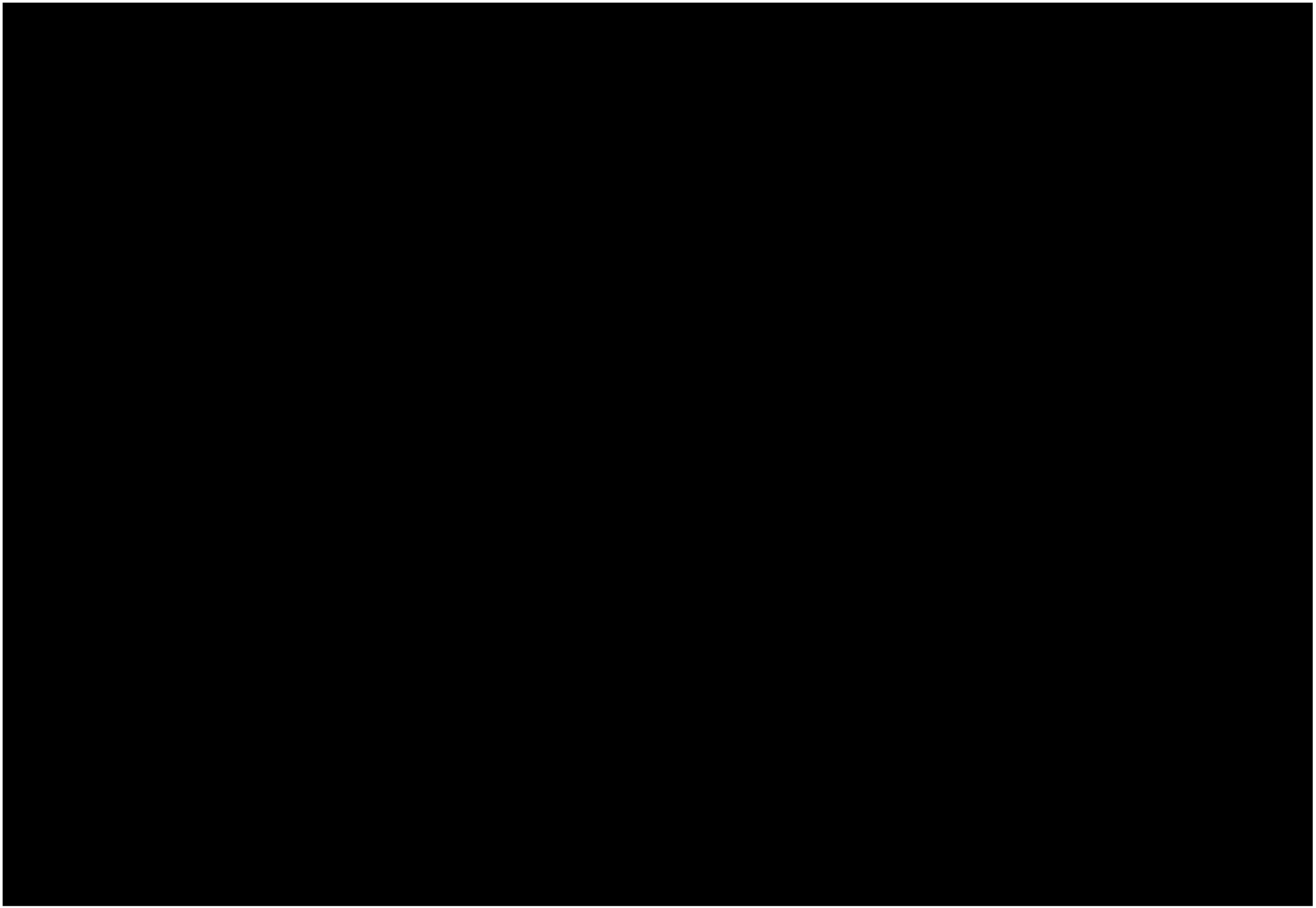
Annual Winter Coincident Peak

Mountain Parks Electric, Inc.



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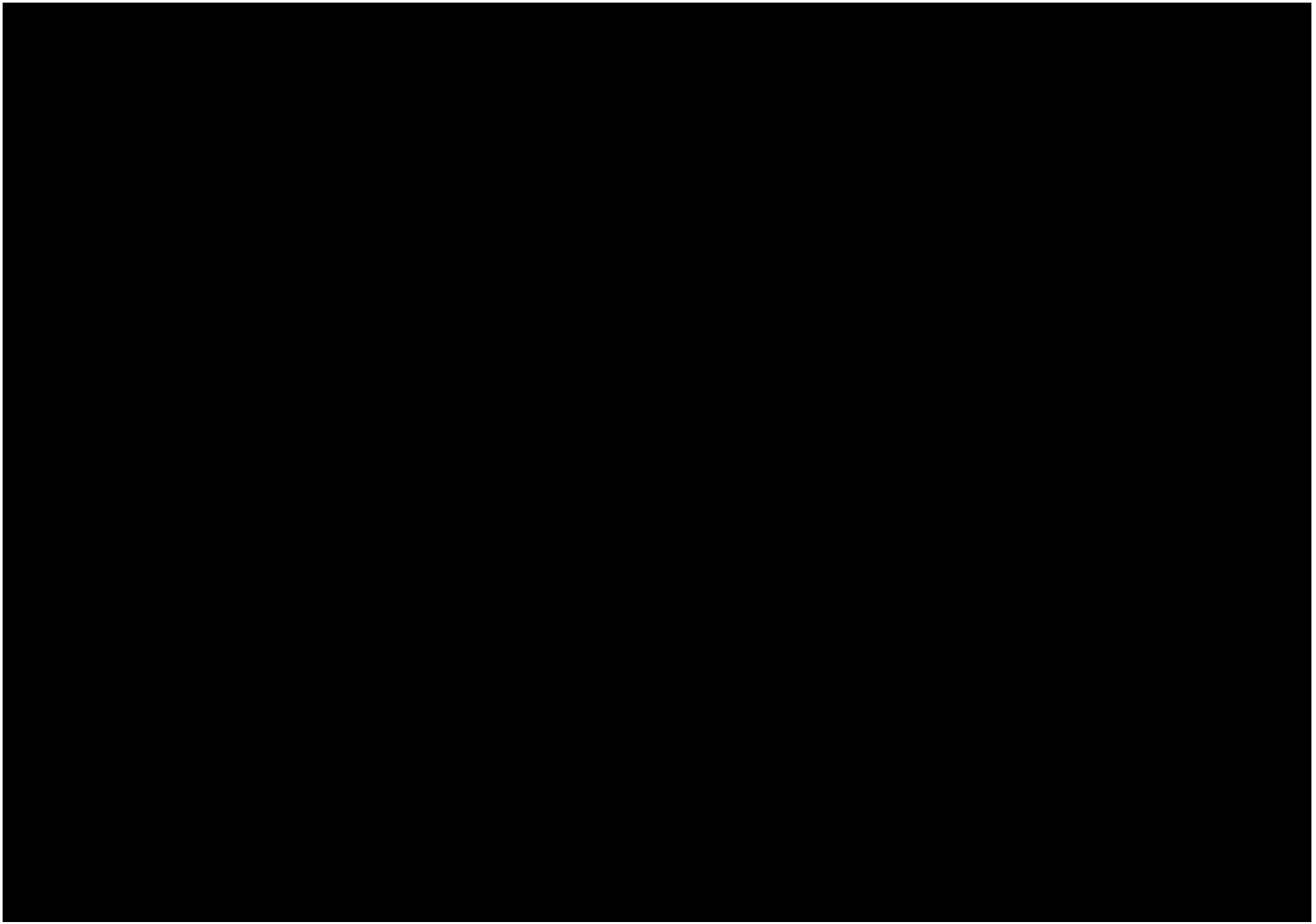
Annual Winter Coincident Peak

Mora-San Miguel Electric Cooperative, Inc.



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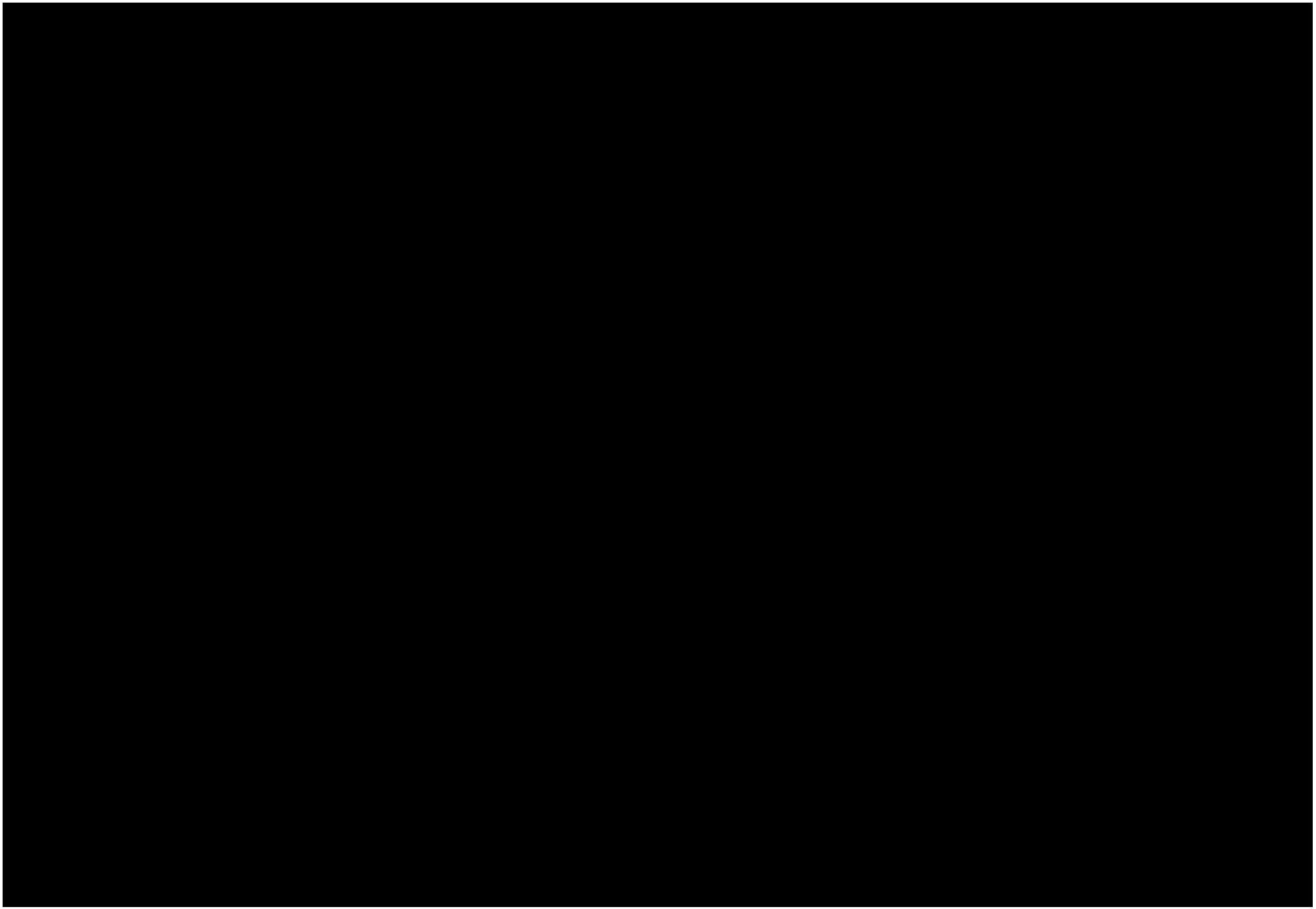
Annual Winter Coincident Peak
Mountain View Electric Association, Inc.



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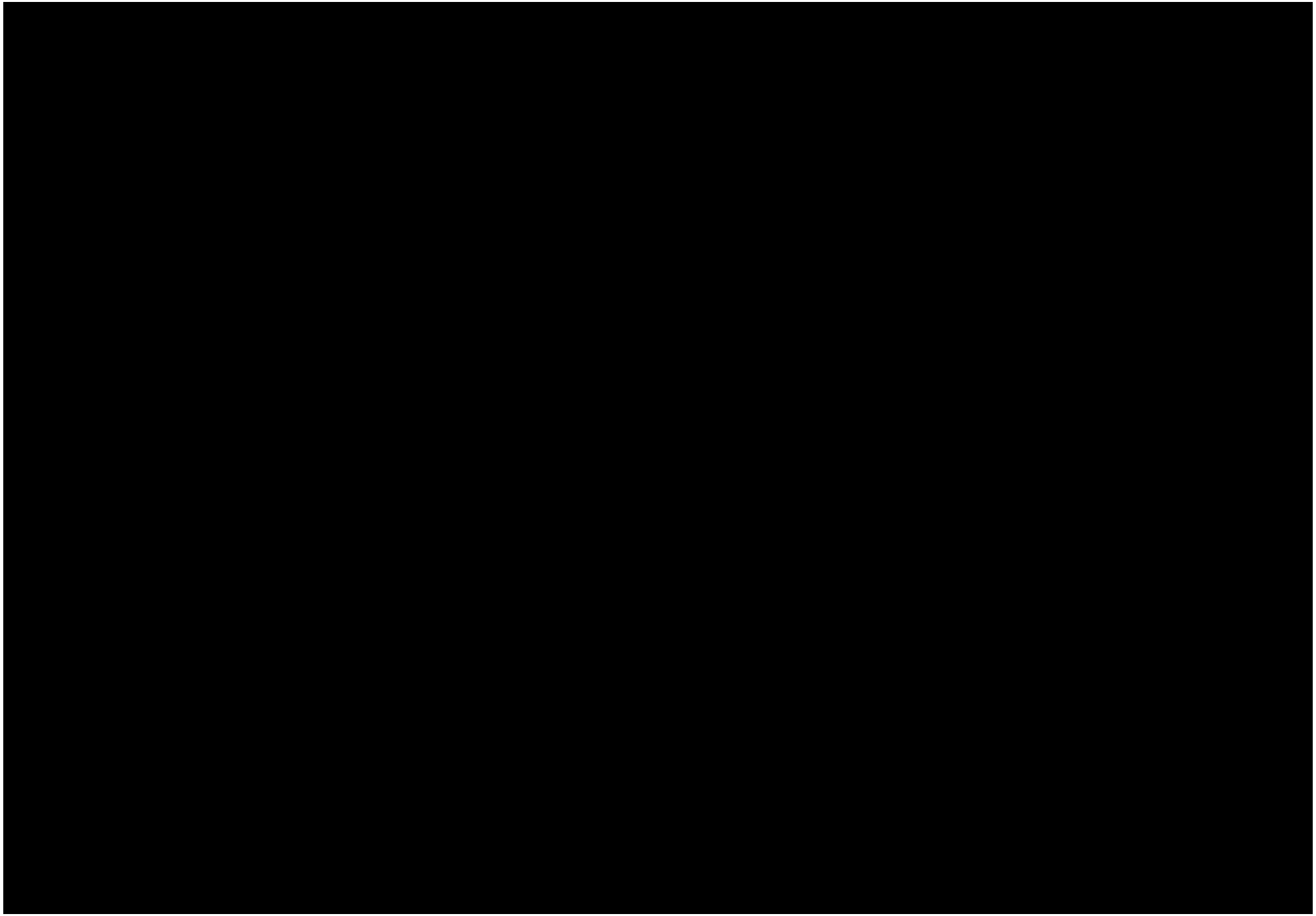
Annual Winter Coincident Peak

Midwest Electric Cooperative Corporation



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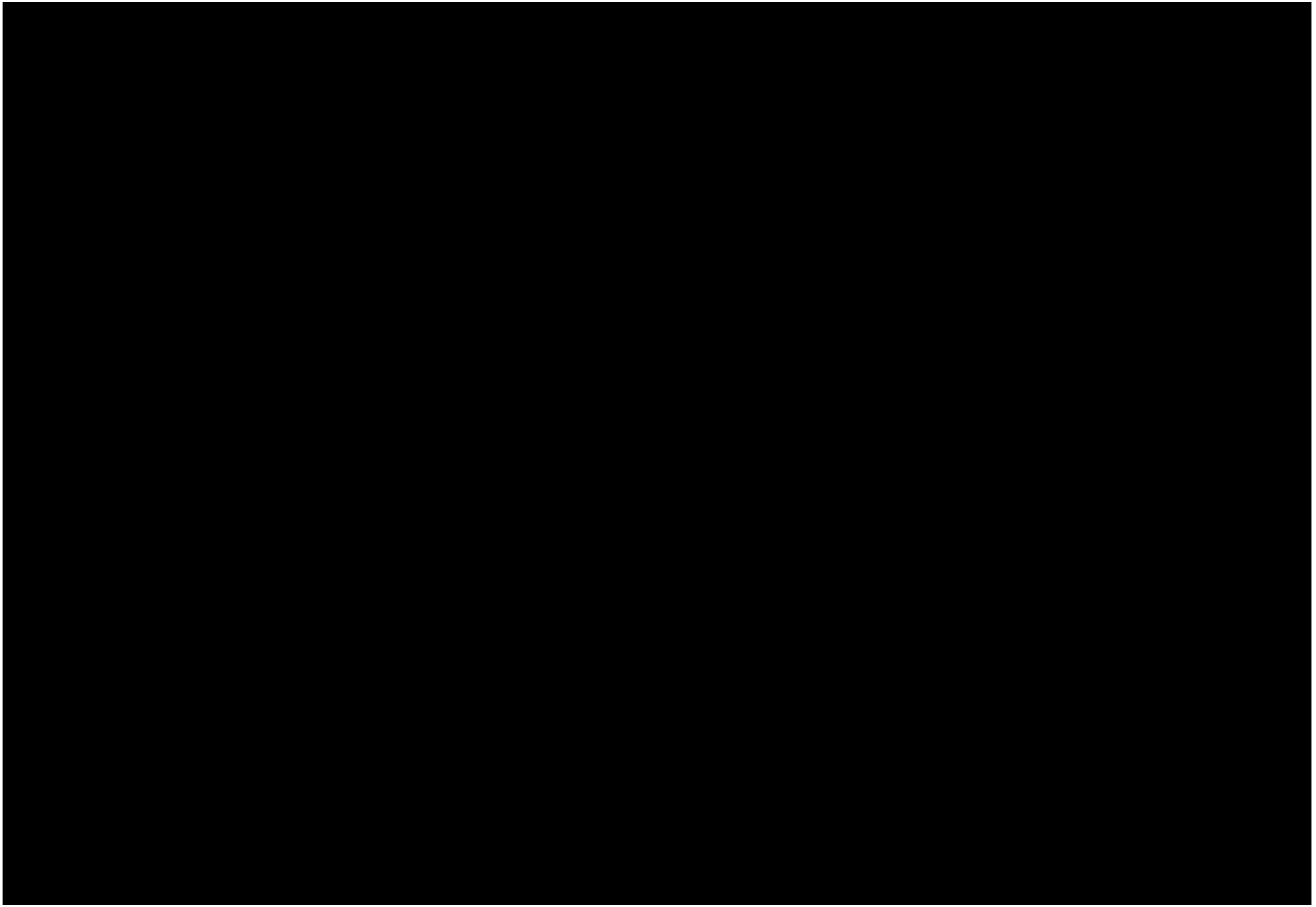
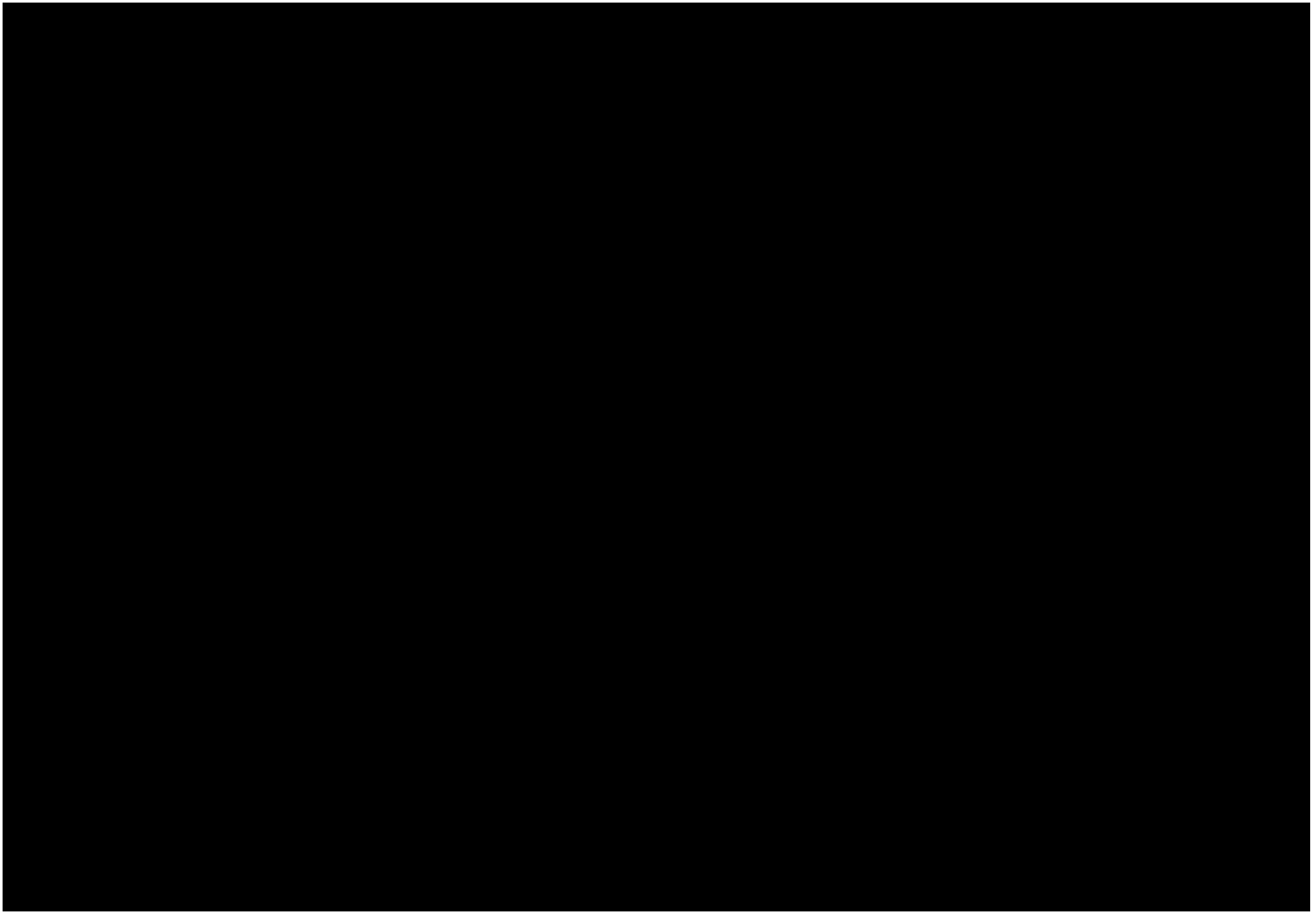
Annual Winter Coincident Peak

Niobrara Electric Association, Inc.



Annual Winter Coincident Peak
Northwest Rural Public Power District



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Annual Winter Coincident Peak
Otero County Electric Cooperative, Inc.

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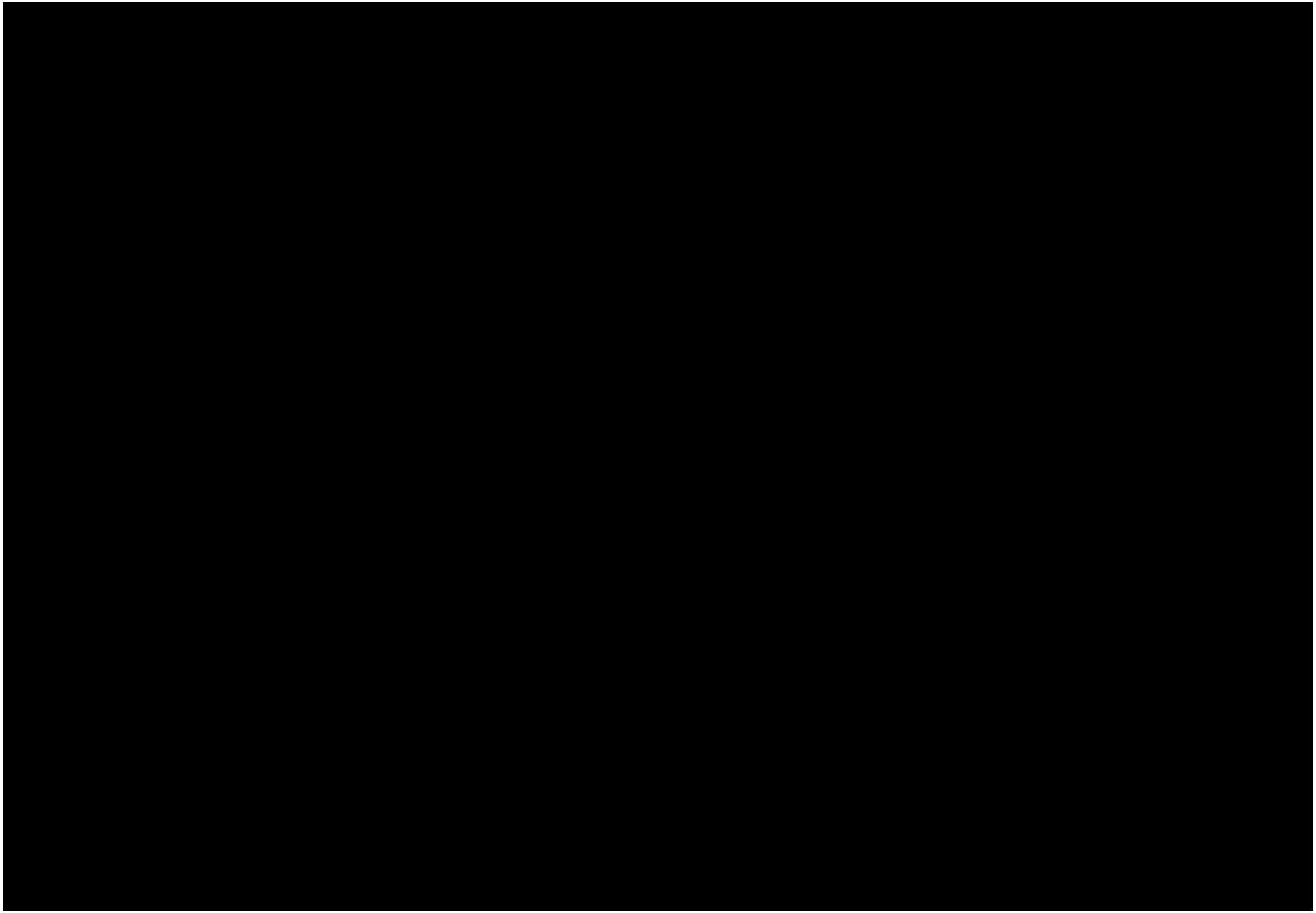
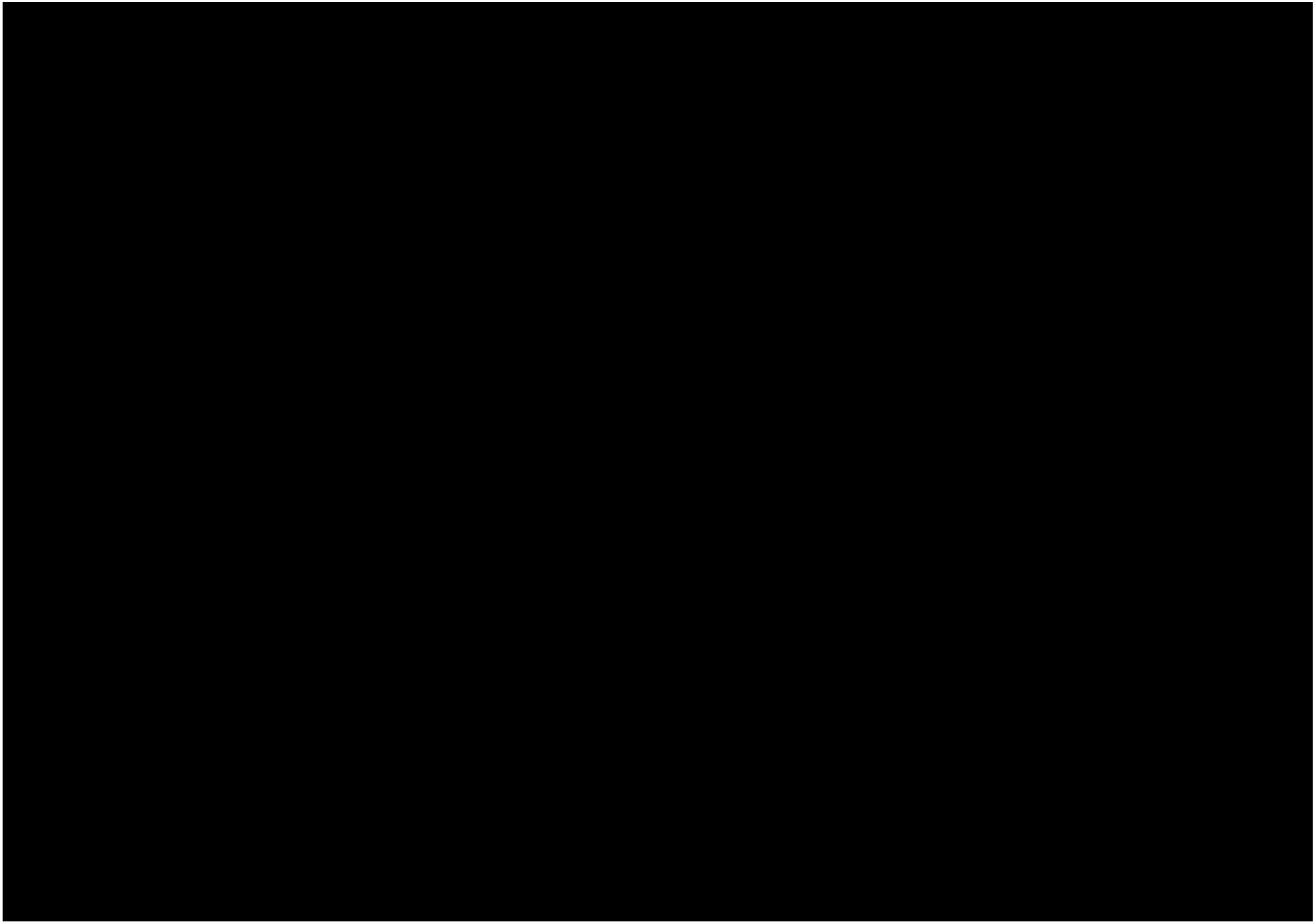
Annual Winter Coincident Peak

Panhandle Rural Electric Membership Association

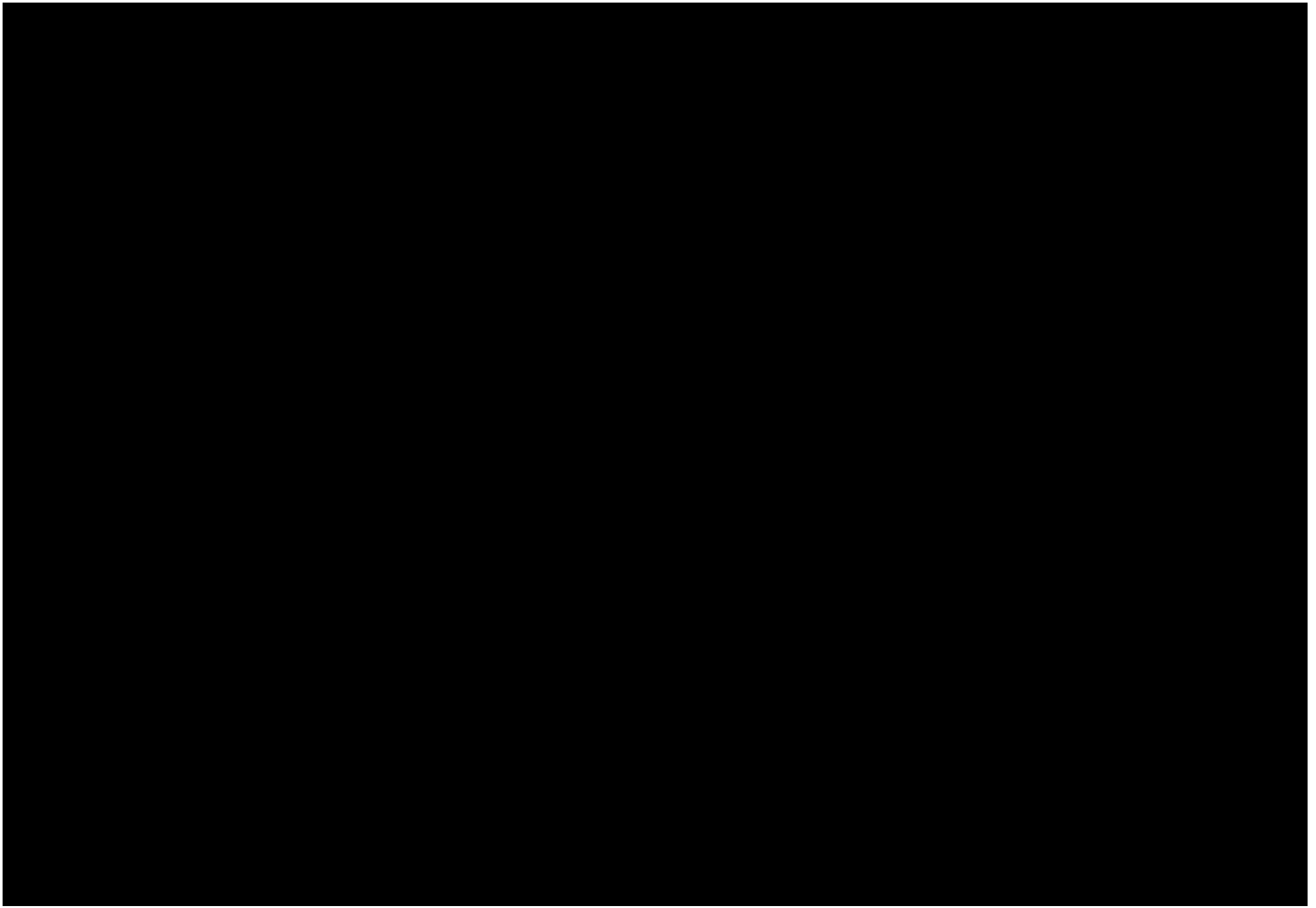


Annual Winter Coincident Peak
Poudre Valley Electric Association, Inc.



Annual Winter Coincident Peak

Northern Rio Arriba Electric Cooperative, Inc.



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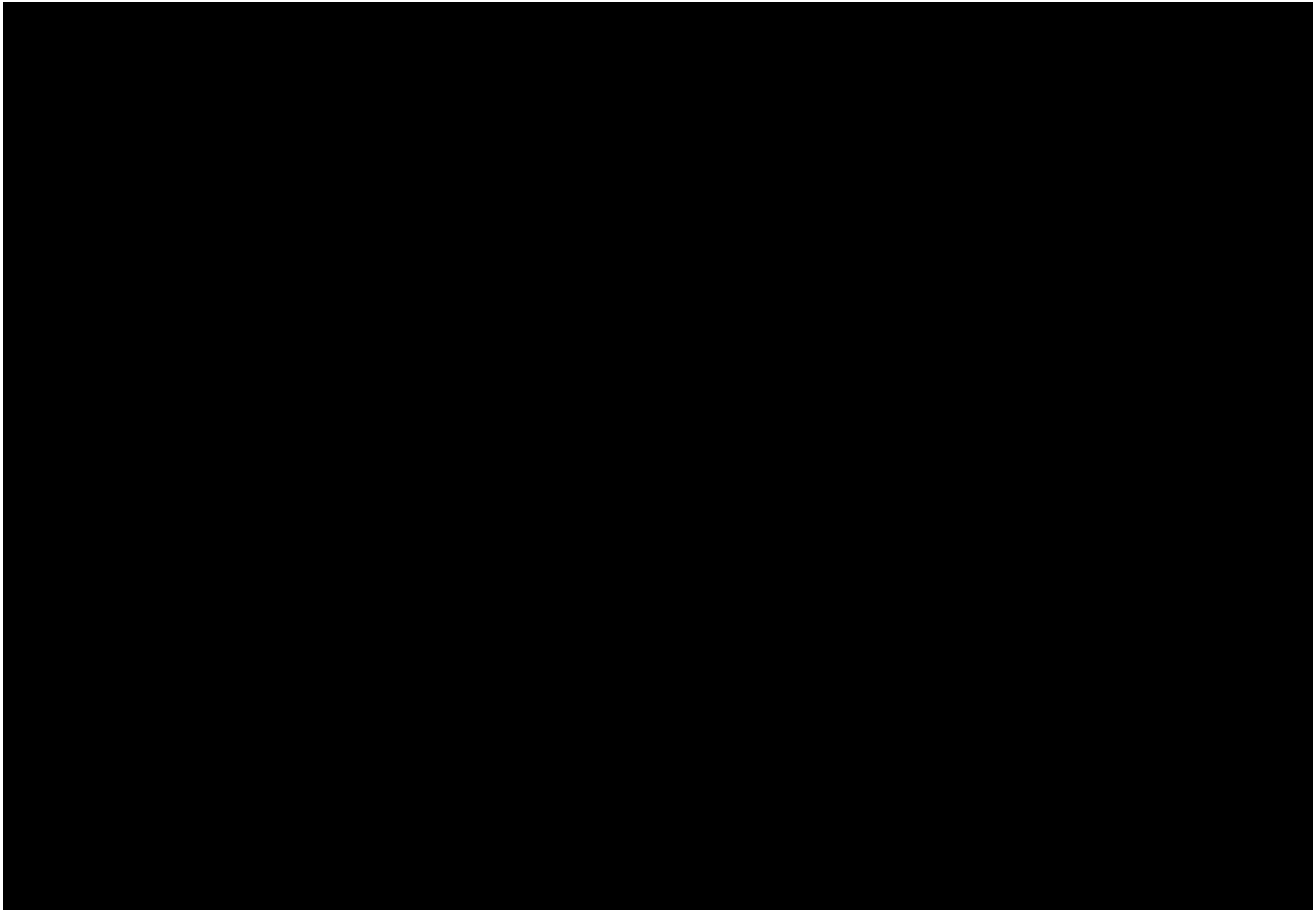
Annual Winter Coincident Peak

Roosevelt Public Power District



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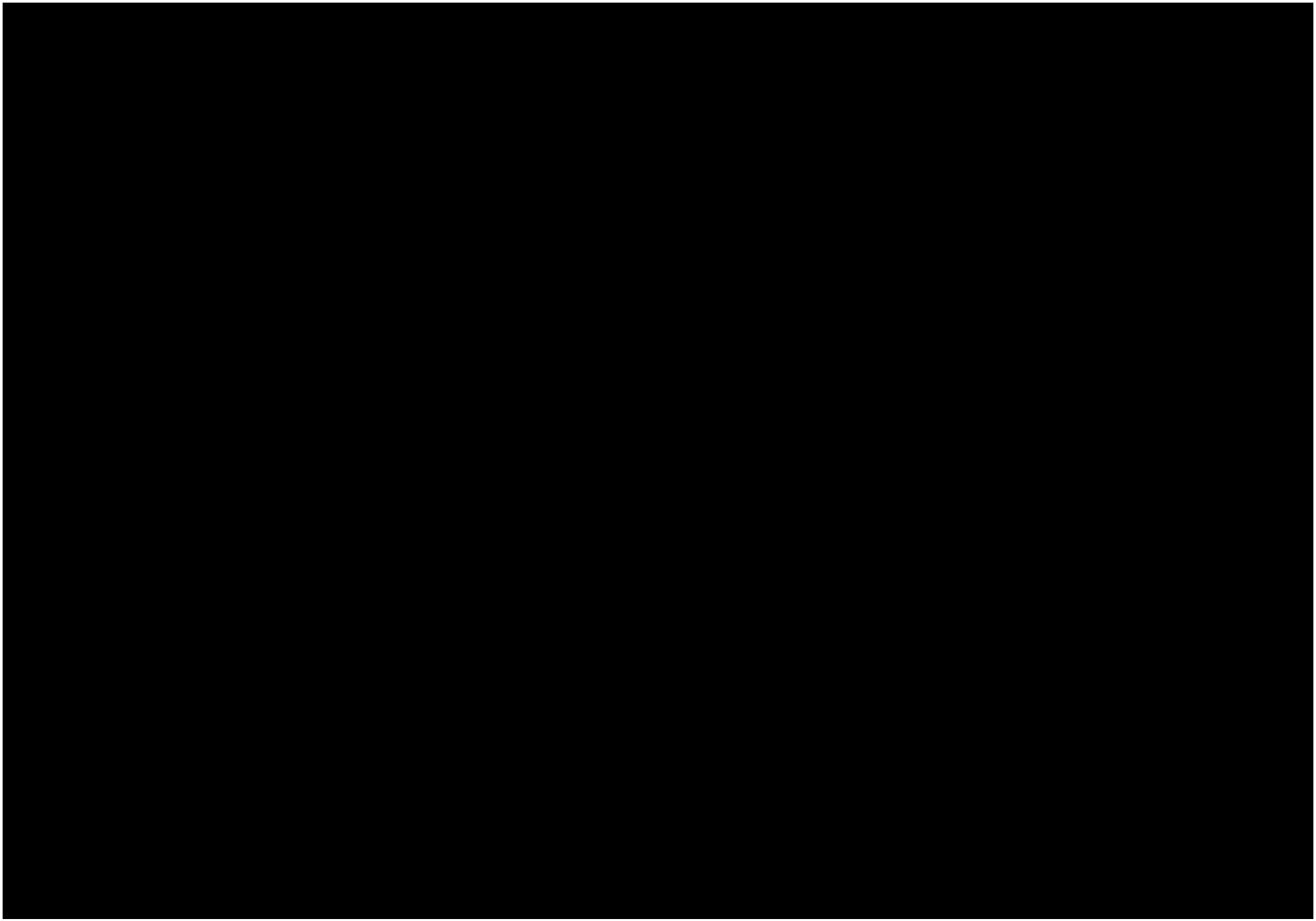
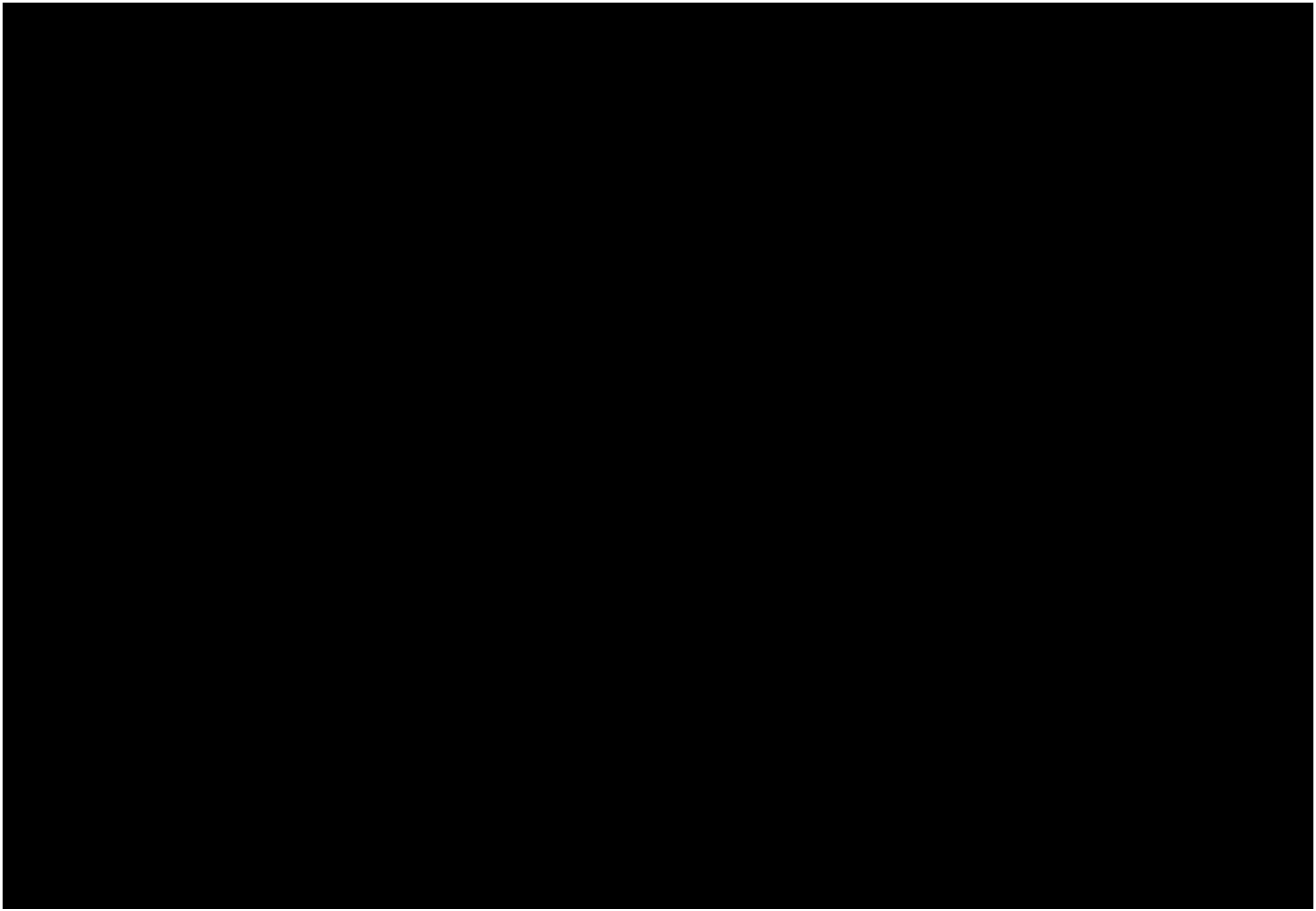
Annual Winter Coincident Peak

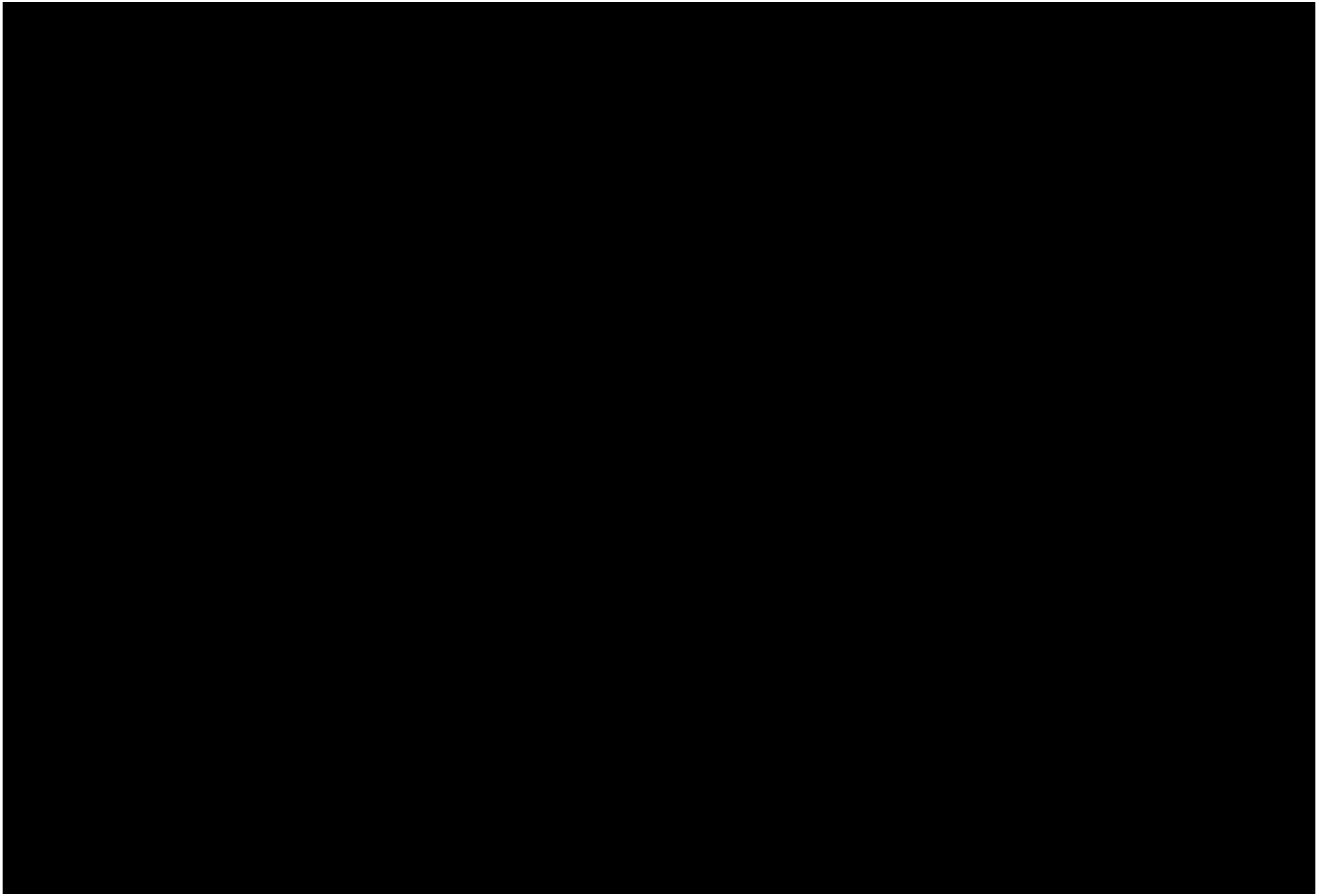
Sierra Electric Cooperative, Inc.



Annual Winter Coincident Peak
Sangre de Cristo Electric Association, Inc.



Annual Winter Coincident Peak
Southeast Colorado Power Association



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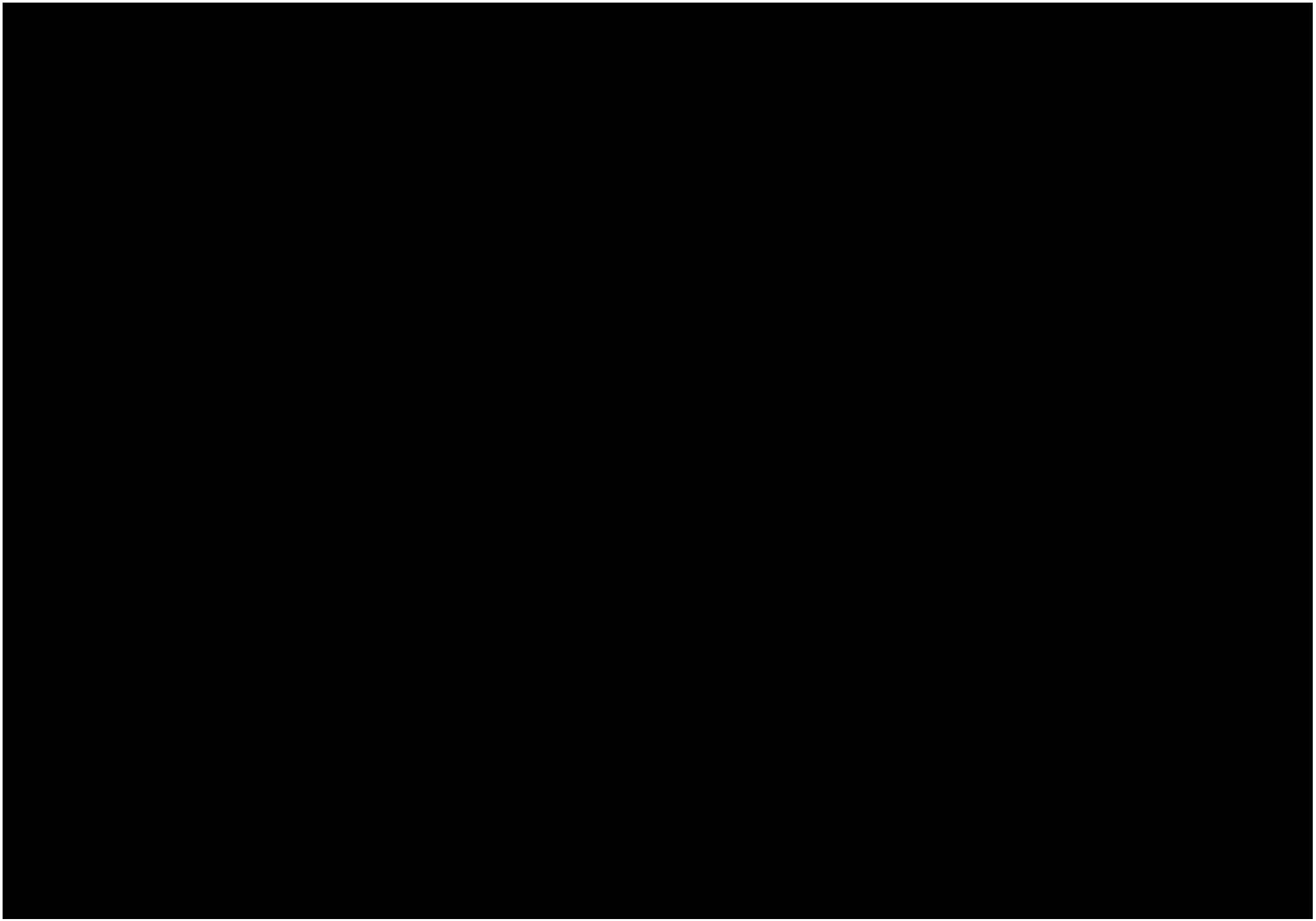
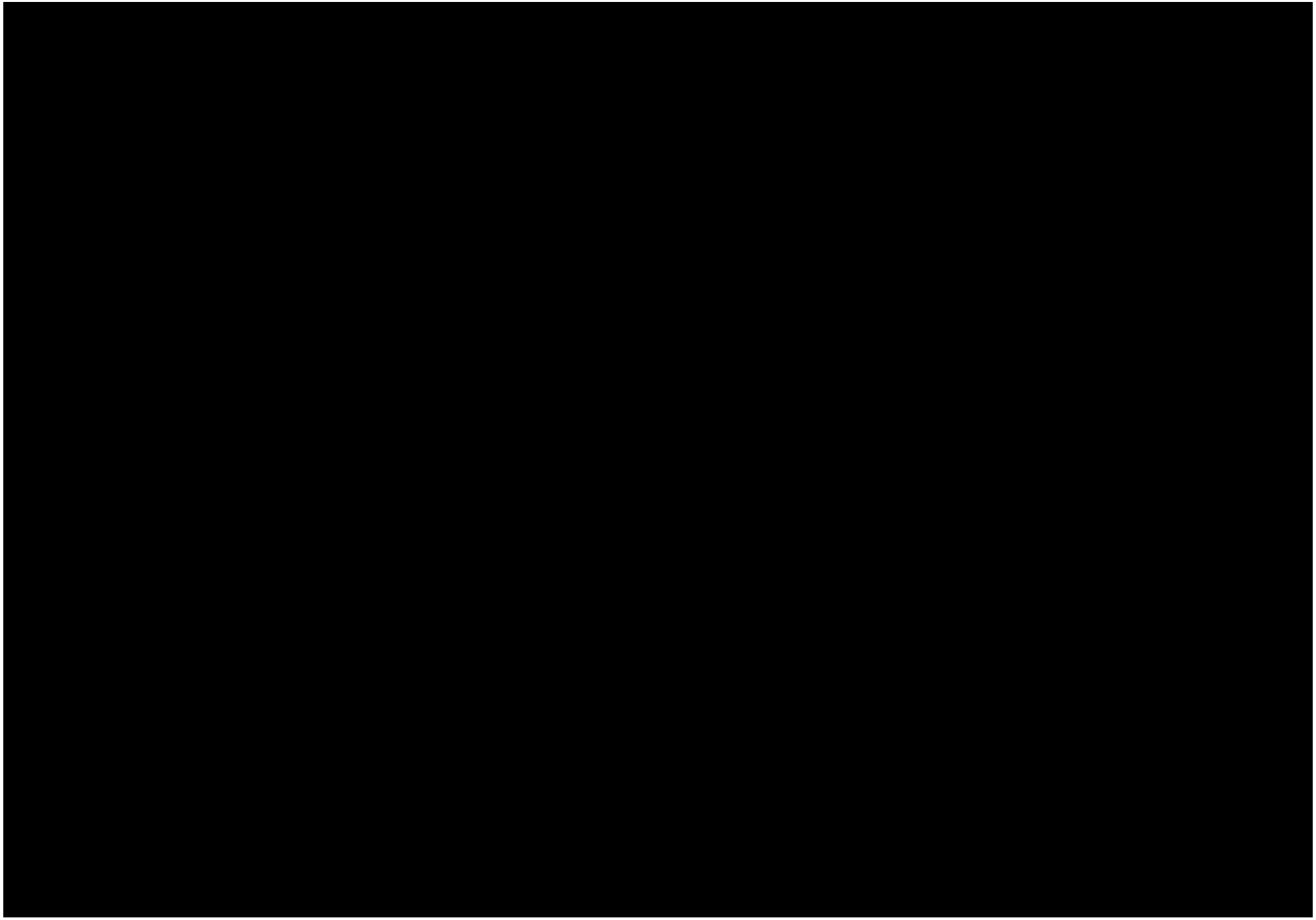
Annual Winter Coincident Peak

San Isabel Electric Association, Inc.



Annual Winter Coincident Peak

San Luis Valley Rural Electric Cooperative, Inc.



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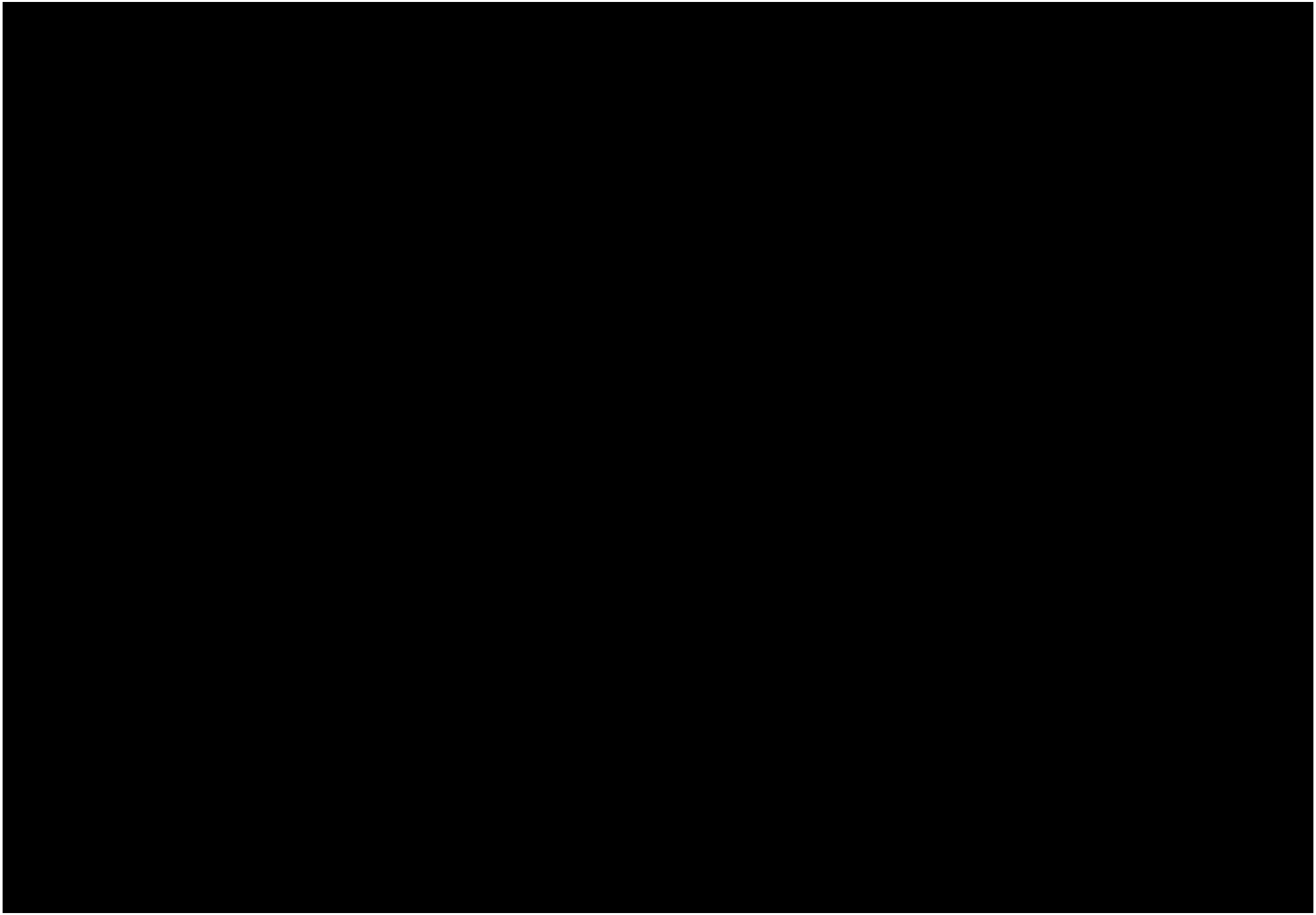
Annual Winter Coincident Peak

San Miguel Power Association, Inc.



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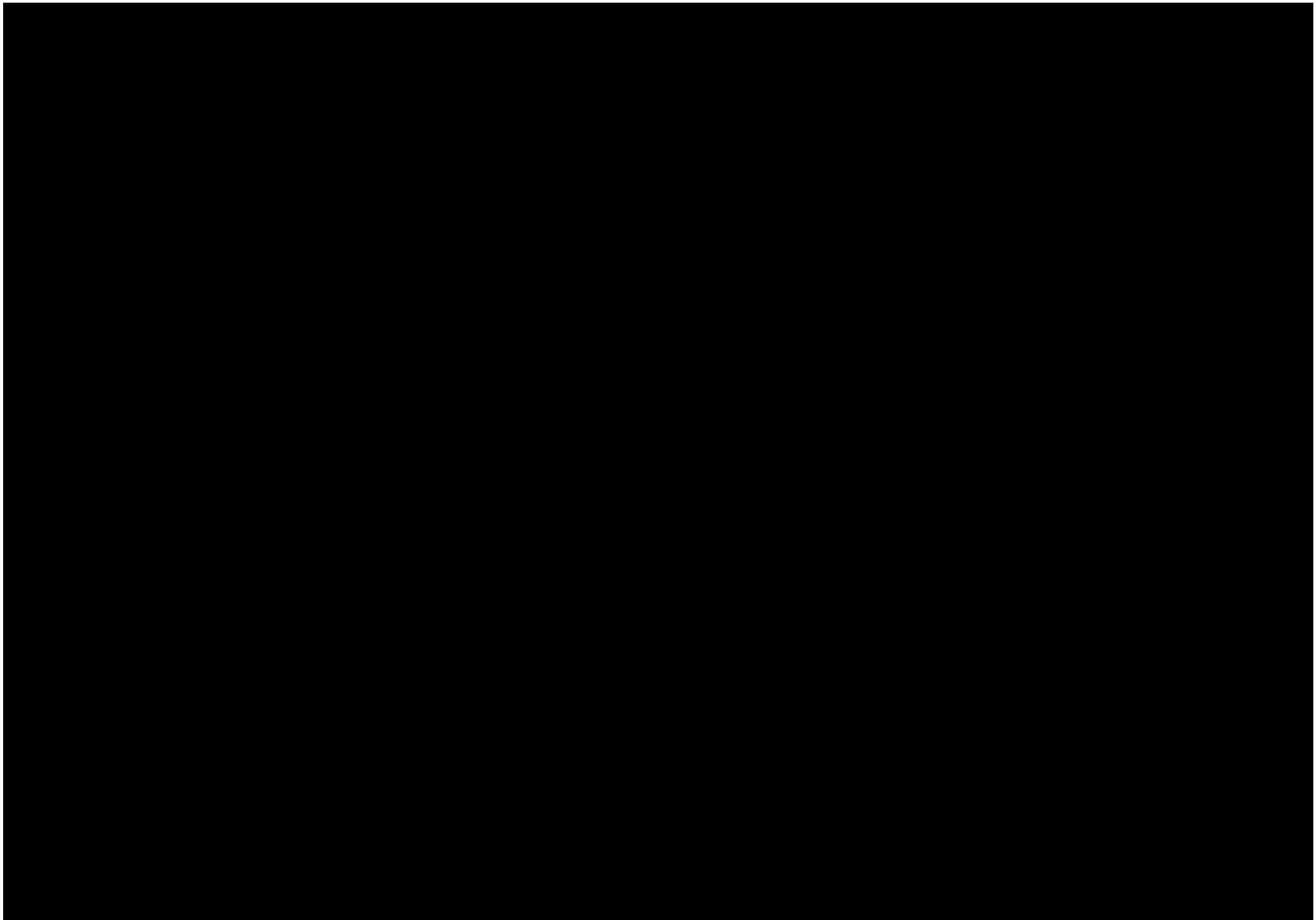
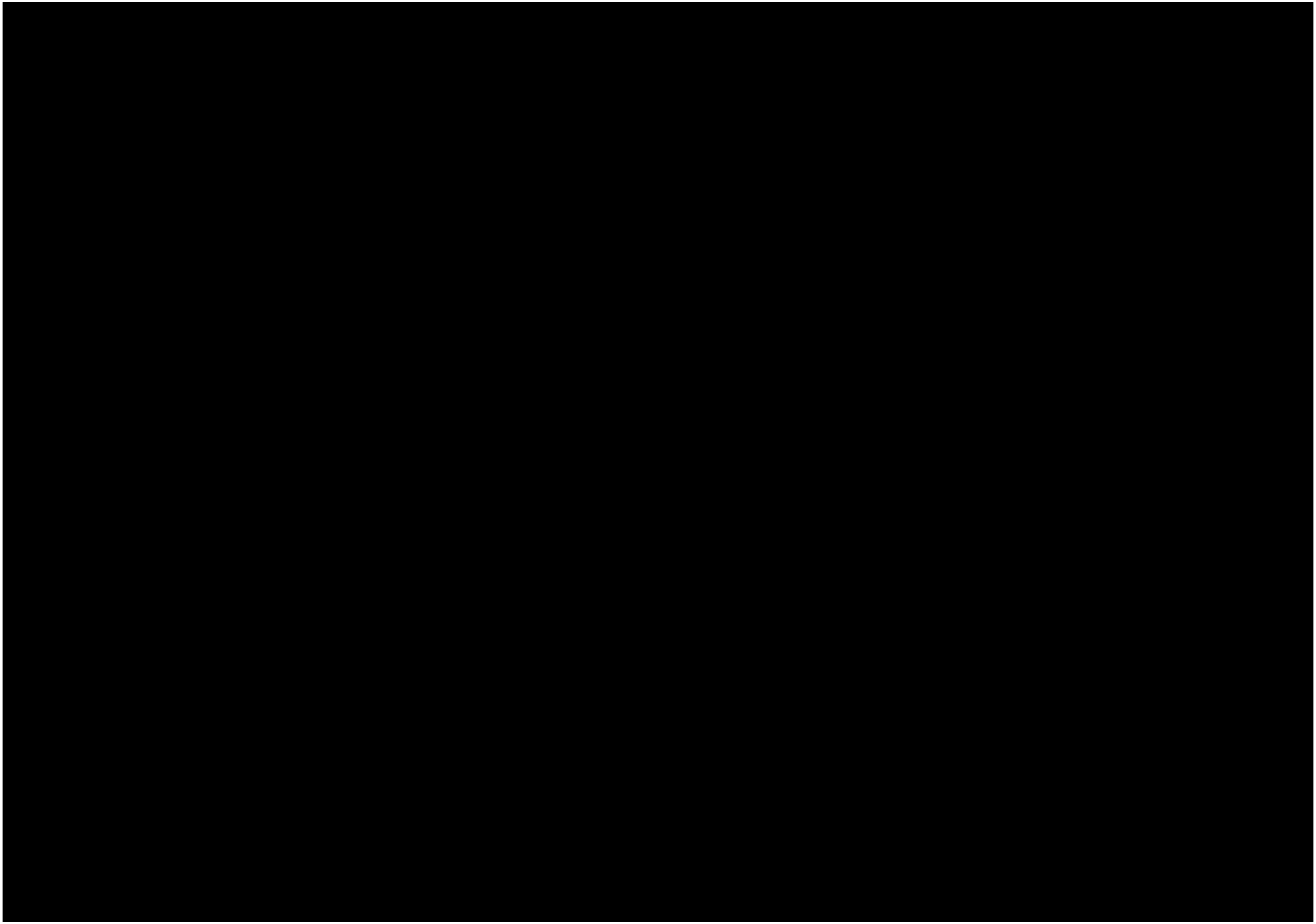
Annual Winter Coincident Peak

Socorro Electric Cooperative, Inc.



Annual Winter Coincident Peak
Springer Electric Cooperative, Inc.



Annual Winter Coincident Peak
Southwestern Electric Cooperative, Inc.

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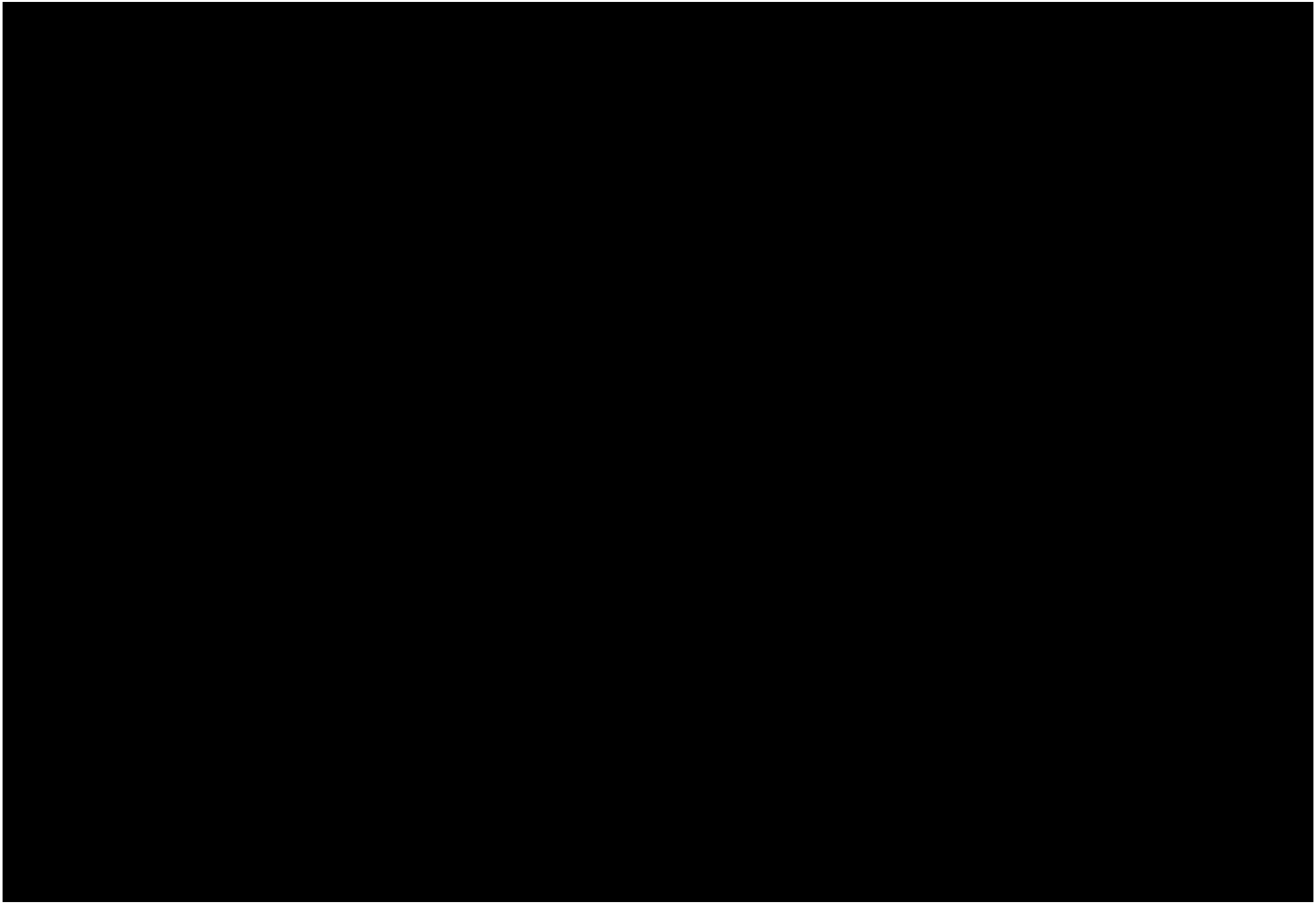
Annual Winter Coincident Peak

United Power, Inc.



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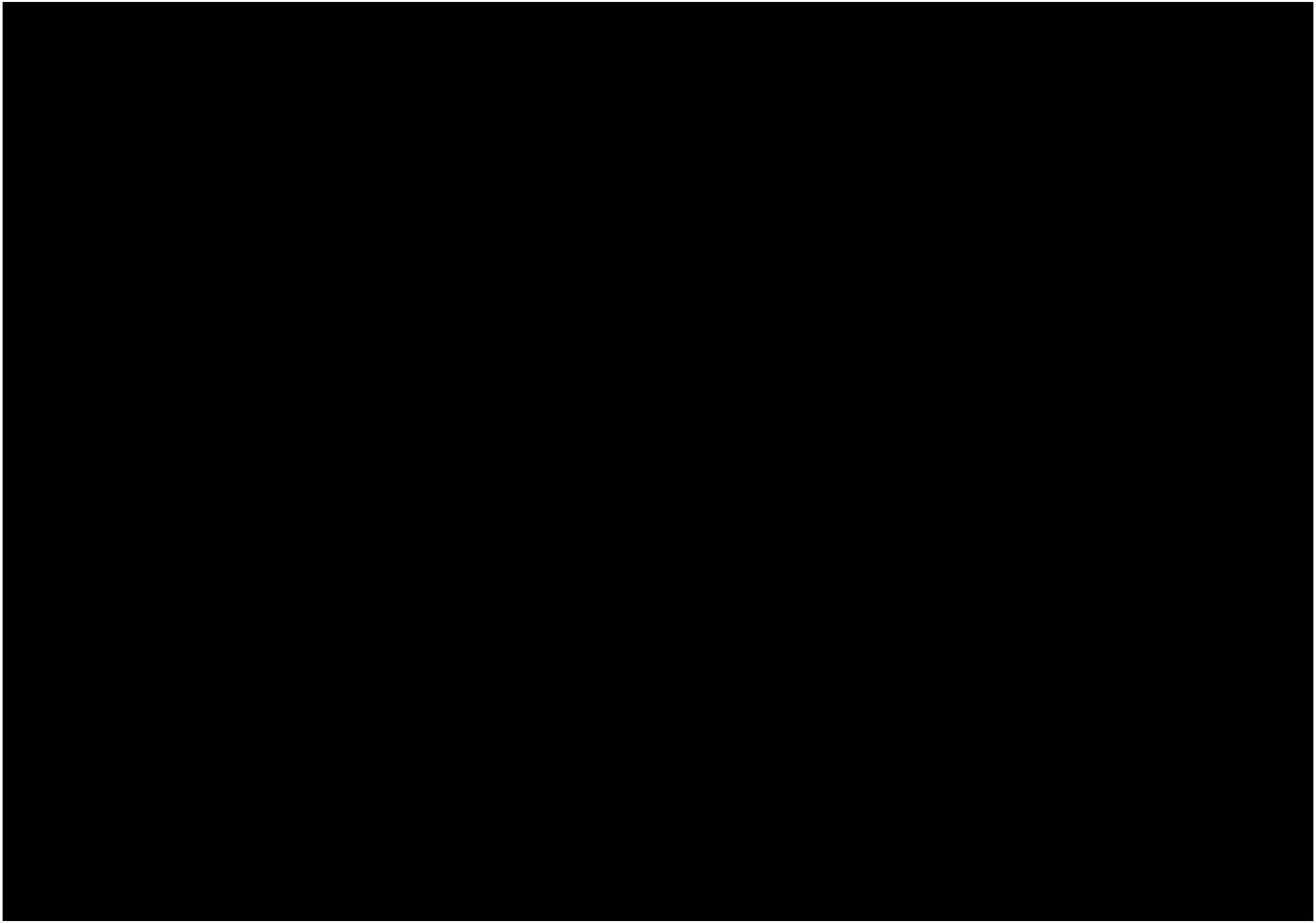
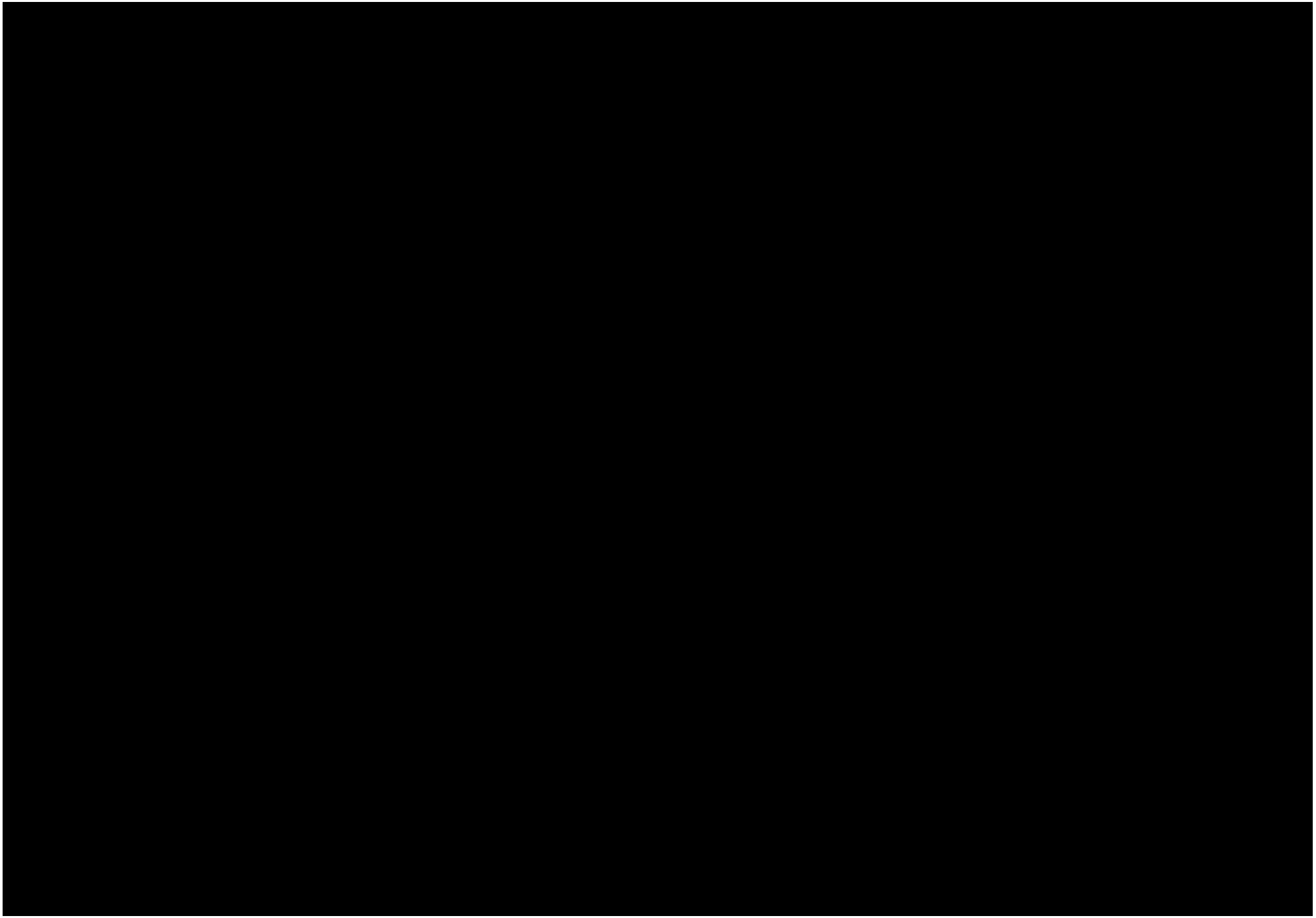
Annual Winter Coincident Peak

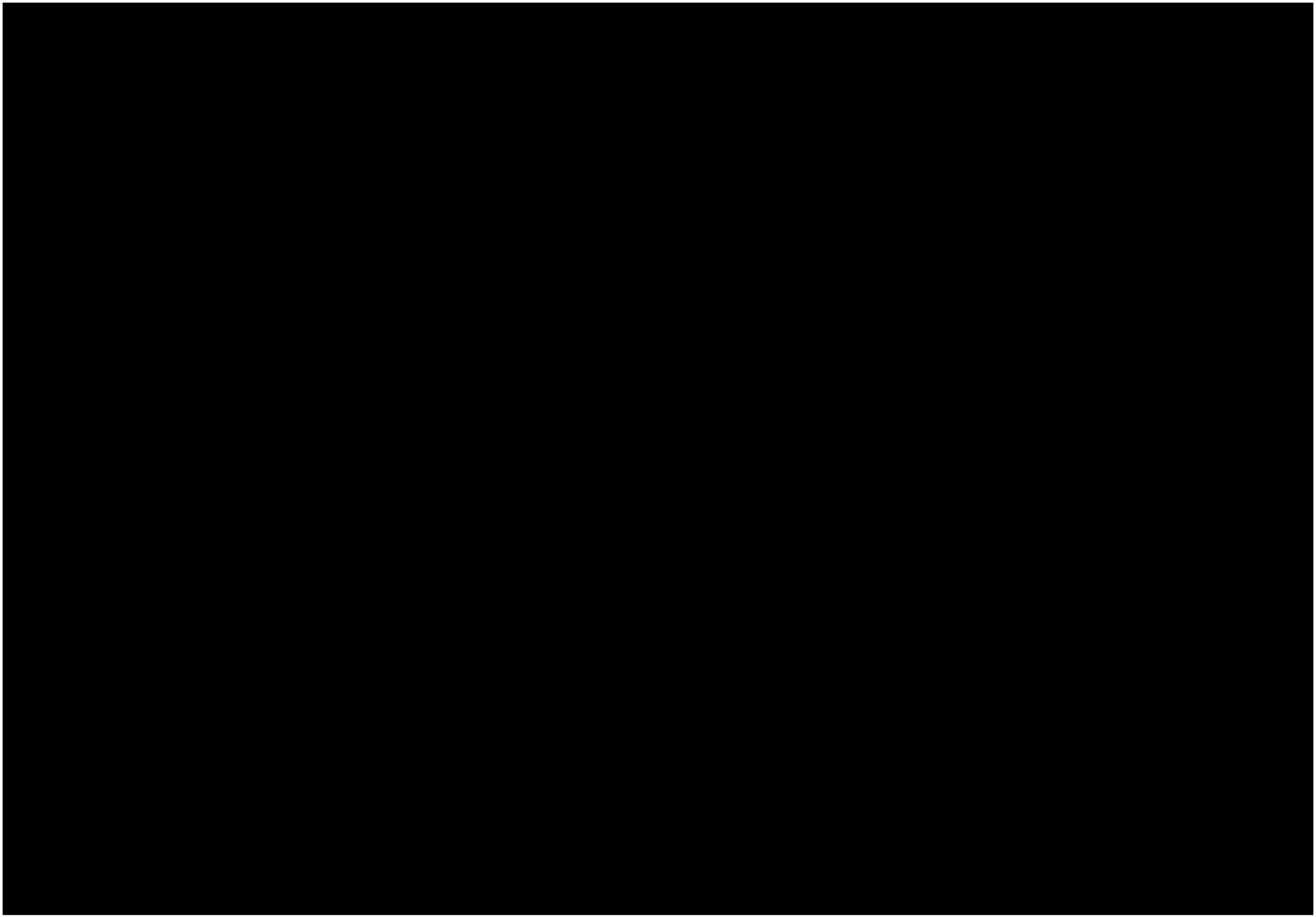
Wheat Belt Public Power District



Annual Winter Coincident Peak
Wheatland Rural Electric Association, Inc.



Annual Winter Coincident Peak
White River Electric Association, Inc.



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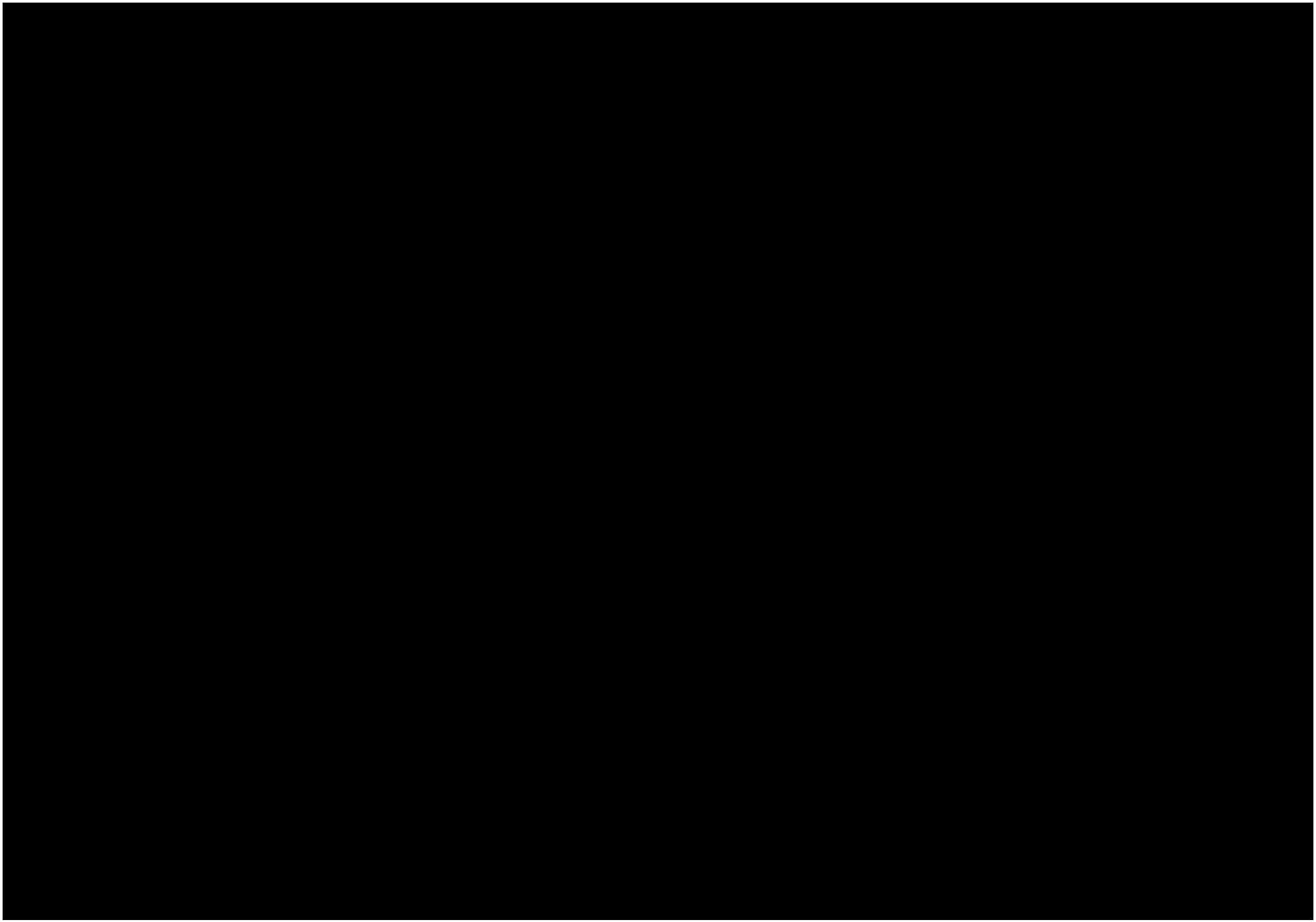
Annual Winter Coincident Peak

Wyrulec Company



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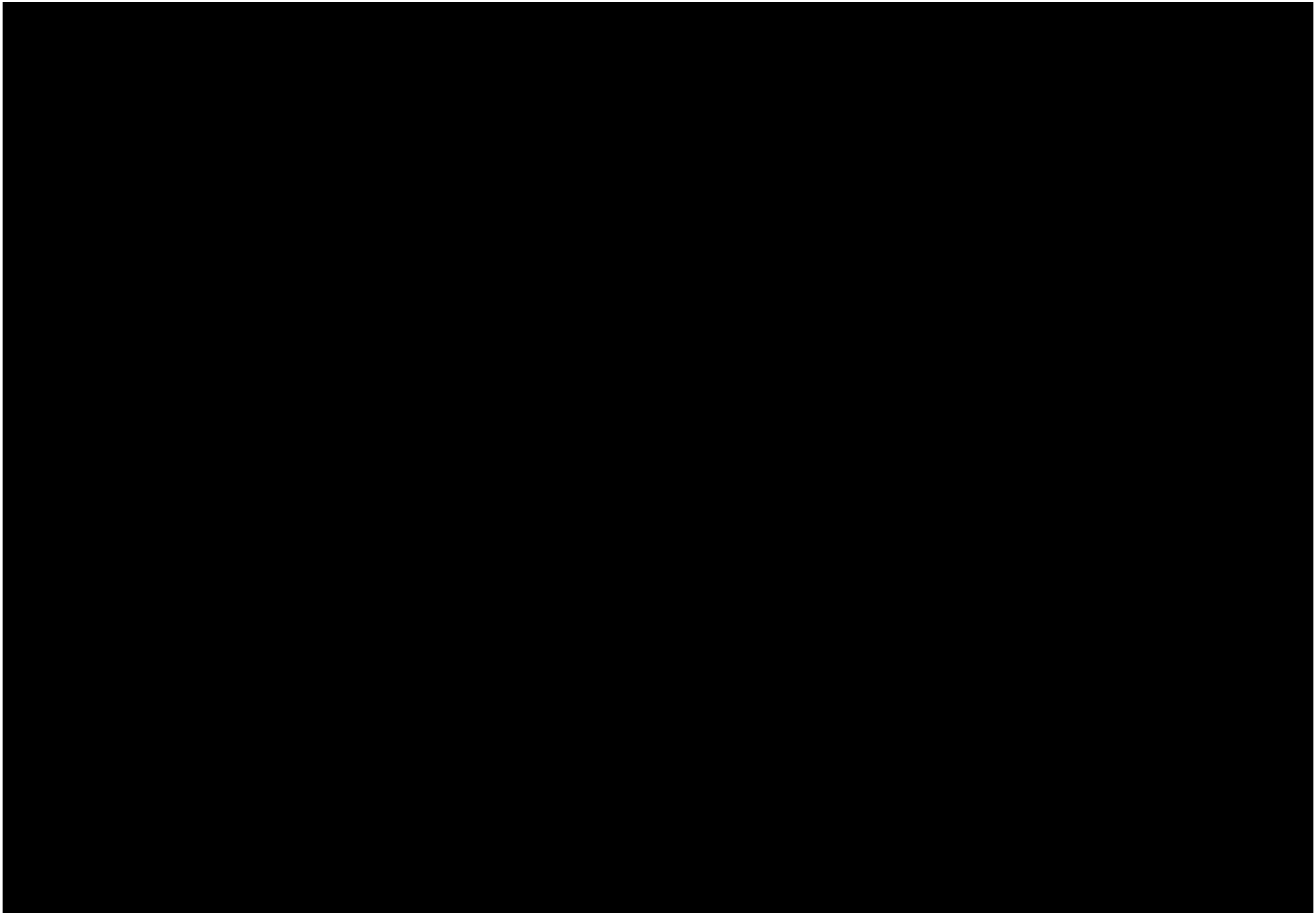
Annual Winter Coincident Peak

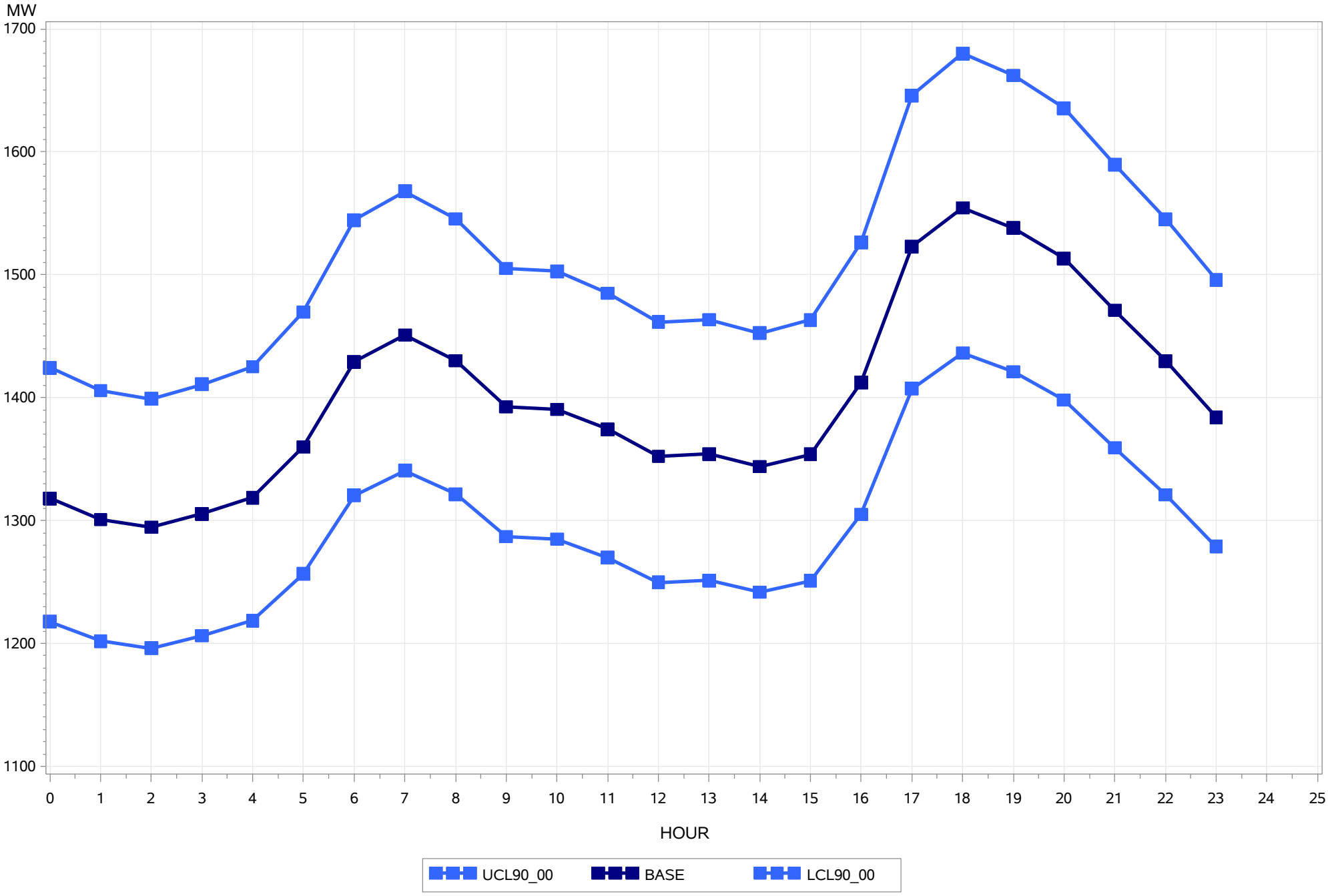
Y-W Electric Association, Inc.



Member Forecasted On Peak Demand Day for January 2021

STATE OF COLORADO

Date of On Peak Day - 01/06/2021



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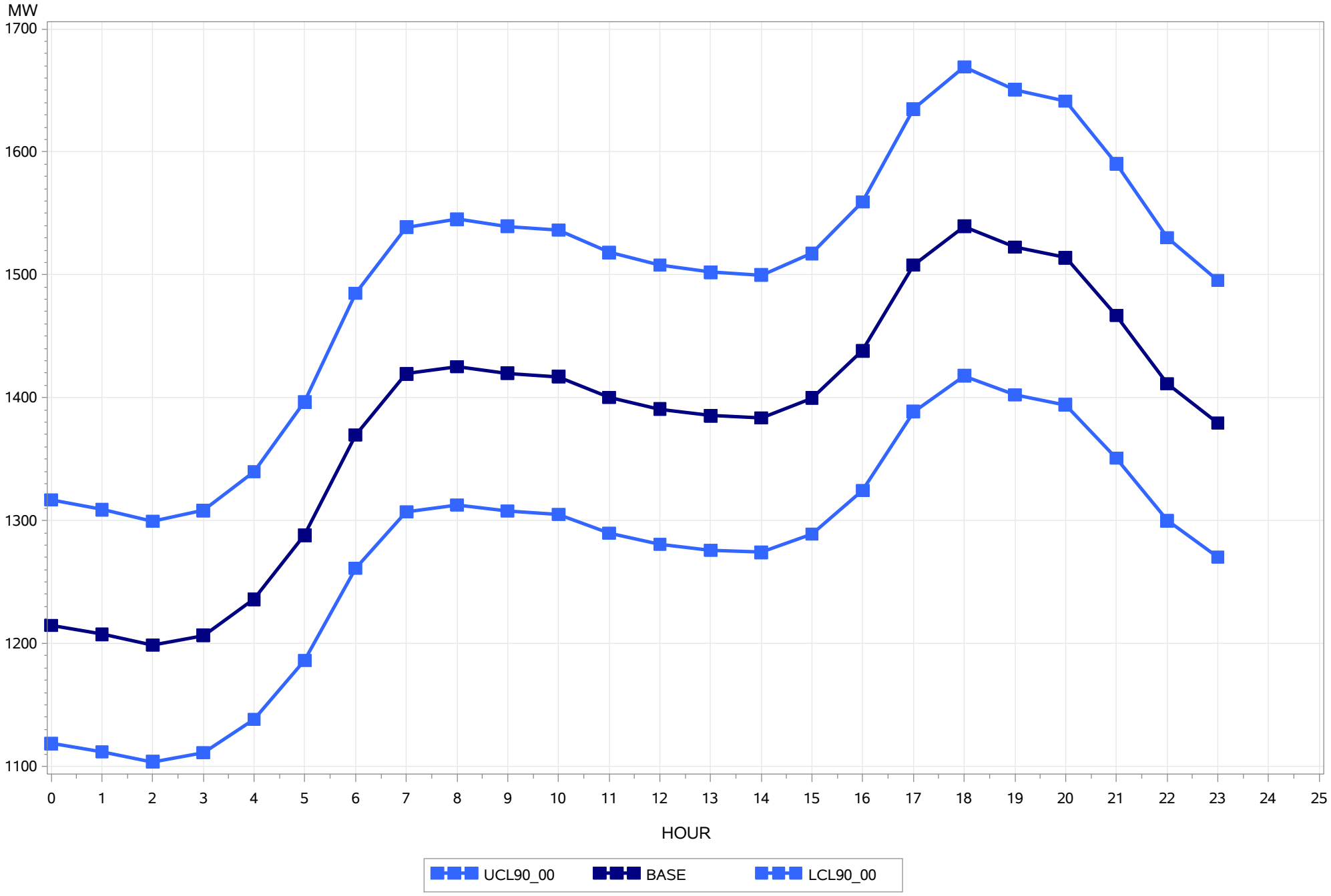
Member Forecasted On Peak Demand Day for February 2021

STATE OF COLORADO

Date of On Peak Day - 02/01/2021



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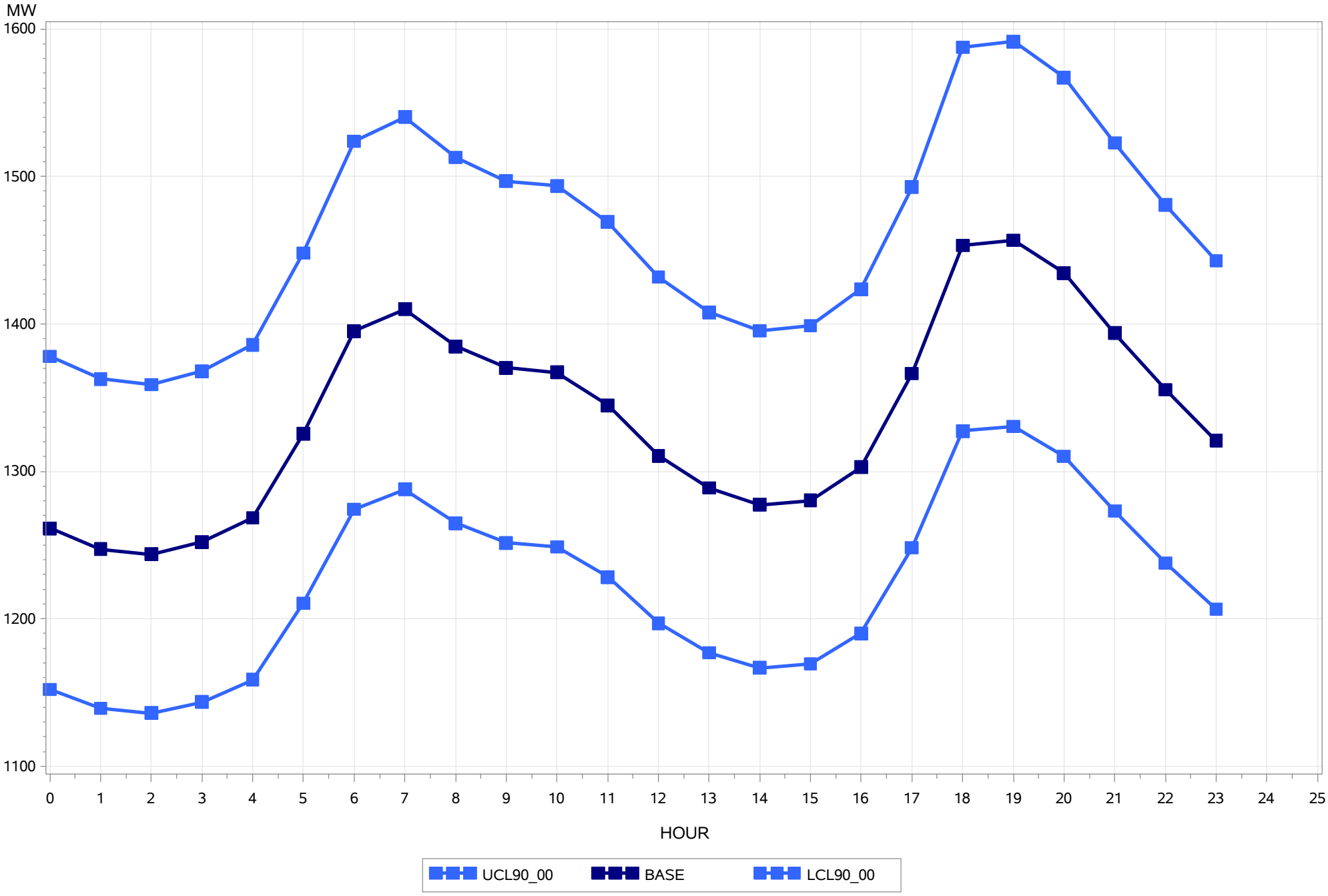
Member Forecasted On Peak Demand Day for March 2021

STATE OF COLORADO

Date of On Peak Day - 03/01/2021



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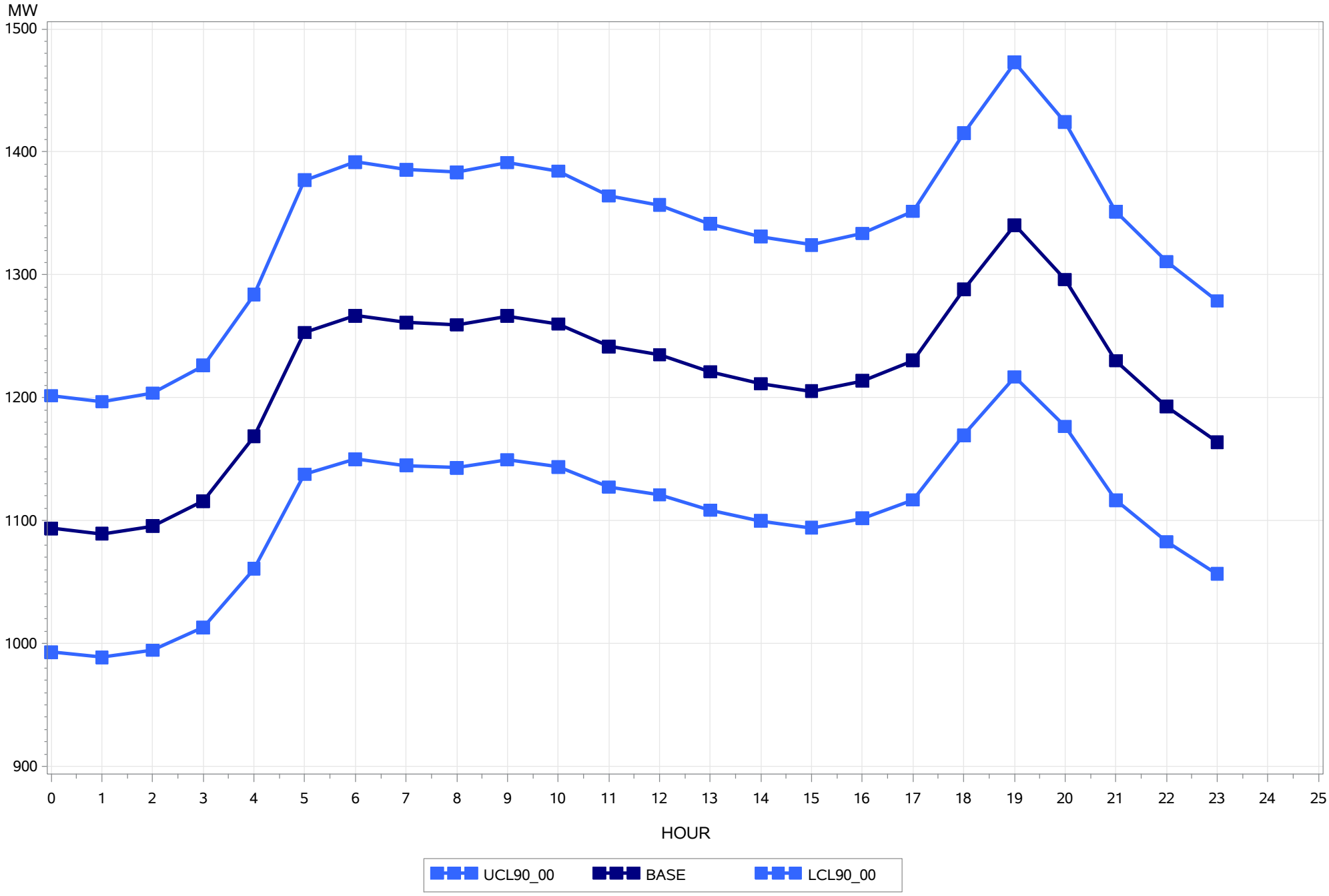
Member Forecasted On Peak Demand Day for April 2021

STATE OF COLORADO

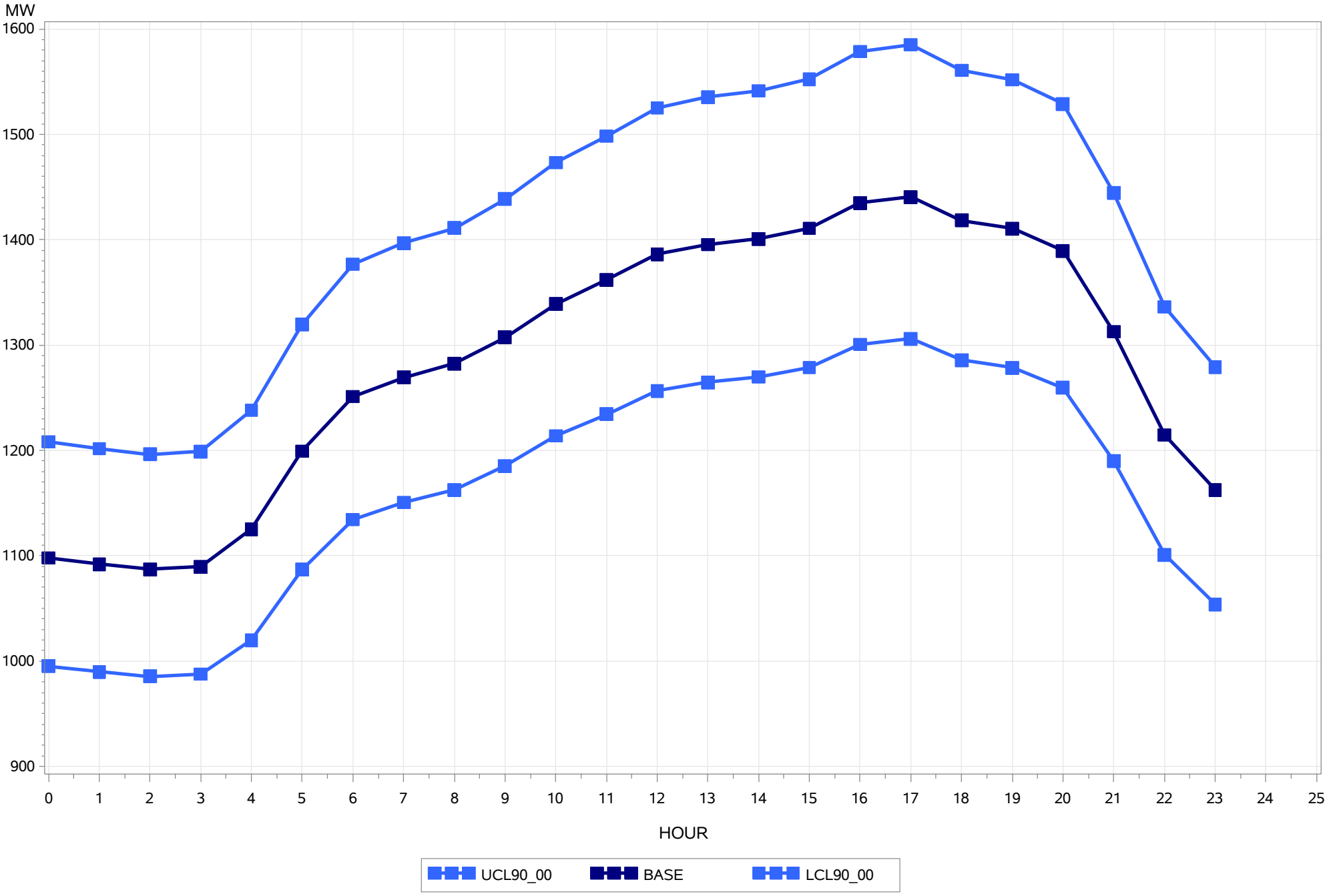
Date of On Peak Day - 04/15/2021



Member Forecasted On Peak Demand Day for May 2021

STATE OF COLORADO

Date of On Peak Day - 05/31/2021



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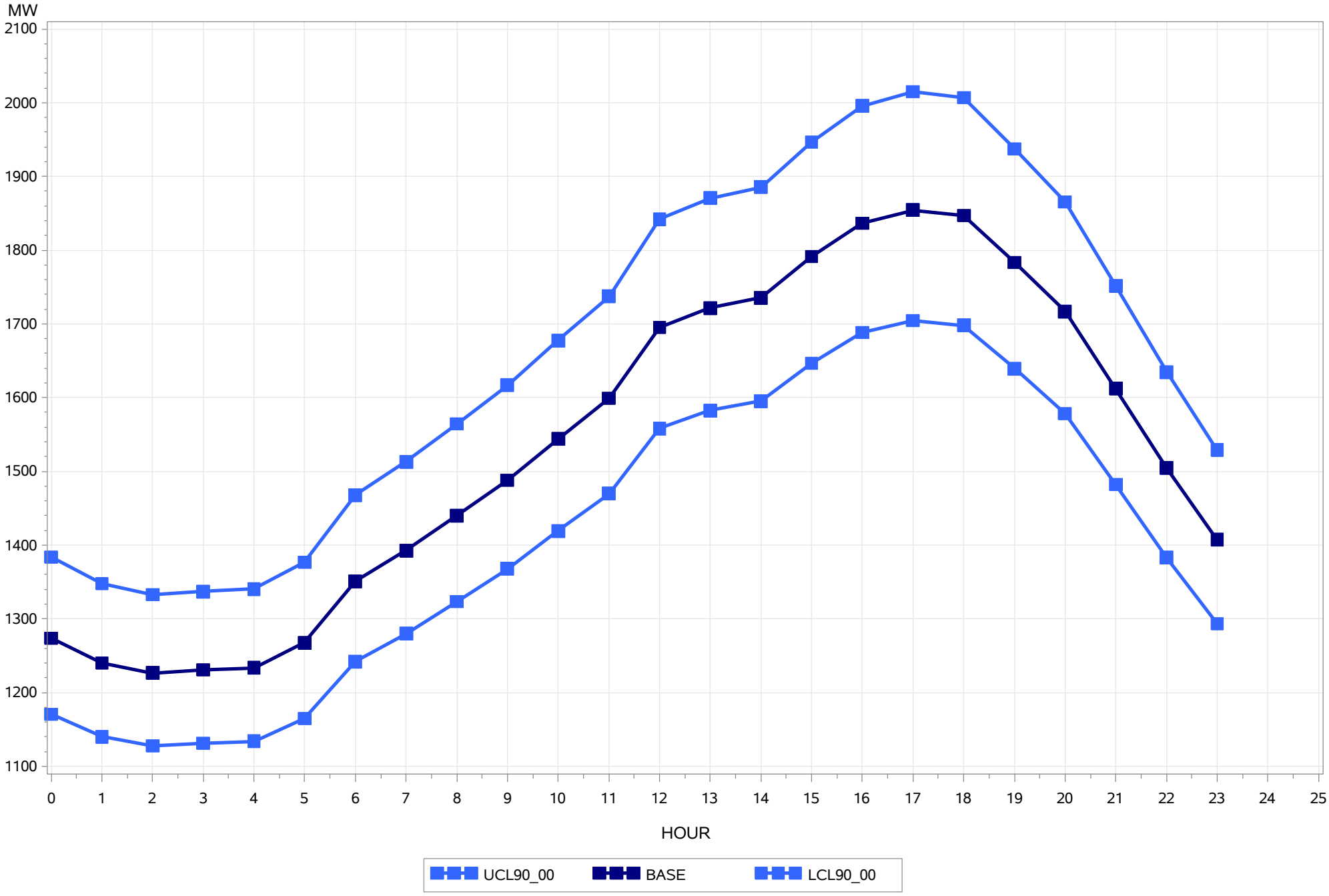
Member Forecasted On Peak Demand Day for June 2021

STATE OF COLORADO

Date of On Peak Day - 06/28/2021



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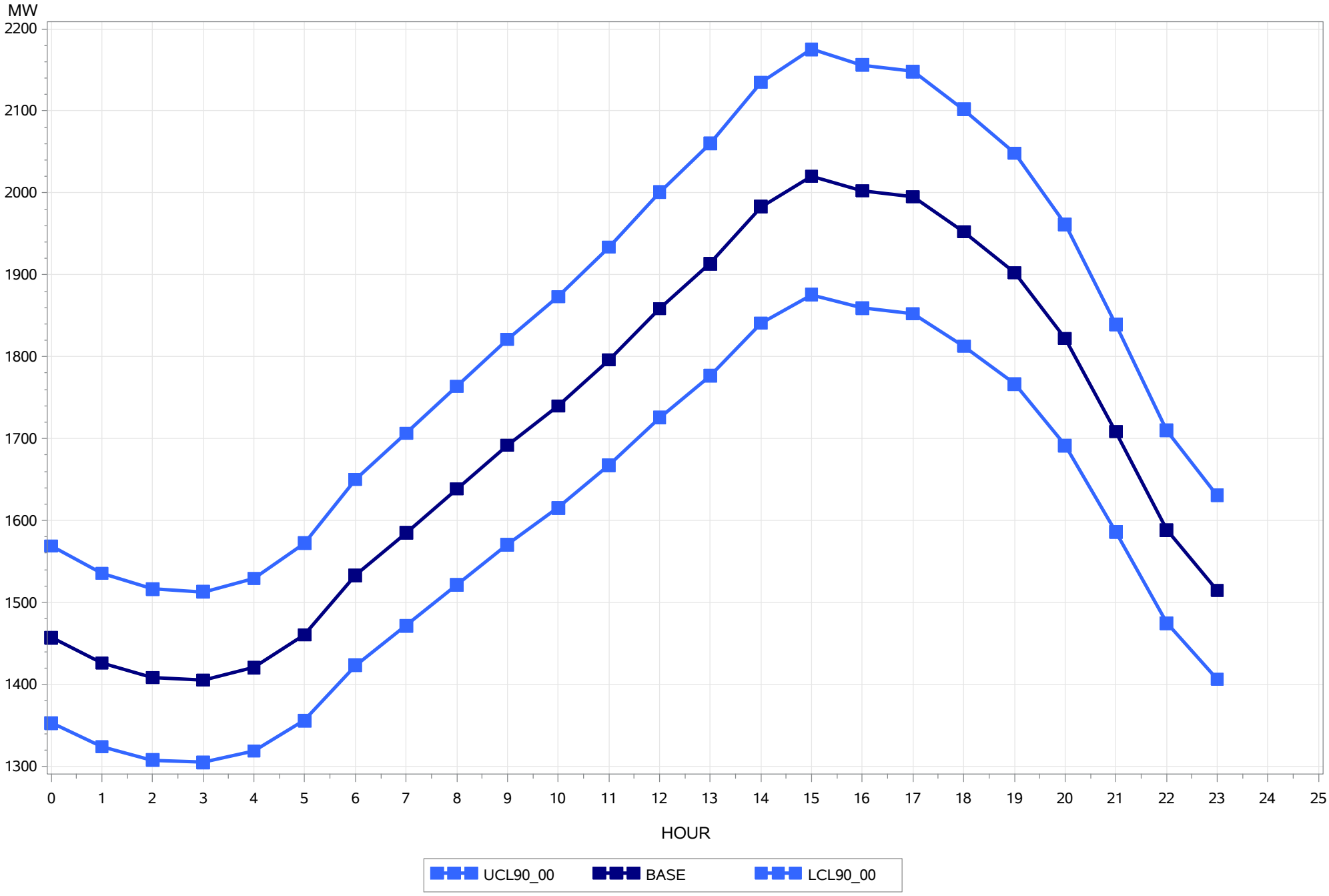
Member Forecasted On Peak Demand Day for July 2021

STATE OF COLORADO

Date of On Peak Day - 07/22/2021



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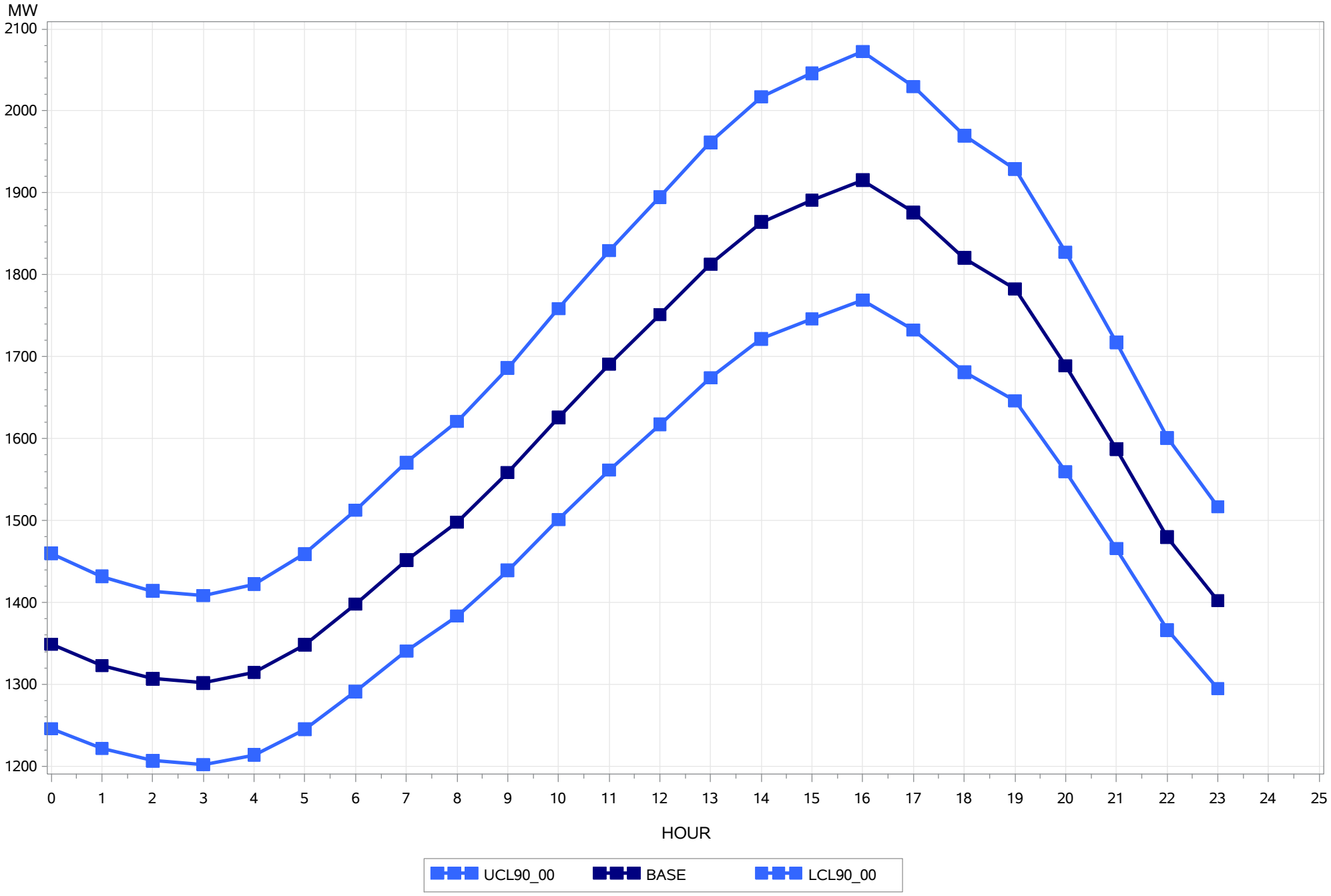
Member Forecasted On Peak Demand Day for August 2021

STATE OF COLORADO

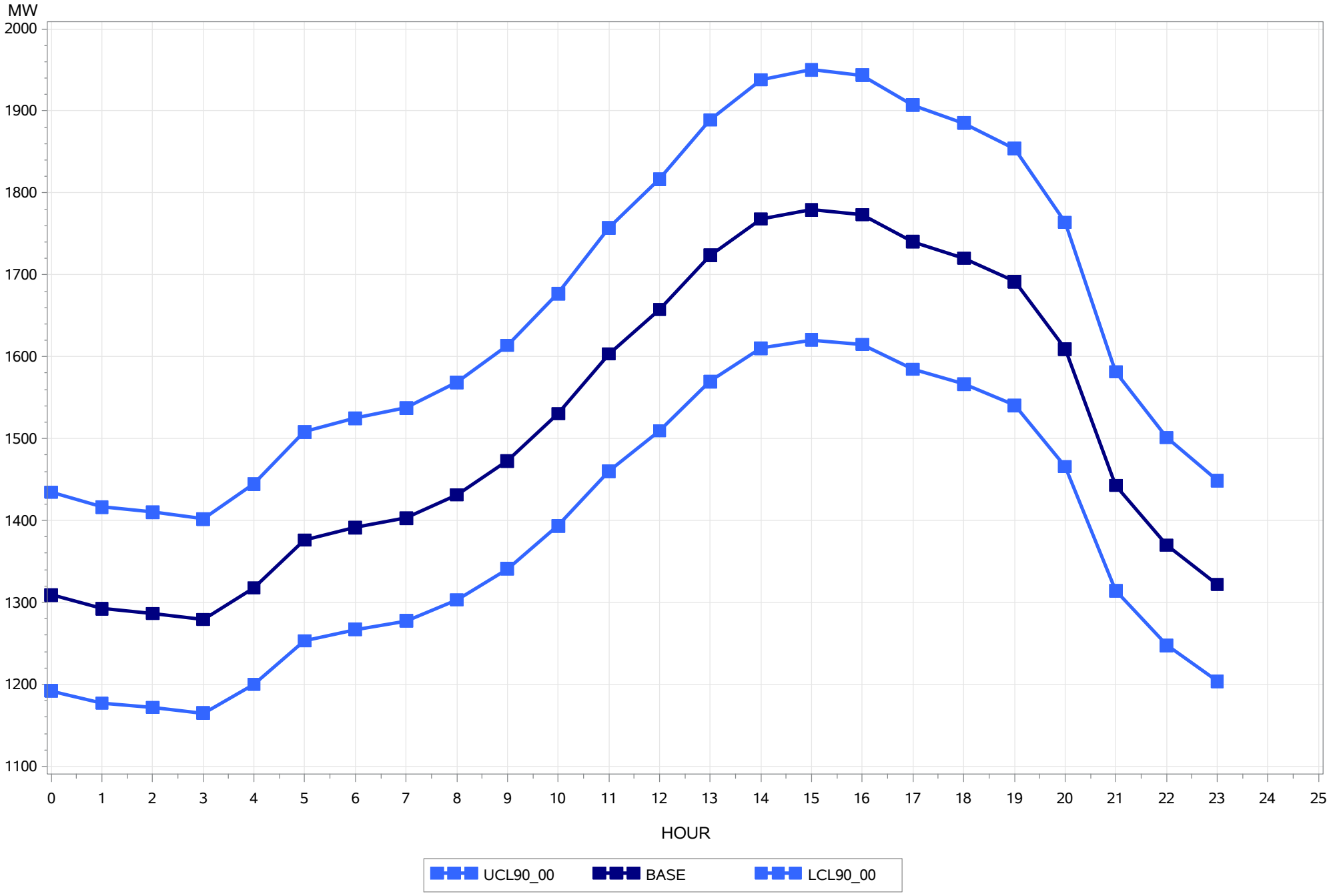
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF COLORADO

Date of On Peak Day - 09/01/2021



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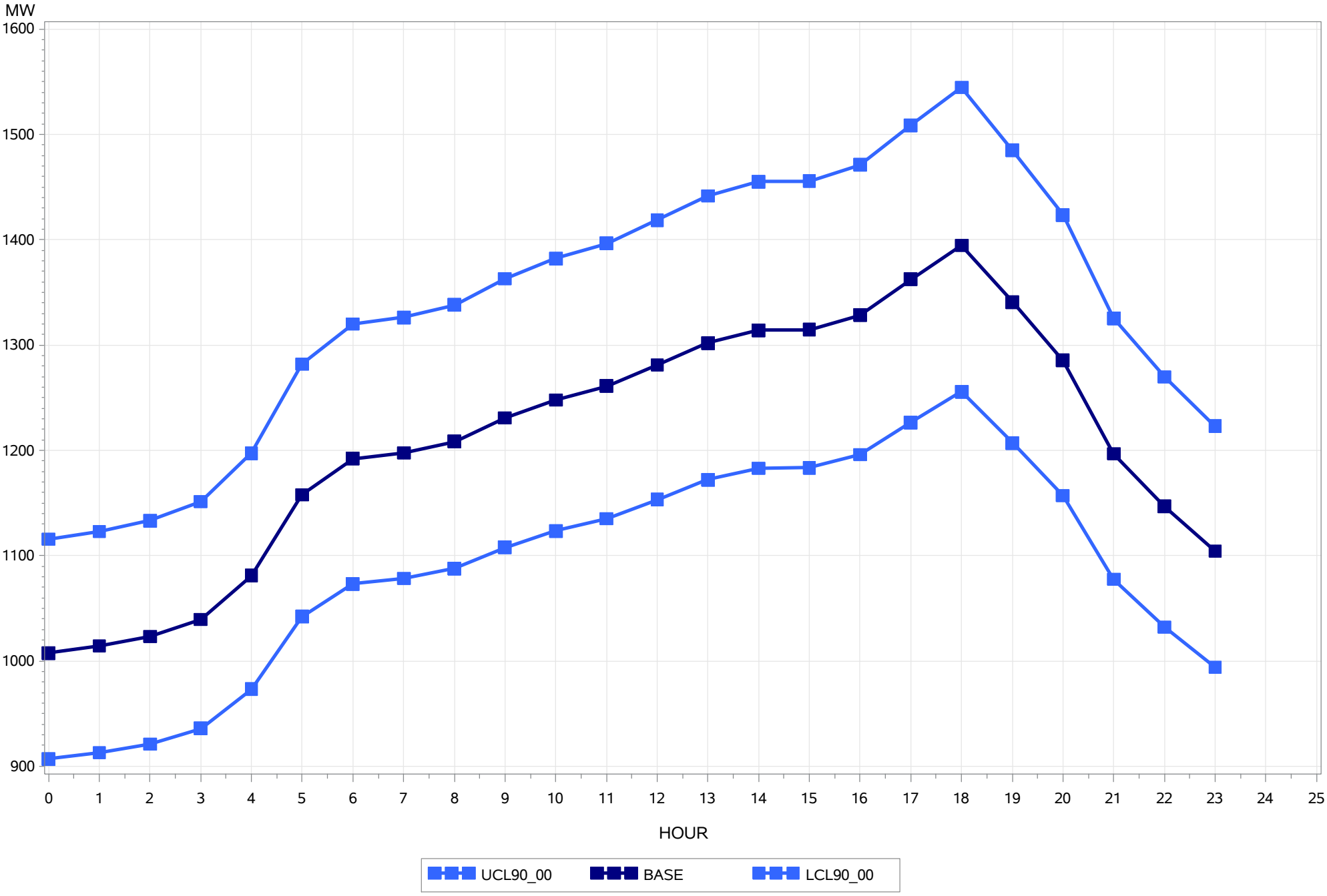
Member Forecasted On Peak Demand Day for October 2021

STATE OF COLORADO

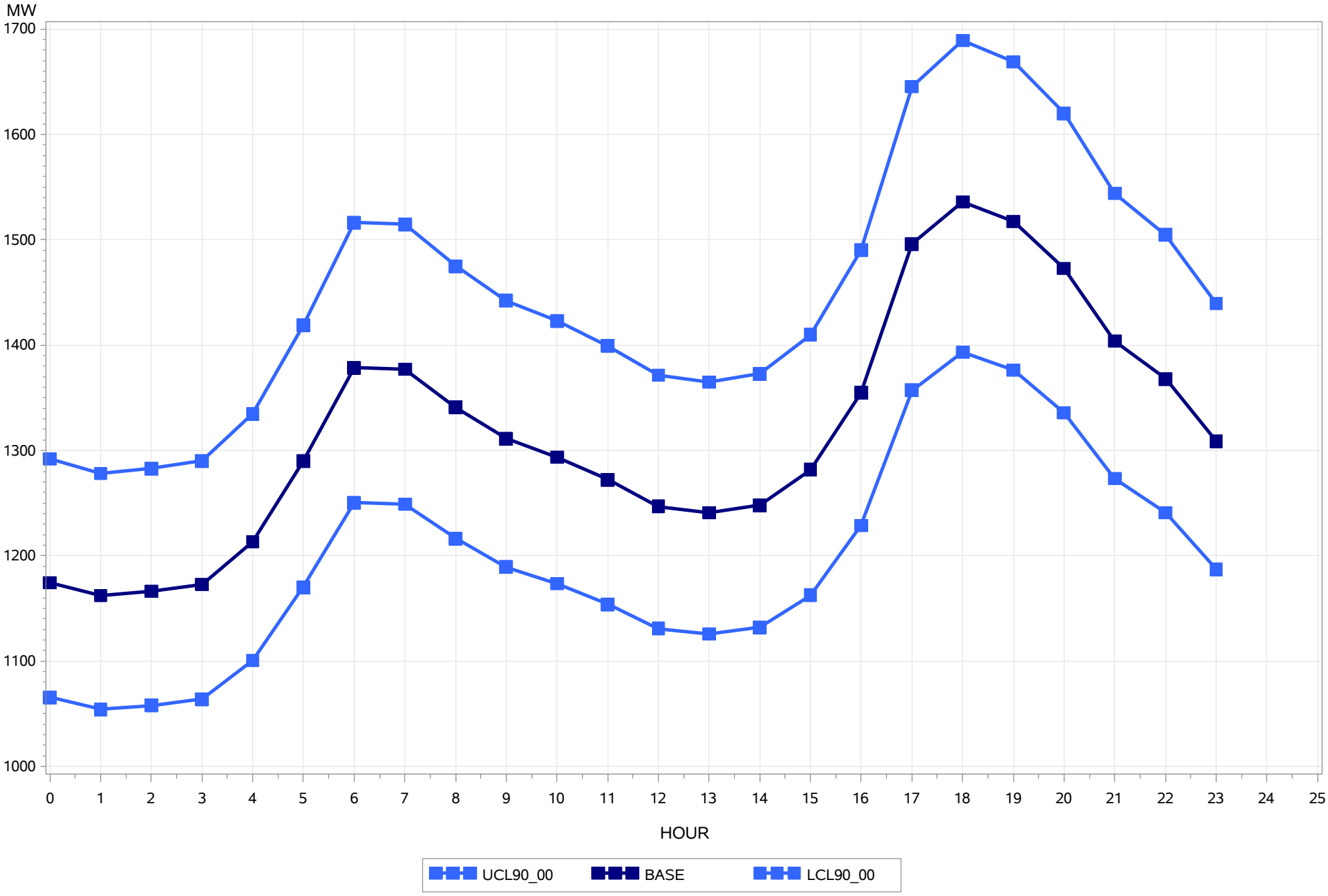
Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF COLORADO

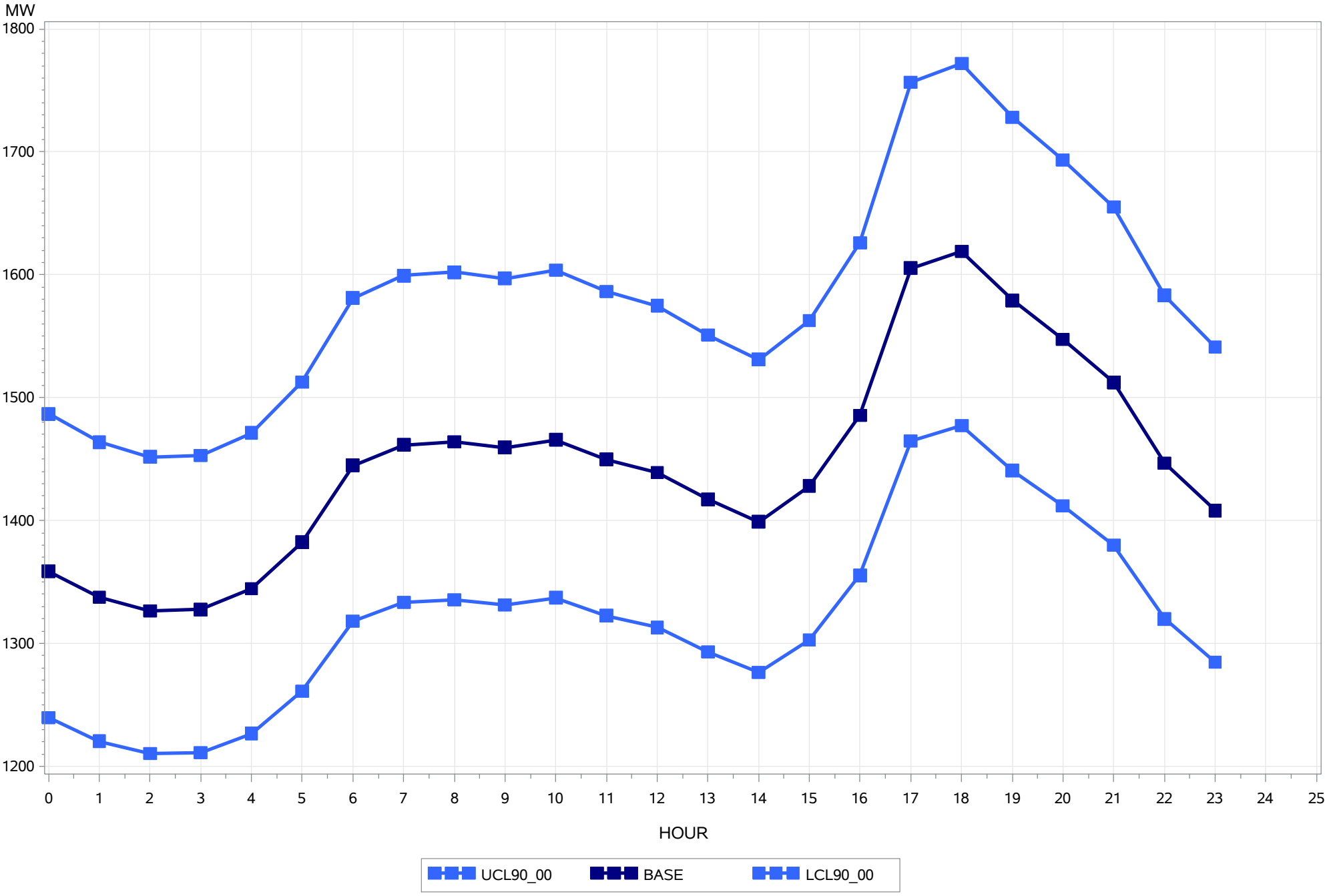
Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

STATE OF COLORADO

Date of On Peak Day - 12/28/2021



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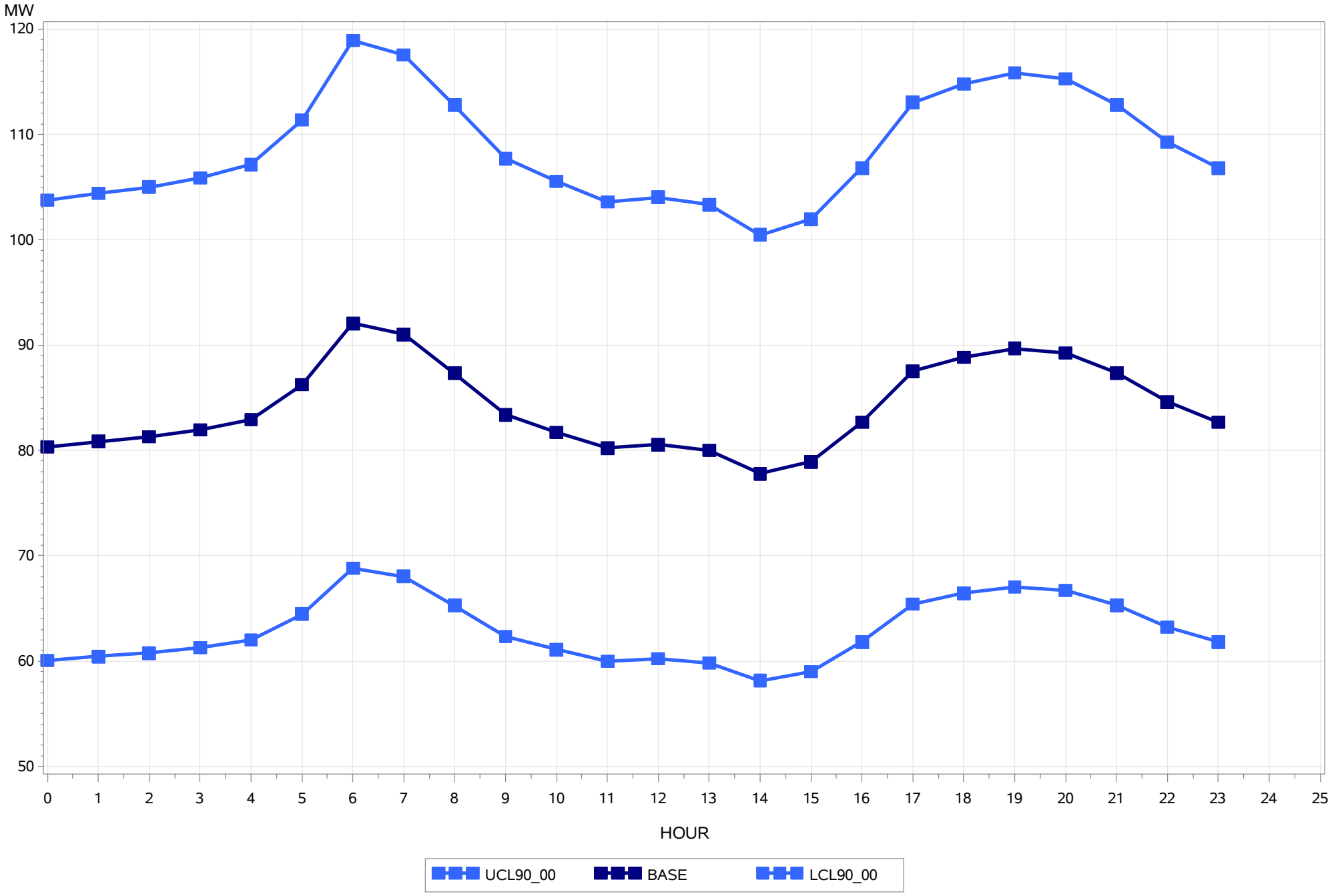
Member Forecasted On Peak Demand Day for January 2021

STATE OF NEBRASKA

Date of On Peak Day - 01/07/2021



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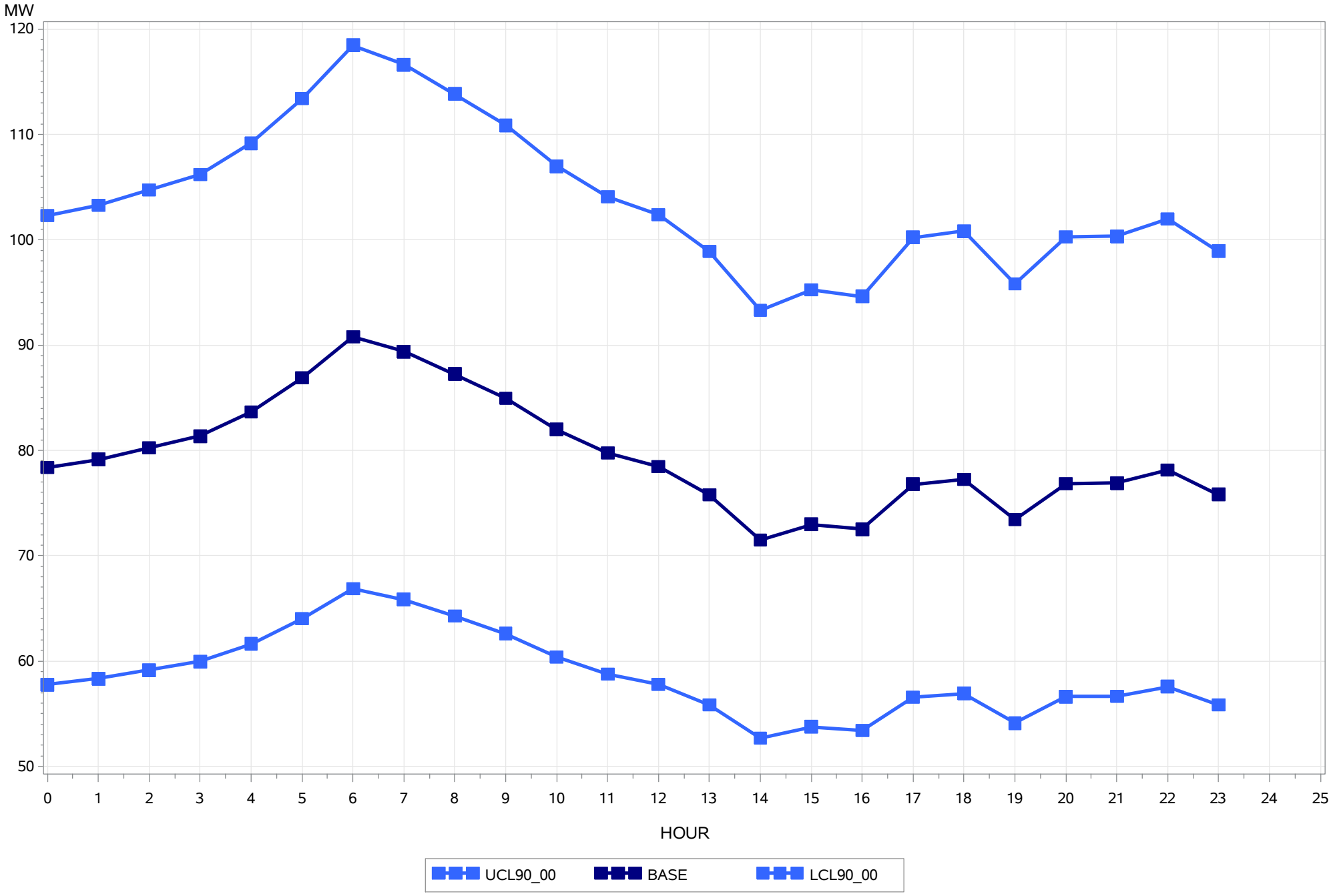
Member Forecasted On Peak Demand Day for February 2021

STATE OF NEBRASKA

Date of On Peak Day - 02/03/2021



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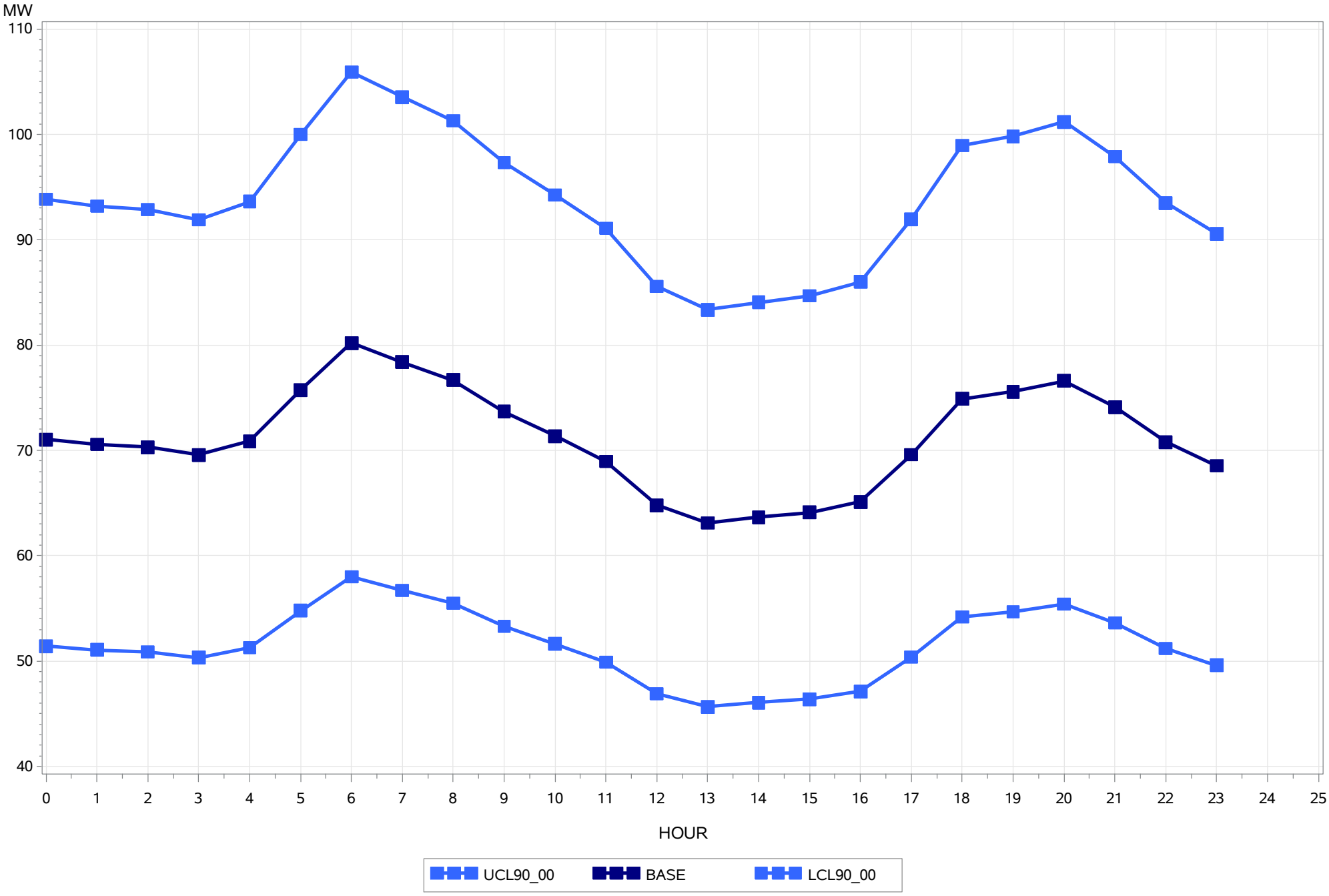
Member Forecasted On Peak Demand Day for March 2021

STATE OF NEBRASKA

Date of On Peak Day - 03/02/2021



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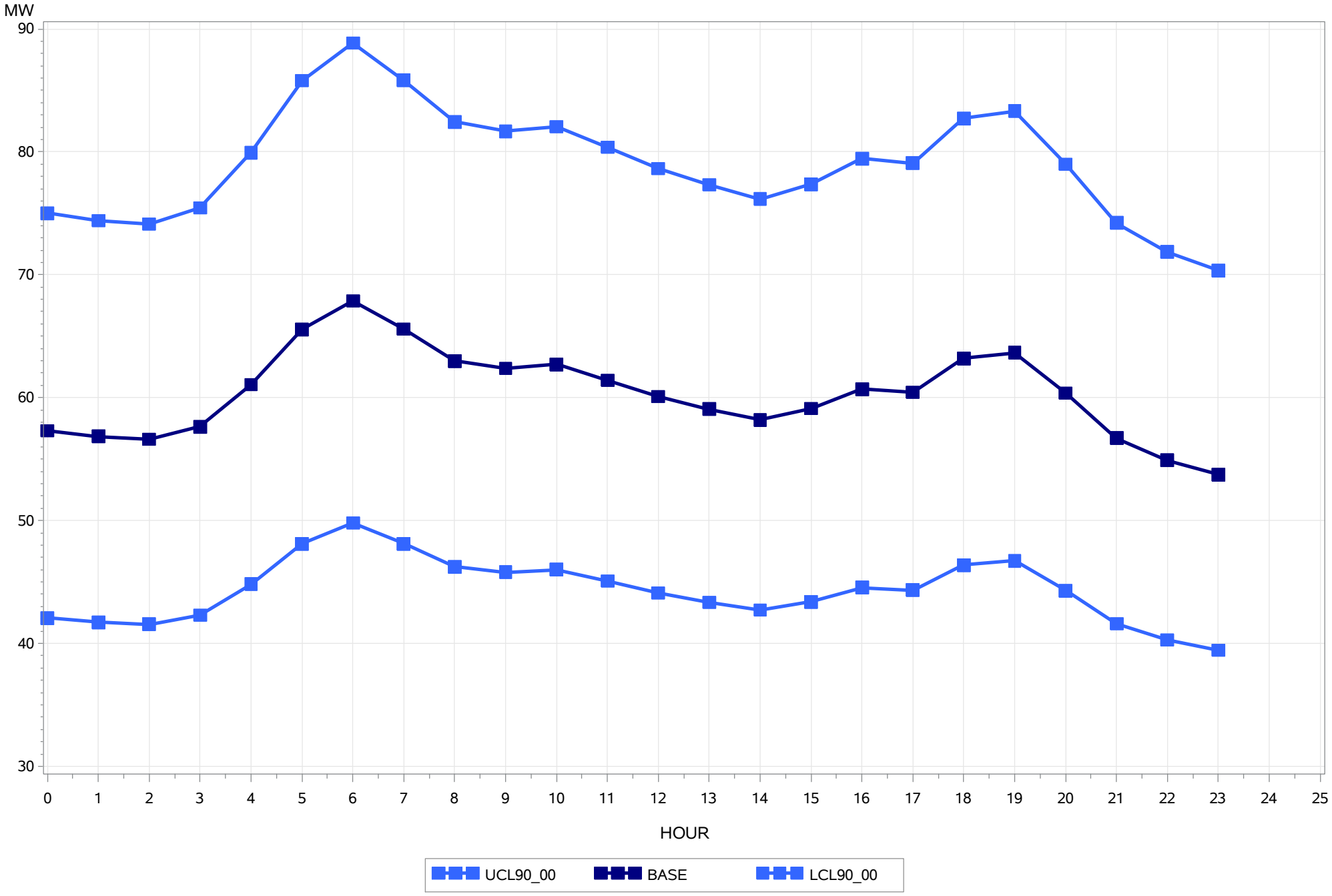
Member Forecasted On Peak Demand Day for April 2021

STATE OF NEBRASKA

Date of On Peak Day - 04/06/2021



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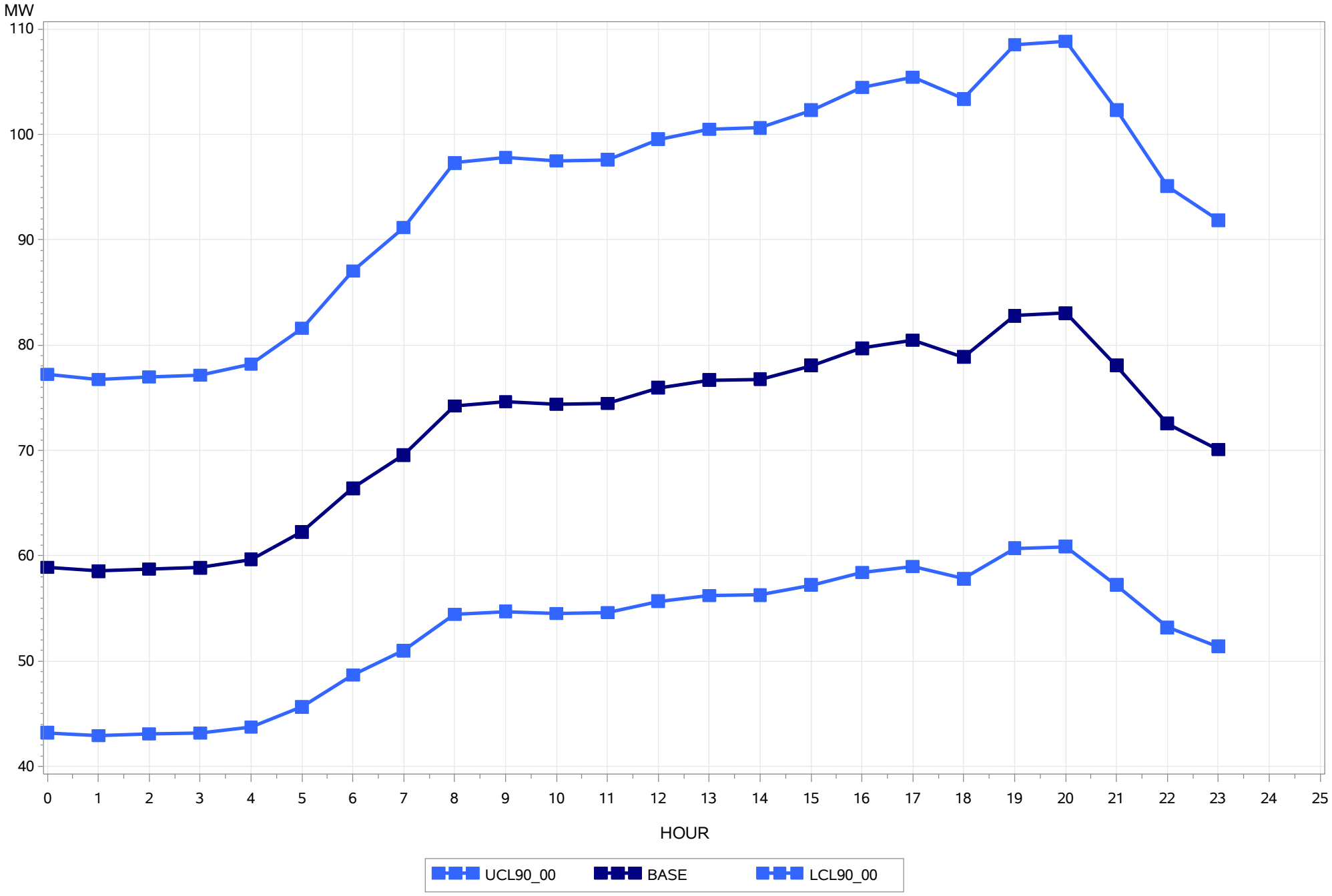
Member Forecasted On Peak Demand Day for May 2021

STATE OF NEBRASKA

Date of On Peak Day - 05/15/2021



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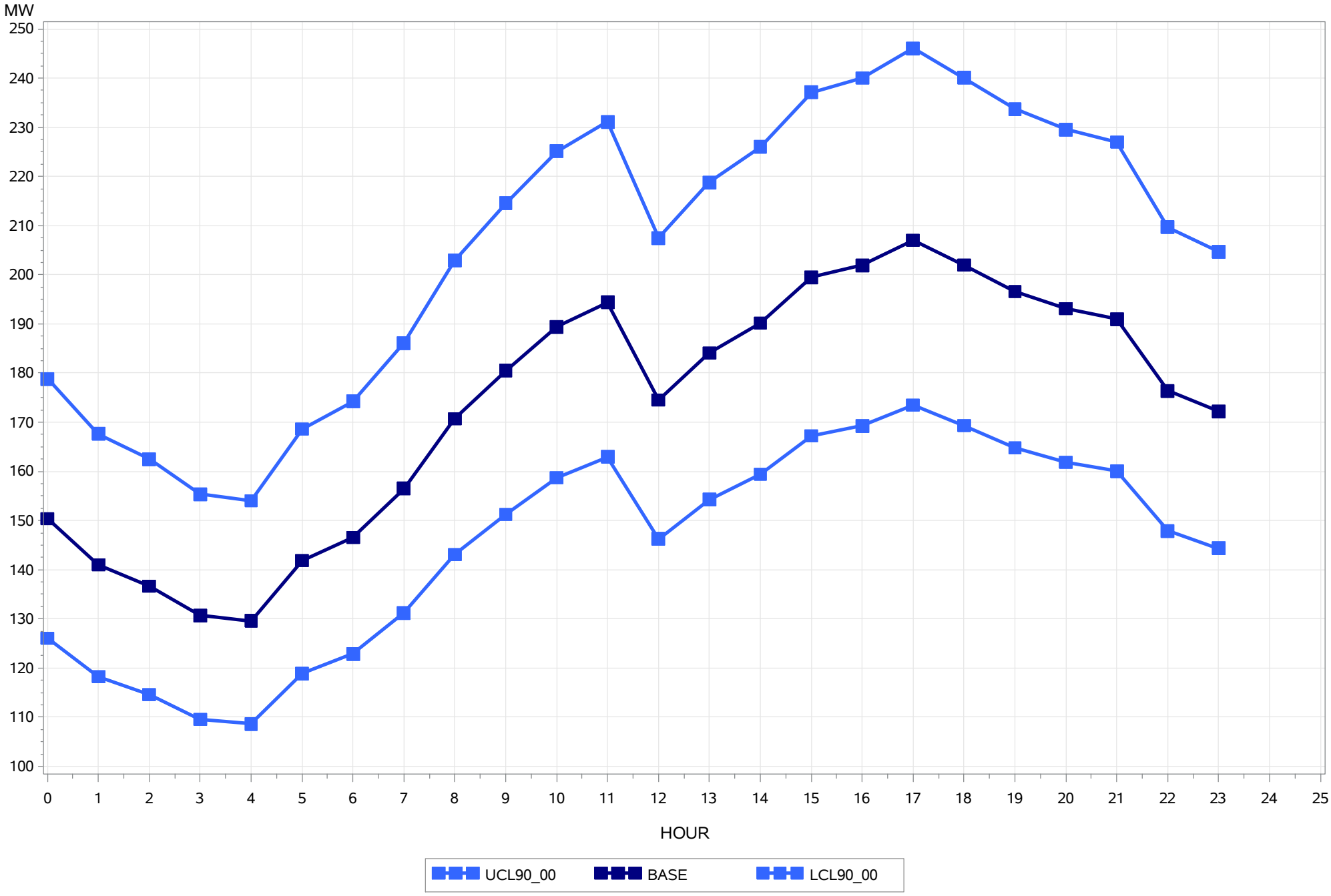
Member Forecasted On Peak Demand Day for June 2021

STATE OF NEBRASKA

Date of On Peak Day - 06/11/2021



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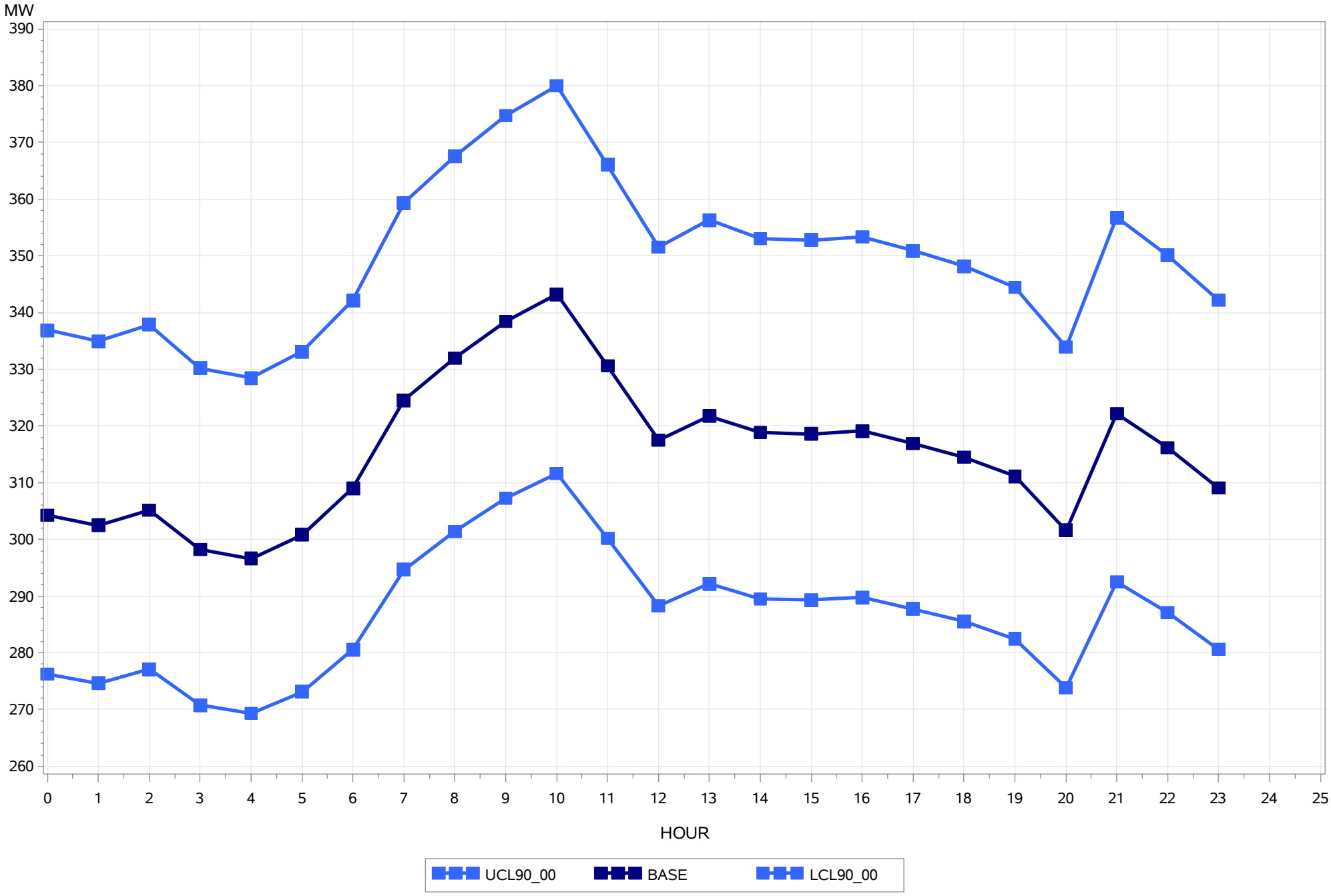
Member Forecasted On Peak Demand Day for July 2021

STATE OF NEBRASKA

Date of On Peak Day - 07/14/2021



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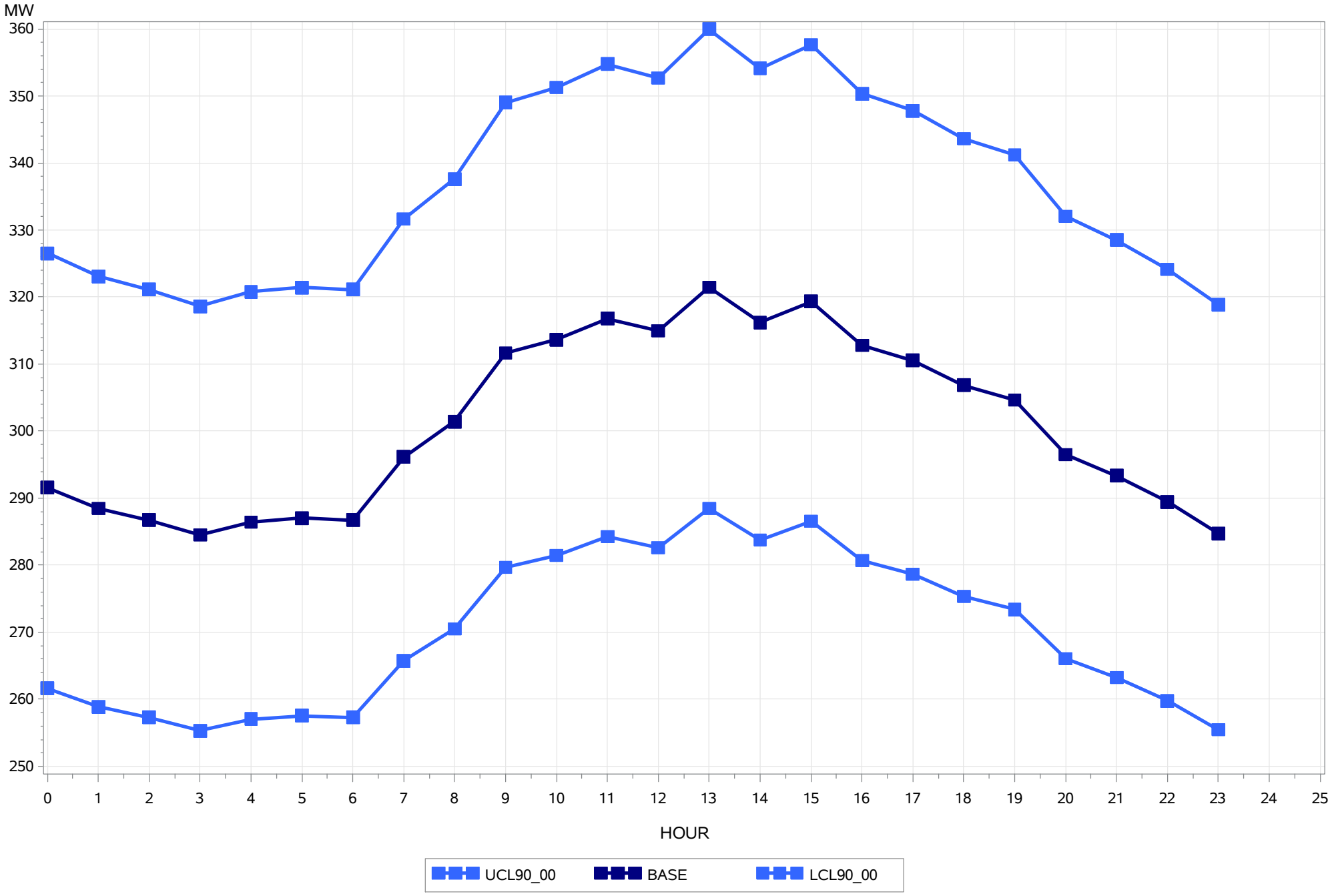
Member Forecasted On Peak Demand Day for August 2021

STATE OF NEBRASKA

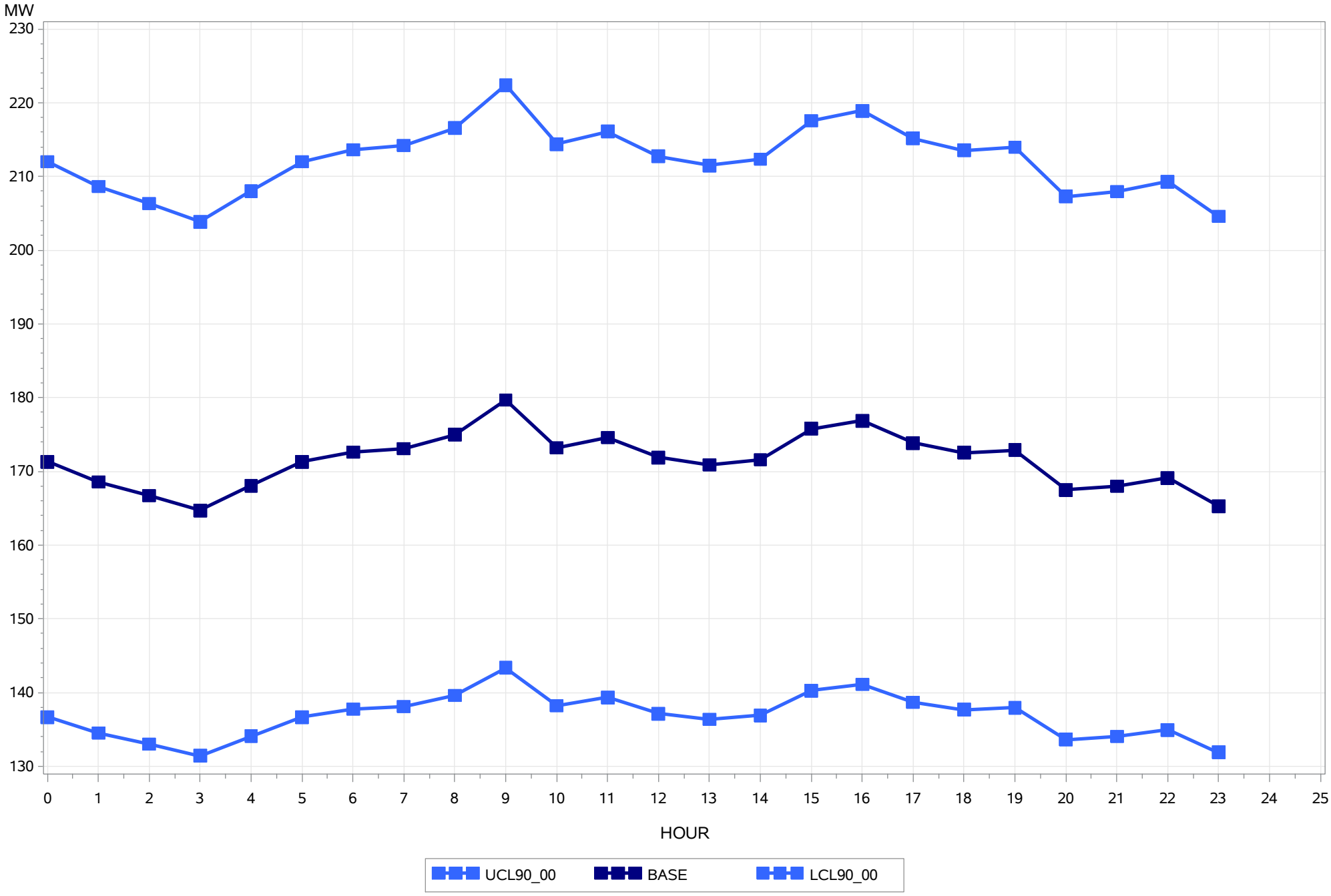
Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEBRASKA

Date of On Peak Day - 09/01/2021



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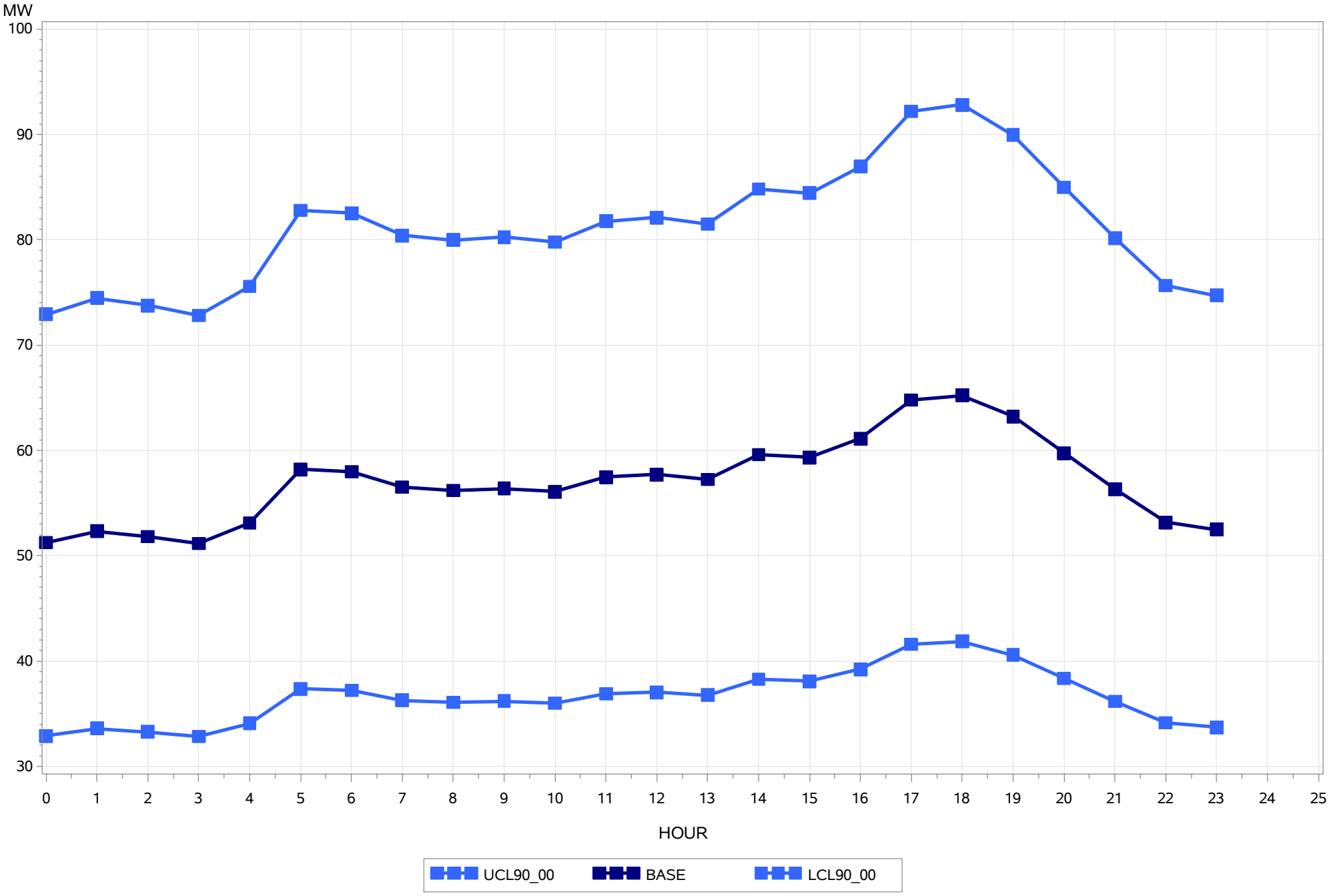
Member Forecasted On Peak Demand Day for October 2021

STATE OF NEBRASKA

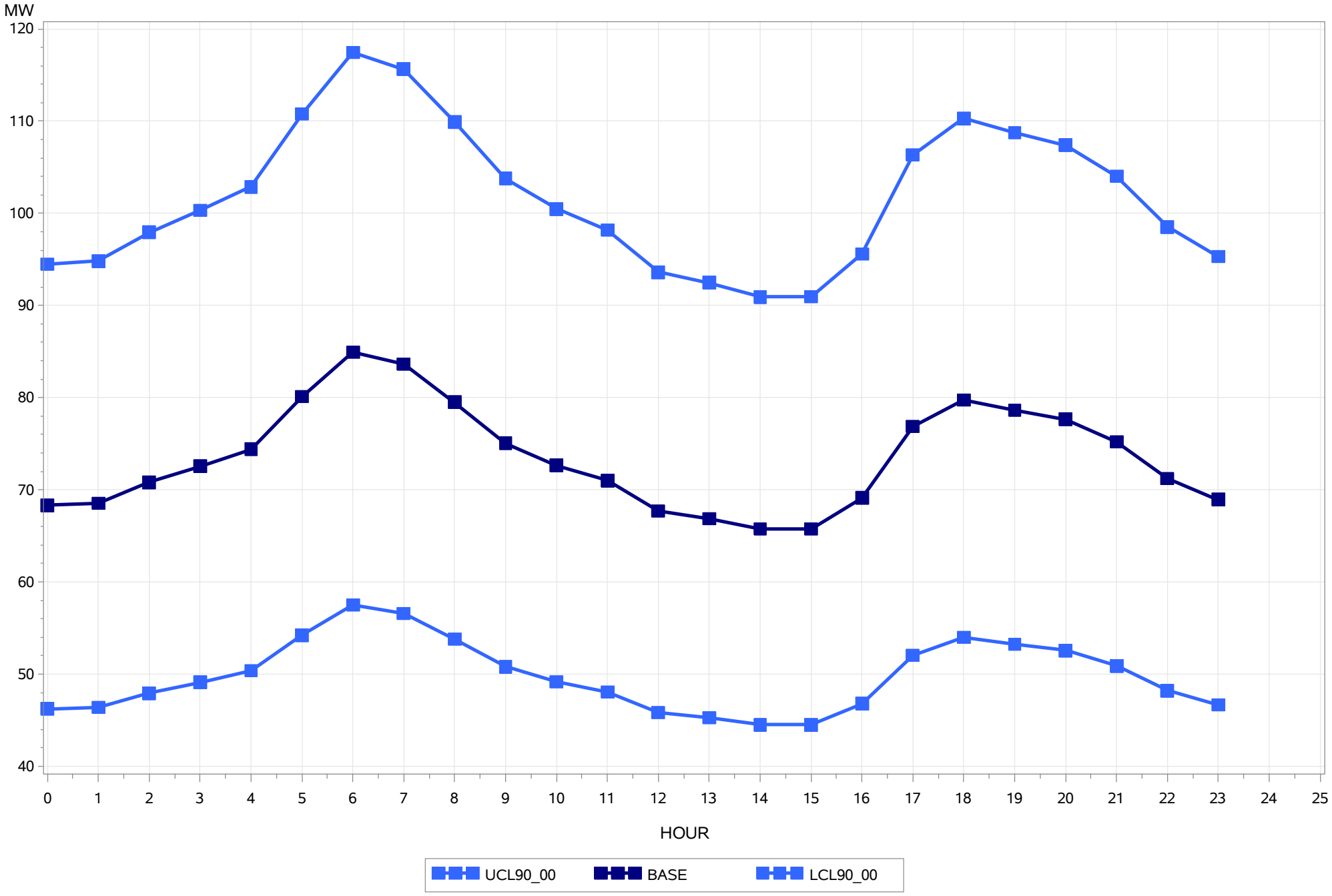
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEBRASKA

Date of On Peak Day - 11/09/2021



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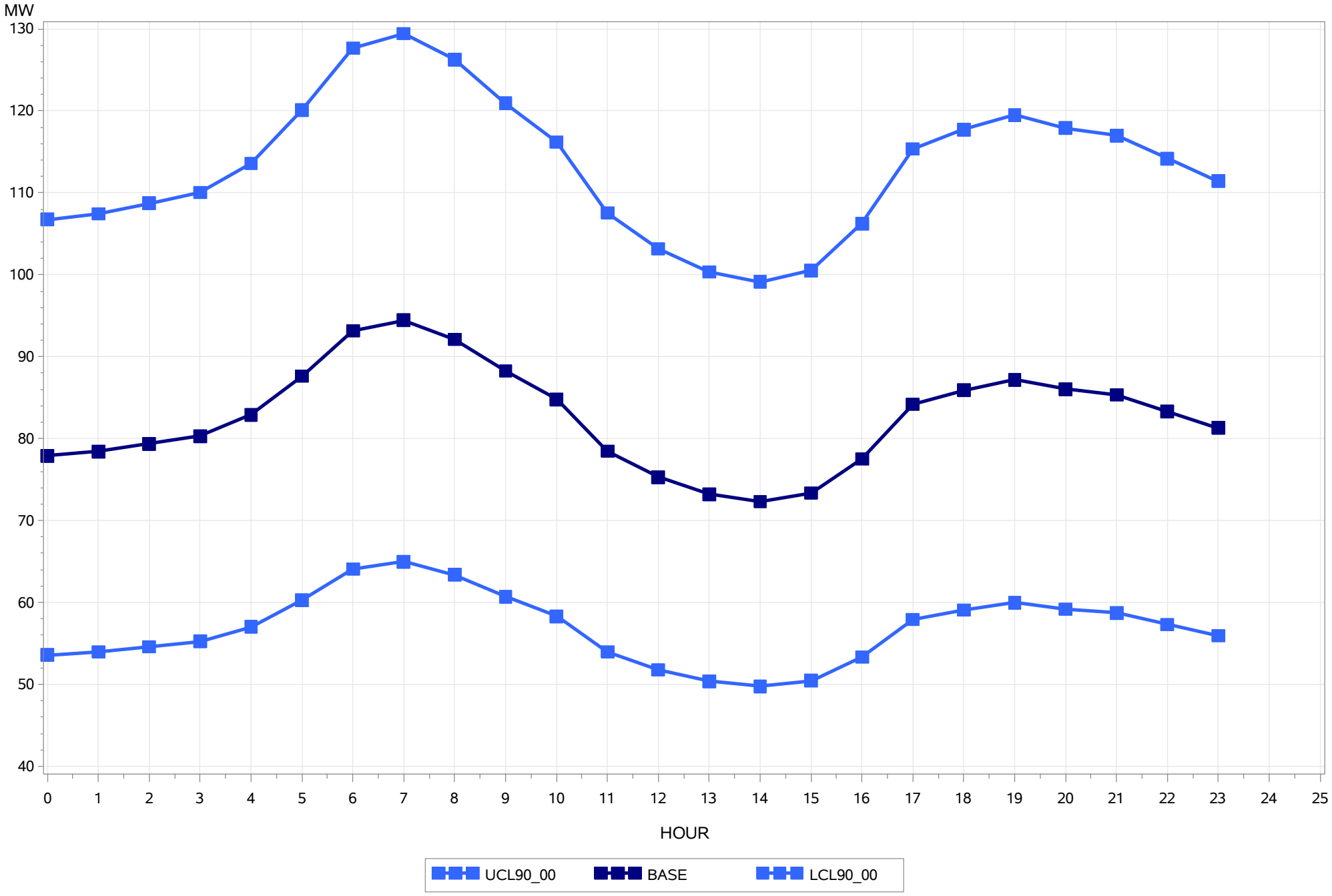
Member Forecasted On Peak Demand Day for December 2021

STATE OF NEBRASKA

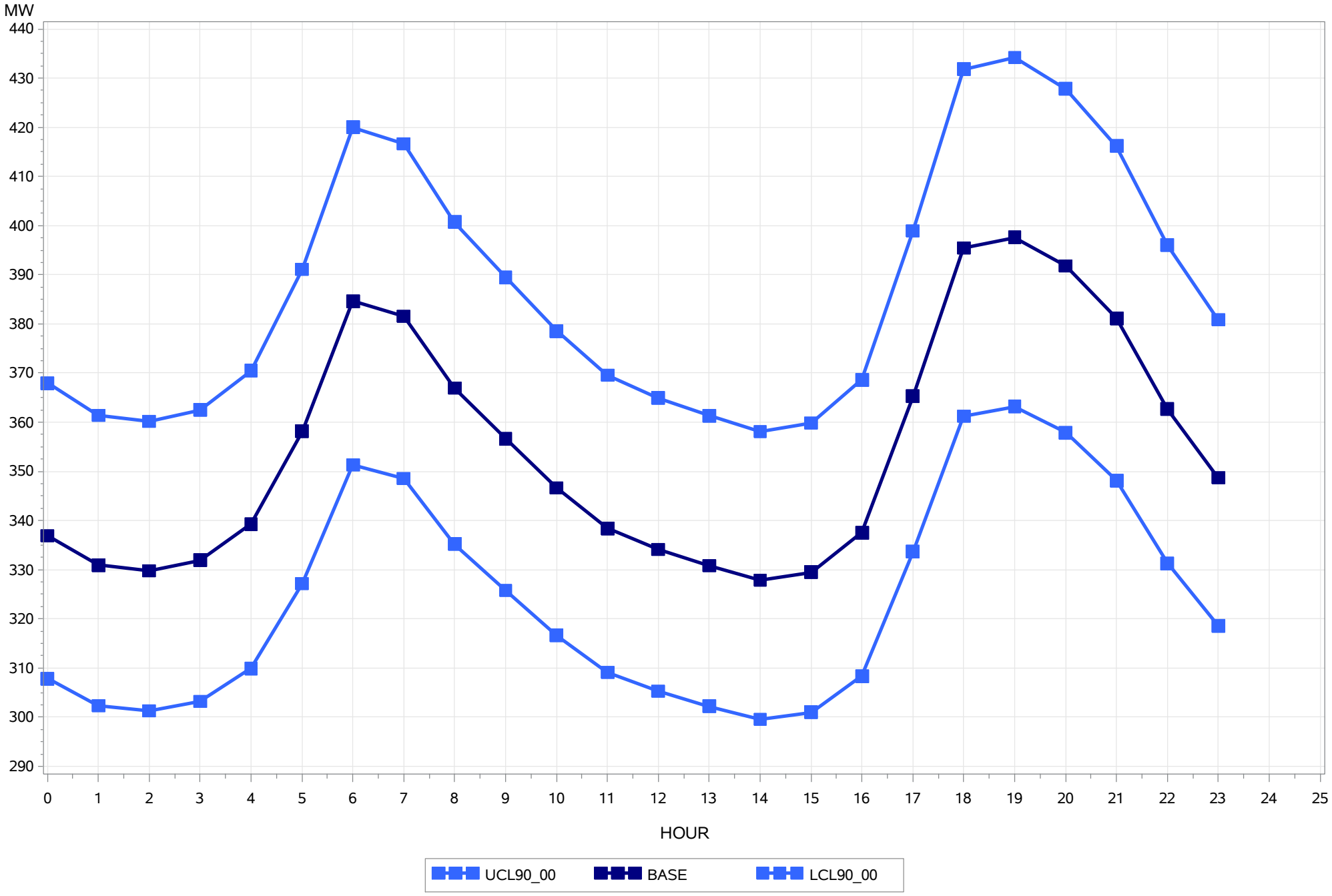
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

STATE OF NEW MEXICO

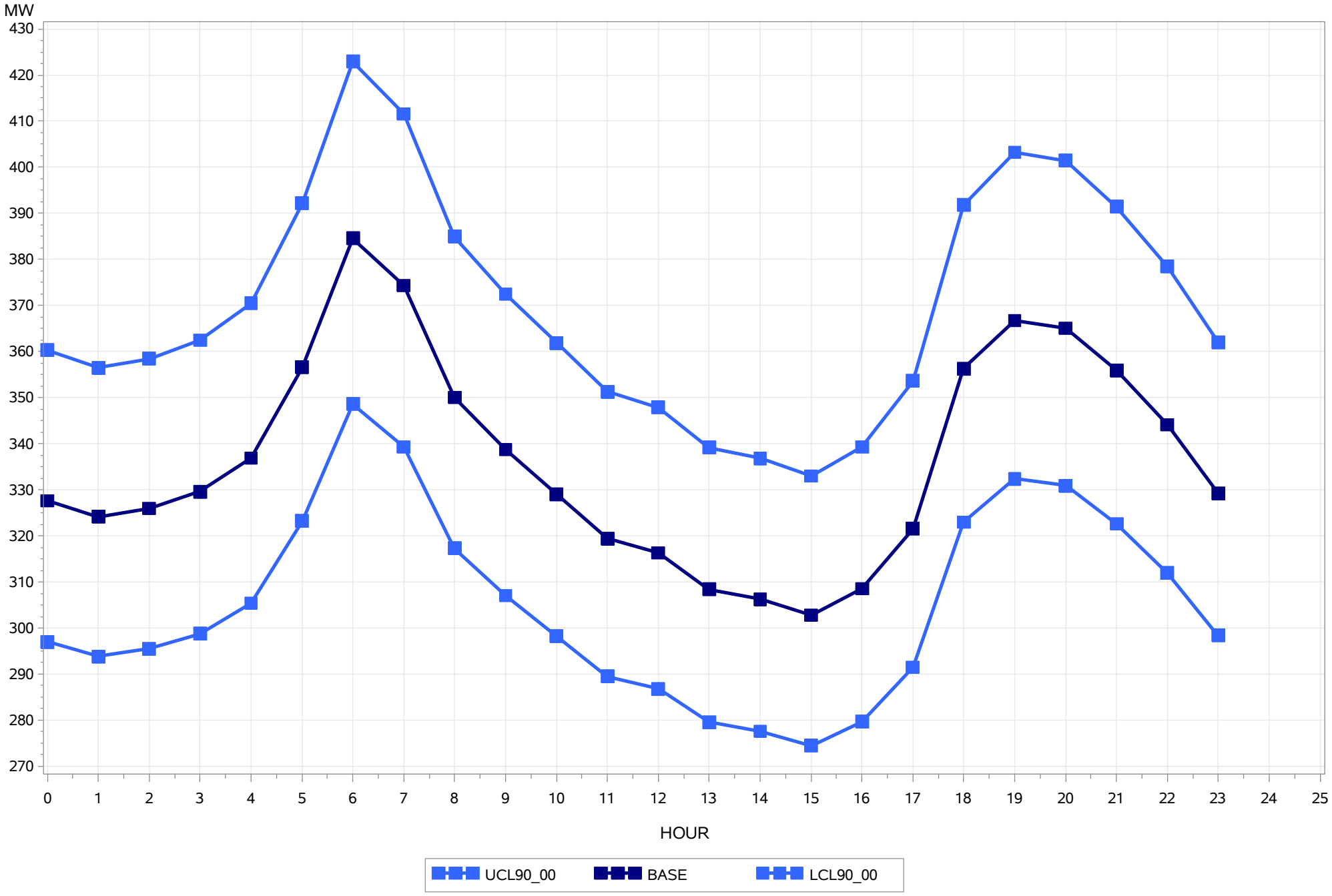
Date of On Peak Day - 01/26/2021



Member Forecasted On Peak Demand Day for February 2021

STATE OF NEW MEXICO

Date of On Peak Day - 02/25/2021



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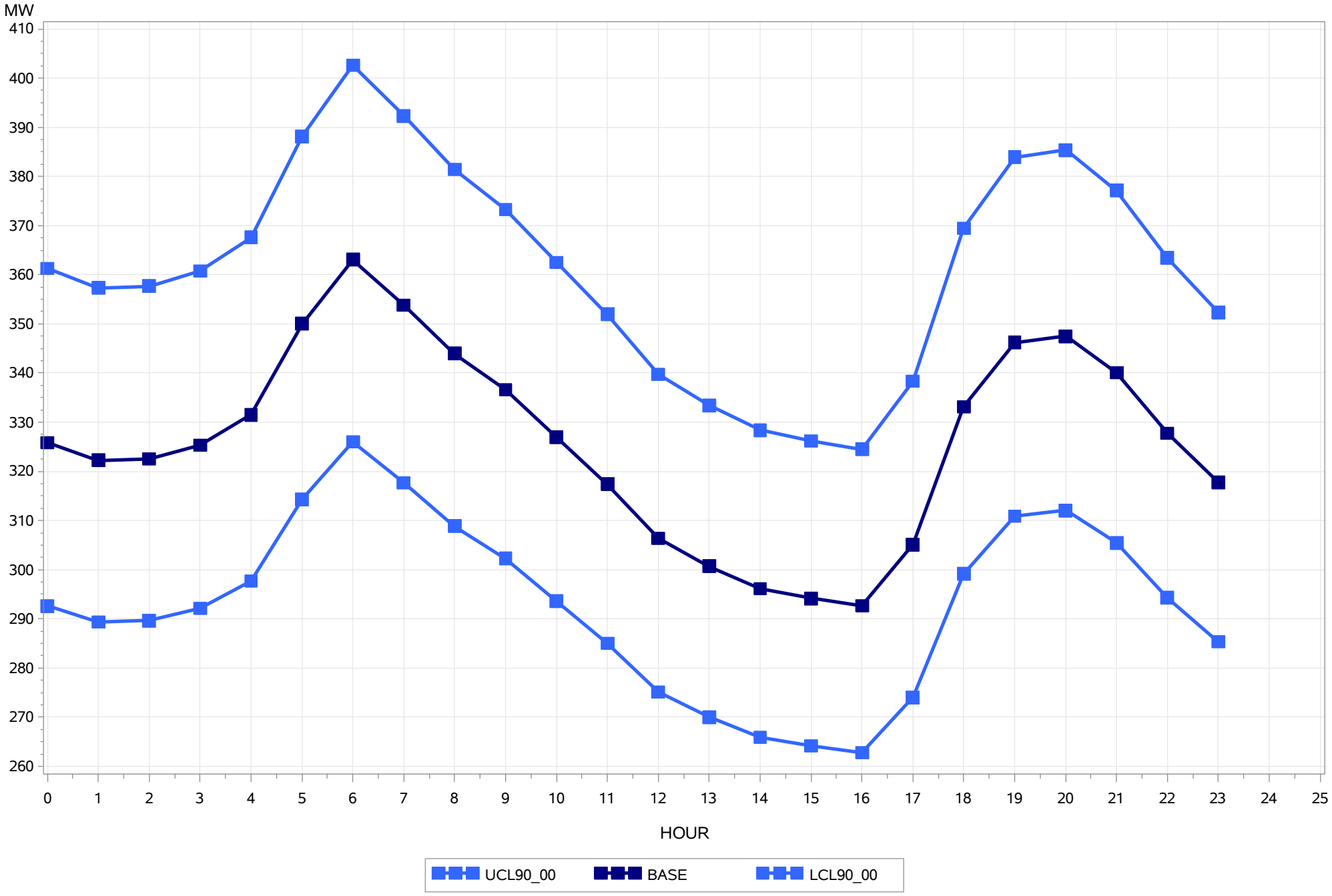
Member Forecasted On Peak Demand Day for March 2021

STATE OF NEW MEXICO

Date of On Peak Day - 03/02/2021



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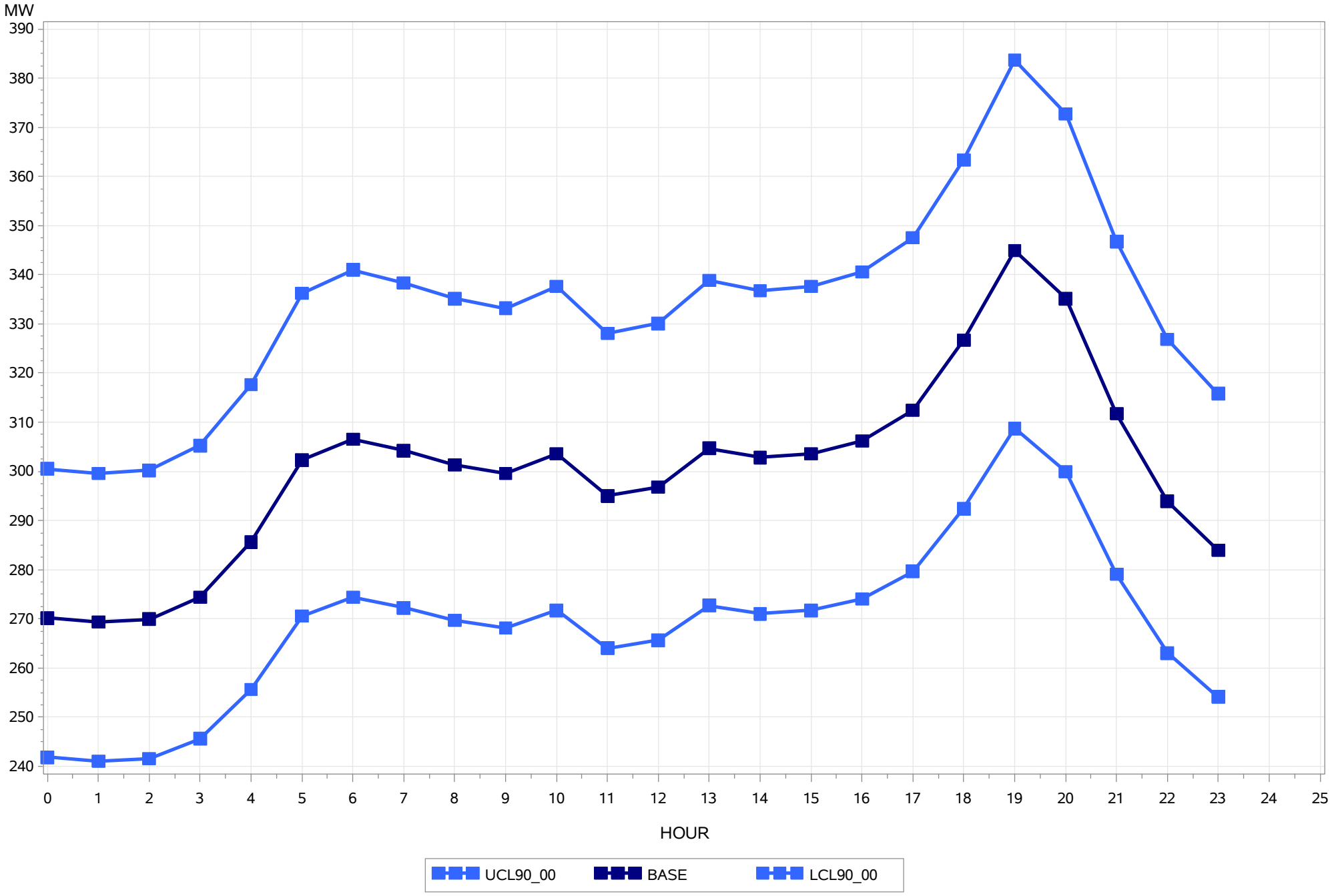
Member Forecasted On Peak Demand Day for April 2021

STATE OF NEW MEXICO

Date of On Peak Day - 04/12/2021



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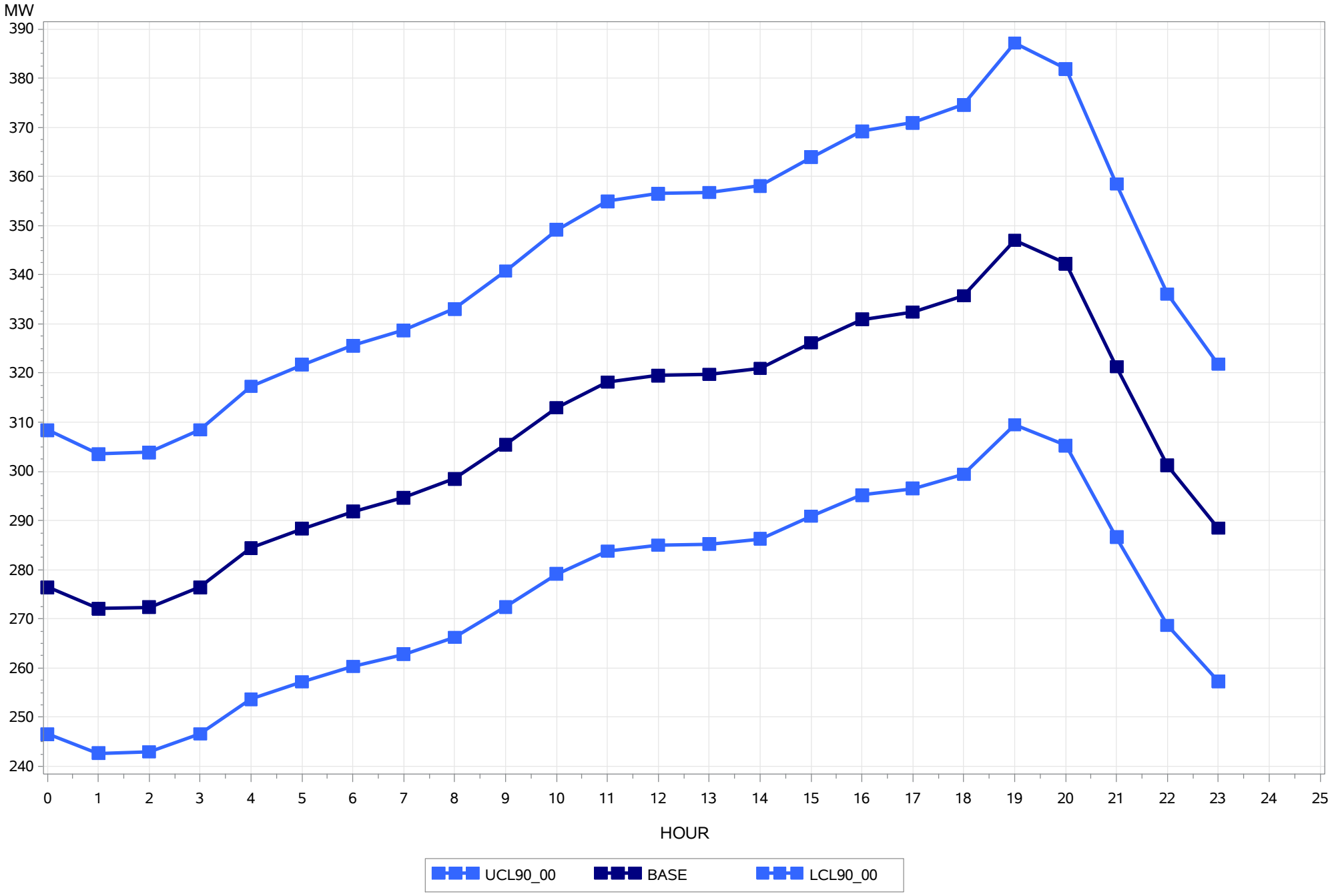
Member Forecasted On Peak Demand Day for May 2021

STATE OF NEW MEXICO

Date of On Peak Day - 05/26/2021



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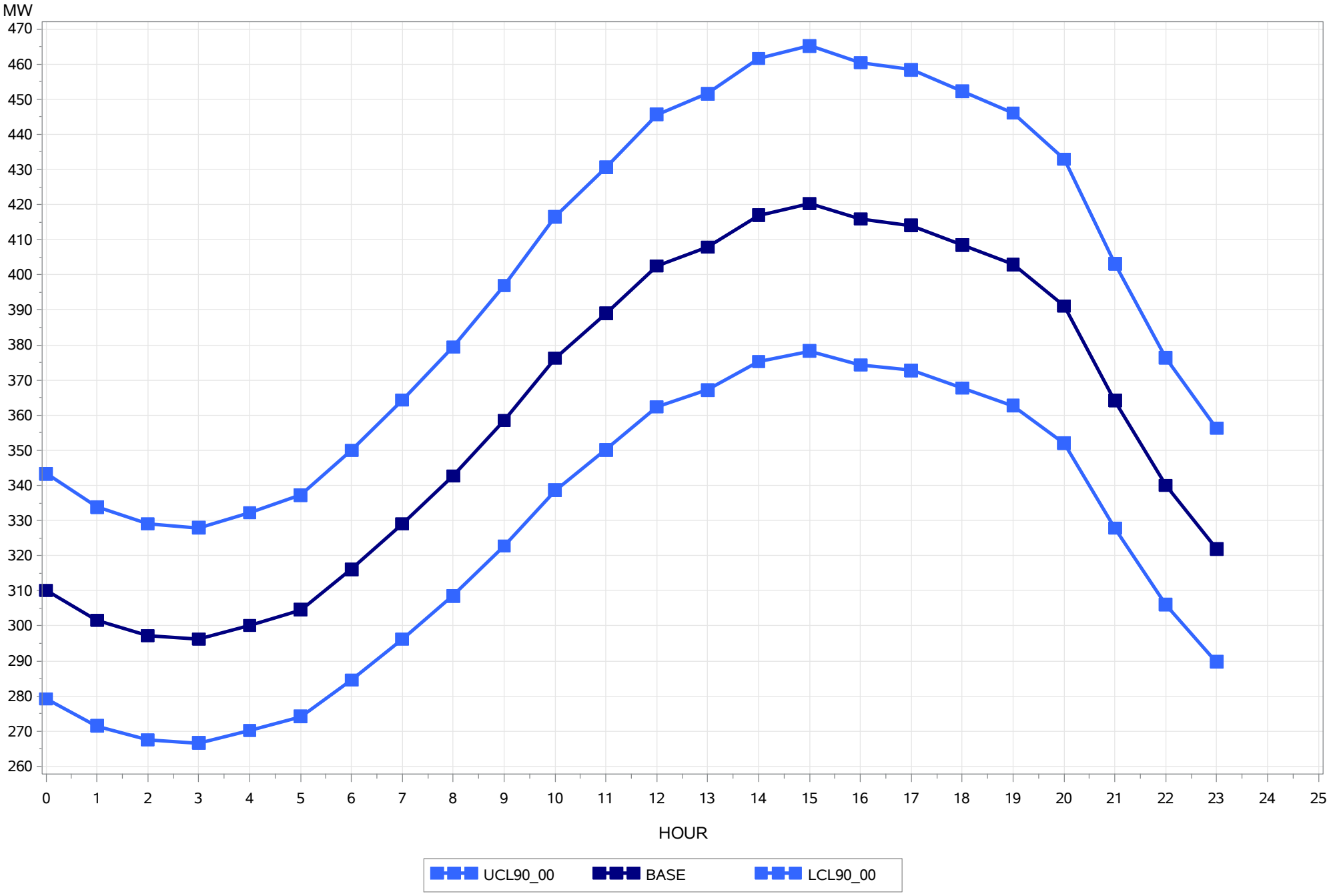
Member Forecasted On Peak Demand Day for June 2021

STATE OF NEW MEXICO

Date of On Peak Day - 06/24/2021



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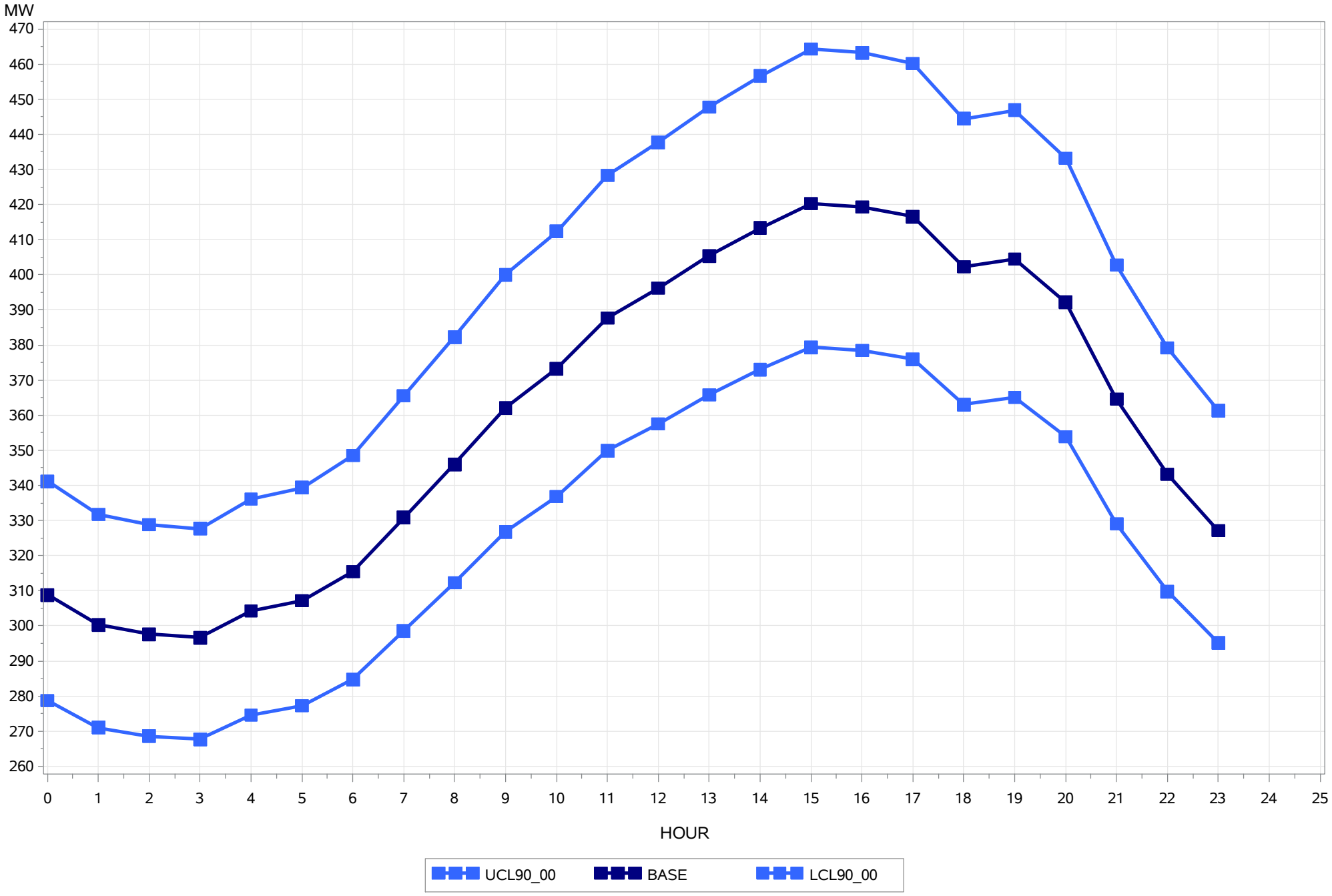
Member Forecasted On Peak Demand Day for July 2021

STATE OF NEW MEXICO

Date of On Peak Day - 07/22/2021



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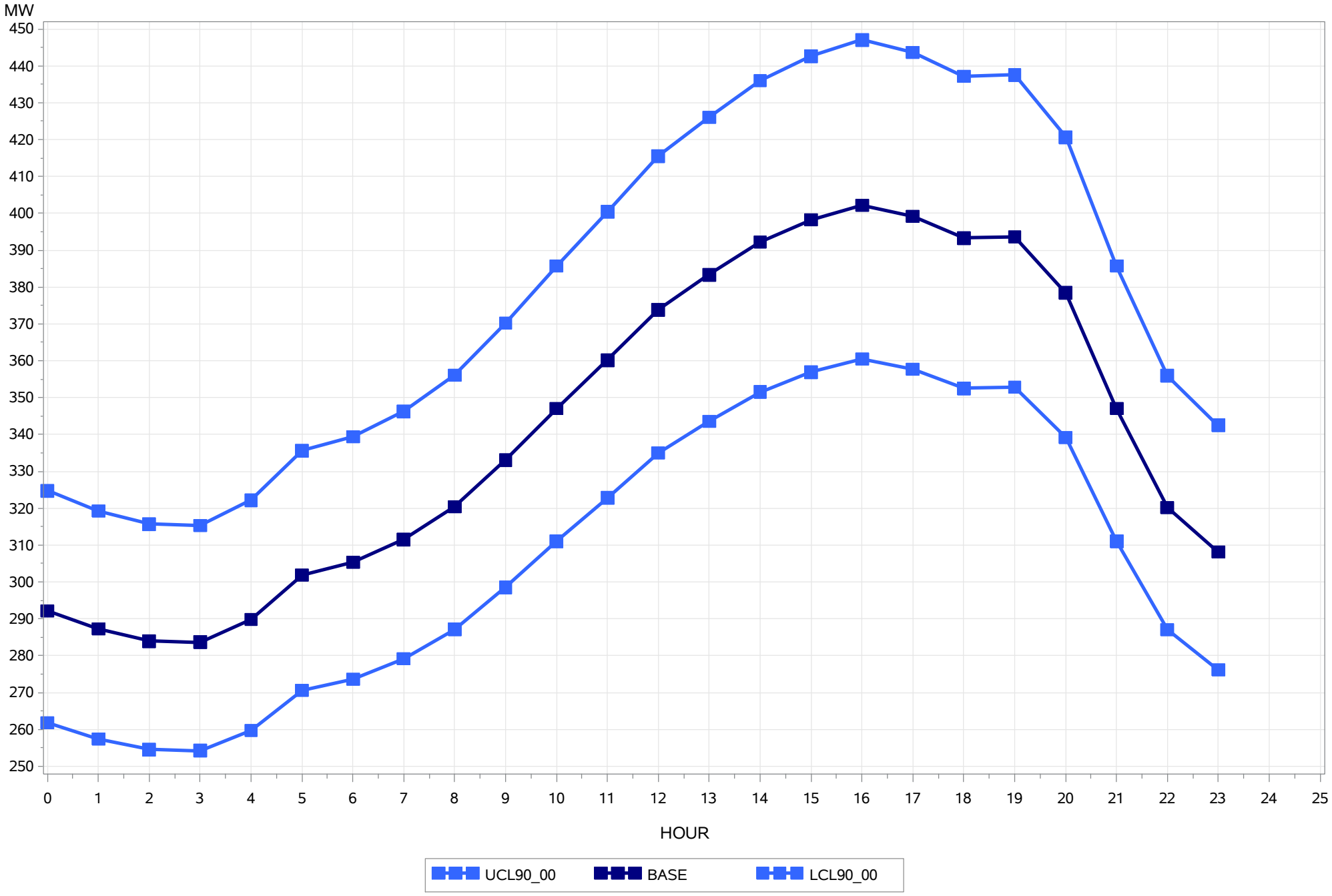
Member Forecasted On Peak Demand Day for August 2021

STATE OF NEW MEXICO

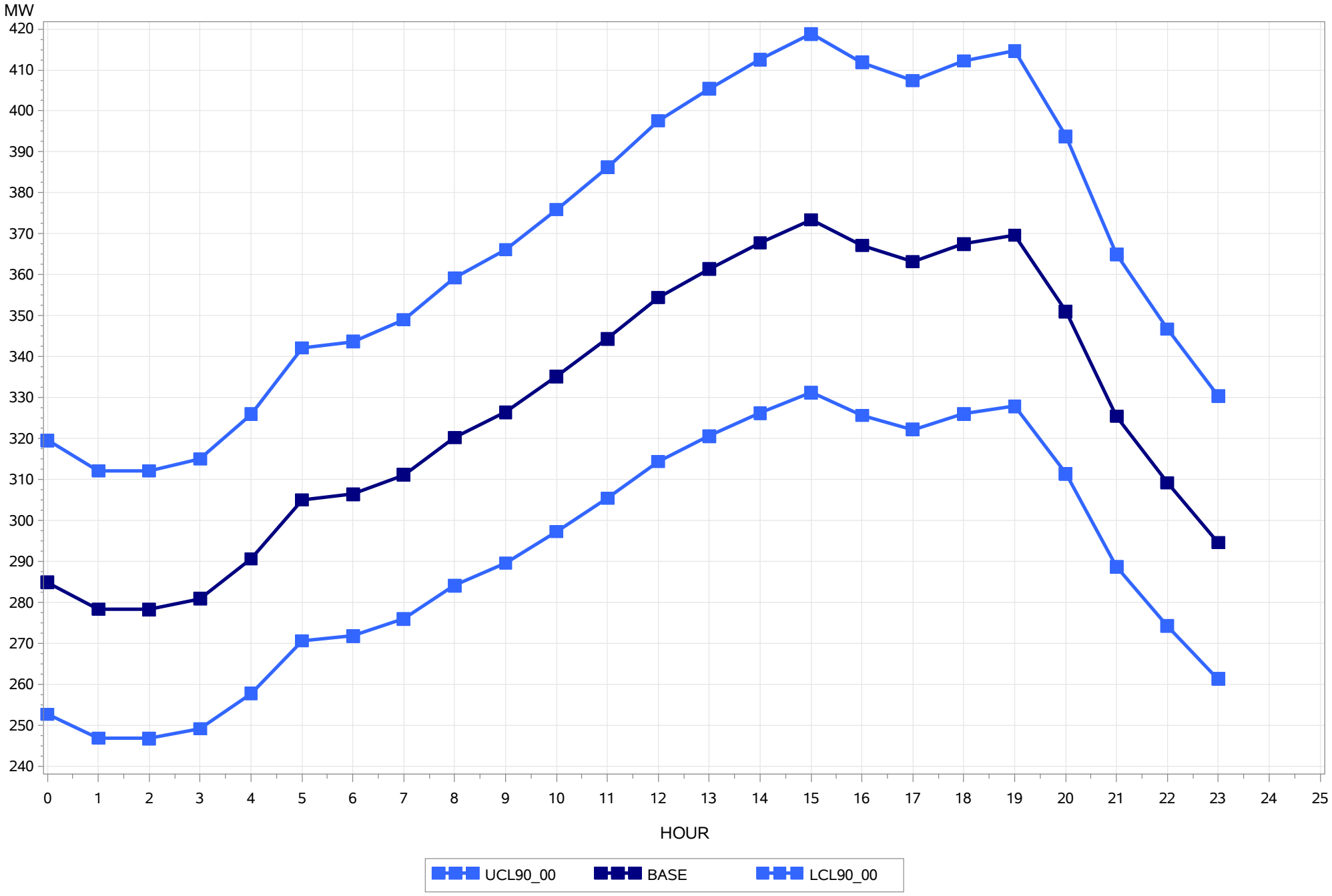
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF NEW MEXICO

Date of On Peak Day - 09/08/2021



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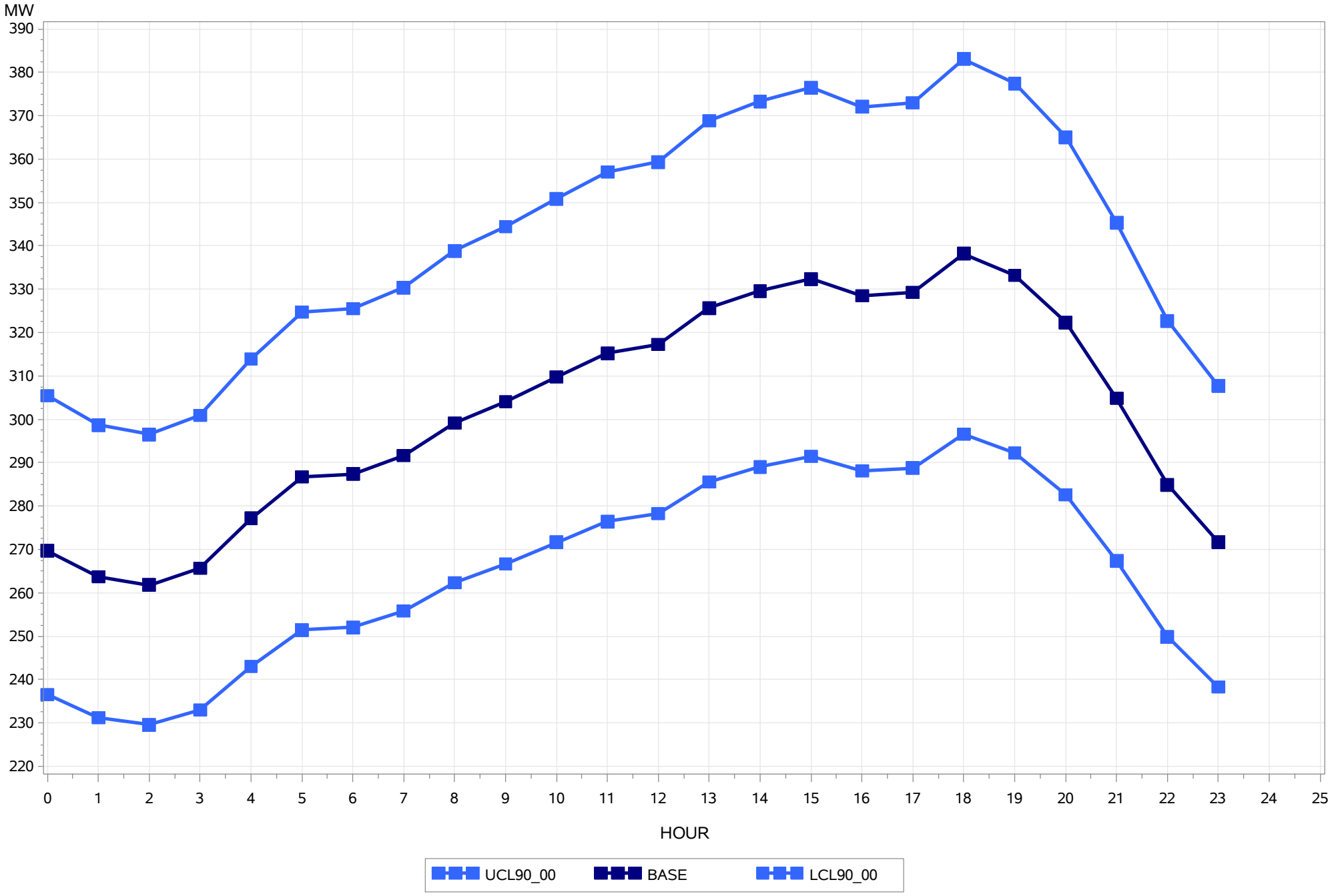
Member Forecasted On Peak Demand Day for October 2021

STATE OF NEW MEXICO

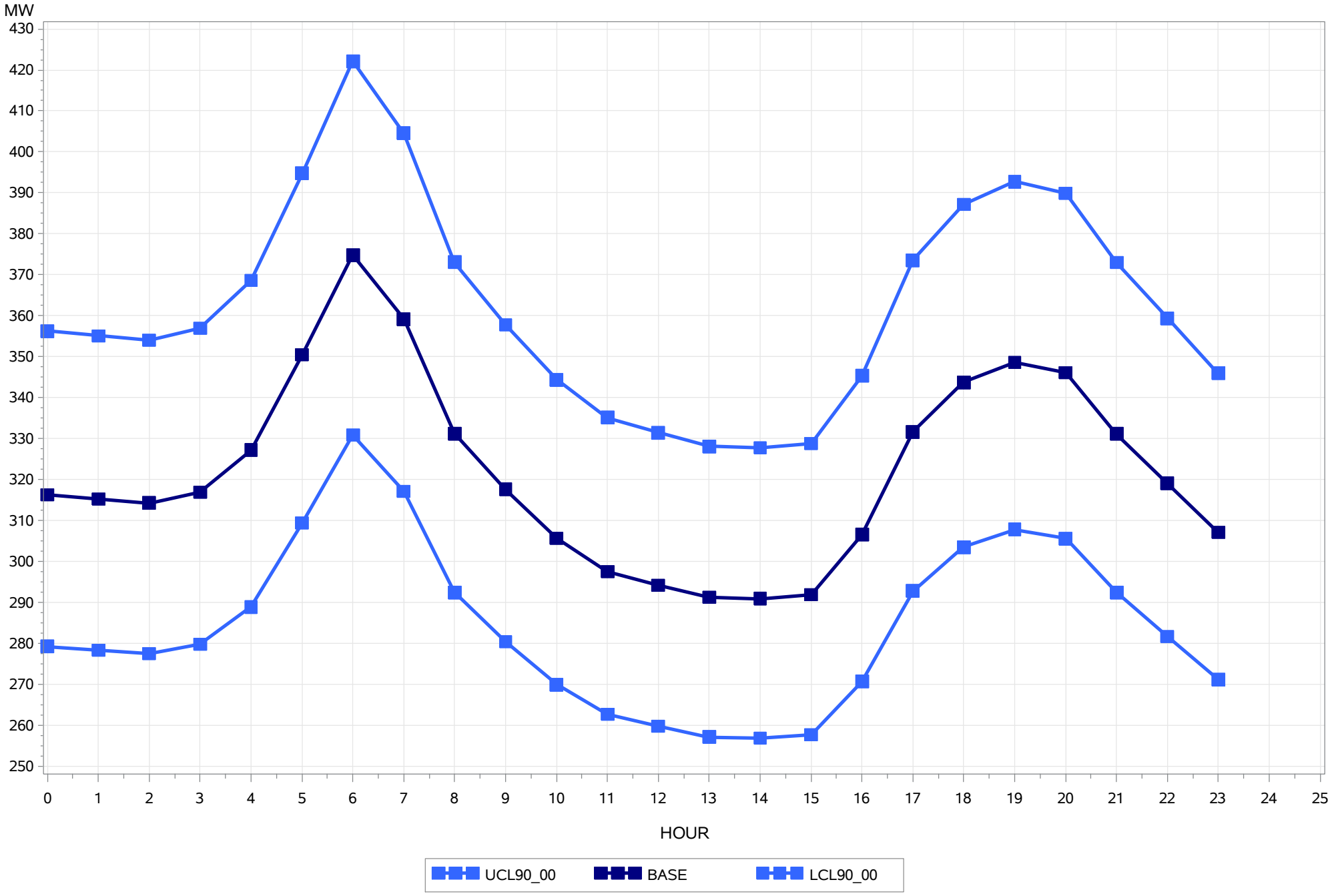
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF NEW MEXICO

Date of On Peak Day - 11/16/2021



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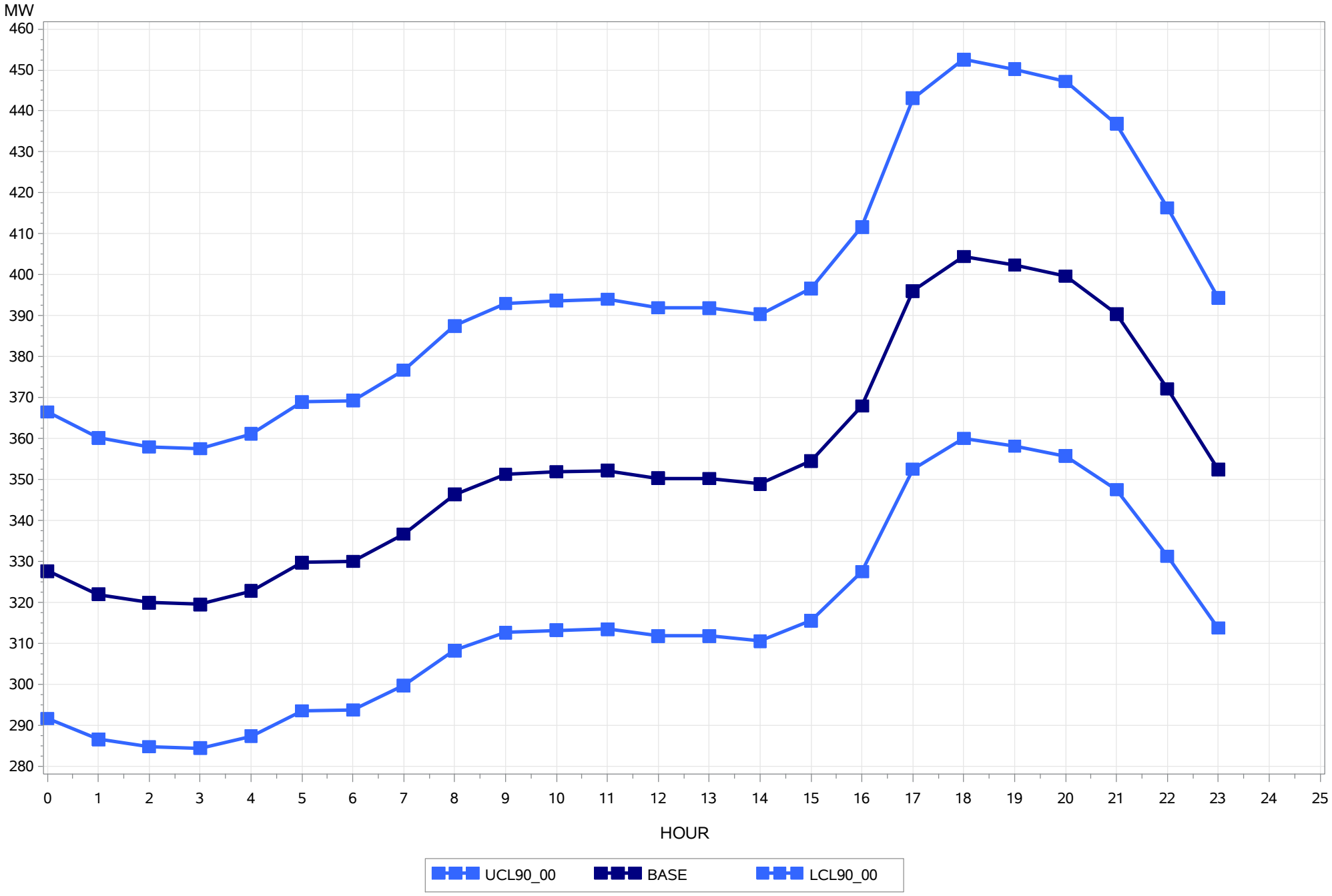
Member Forecasted On Peak Demand Day for December 2021

STATE OF NEW MEXICO

Date of On Peak Day - 12/26/2021



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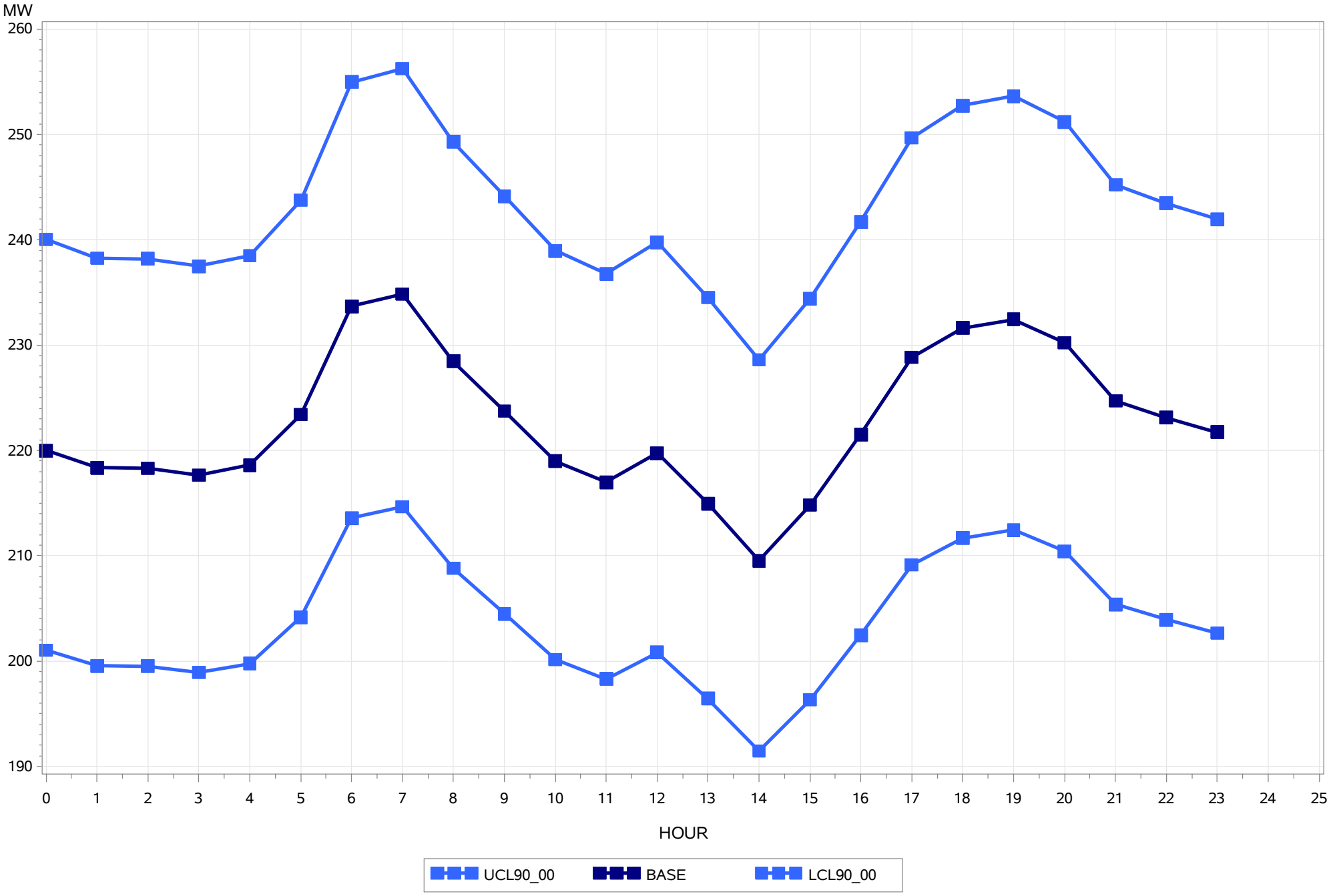
Member Forecasted On Peak Demand Day for January 2021

STATE OF WYOMING

Date of On Peak Day - 01/07/2021



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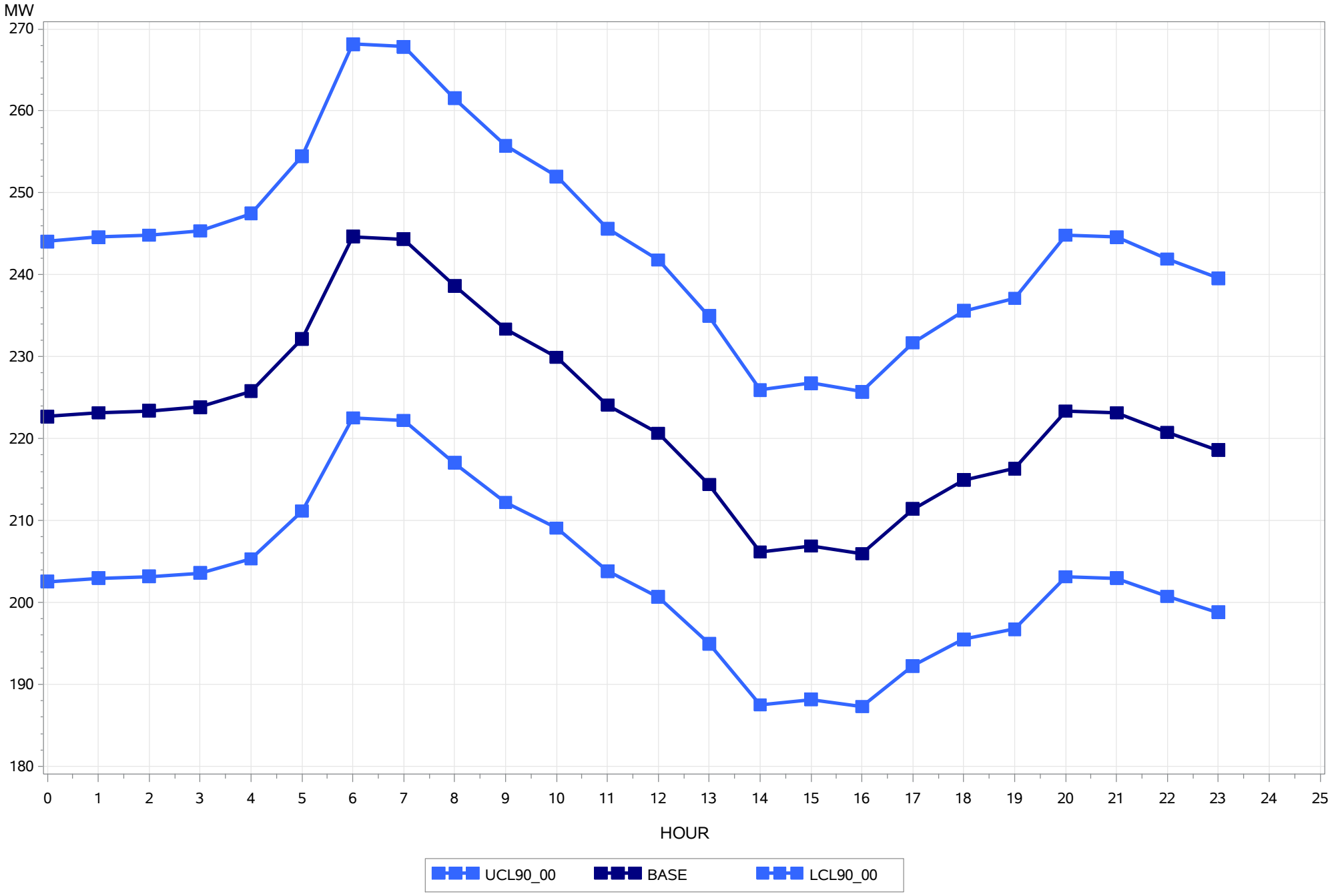
Member Forecasted On Peak Demand Day for February 2021

STATE OF WYOMING

Date of On Peak Day - 02/03/2021



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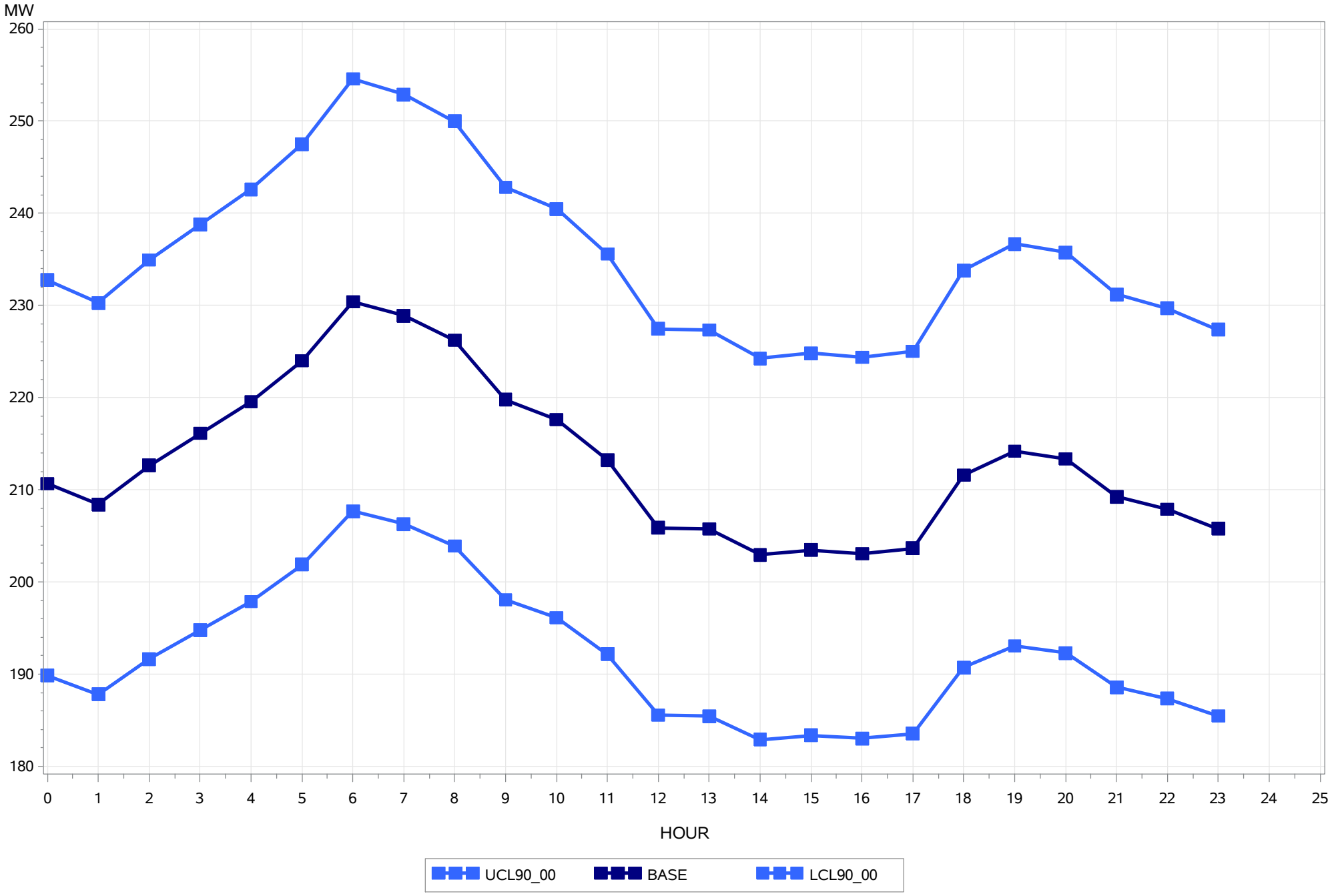
Member Forecasted On Peak Demand Day for March 2021

STATE OF WYOMING

Date of On Peak Day - 03/02/2021



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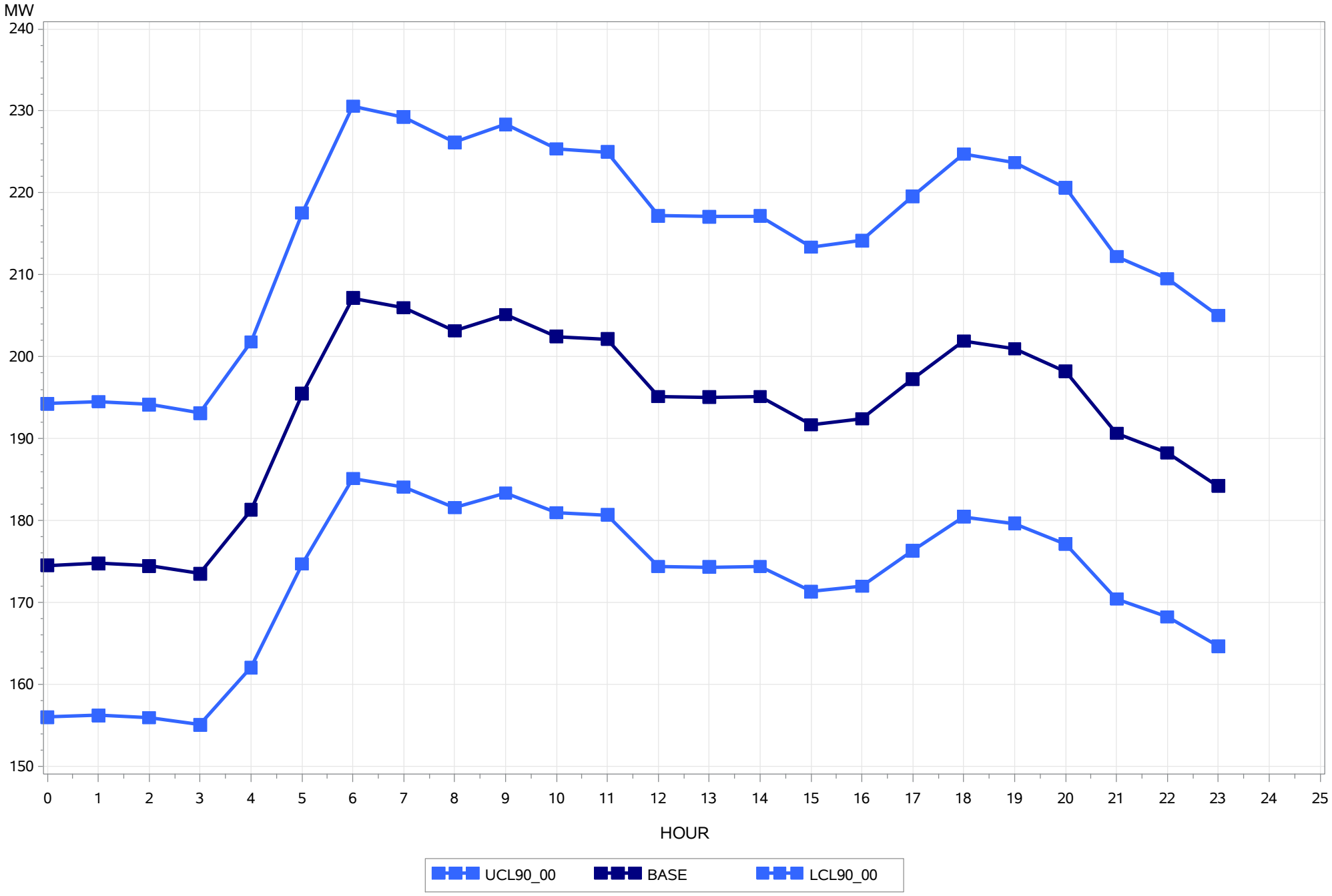
Member Forecasted On Peak Demand Day for April 2021

STATE OF WYOMING

Date of On Peak Day - 04/07/2021



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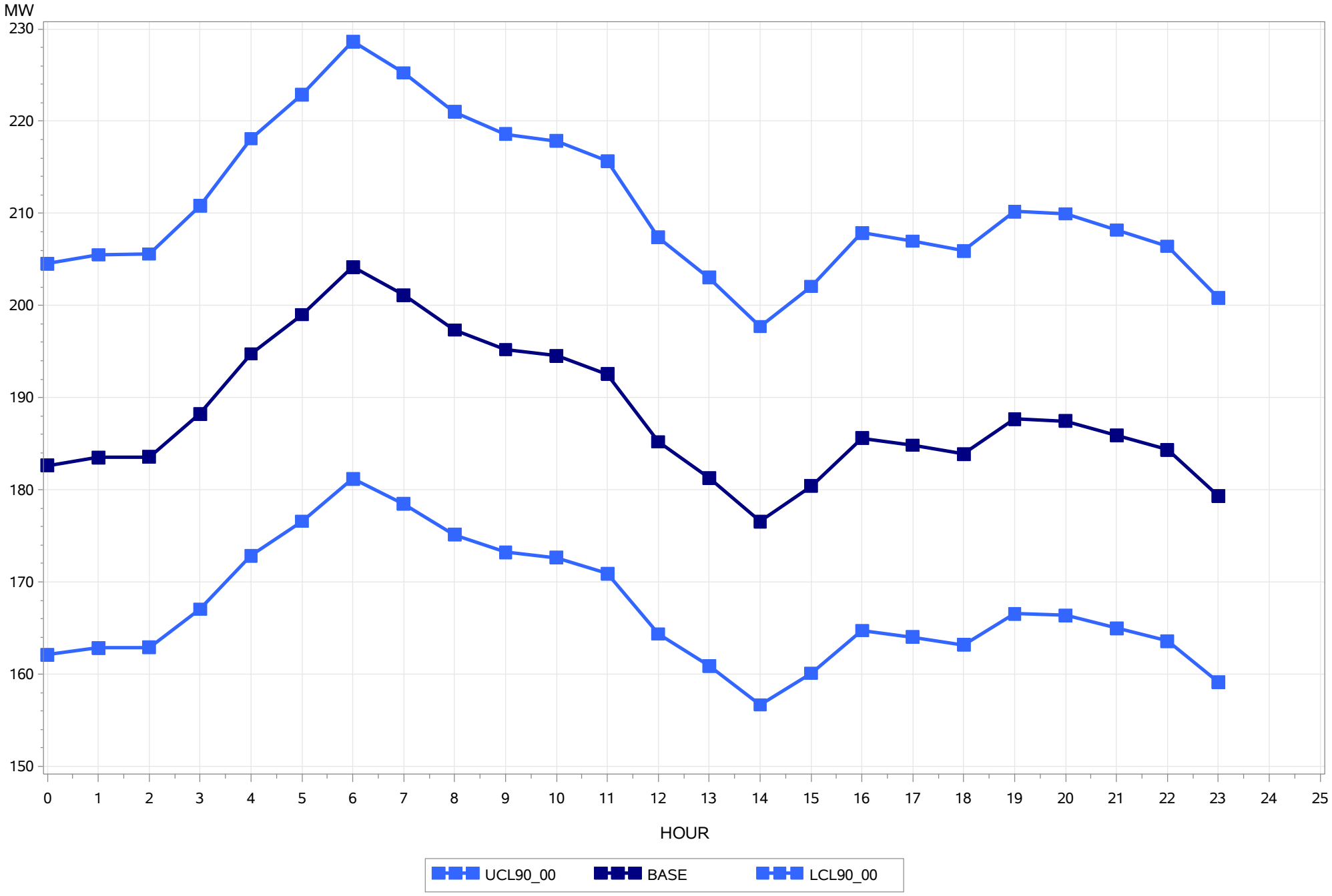
Member Forecasted On Peak Demand Day for May 2021

STATE OF WYOMING

Date of On Peak Day - 05/03/2021



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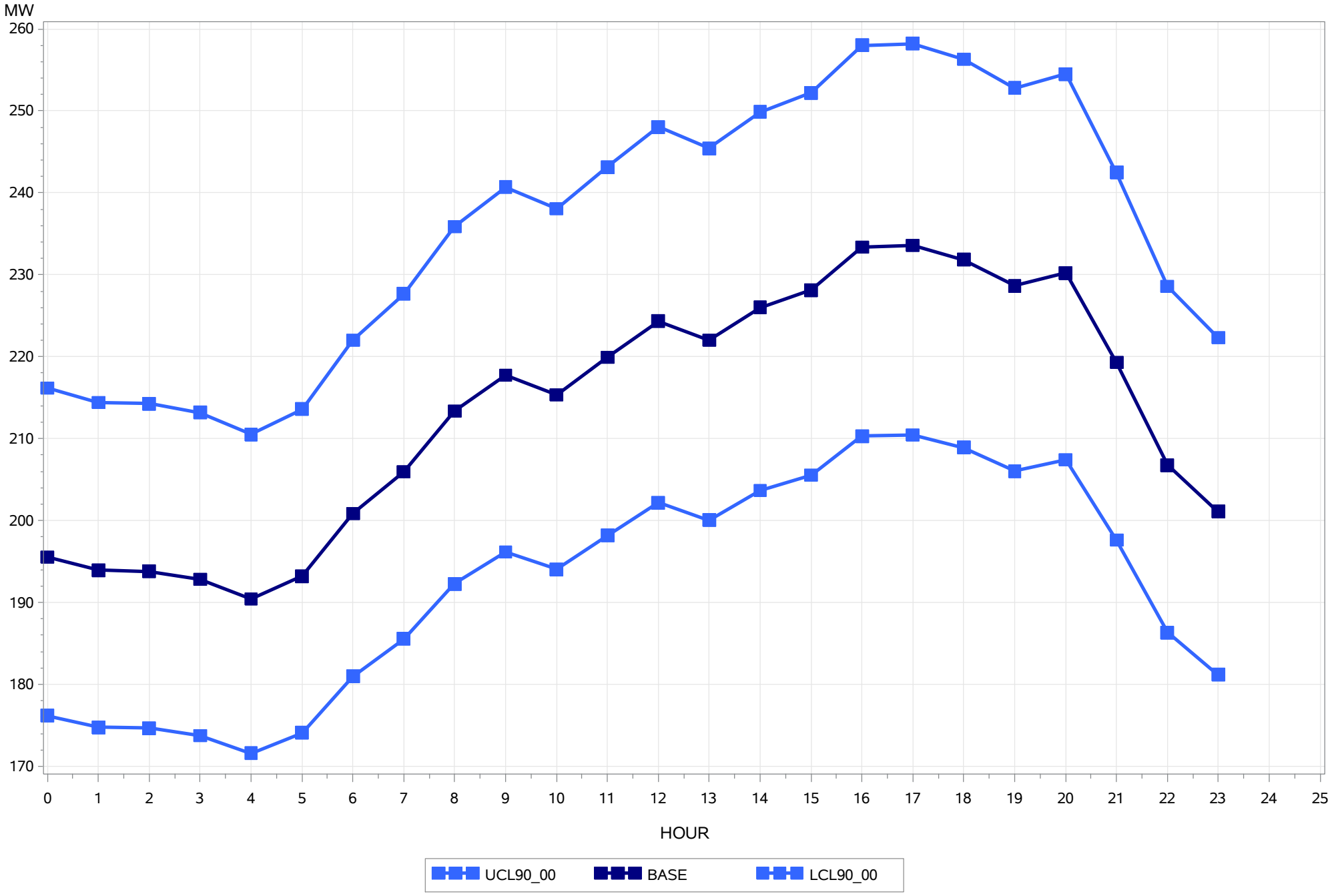
Member Forecasted On Peak Demand Day for June 2021

STATE OF WYOMING

Date of On Peak Day - 06/27/2021



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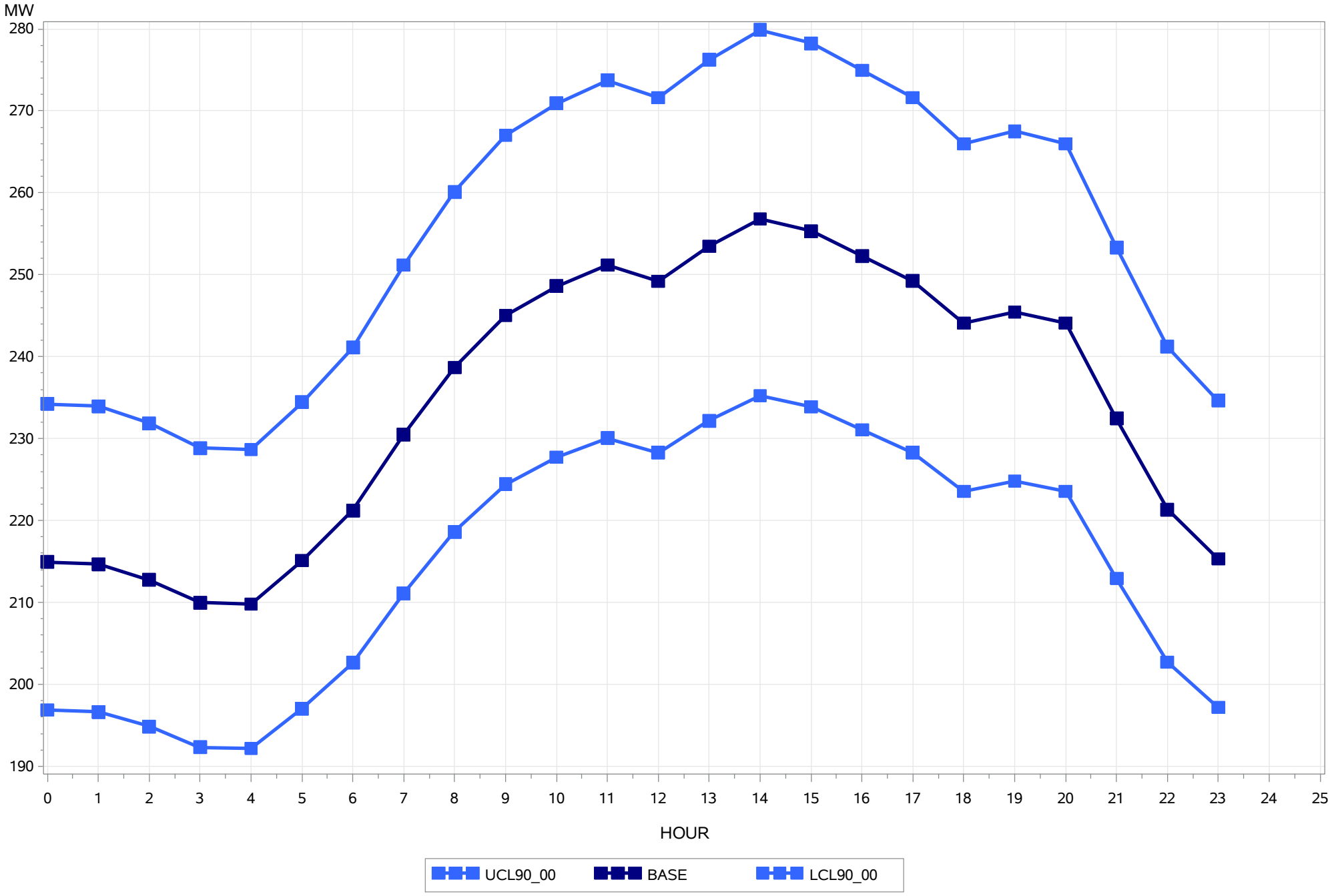
Member Forecasted On Peak Demand Day for July 2021

STATE OF WYOMING

Date of On Peak Day - 07/21/2021



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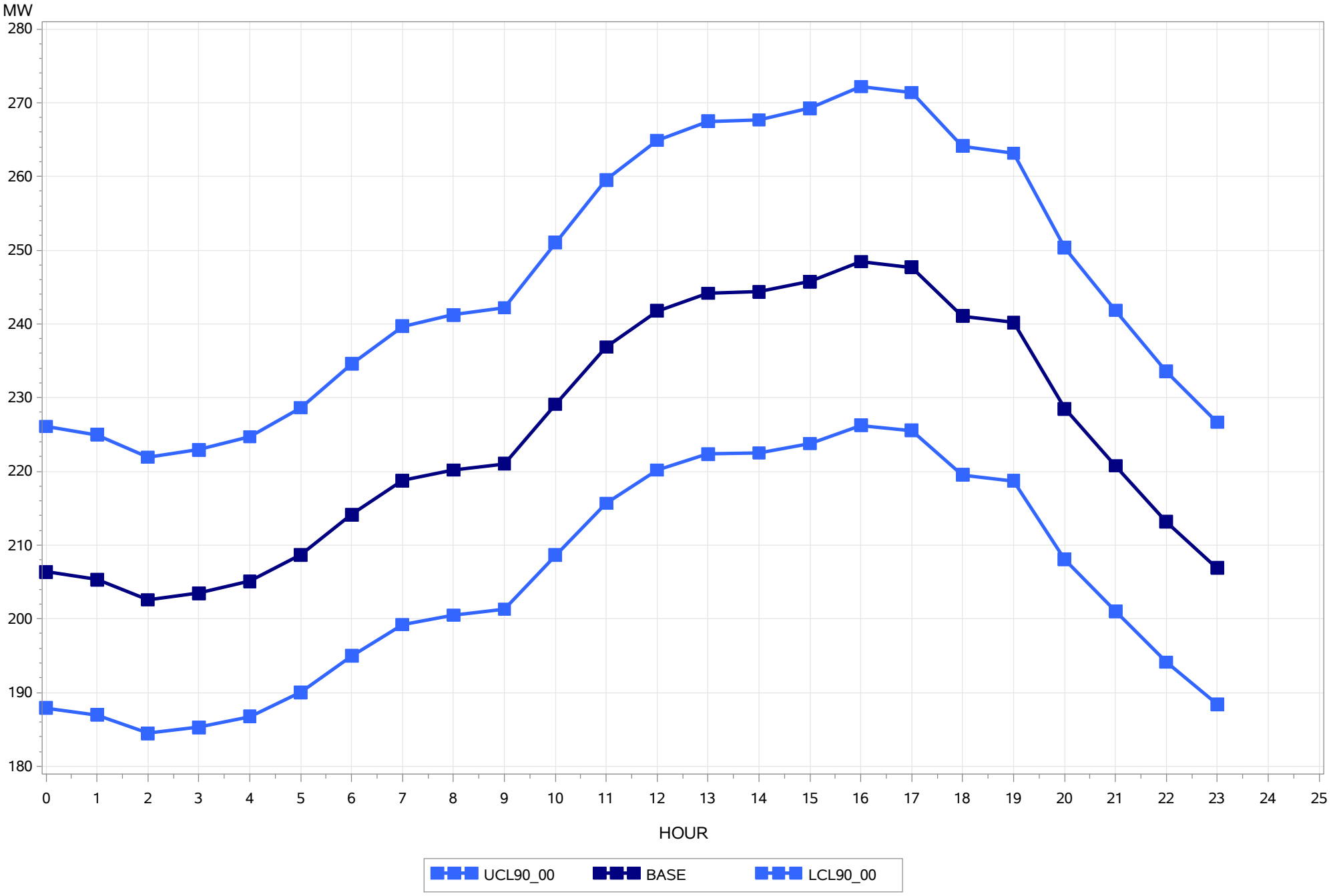
Member Forecasted On Peak Demand Day for August 2021

STATE OF WYOMING

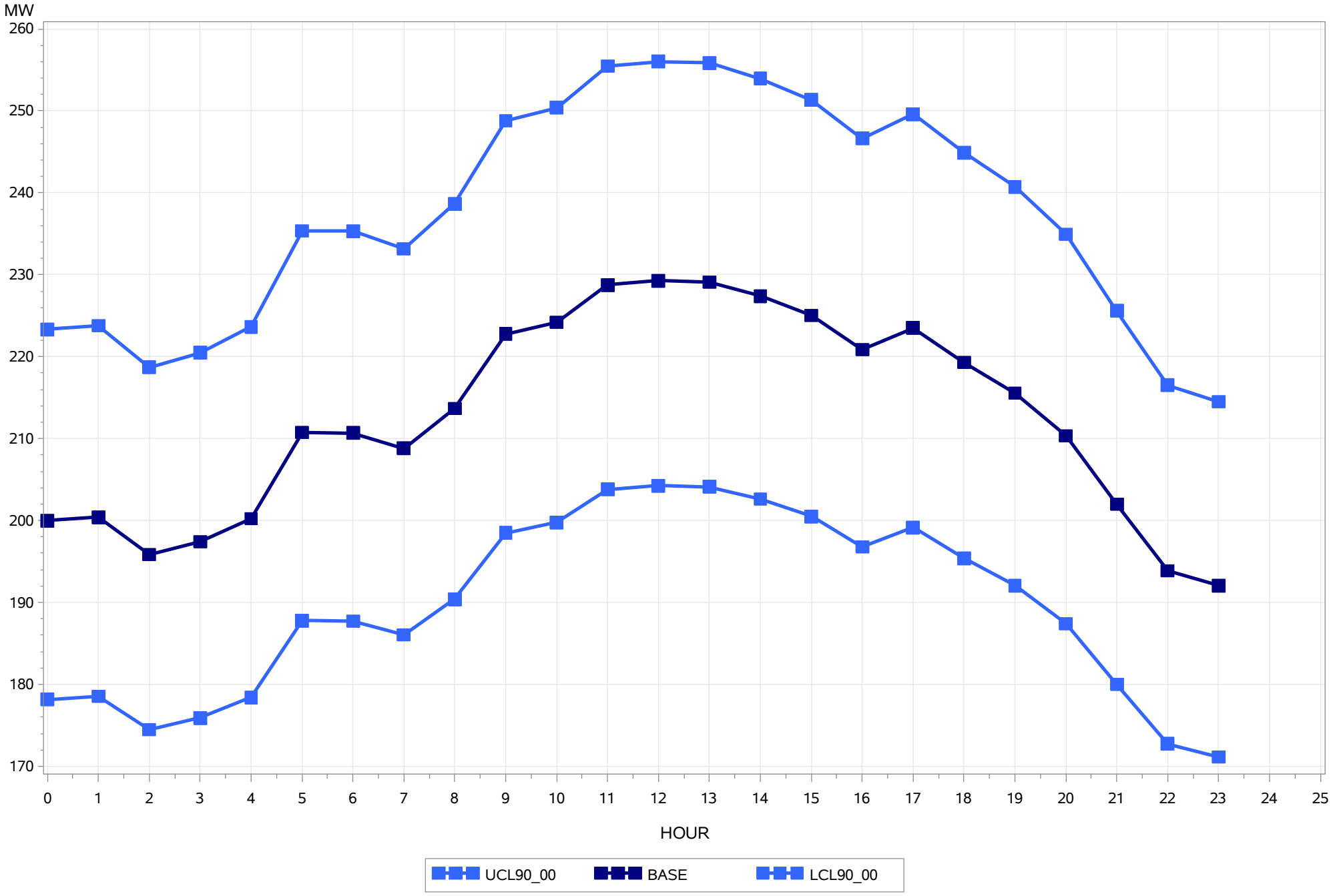
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

STATE OF WYOMING

Date of On Peak Day - 09/02/2021



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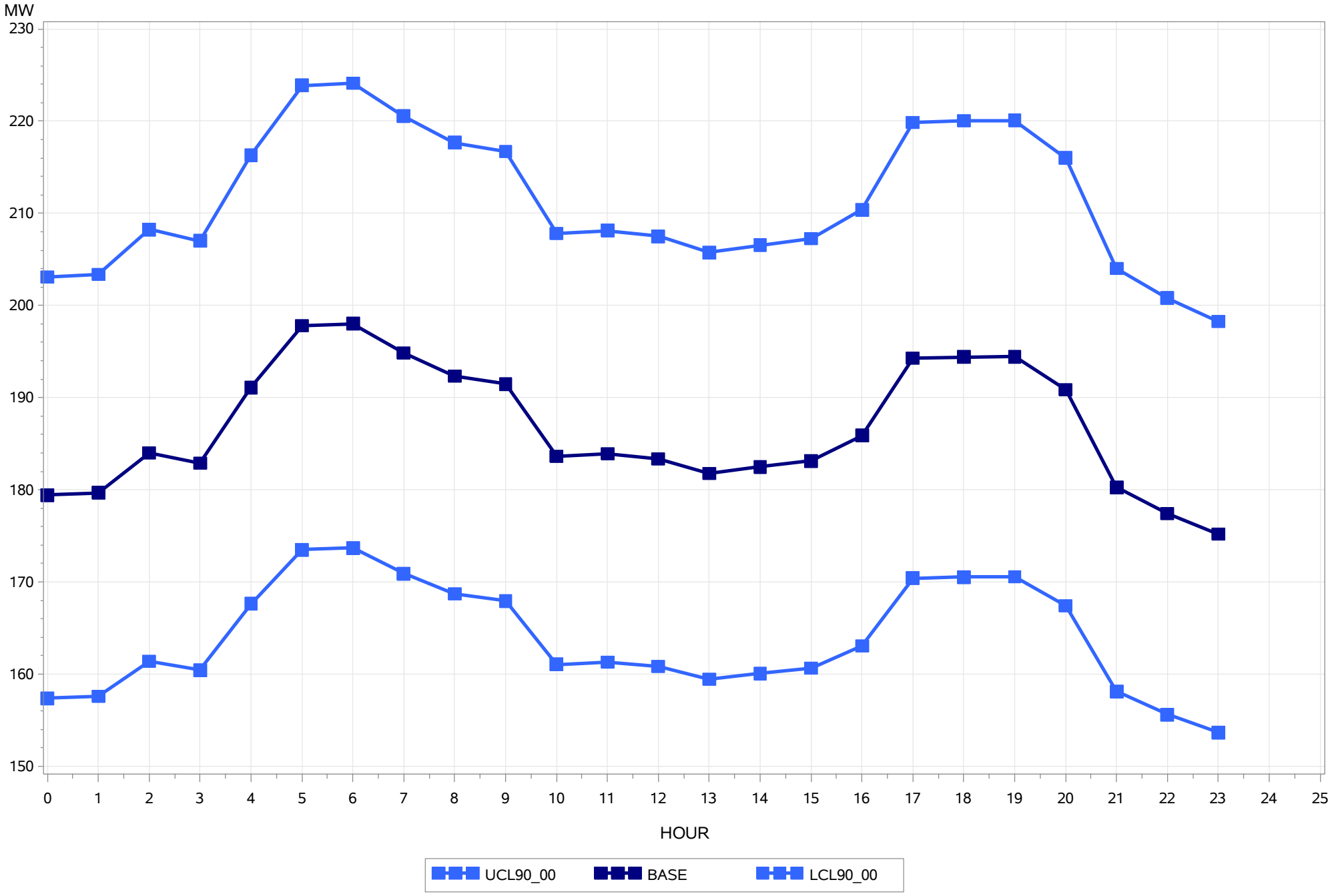
Member Forecasted On Peak Demand Day for October 2021

STATE OF WYOMING

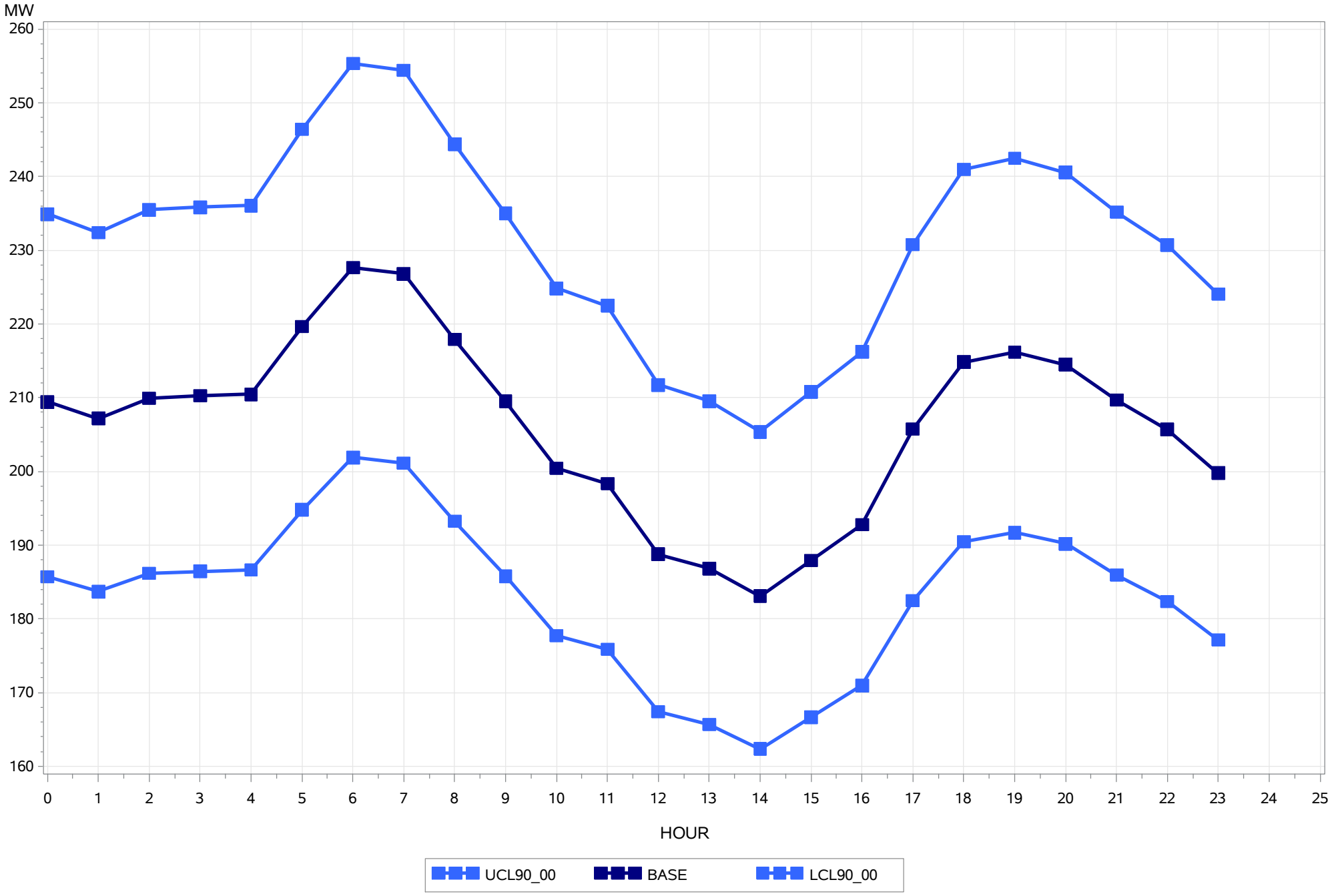
Date of On Peak Day - 10/22/2021



Member Forecasted On Peak Demand Day for November 2021

STATE OF WYOMING

Date of On Peak Day - 11/09/2021



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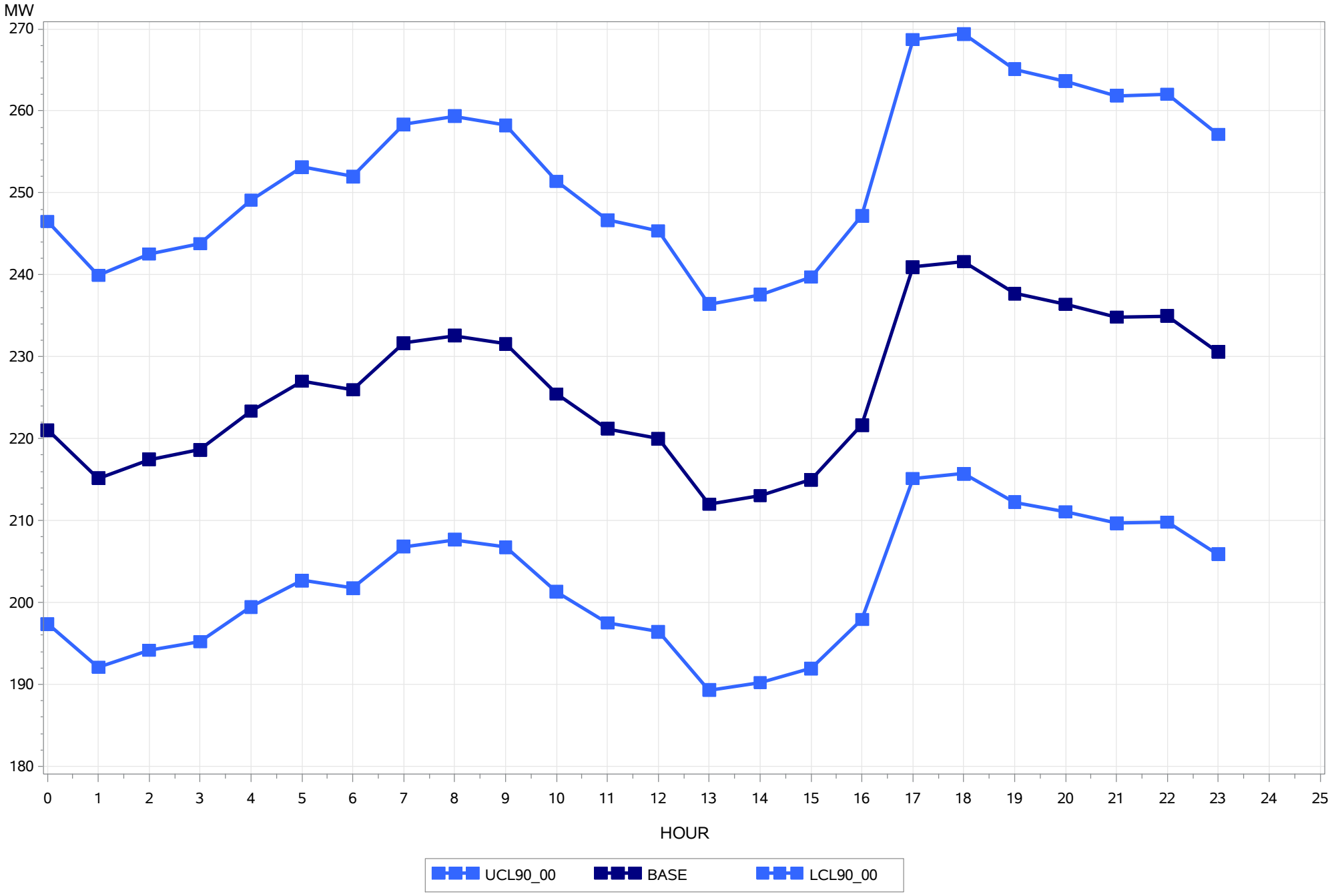
Member Forecasted On Peak Demand Day for December 2021

STATE OF WYOMING

Date of On Peak Day - 12/28/2021



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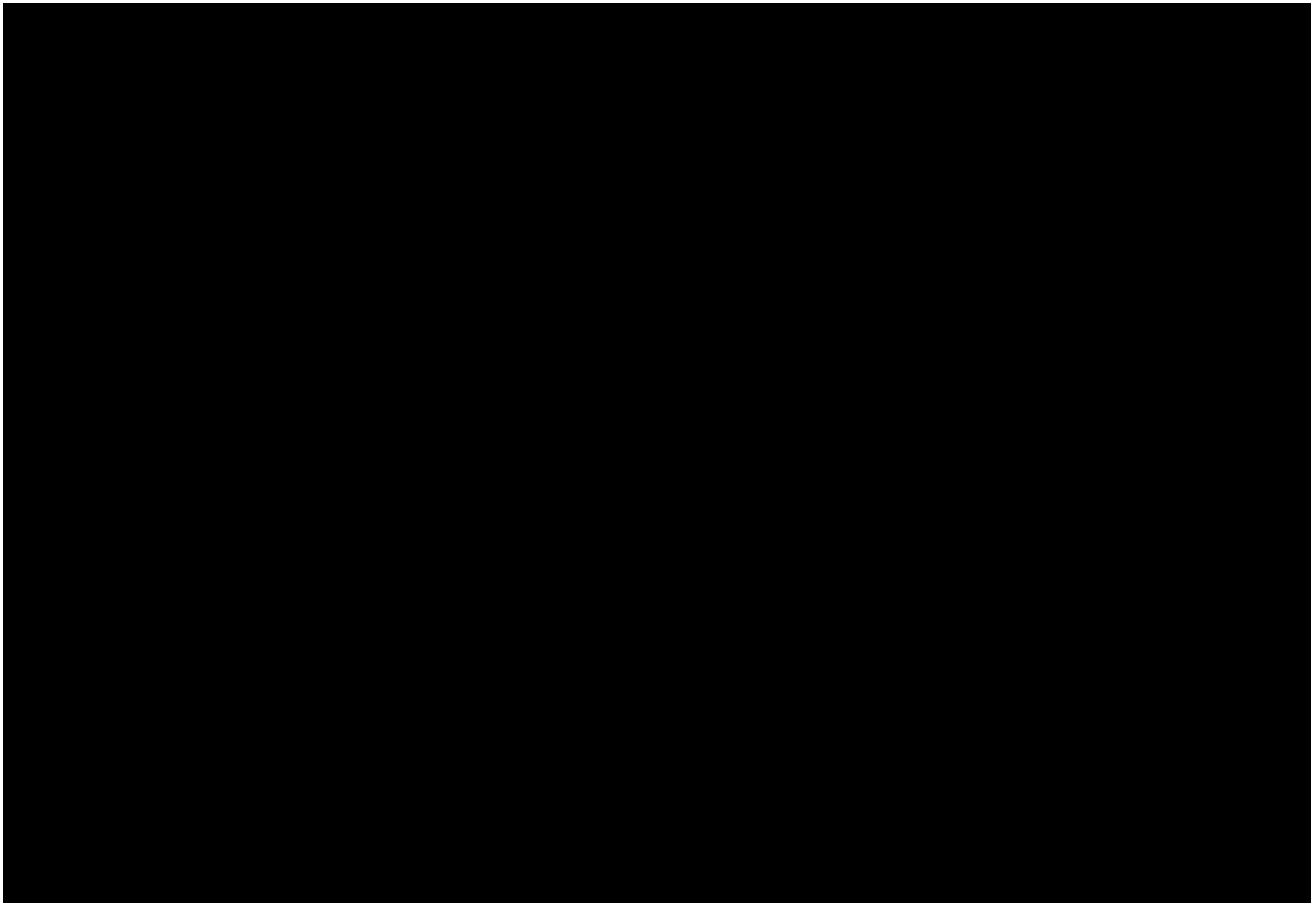
Member Forecasted On Peak Demand Day for January 2021

Big Horn Rural Electric Company

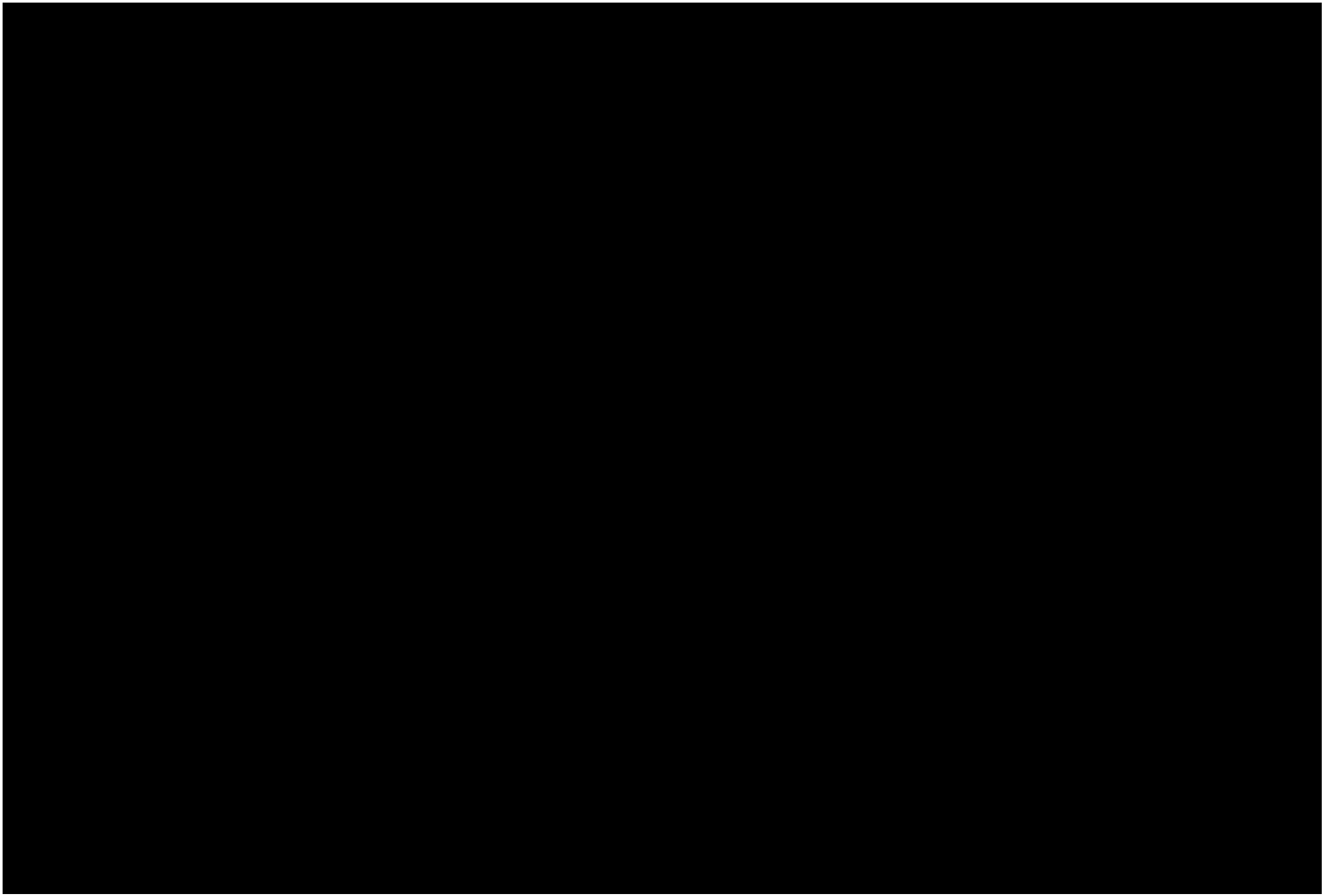
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Big Horn Rural Electric Company

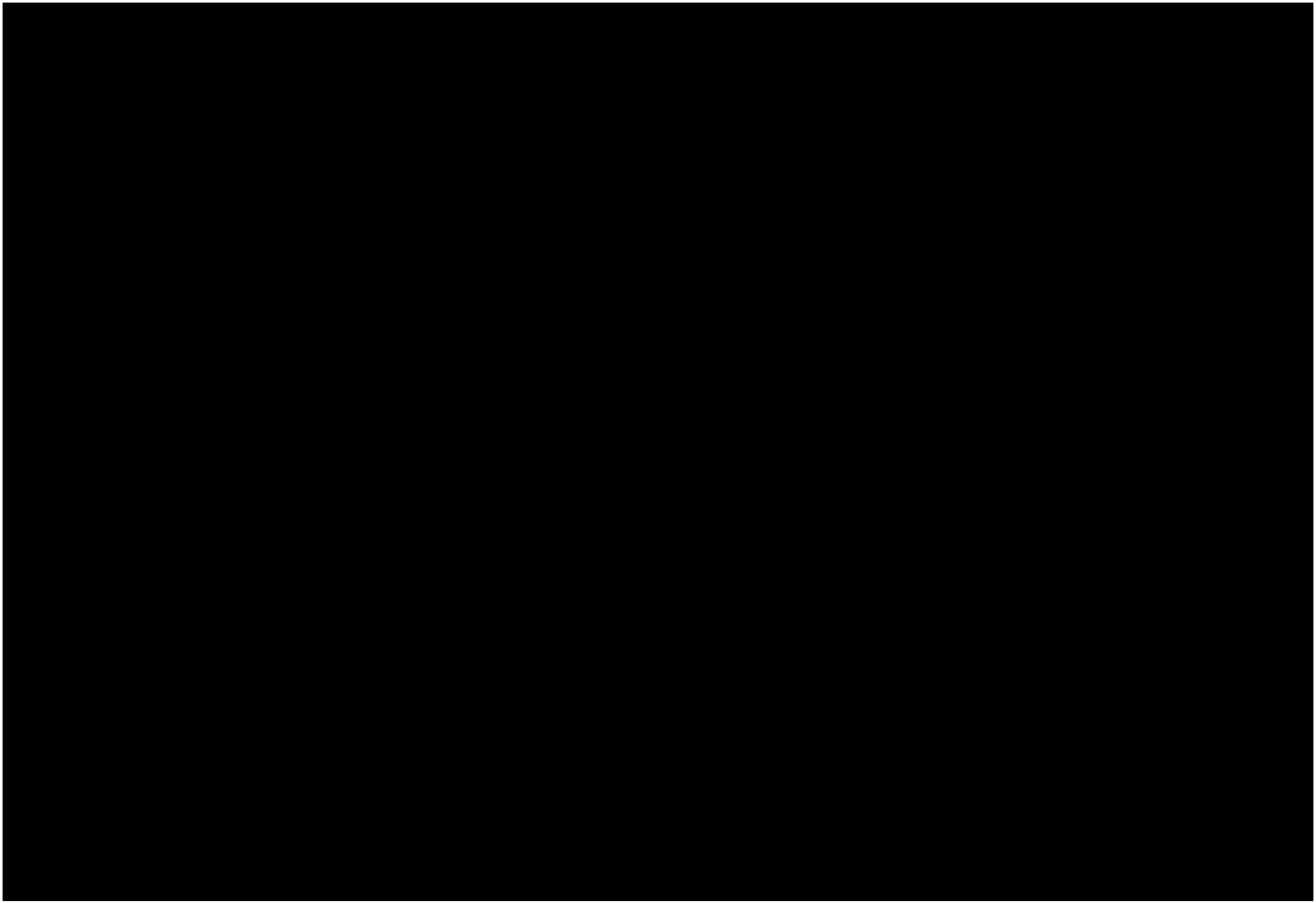
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Big Horn Rural Electric Company

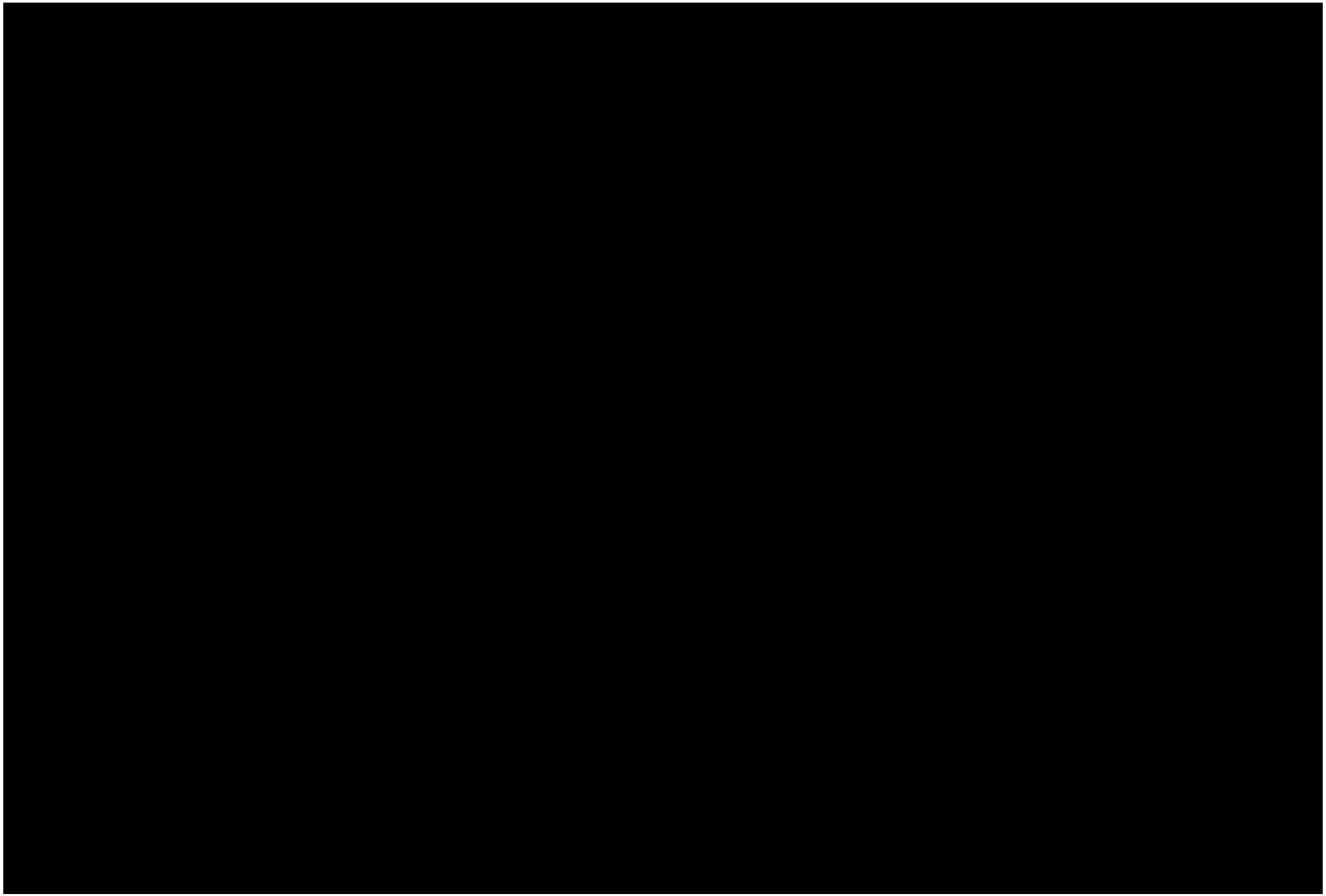
Date of On Peak Day - 03/04/2021



Member Forecasted On Peak Demand Day for April 2021

Big Horn Rural Electric Company

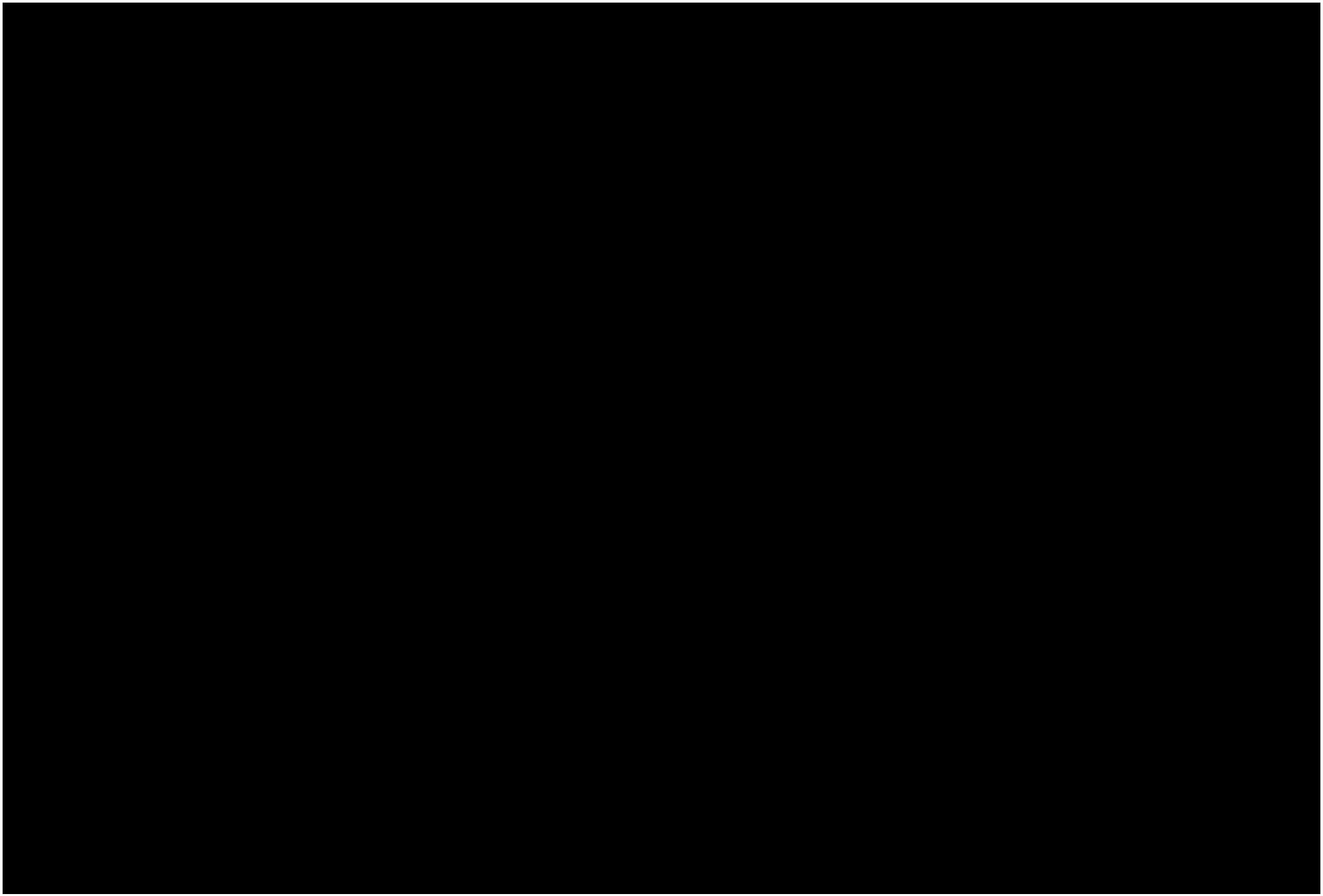
Date of On Peak Day - 04/02/2021



Member Forecasted On Peak Demand Day for May 2021

Big Horn Rural Electric Company

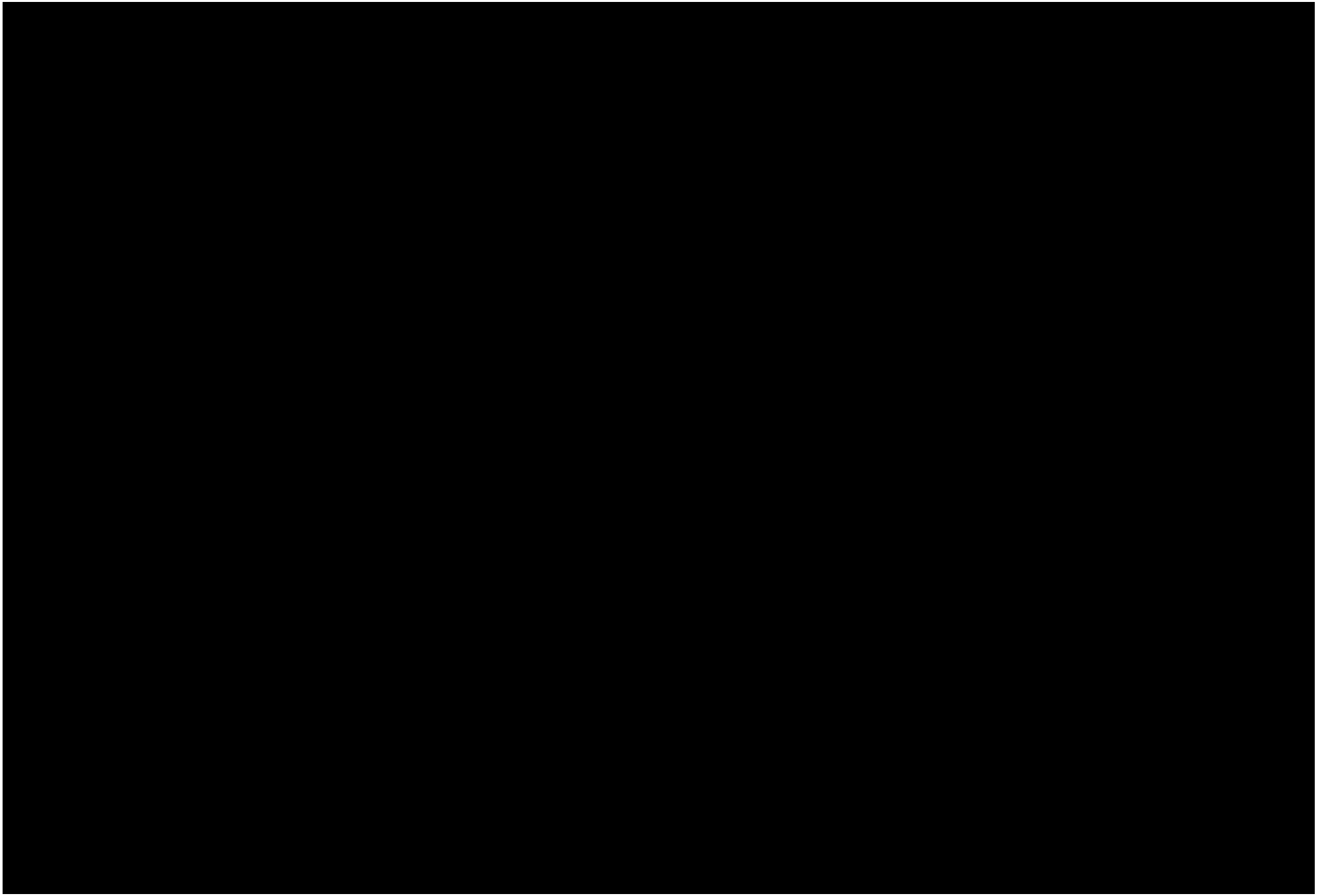
Date of On Peak Day - 05/14/2021



Member Forecasted On Peak Demand Day for June 2021

Big Horn Rural Electric Company

Date of On Peak Day - 06/02/2021



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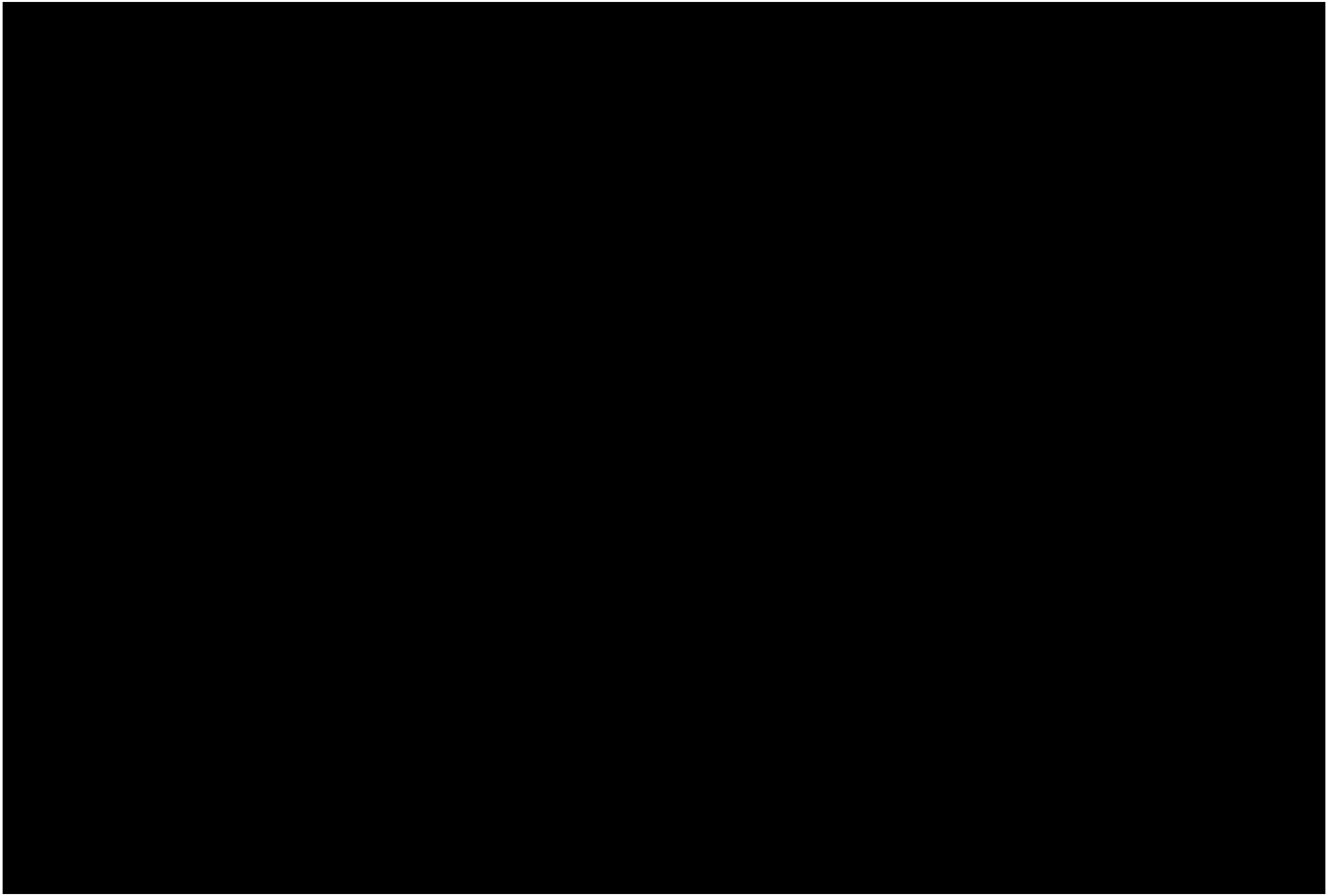
Member Forecasted On Peak Demand Day for July 2021

Big Horn Rural Electric Company

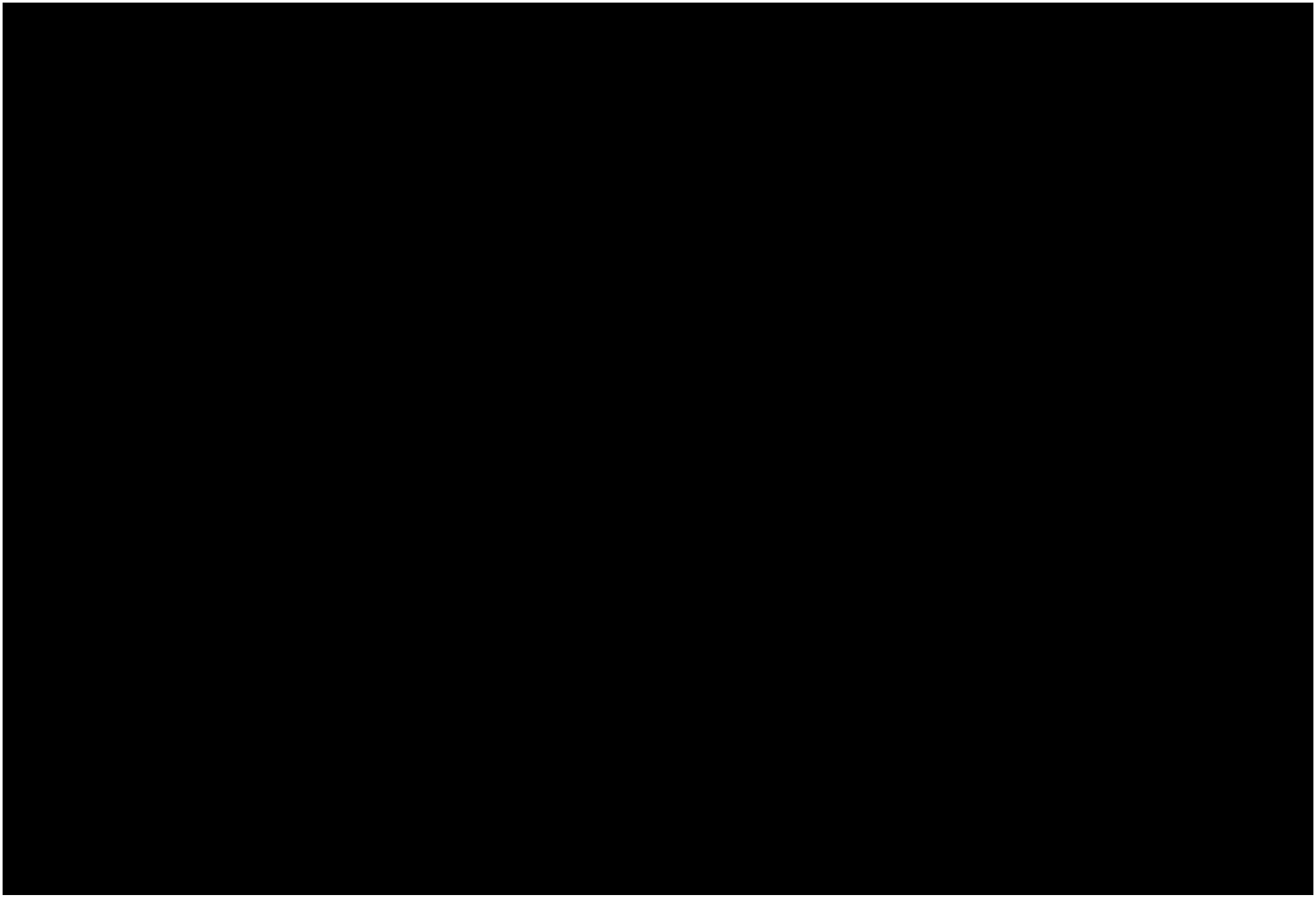
Date of On Peak Day - 07/04/2021



Member Forecasted On Peak Demand Day for August 2021

Big Horn Rural Electric Company

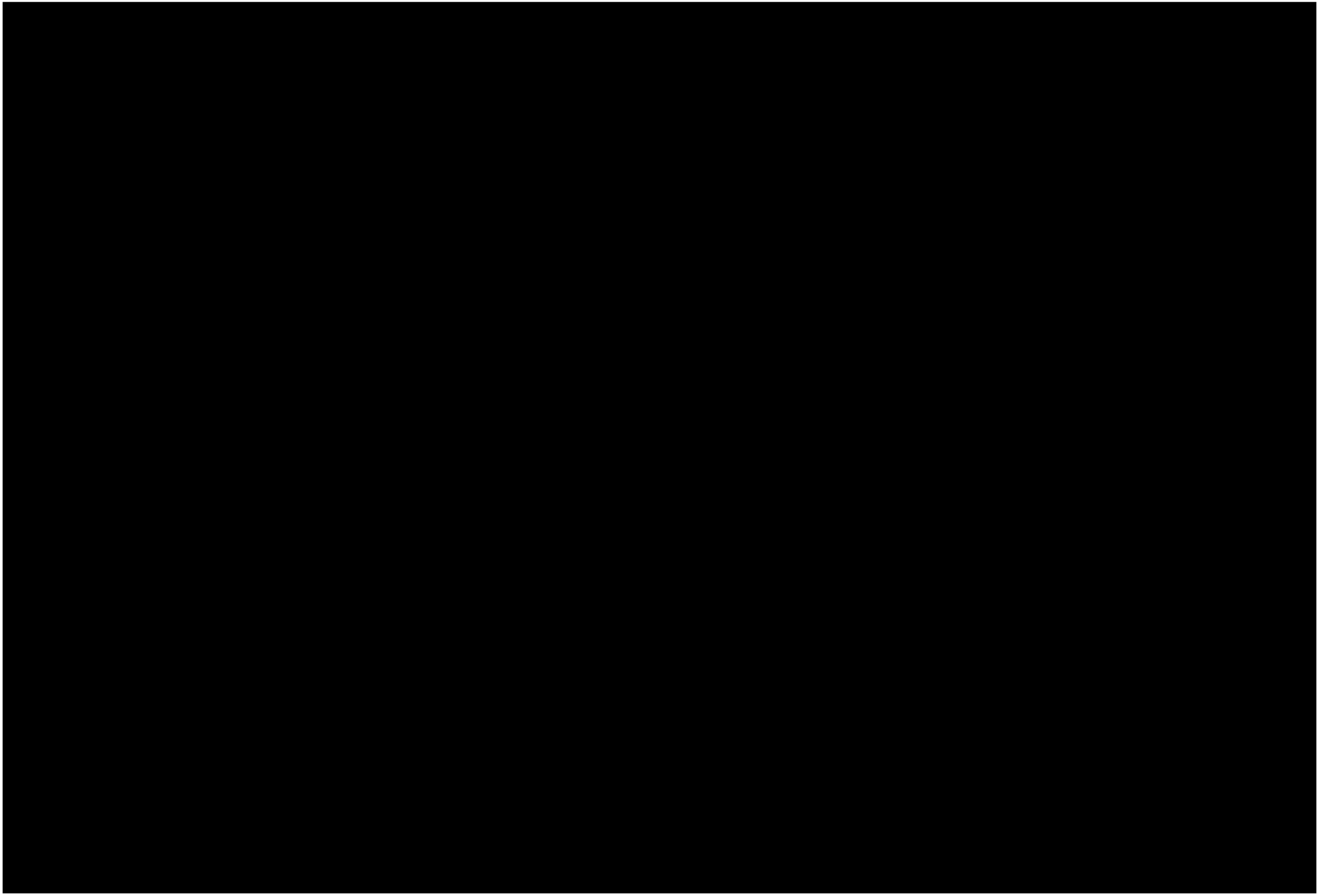
Date of On Peak Day - 08/12/2021



Member Forecasted On Peak Demand Day for September 2021

Big Horn Rural Electric Company

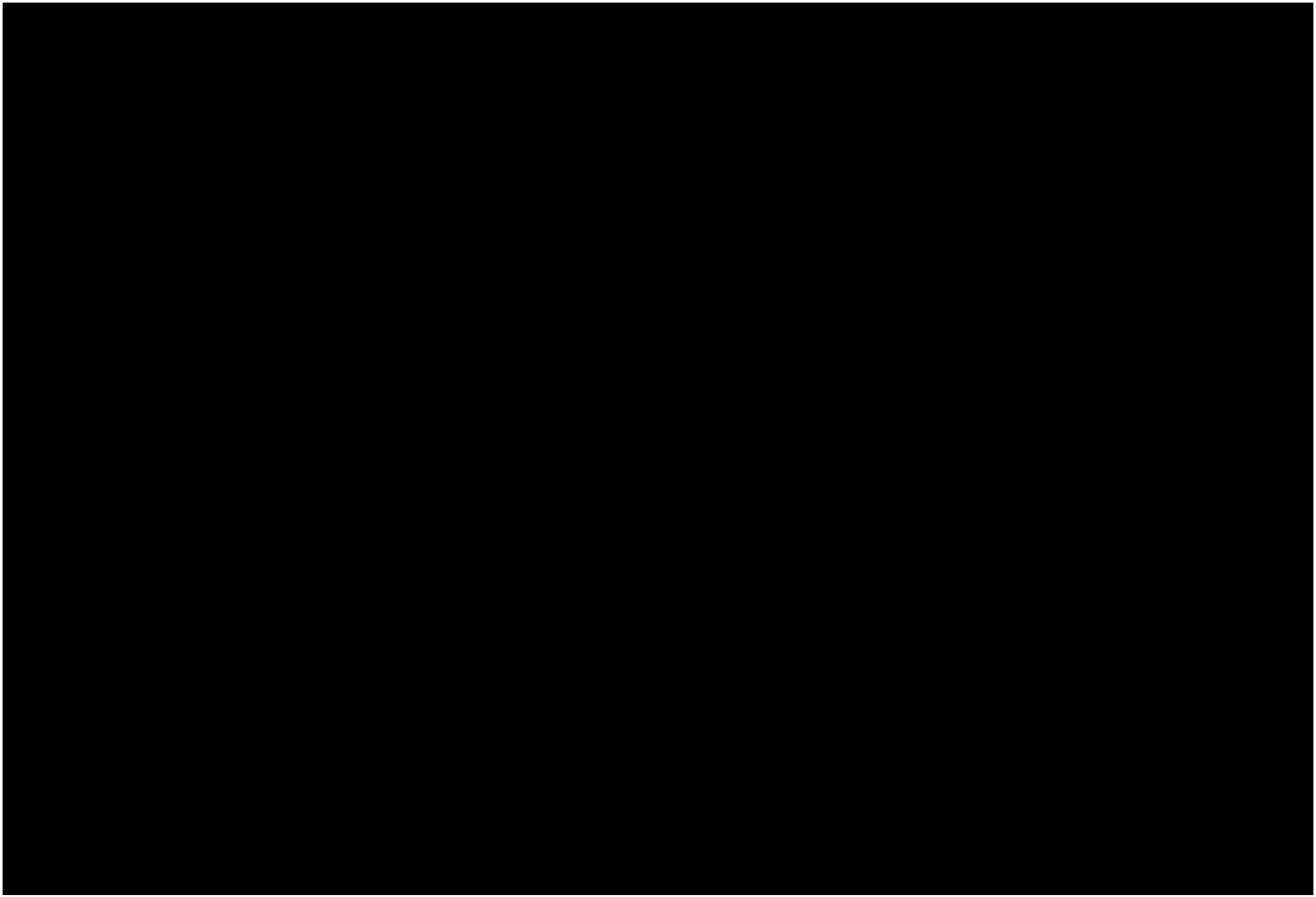
Date of On Peak Day - 09/25/2021



Member Forecasted On Peak Demand Day for October 2021

Big Horn Rural Electric Company

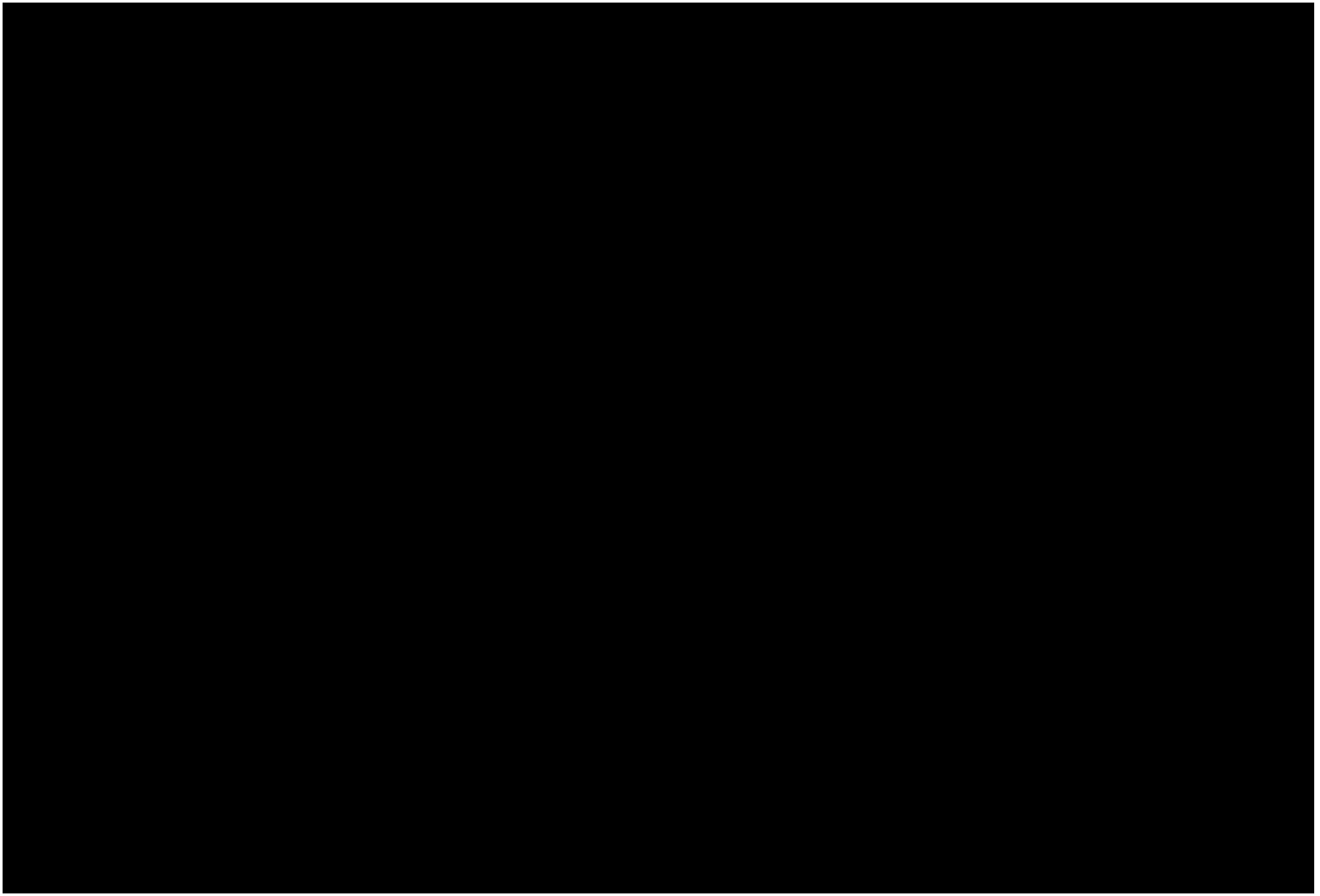
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Big Horn Rural Electric Company

Date of On Peak Day - 11/01/2021



Member Forecasted On Peak Demand Day for December 2021

Big Horn Rural Electric Company

Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 01/05/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Carbon Power and Light, Inc.

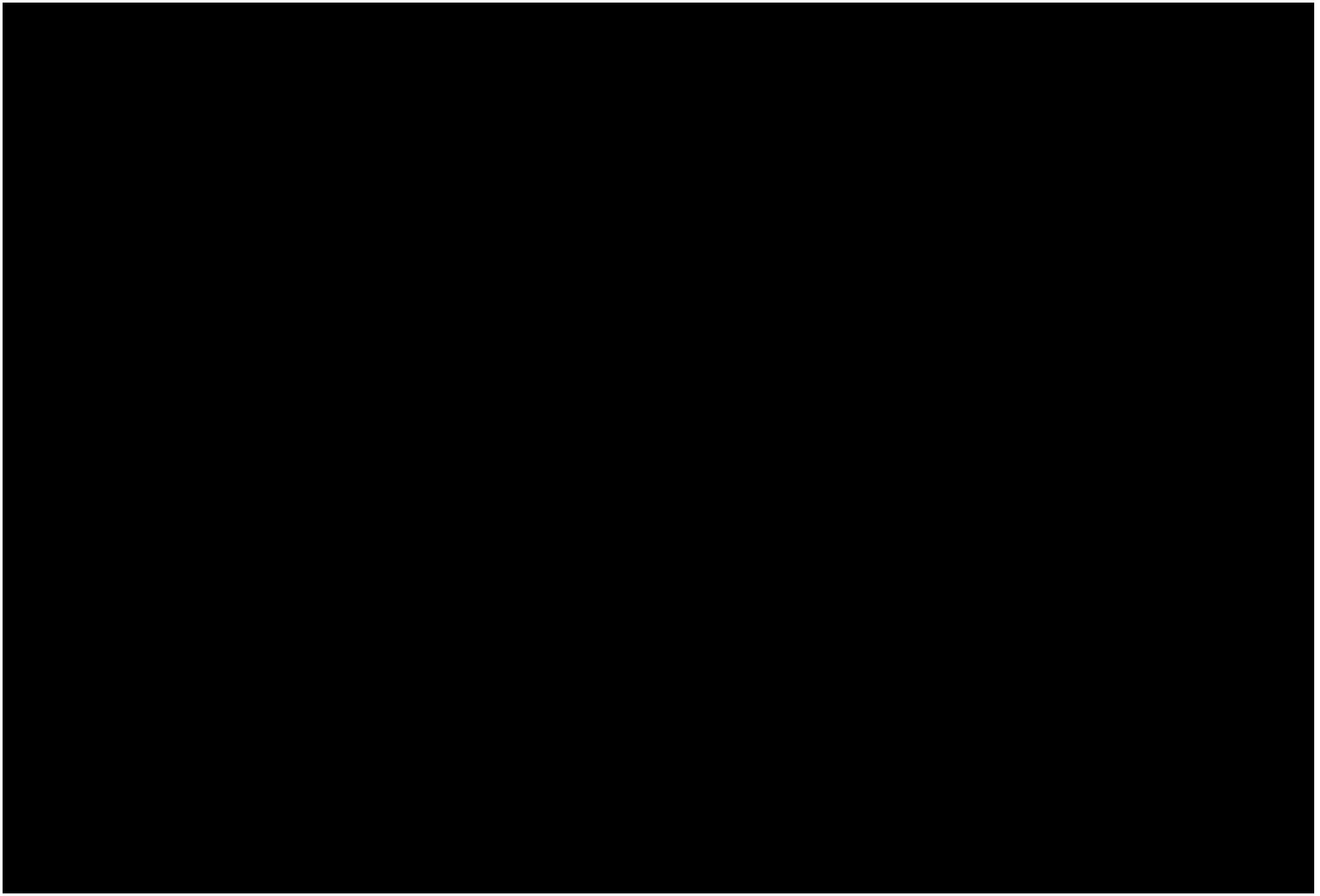
Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Carbon Power and Light, Inc.

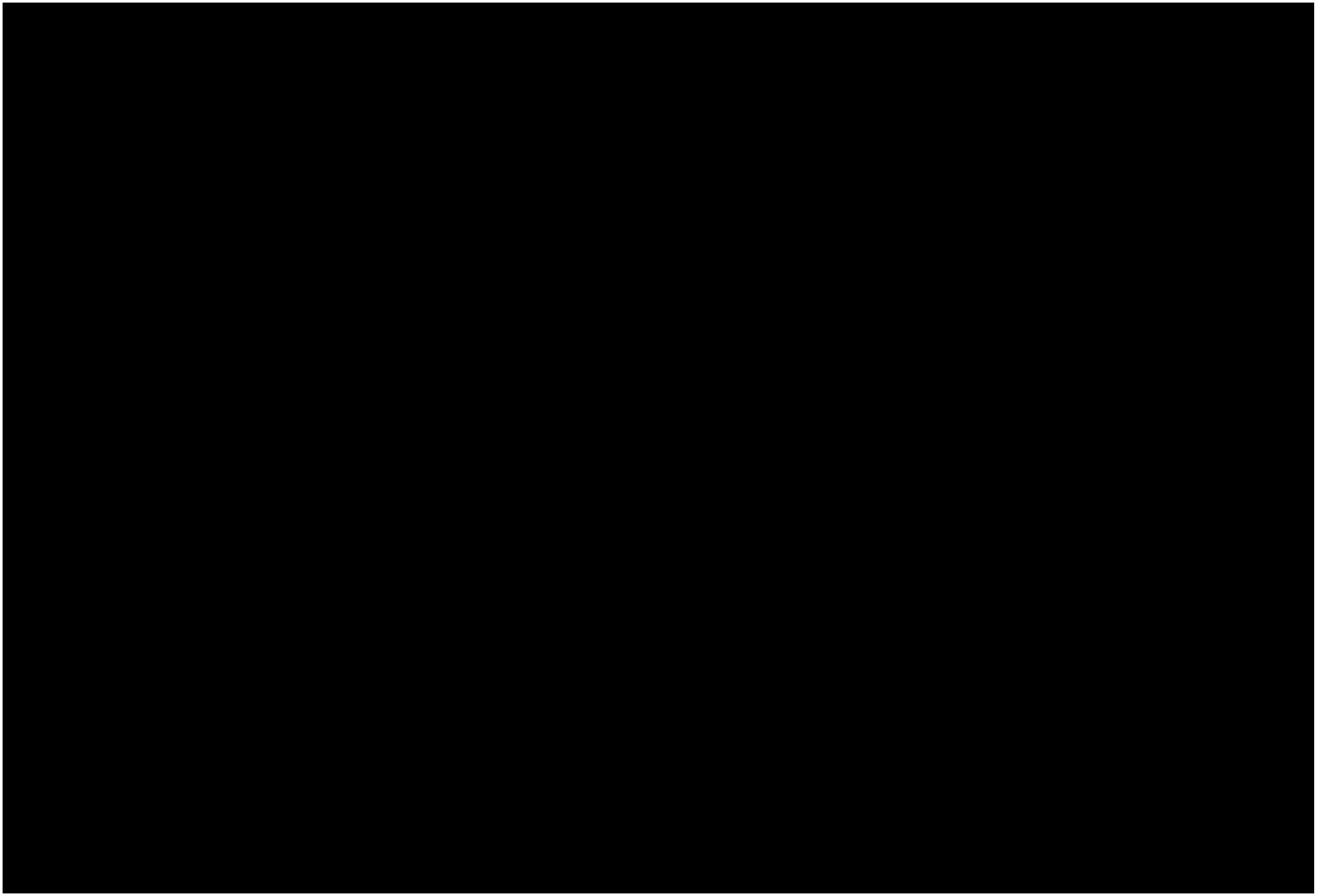
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Carbon Power and Light, Inc.

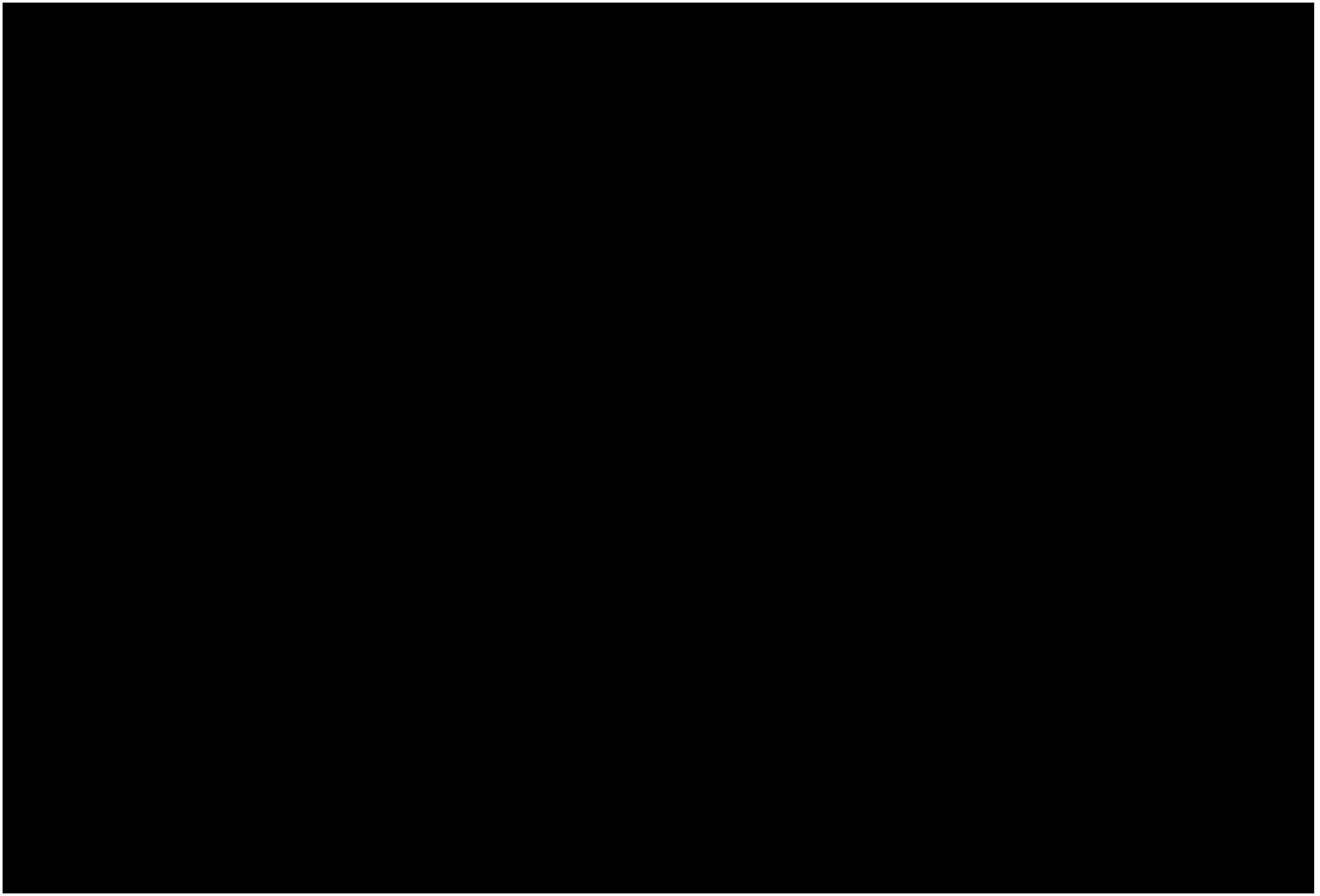
Date of On Peak Day - 05/03/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Carbon Power and Light, Inc.

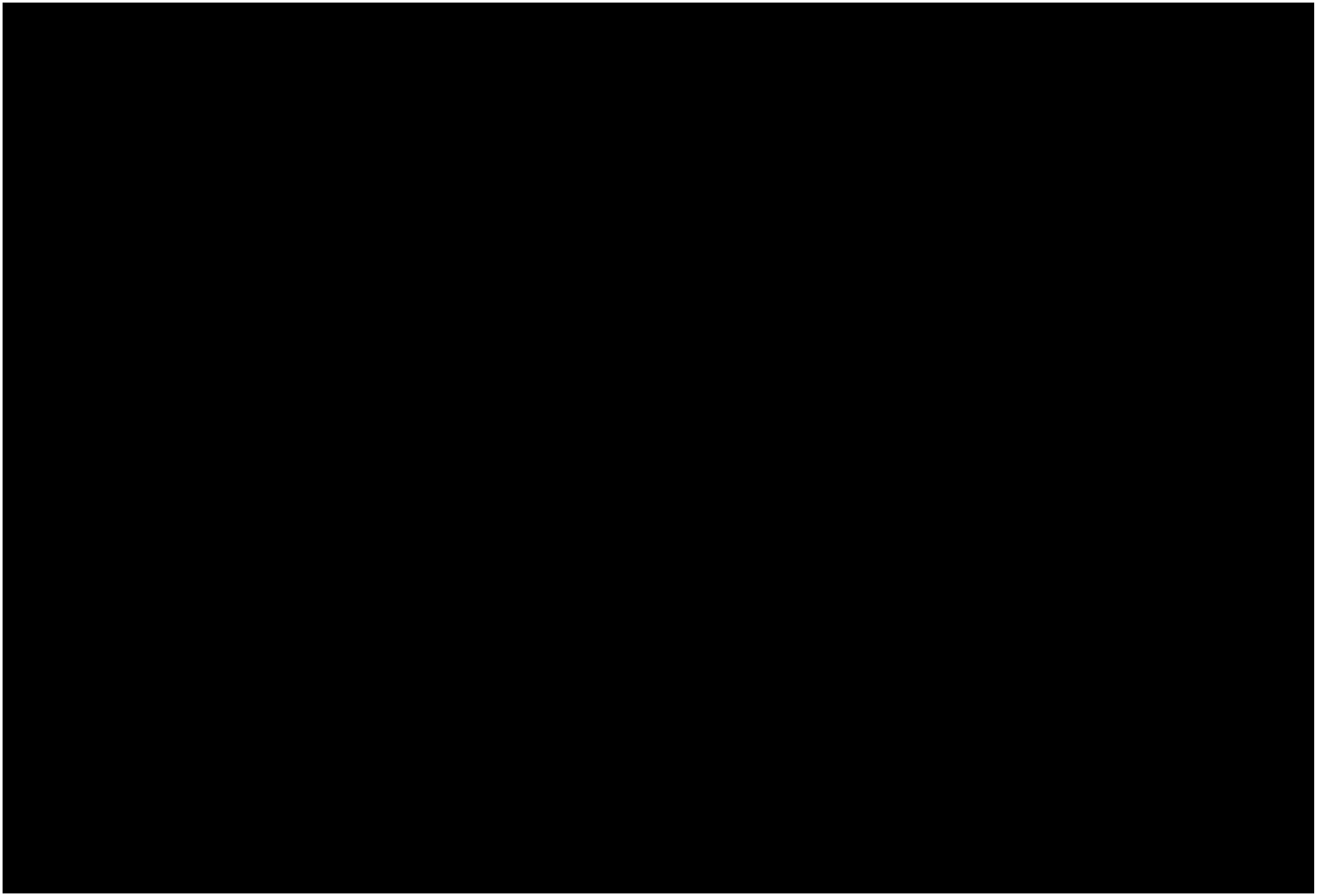
Date of On Peak Day - 06/25/2021



Member Forecasted On Peak Demand Day for July 2021

Carbon Power and Light, Inc.

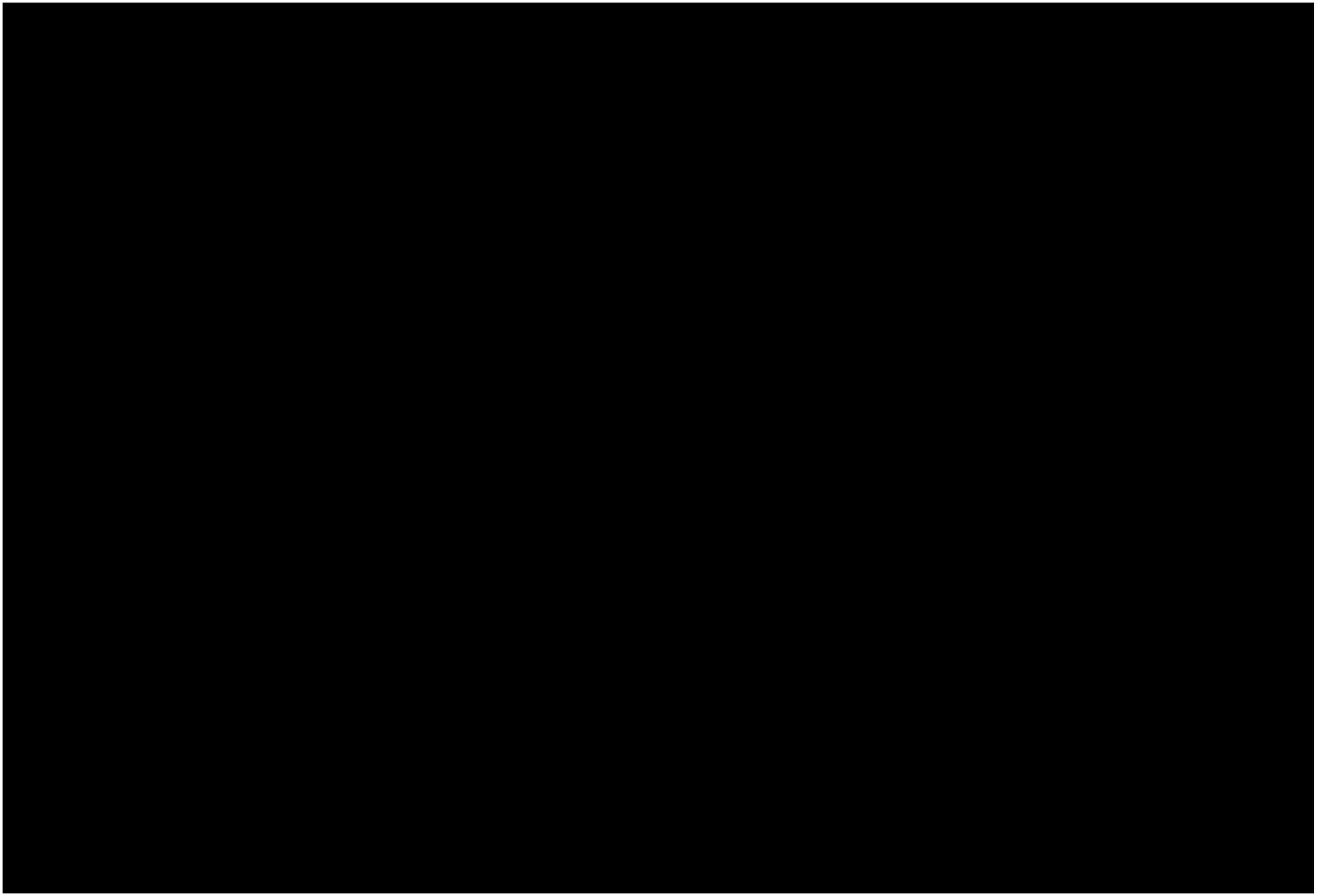
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Carbon Power and Light, Inc.

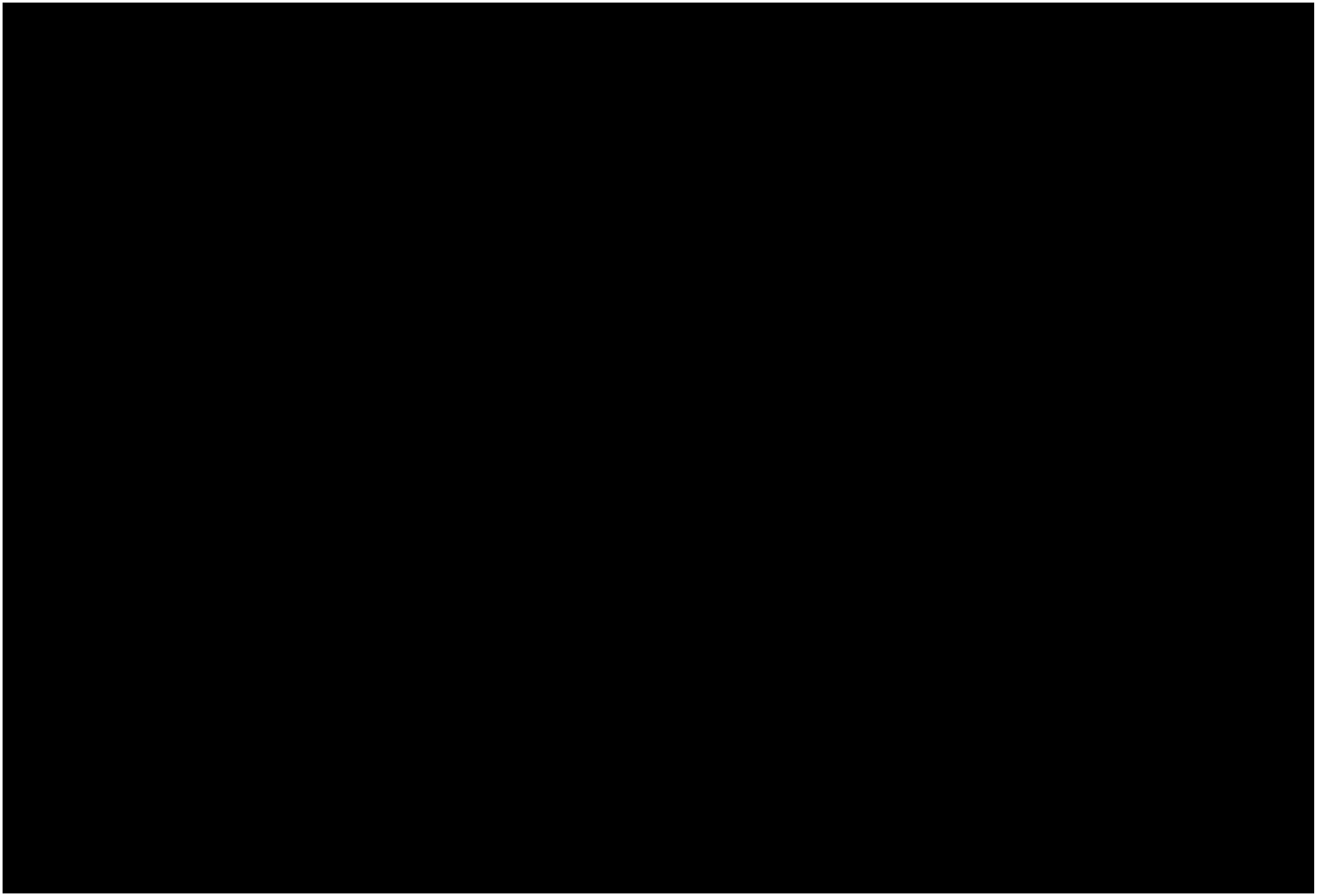
Date of On Peak Day - 08/20/2021



Member Forecasted On Peak Demand Day for September 2021

Carbon Power and Light, Inc.

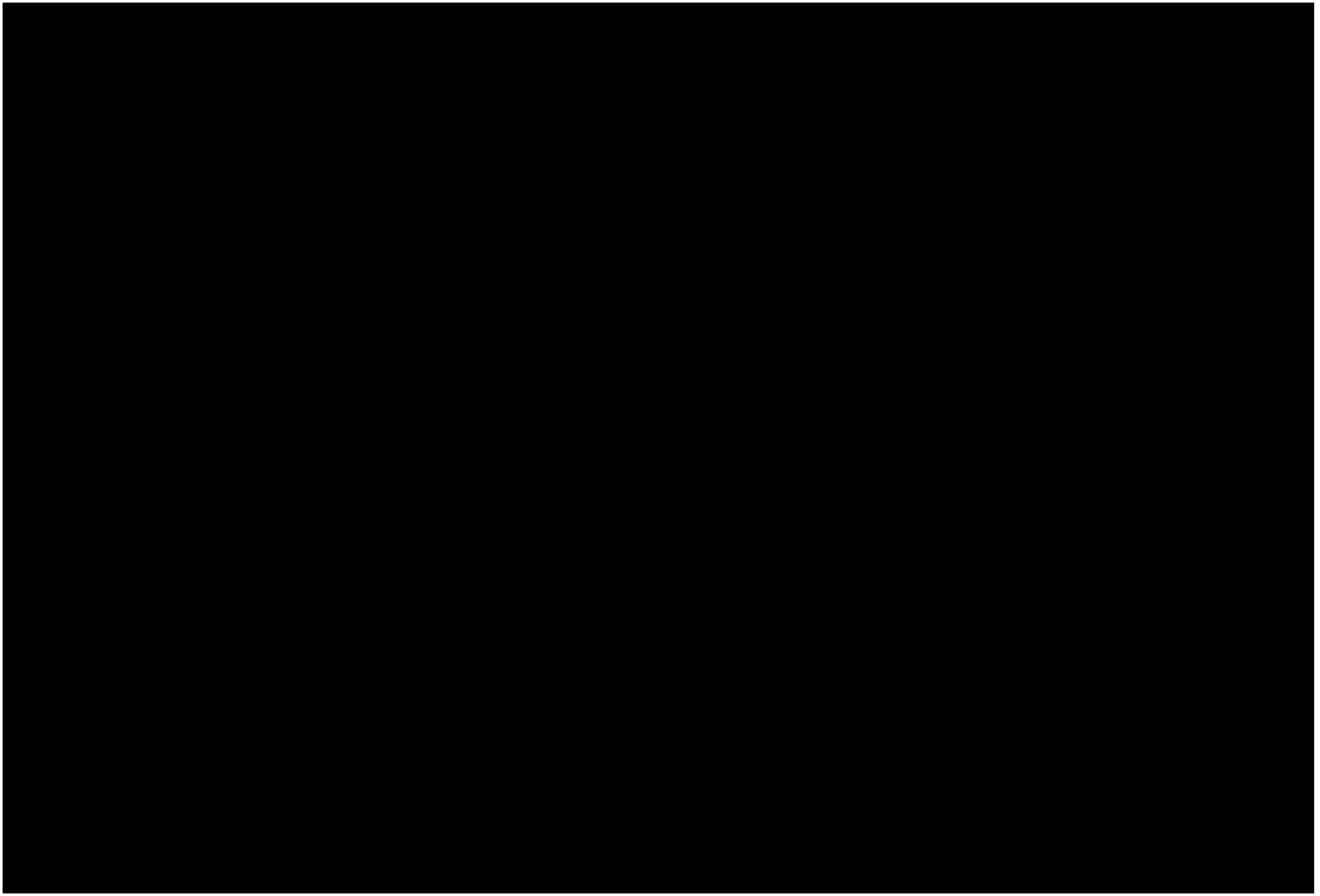
Date of On Peak Day - 09/09/2021



Member Forecasted On Peak Demand Day for October 2021

Carbon Power and Light, Inc.

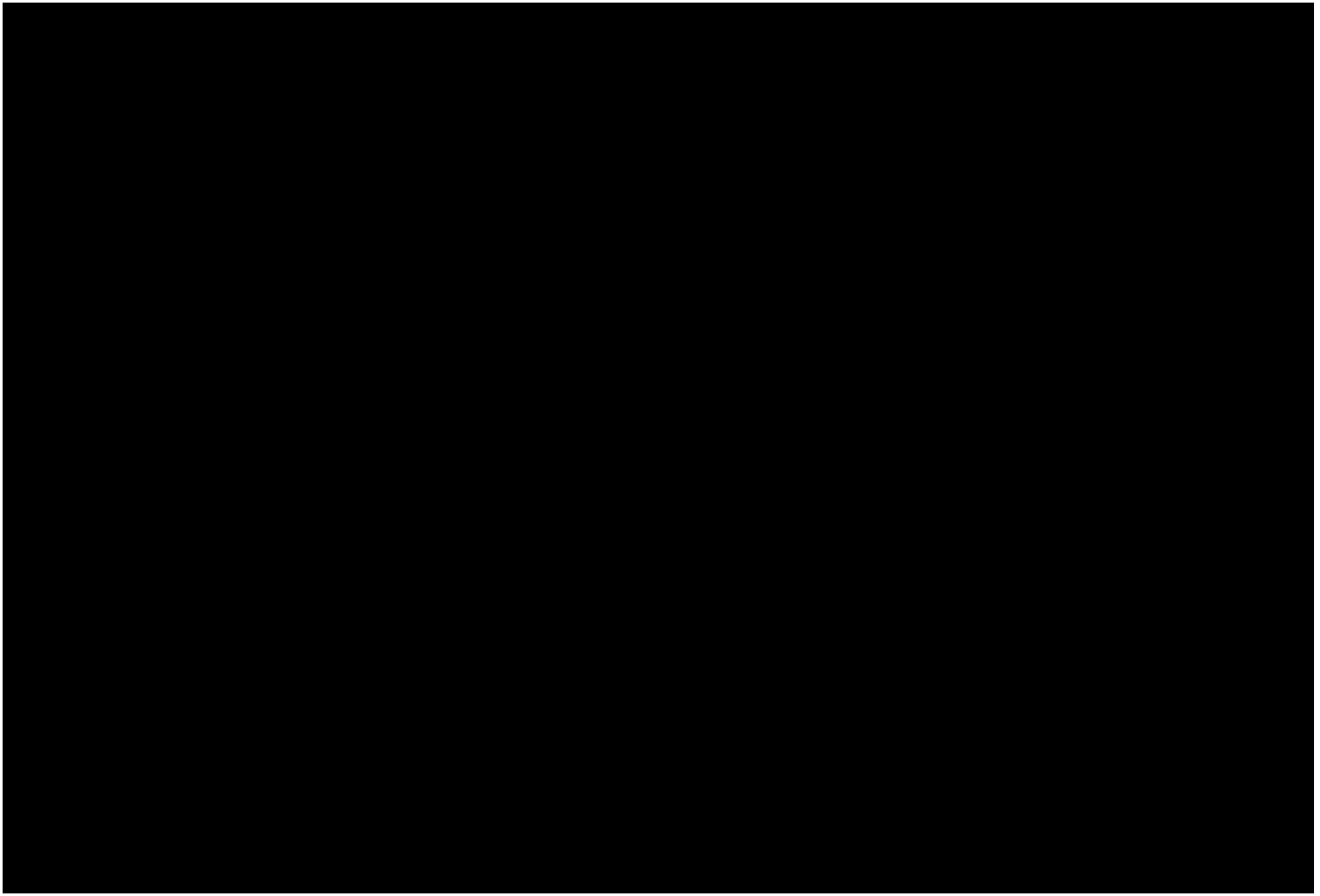
Date of On Peak Day - 10/22/2021



Member Forecasted On Peak Demand Day for November 2021

Carbon Power and Light, Inc.

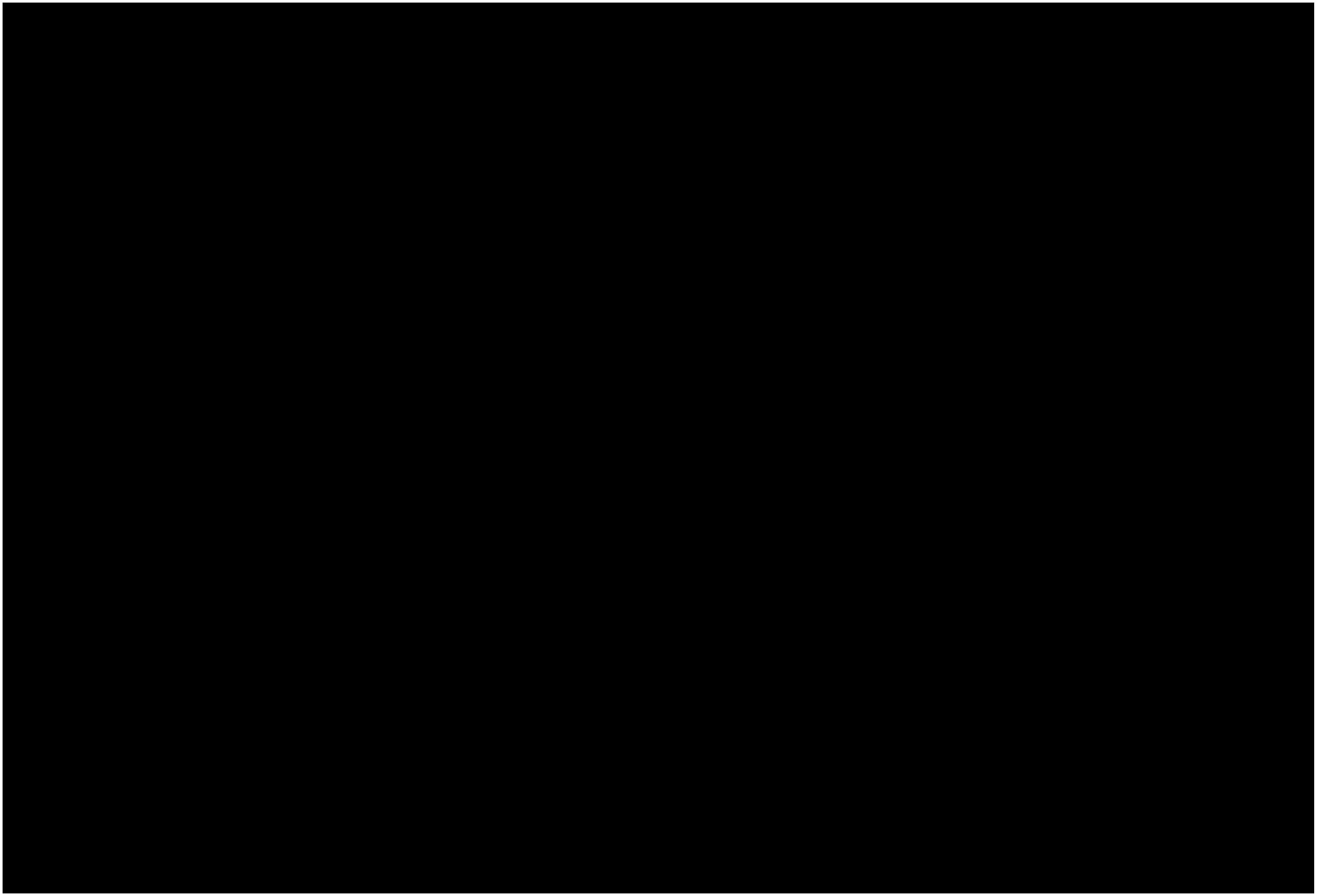
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Carbon Power and Light, Inc.

Date of On Peak Day - 12/28/2021



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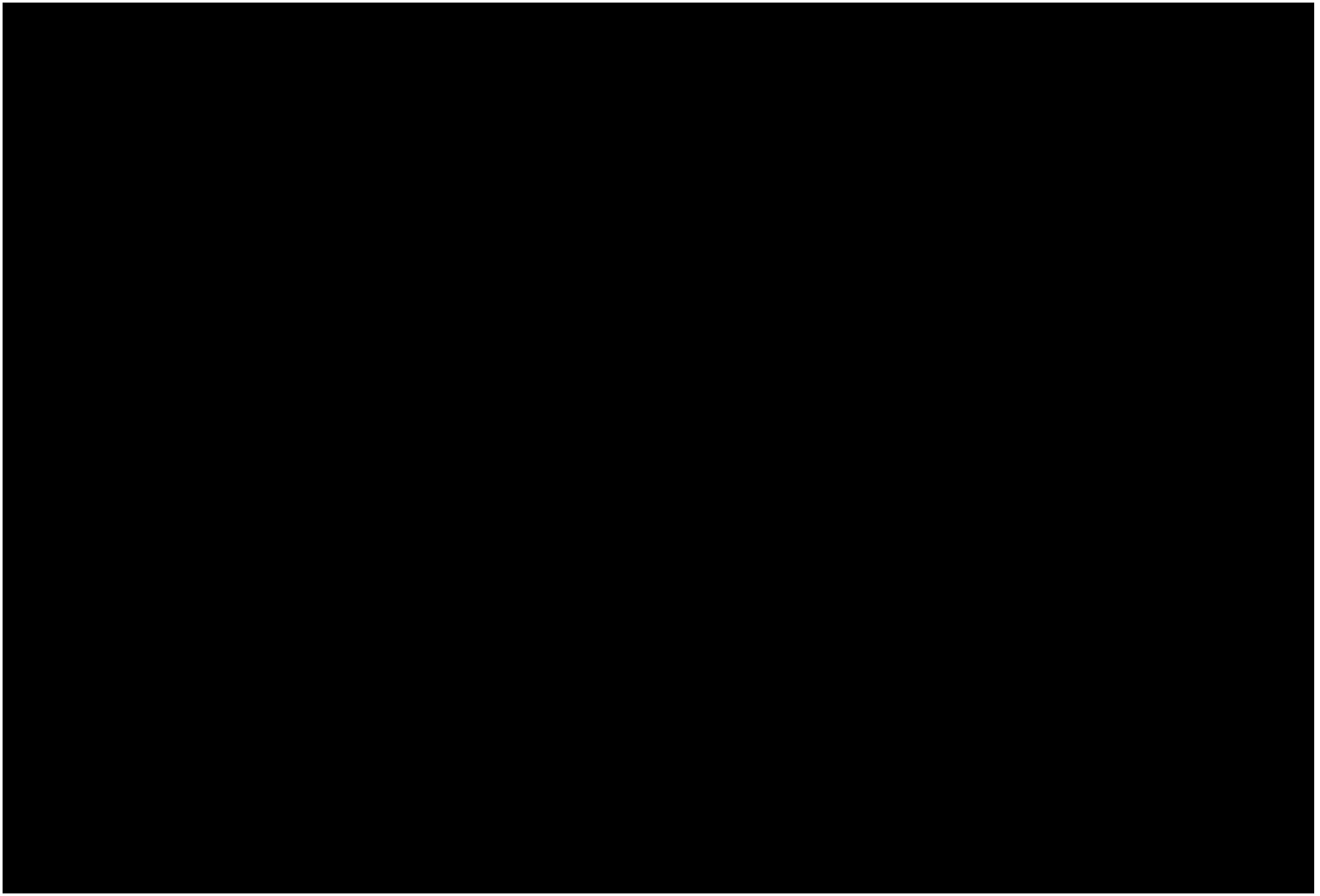
Member Forecasted On Peak Demand Day for January 2021

Continental Divide Electric Cooperative, Inc.

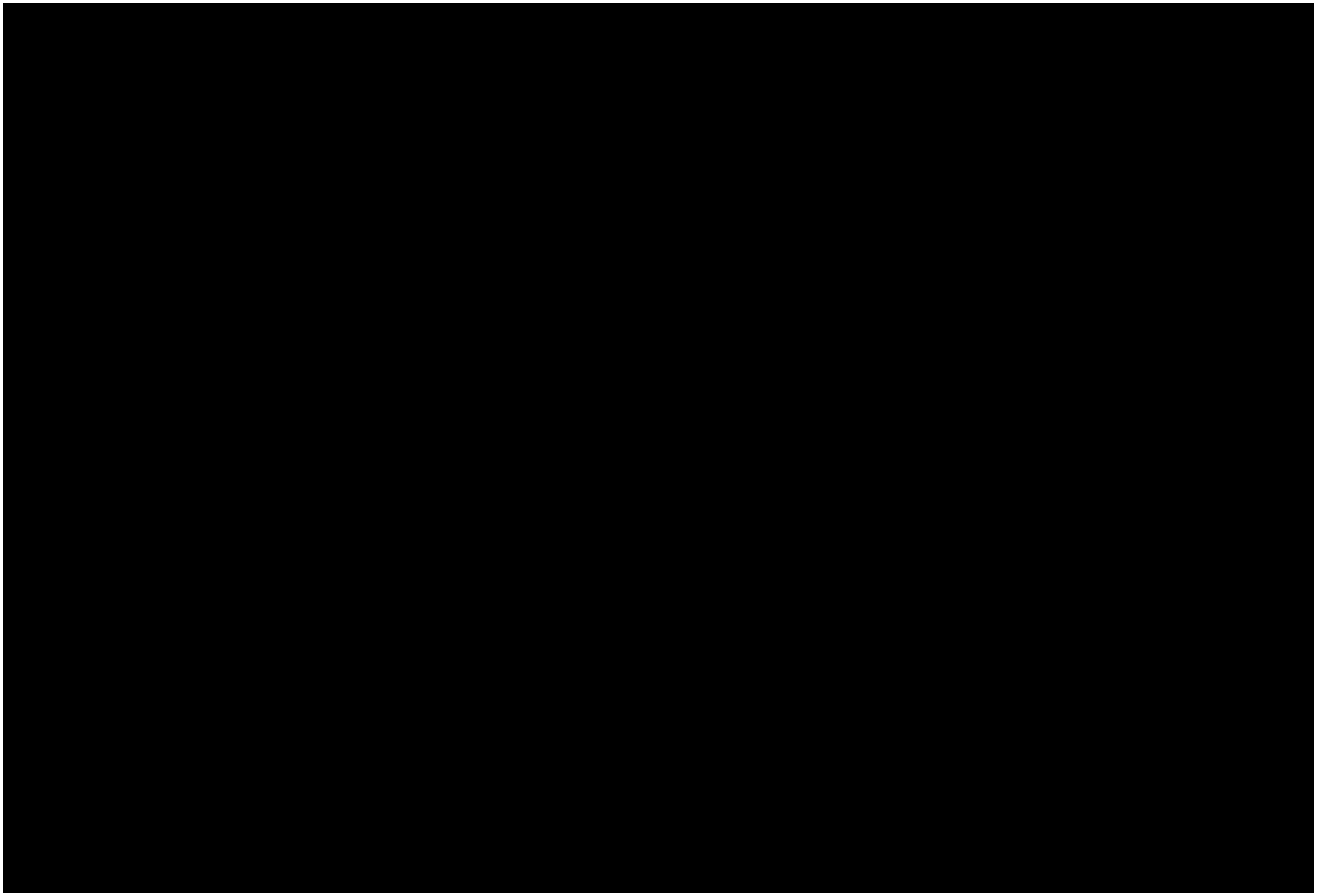
Date of On Peak Day - 01/25/2021



Member Forecasted On Peak Demand Day for February 2021

Continental Divide Electric Cooperative, Inc.

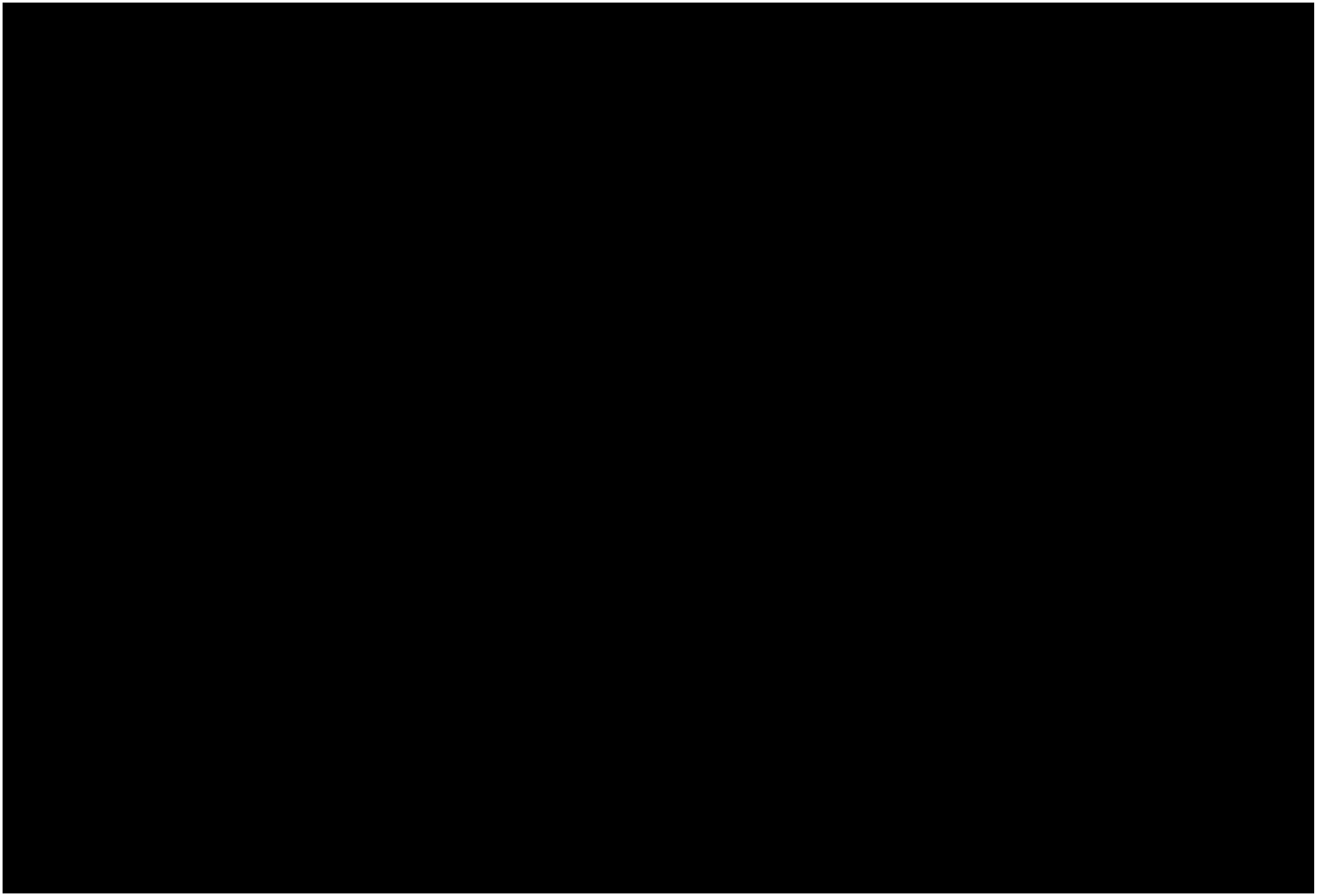
Date of On Peak Day - 02/04/2021



Member Forecasted On Peak Demand Day for March 2021

Continental Divide Electric Cooperative, Inc.

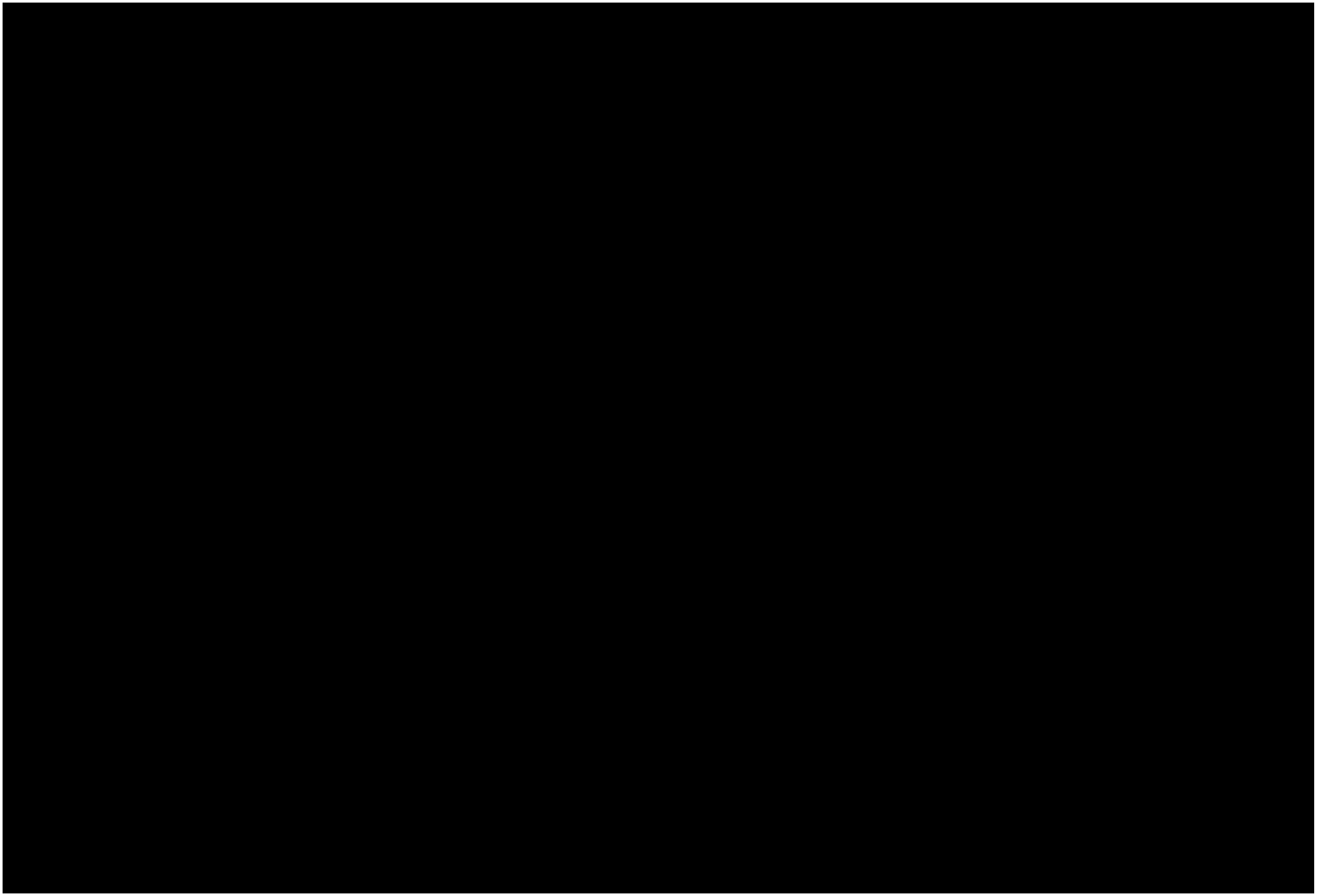
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Continental Divide Electric Cooperative, Inc.

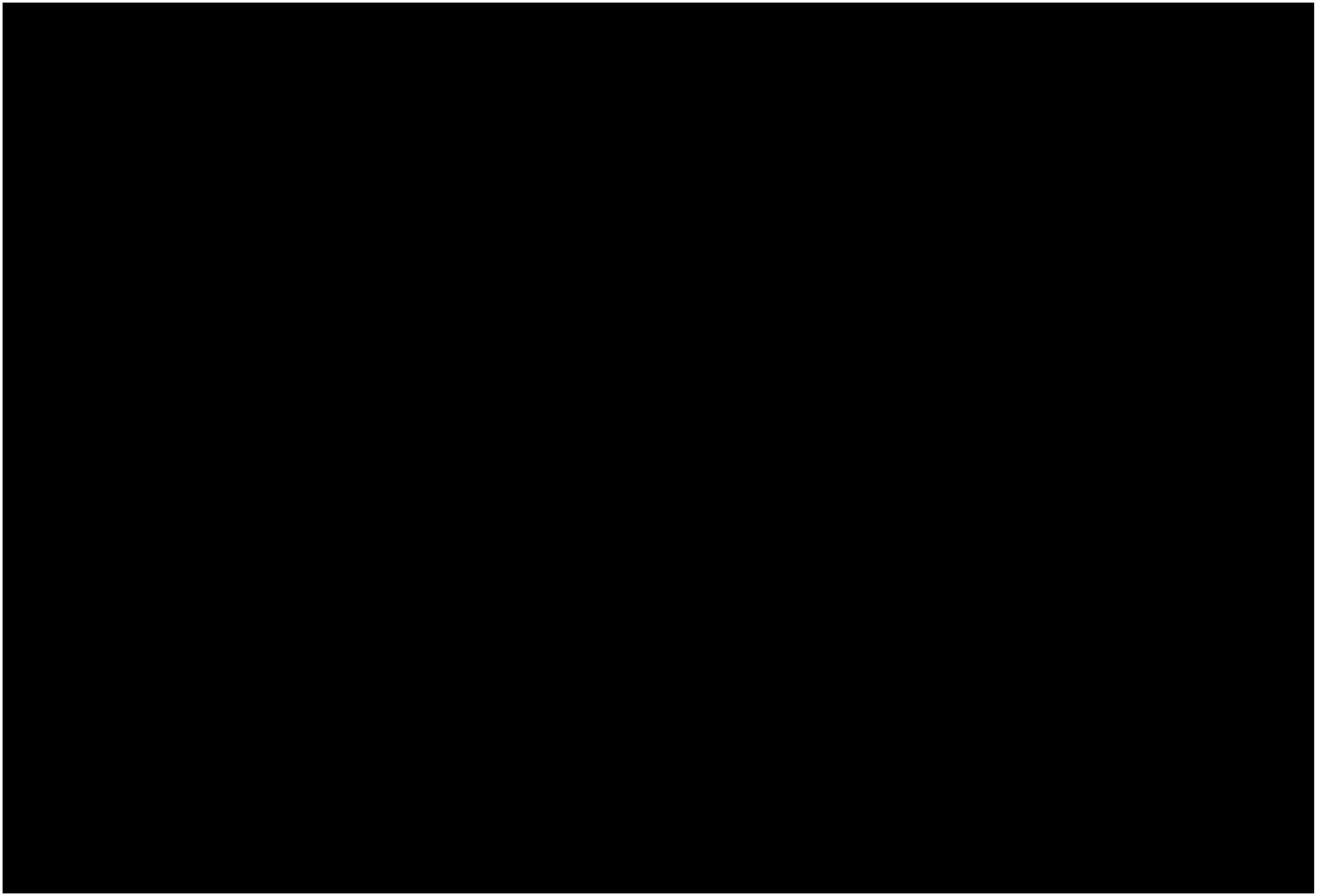
Date of On Peak Day - 04/26/2021



Member Forecasted On Peak Demand Day for May 2021

Continental Divide Electric Cooperative, Inc.

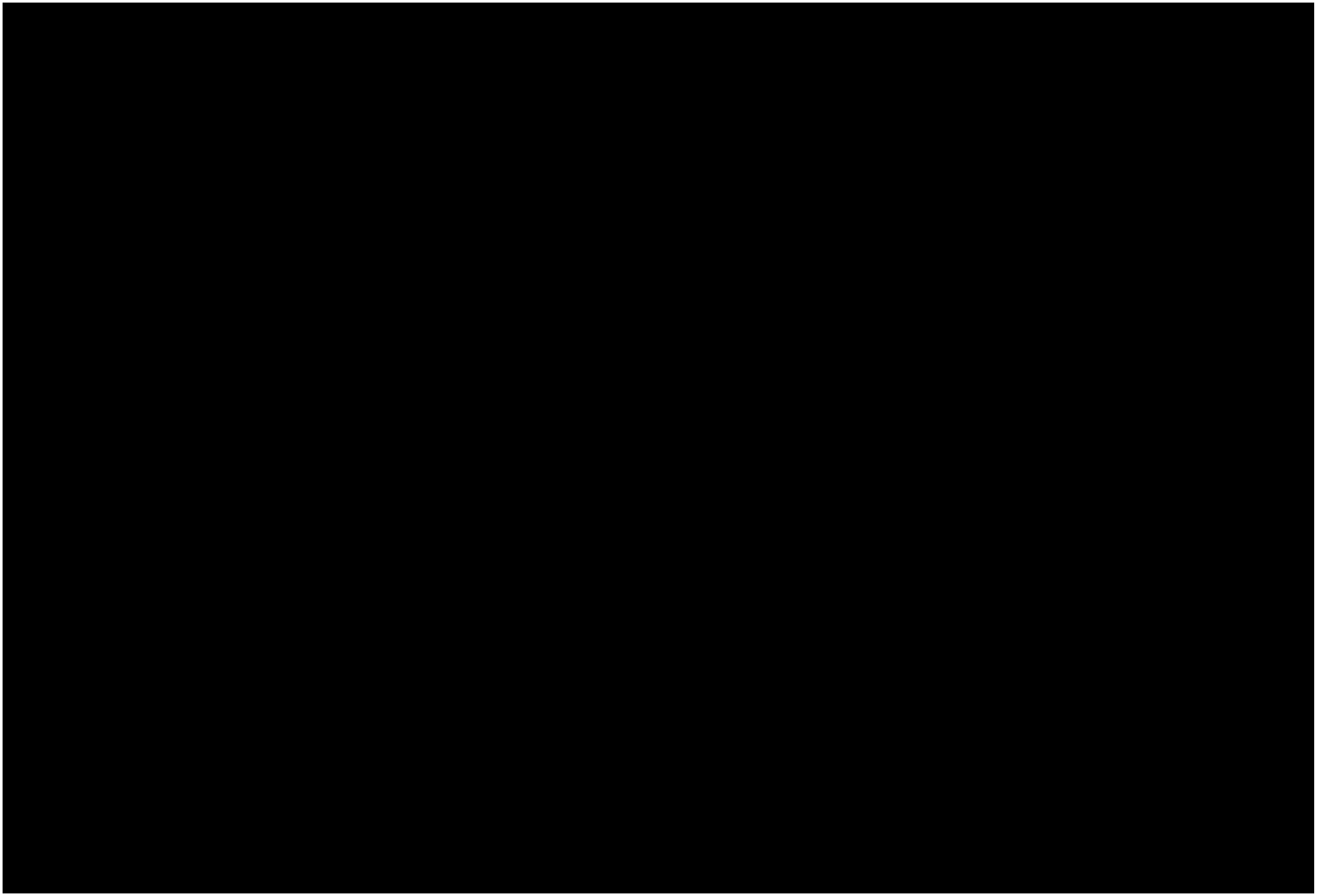
Date of On Peak Day - 05/10/2021



Member Forecasted On Peak Demand Day for June 2021

Continental Divide Electric Cooperative, Inc.

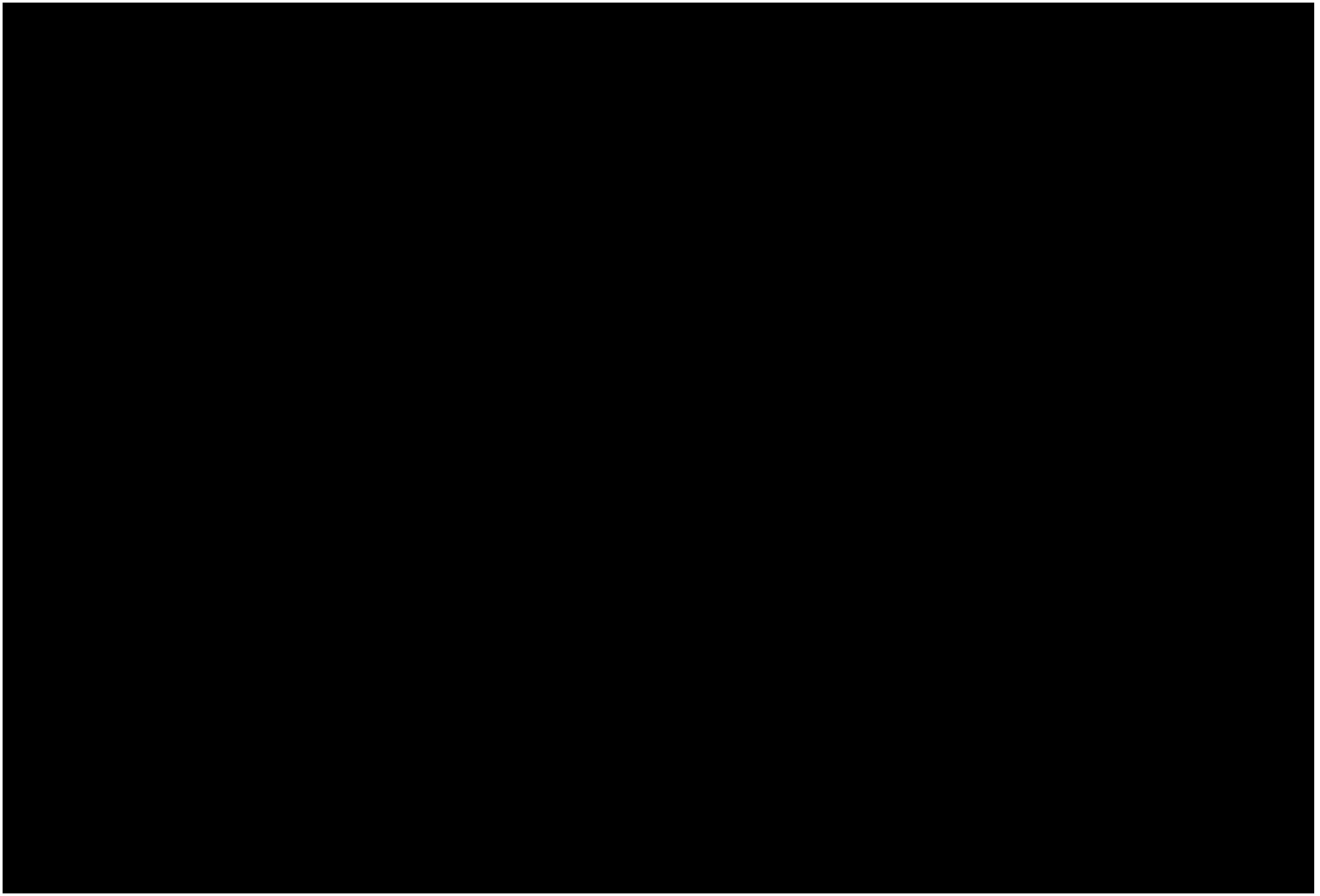
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Continental Divide Electric Cooperative, Inc.

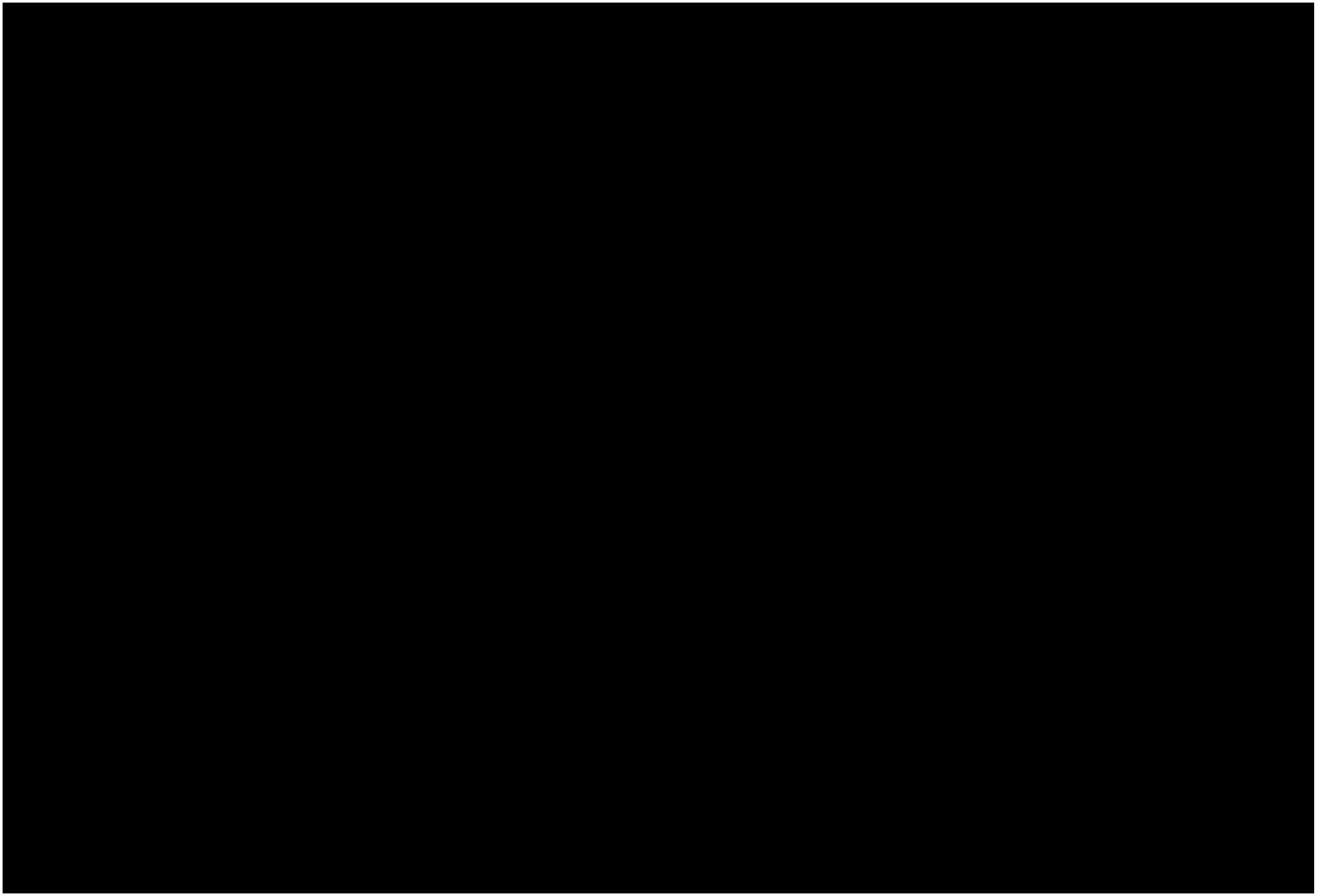
Date of On Peak Day - 07/27/2021



Member Forecasted On Peak Demand Day for August 2021

Continental Divide Electric Cooperative, Inc.

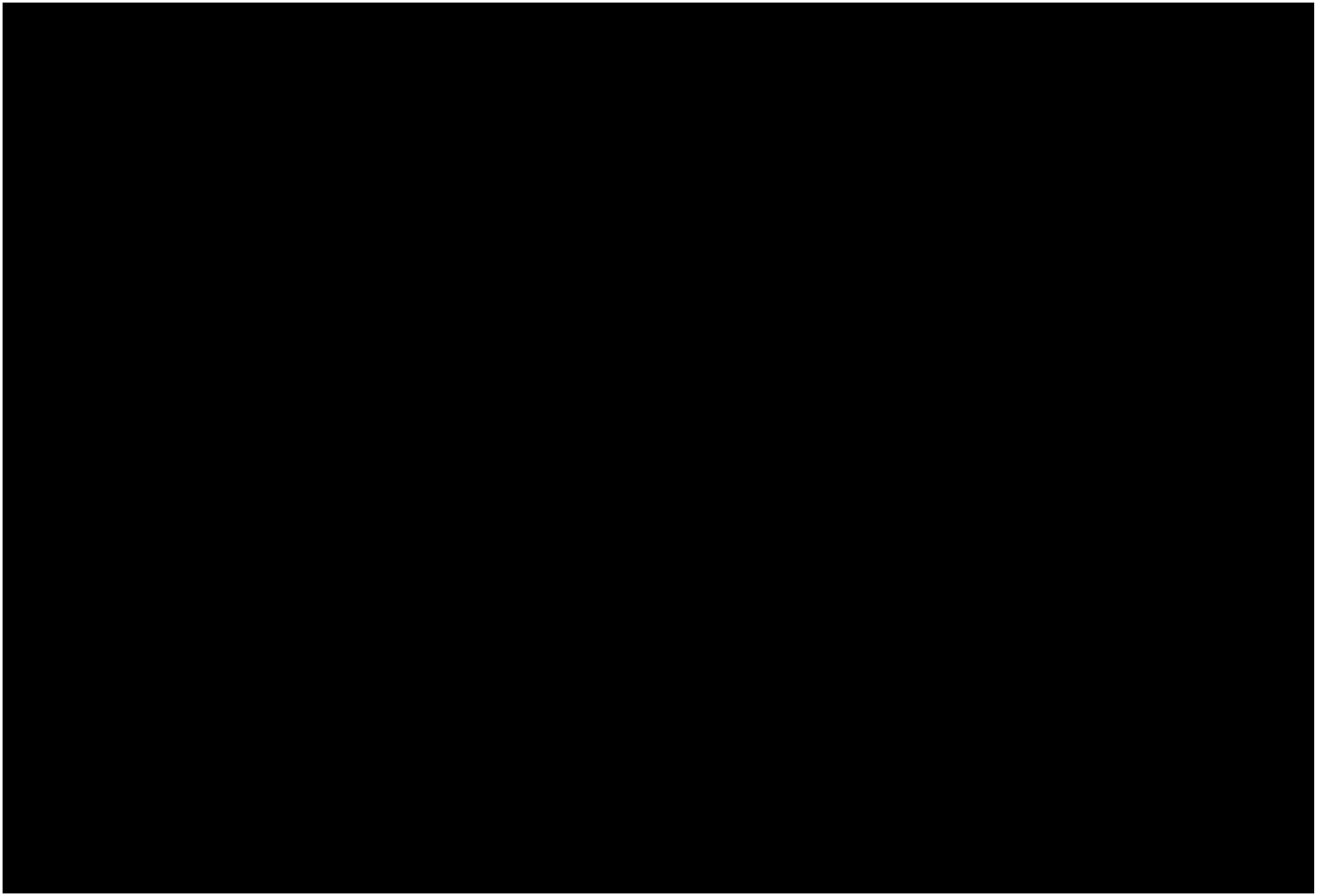
Date of On Peak Day - 08/03/2021



Member Forecasted On Peak Demand Day for September 2021

Continental Divide Electric Cooperative, Inc.

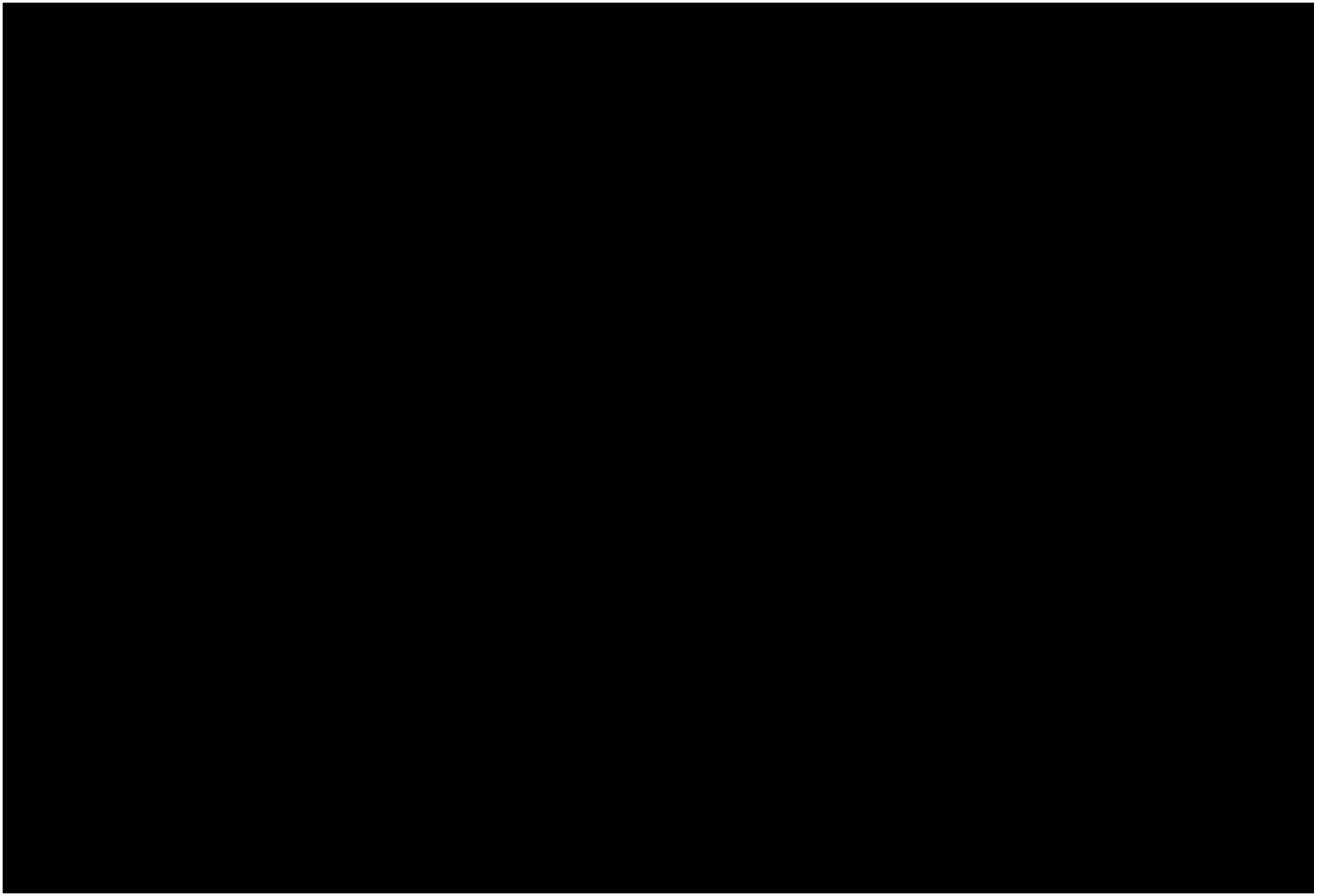
Date of On Peak Day - 09/29/2021



Member Forecasted On Peak Demand Day for October 2021

Continental Divide Electric Cooperative, Inc.

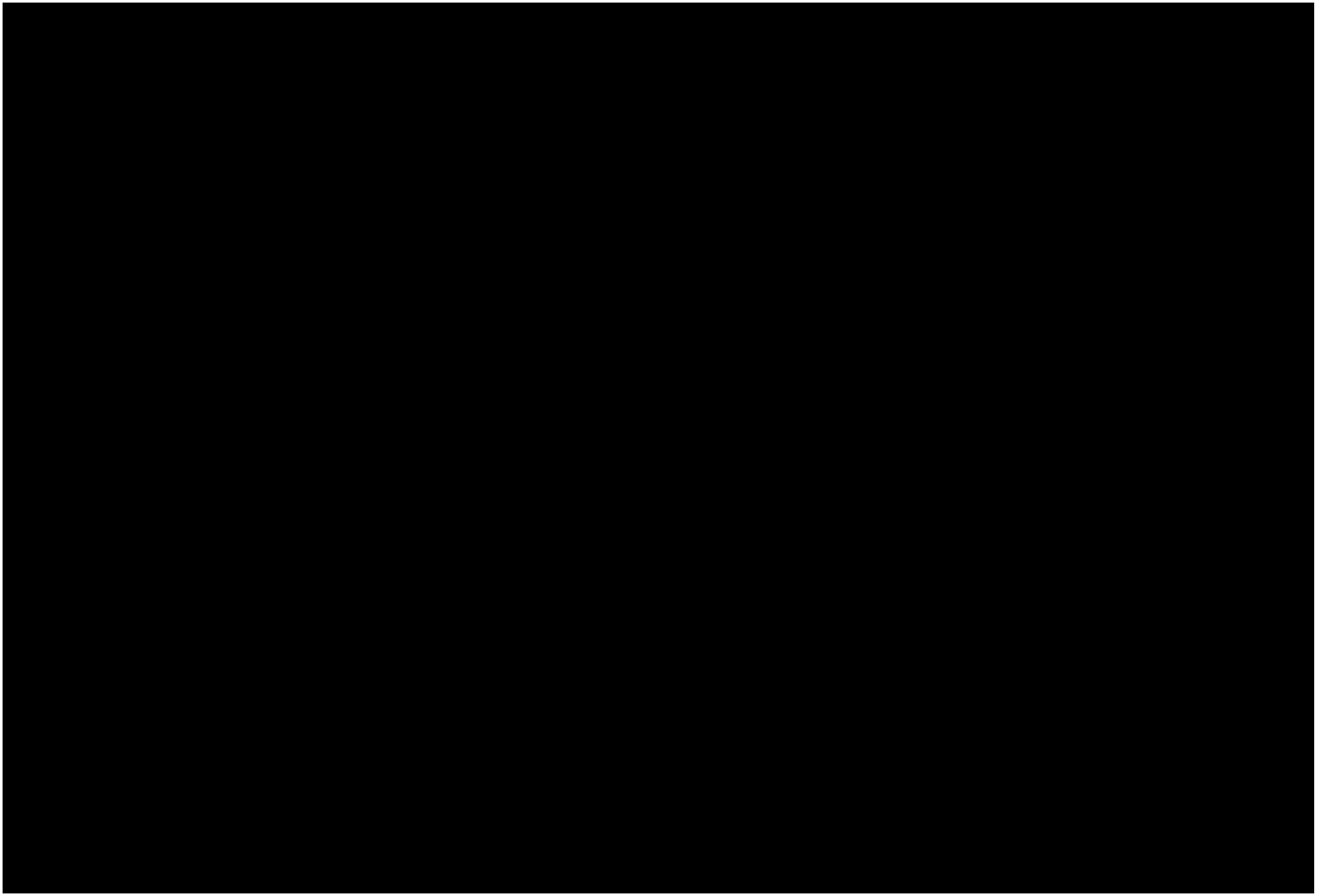
Date of On Peak Day - 10/25/2021



Member Forecasted On Peak Demand Day for November 2021

Continental Divide Electric Cooperative, Inc.

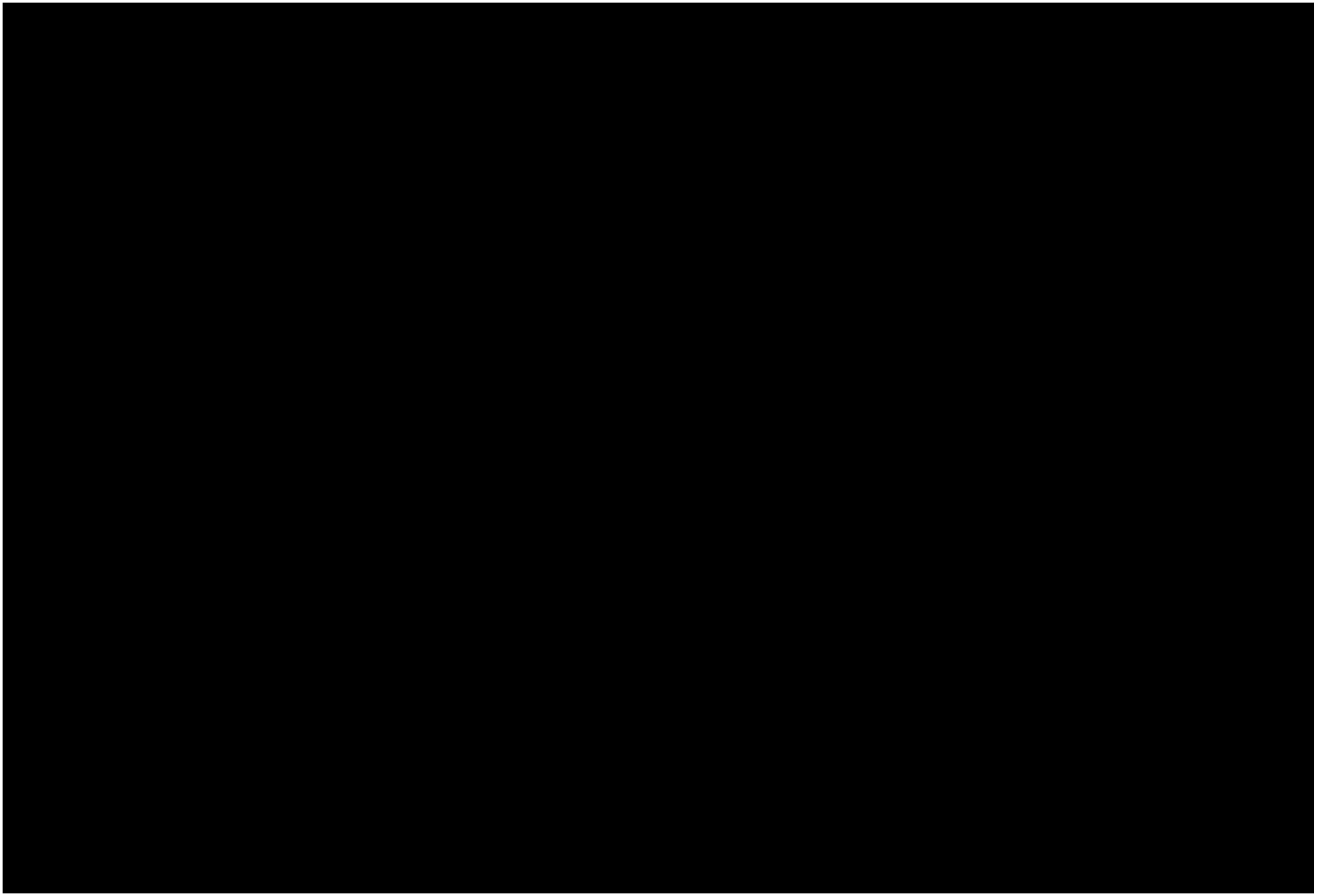
Date of On Peak Day - 11/30/2021



Member Forecasted On Peak Demand Day for December 2021

Continental Divide Electric Cooperative, Inc.

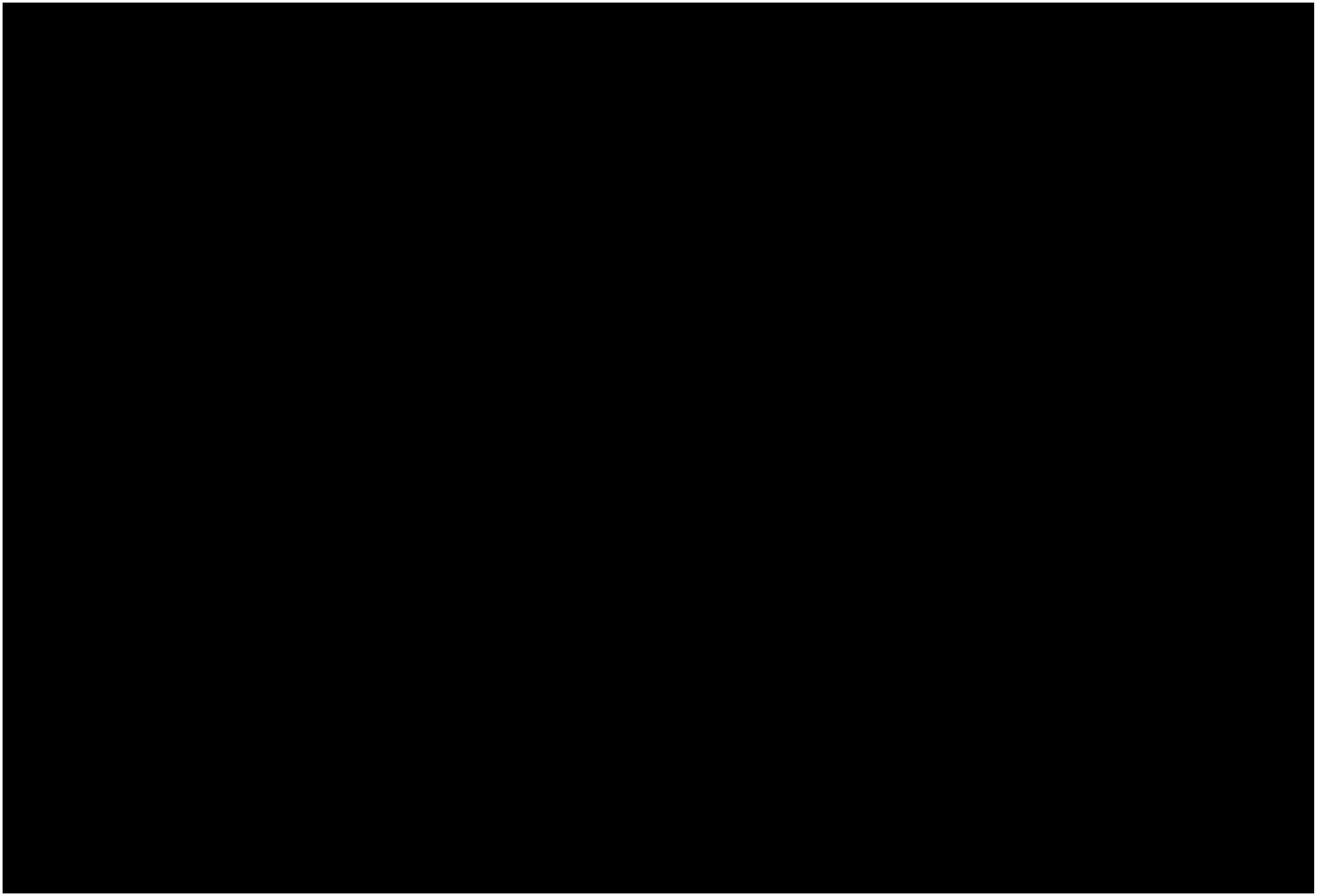
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Columbus Electric Cooperative, Inc.

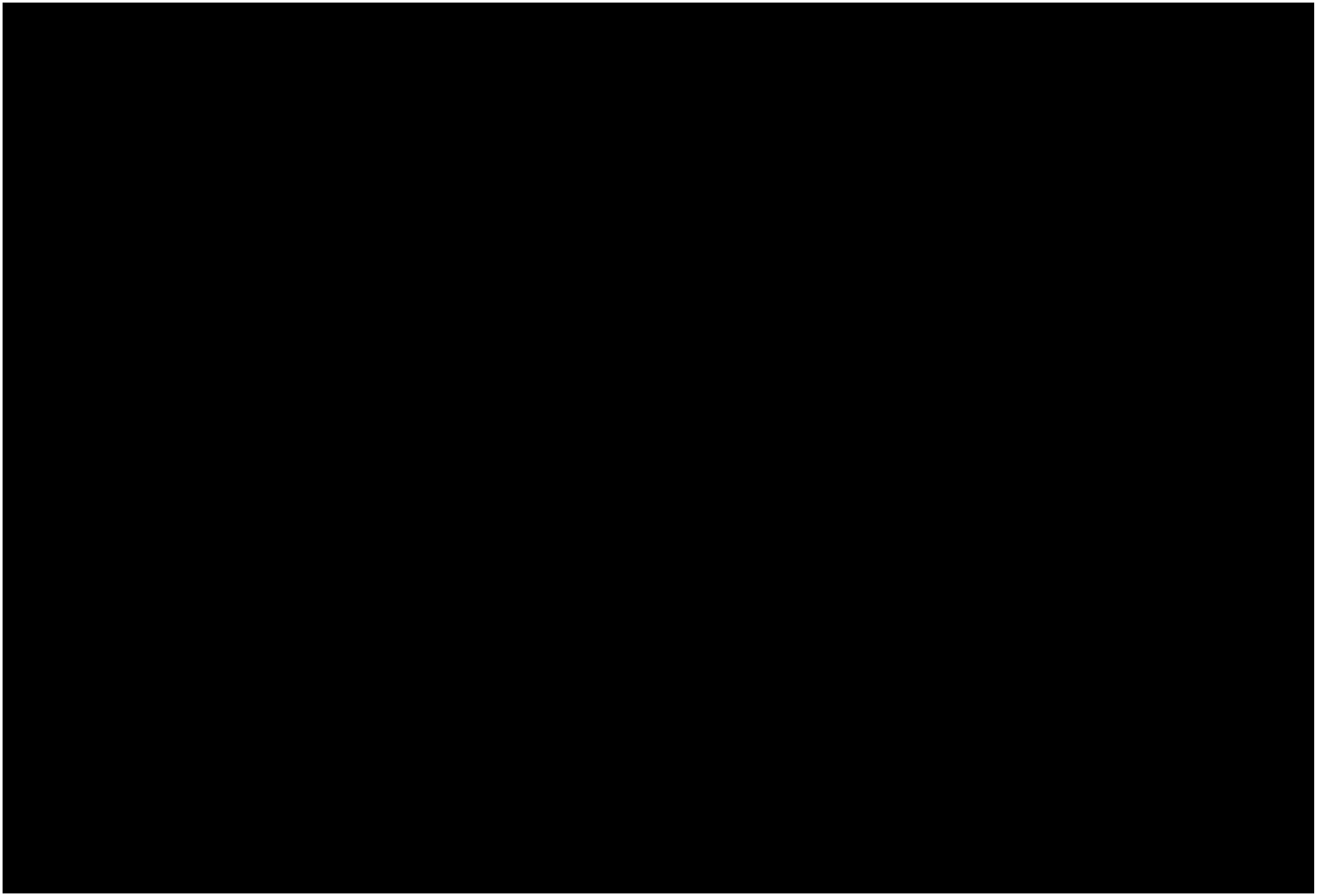
Date of On Peak Day - 01/30/2021



Member Forecasted On Peak Demand Day for February 2021

Columbus Electric Cooperative, Inc.

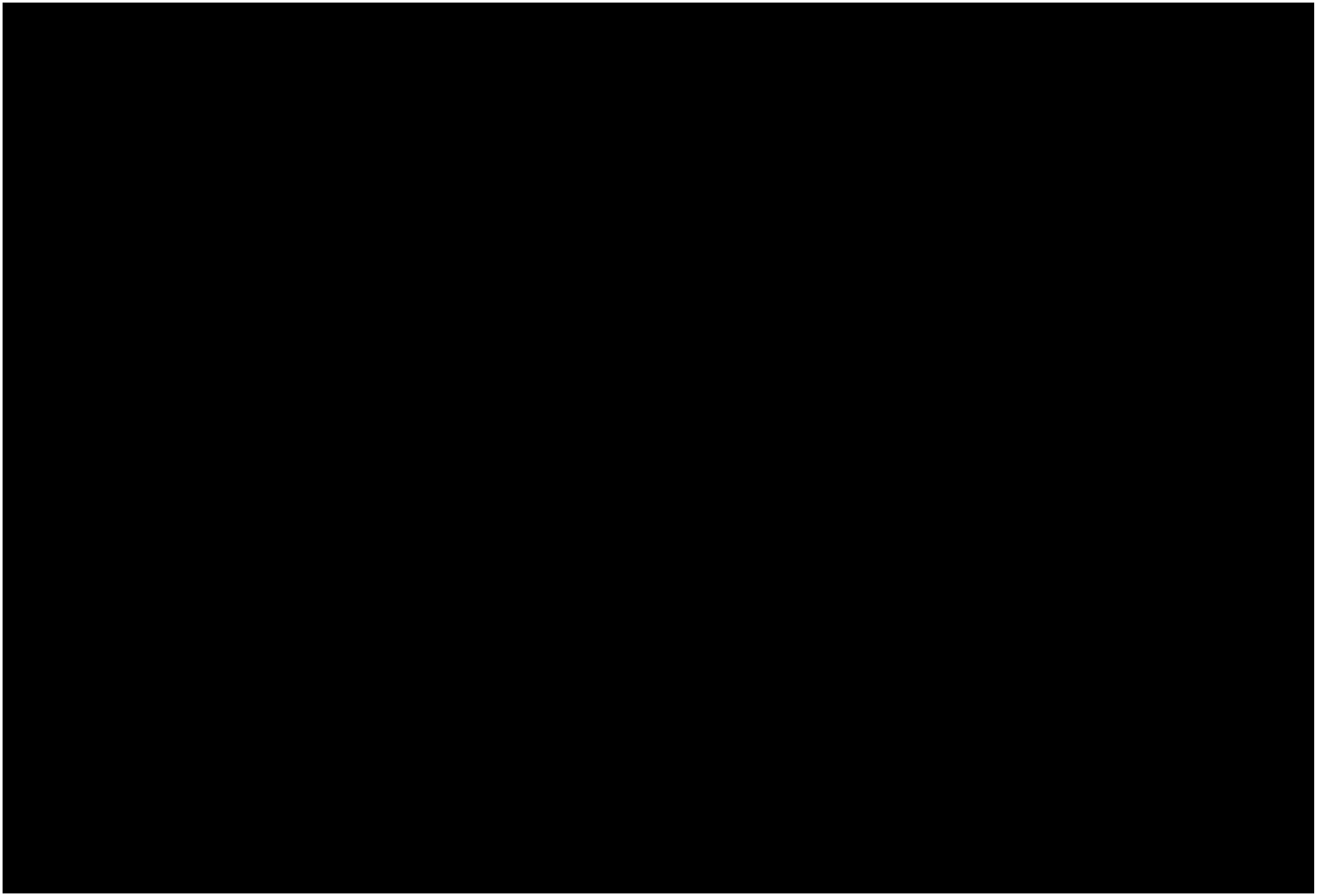
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Columbus Electric Cooperative, Inc.

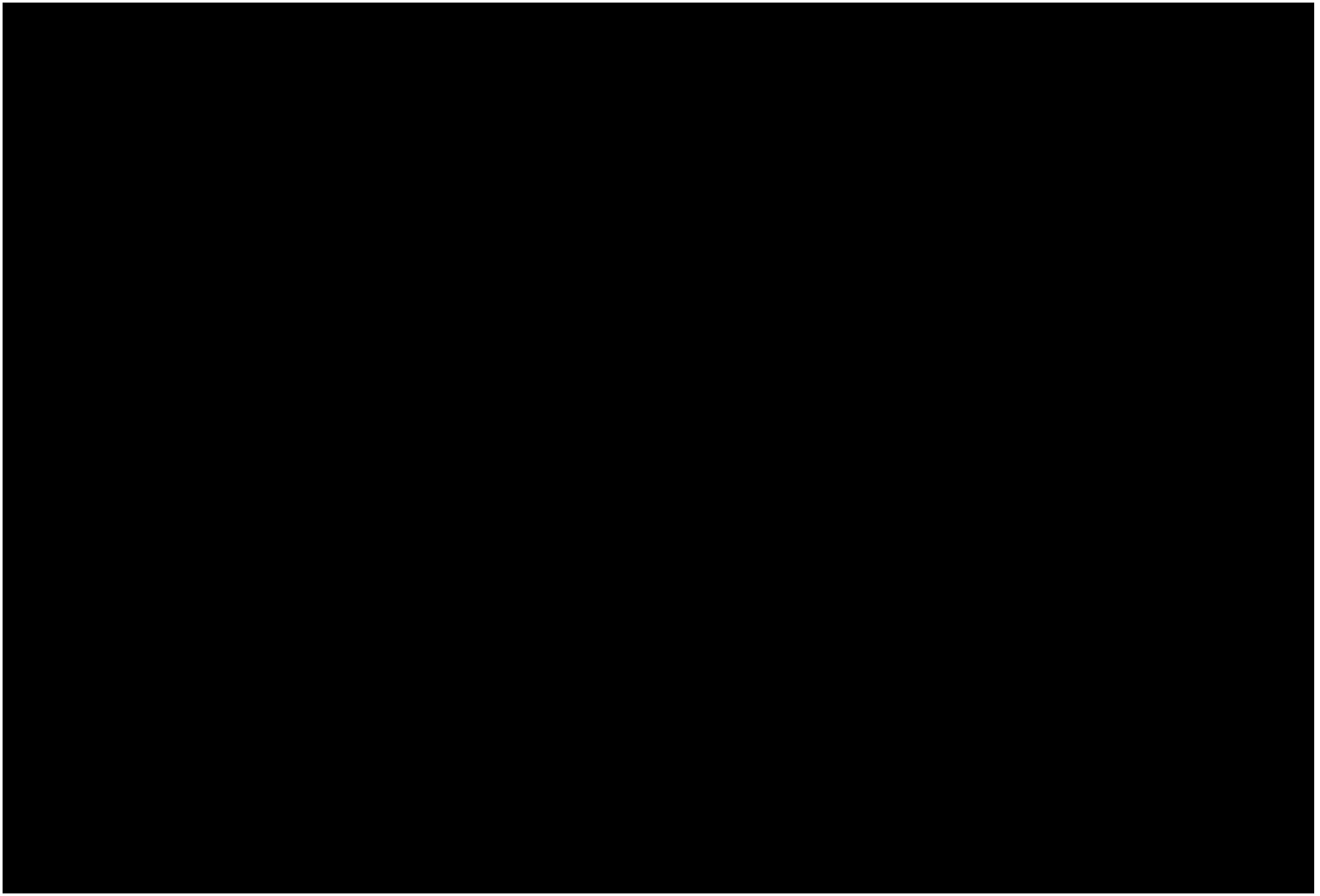
Date of On Peak Day - 03/17/2021



Member Forecasted On Peak Demand Day for April 2021

Columbus Electric Cooperative, Inc.

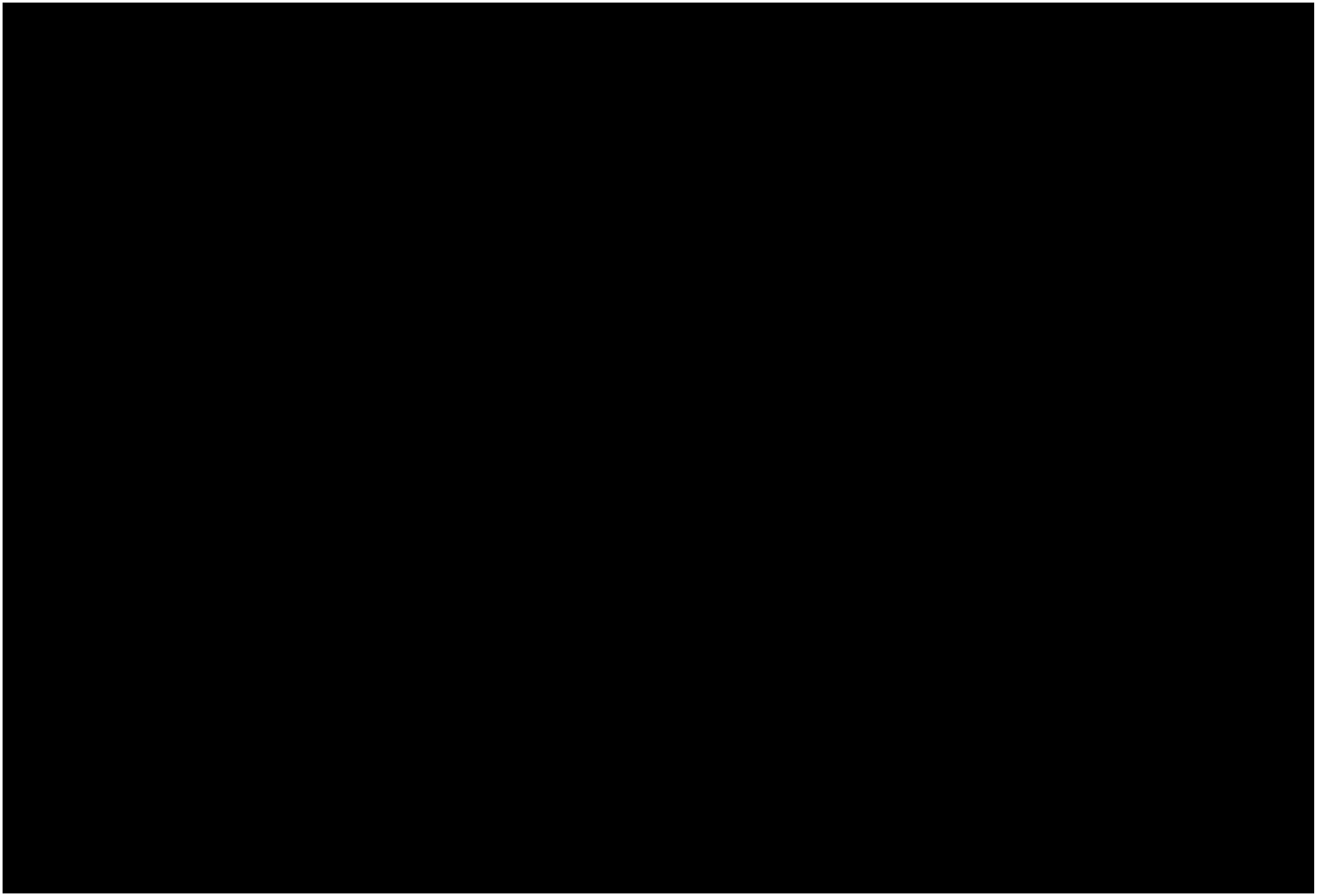
Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Columbus Electric Cooperative, Inc.

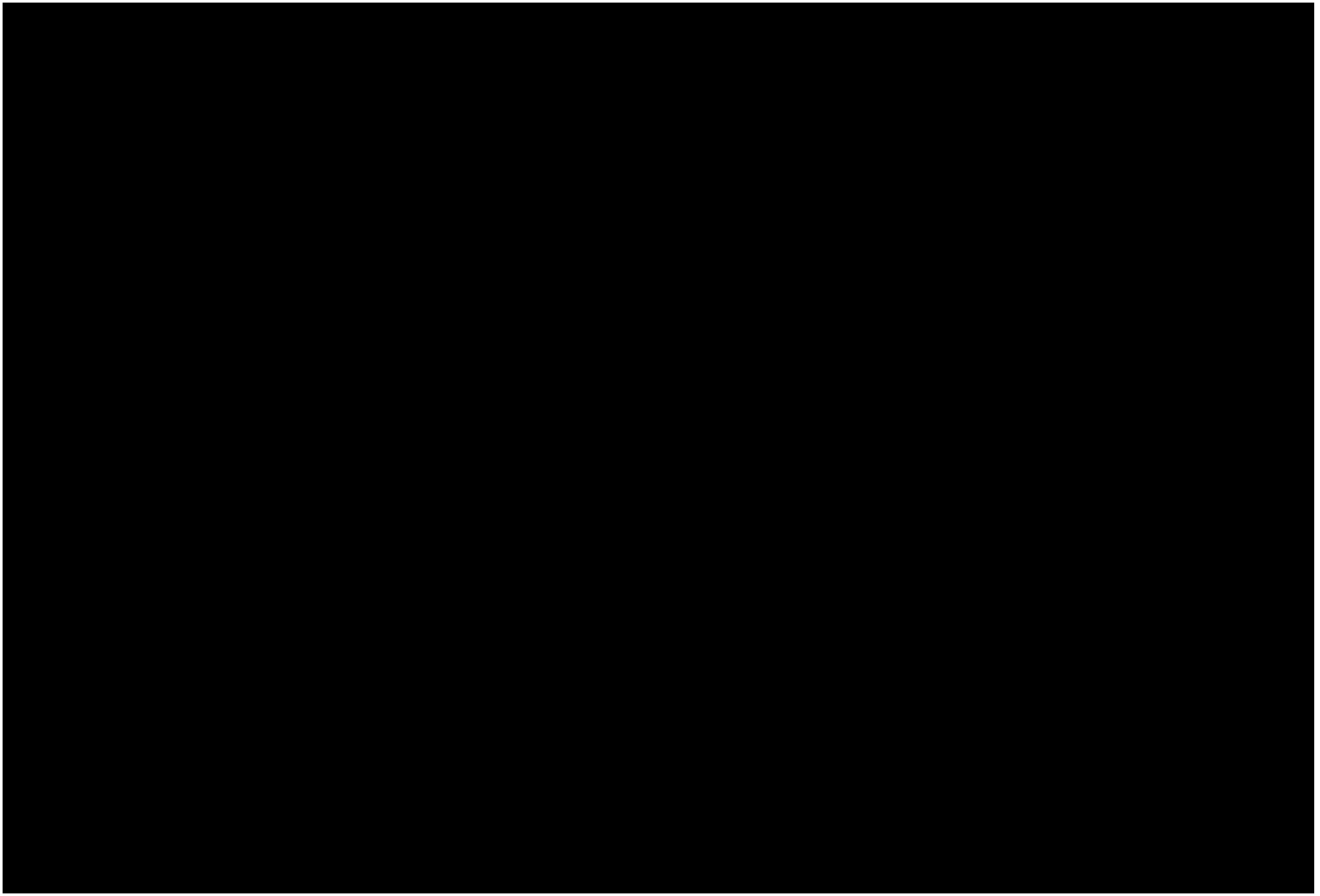
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

Columbus Electric Cooperative, Inc.

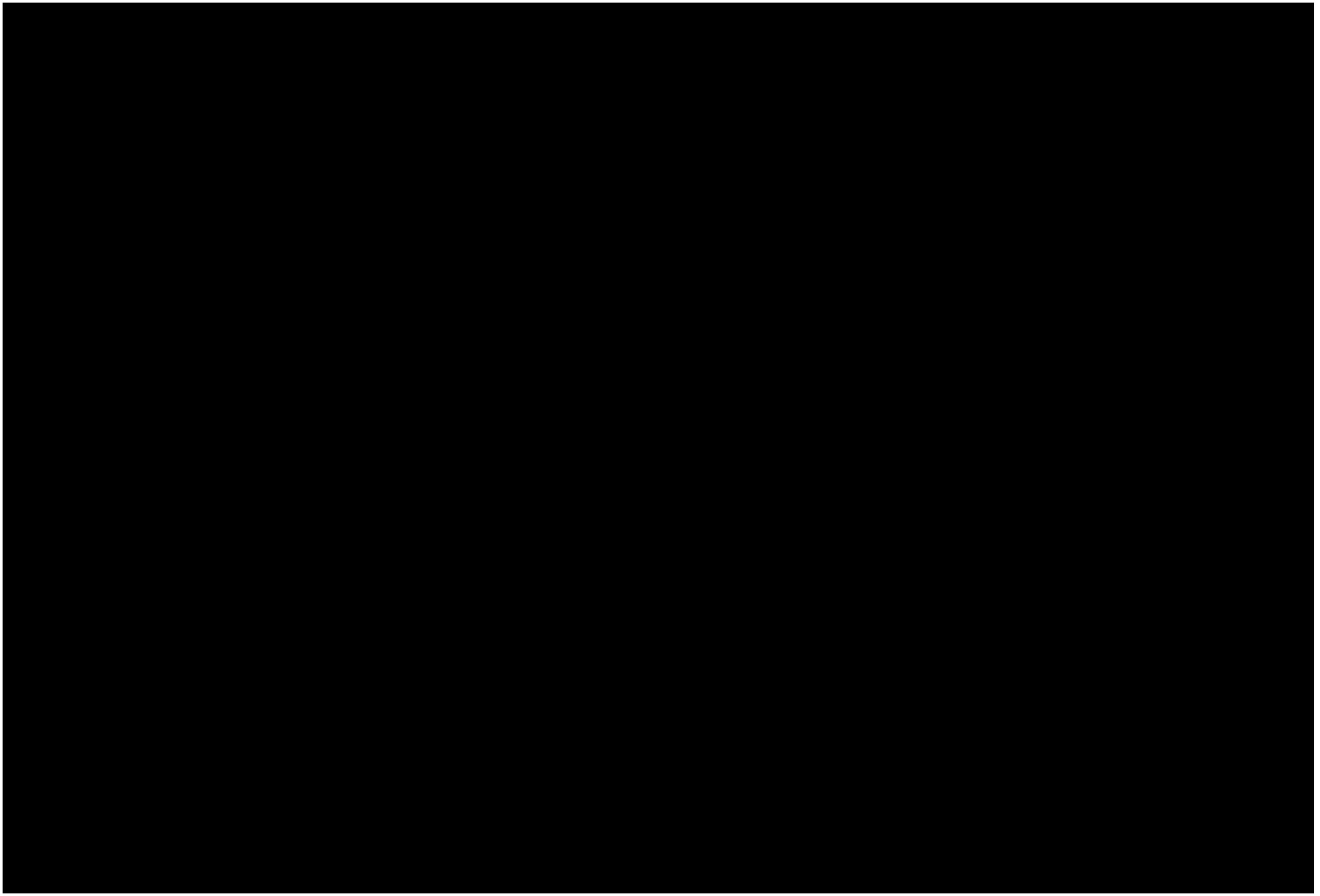
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Columbus Electric Cooperative, Inc.

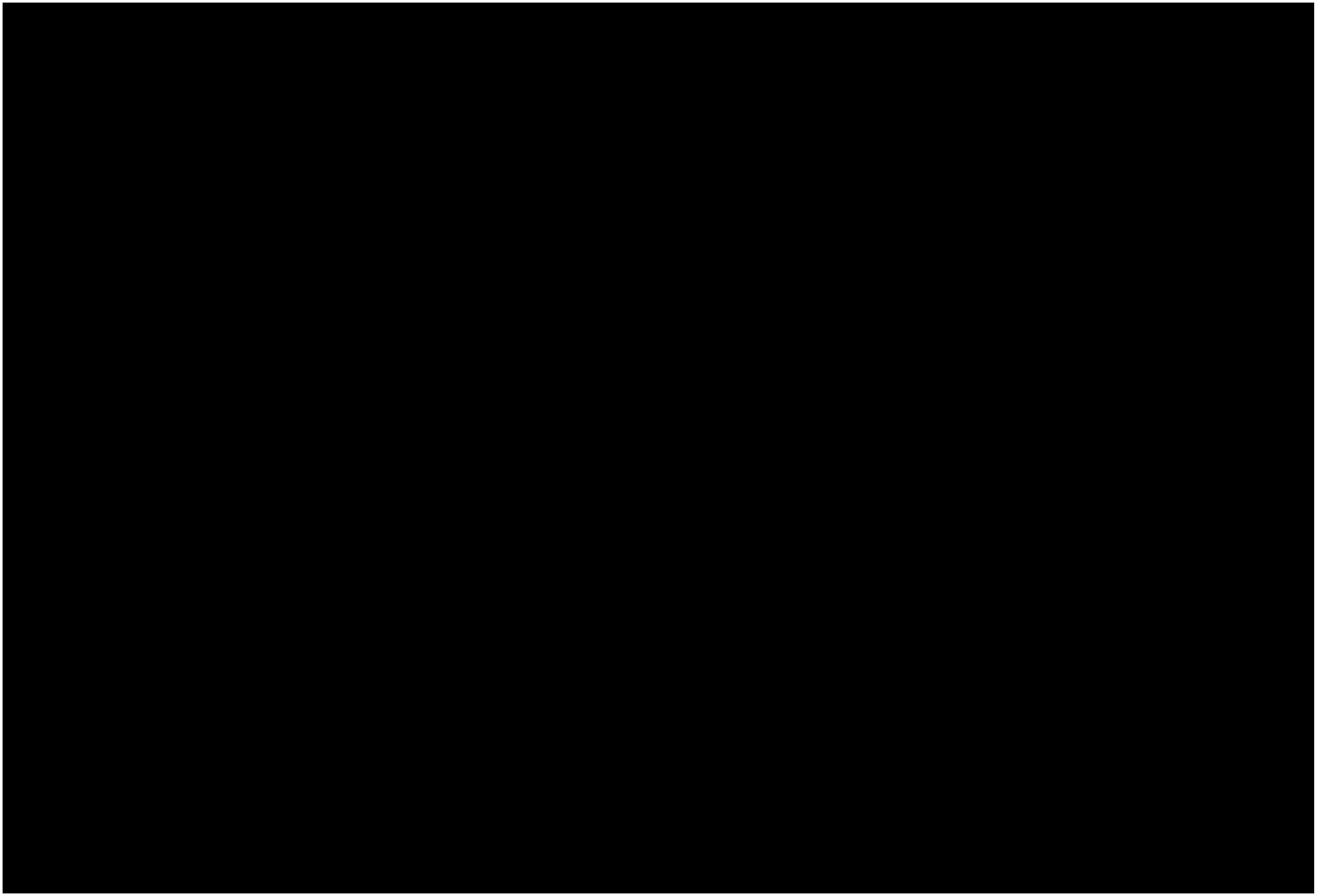
Date of On Peak Day - 07/13/2021



Member Forecasted On Peak Demand Day for August 2021

Columbus Electric Cooperative, Inc.

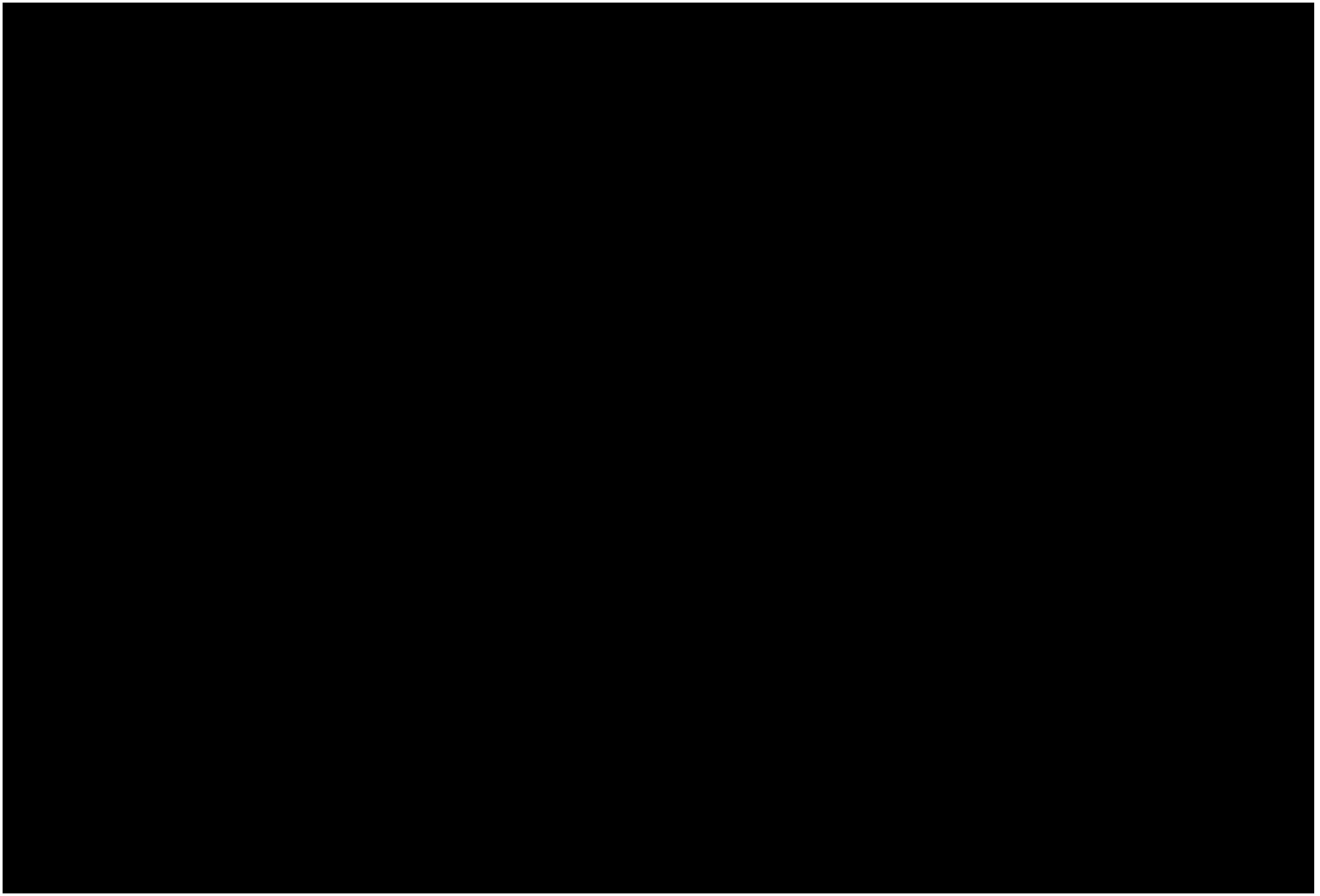
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Columbus Electric Cooperative, Inc.

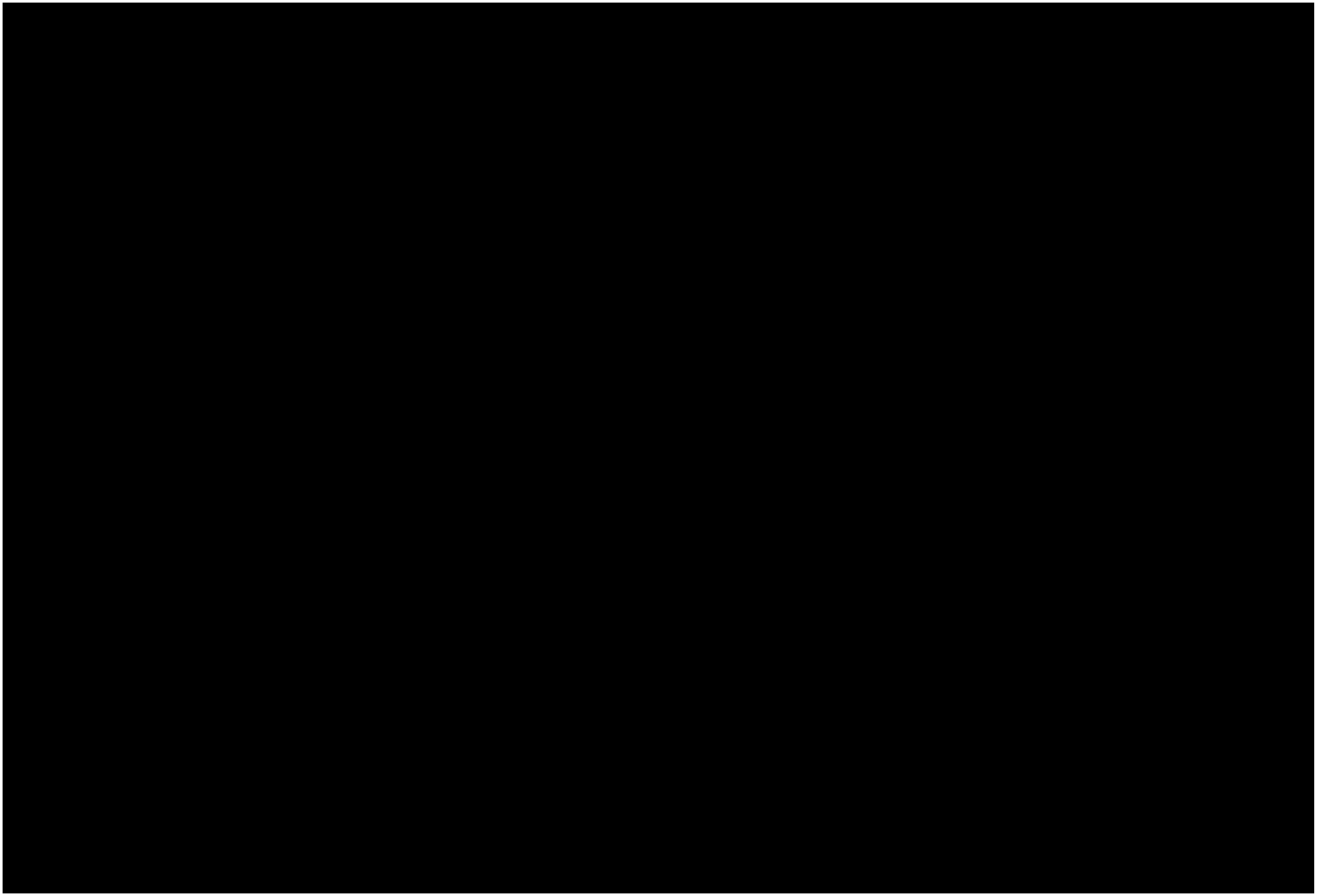
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Columbus Electric Cooperative, Inc.

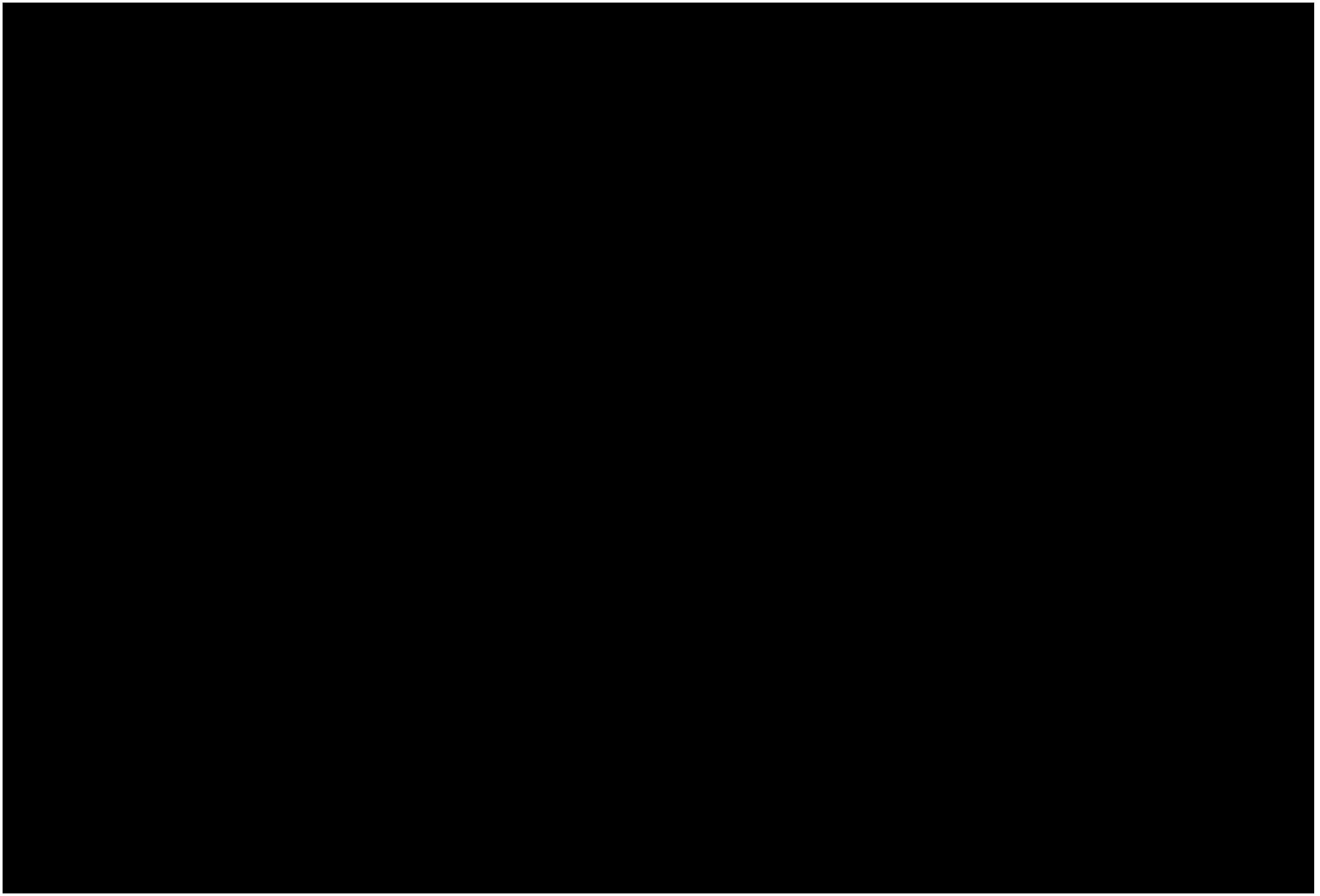
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Columbus Electric Cooperative, Inc.

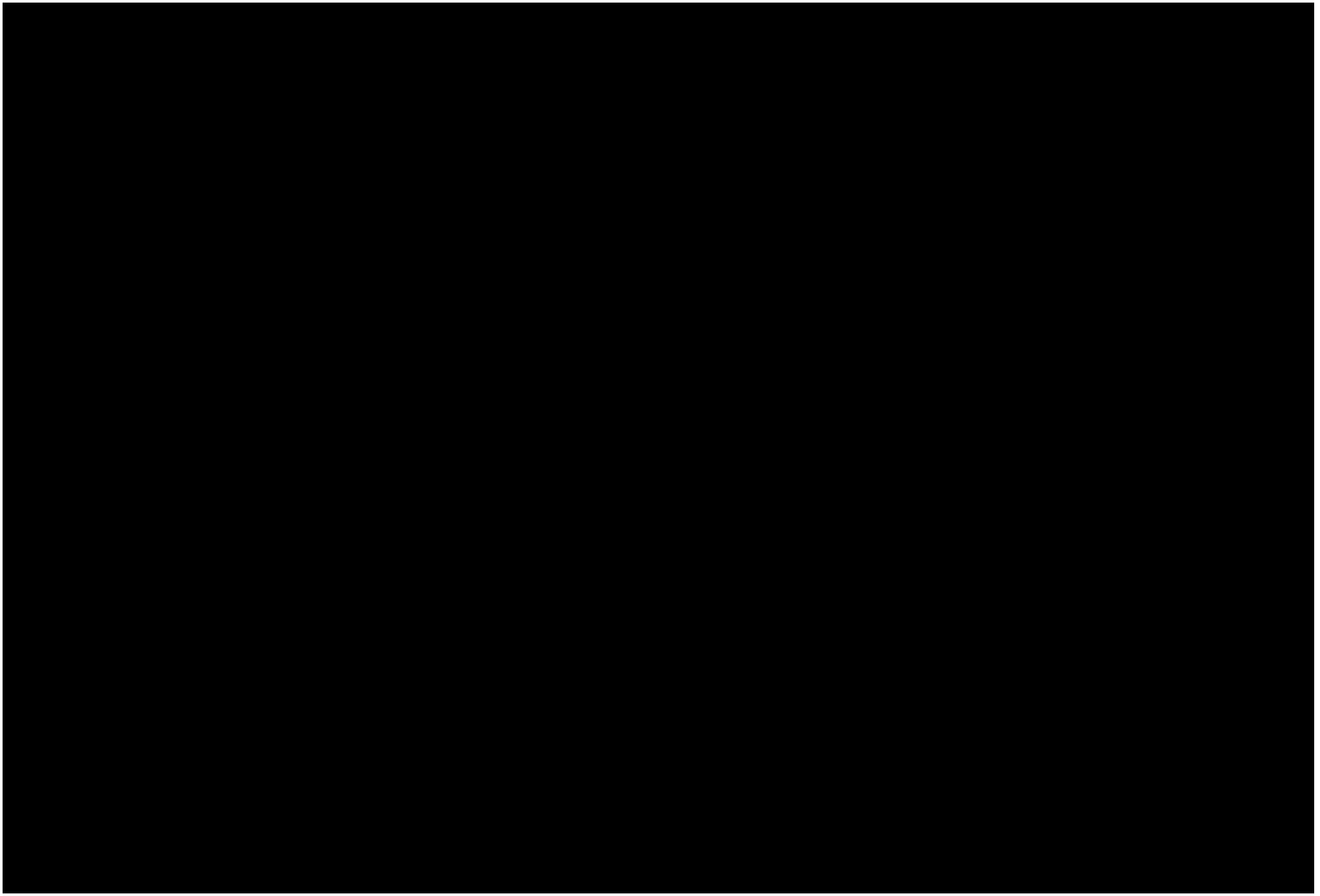
Date of On Peak Day - 11/26/2021



Member Forecasted On Peak Demand Day for December 2021

Columbus Electric Cooperative, Inc.

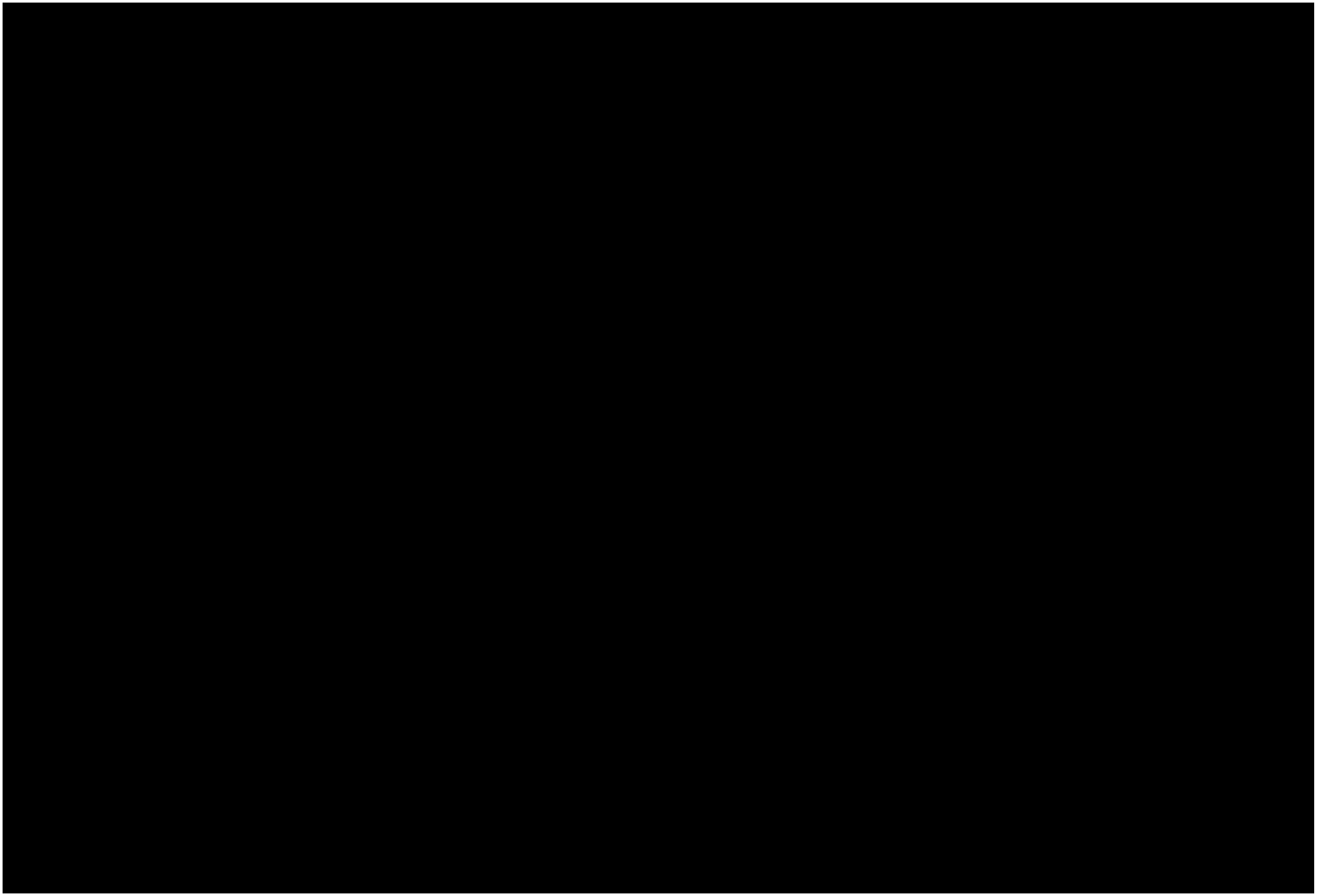
Date of On Peak Day - 12/18/2021



Member Forecasted On Peak Demand Day for January 2021

Central New Mexico Electric Cooperative, Inc.

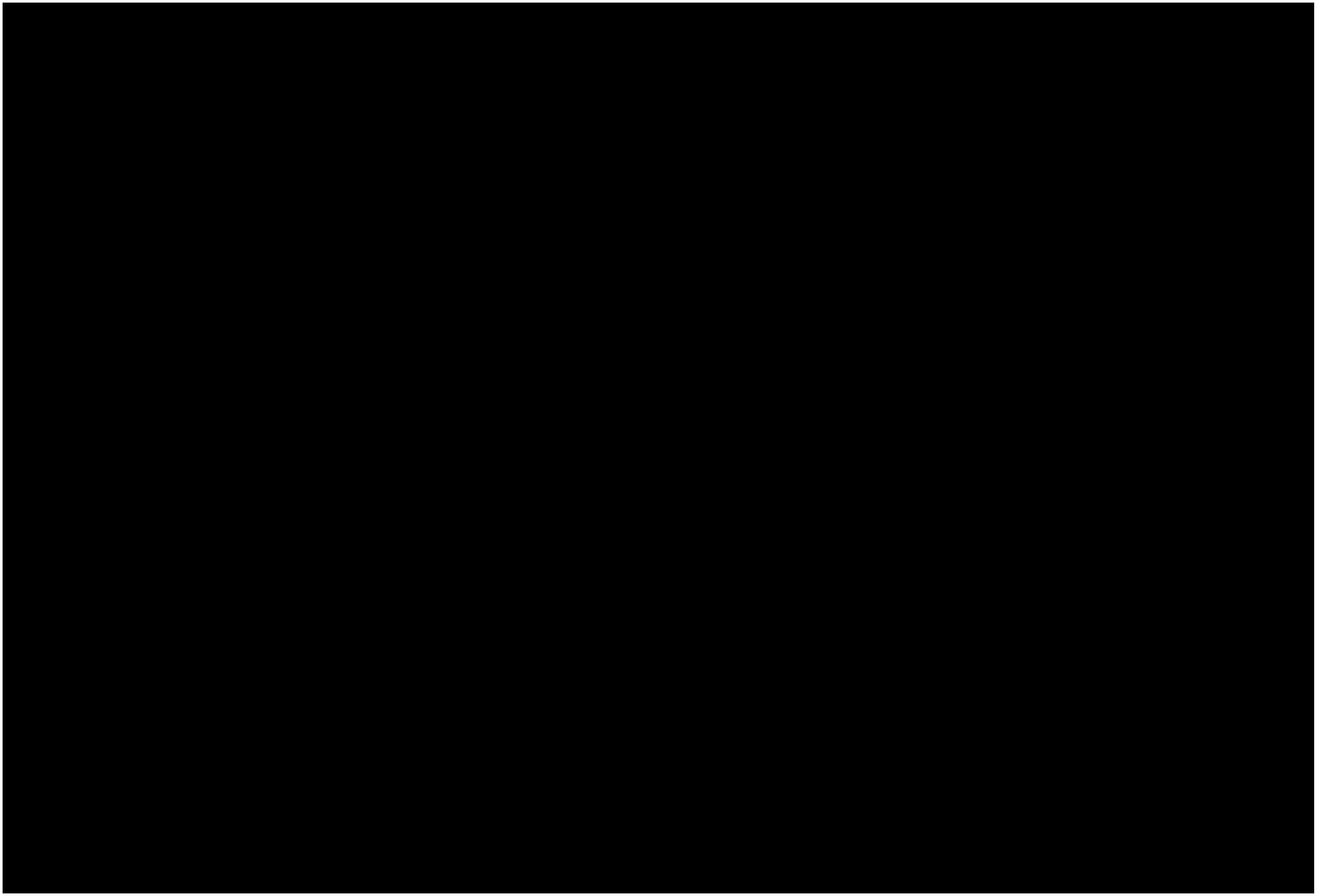
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Central New Mexico Electric Cooperative, Inc.

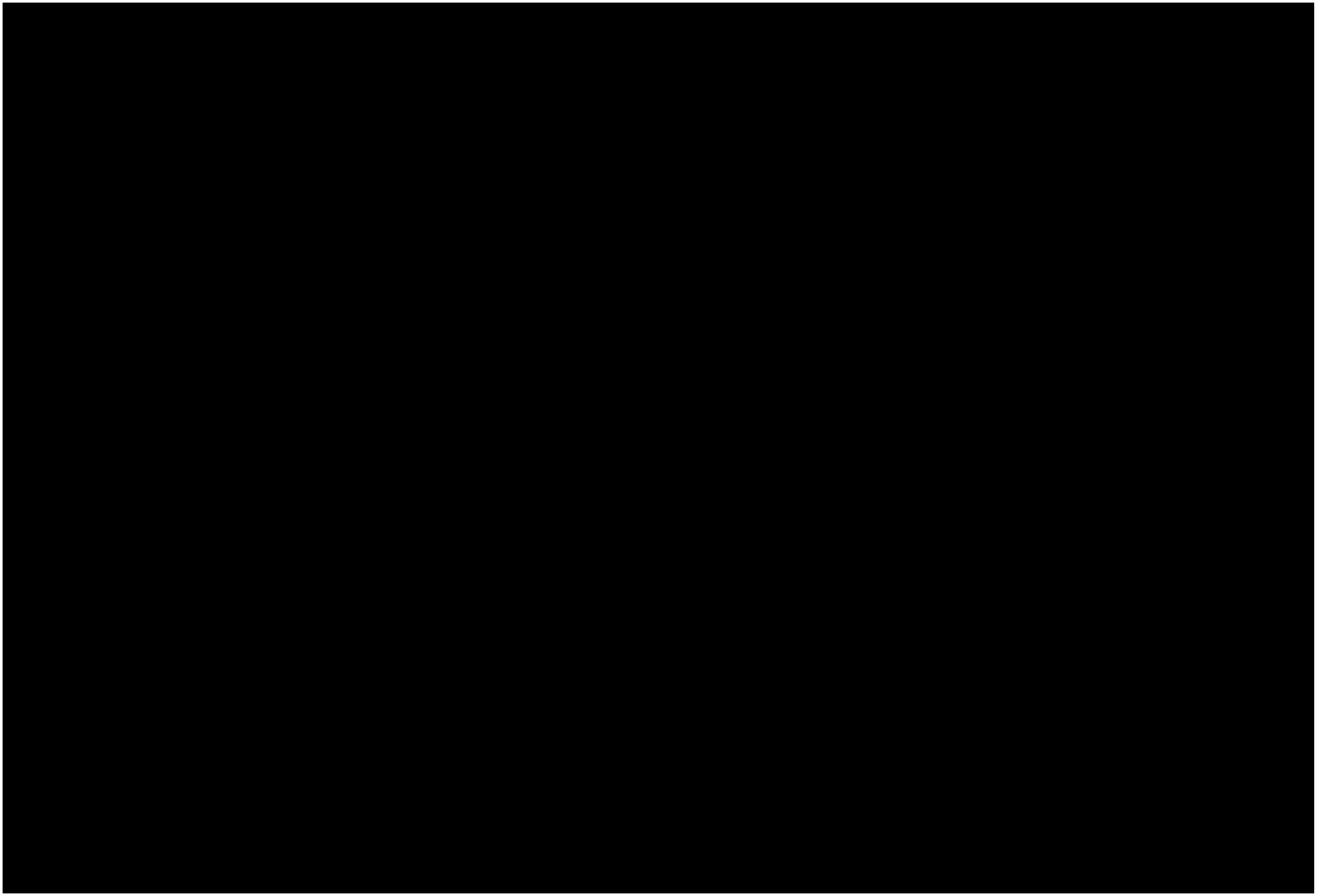
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Central New Mexico Electric Cooperative, Inc.

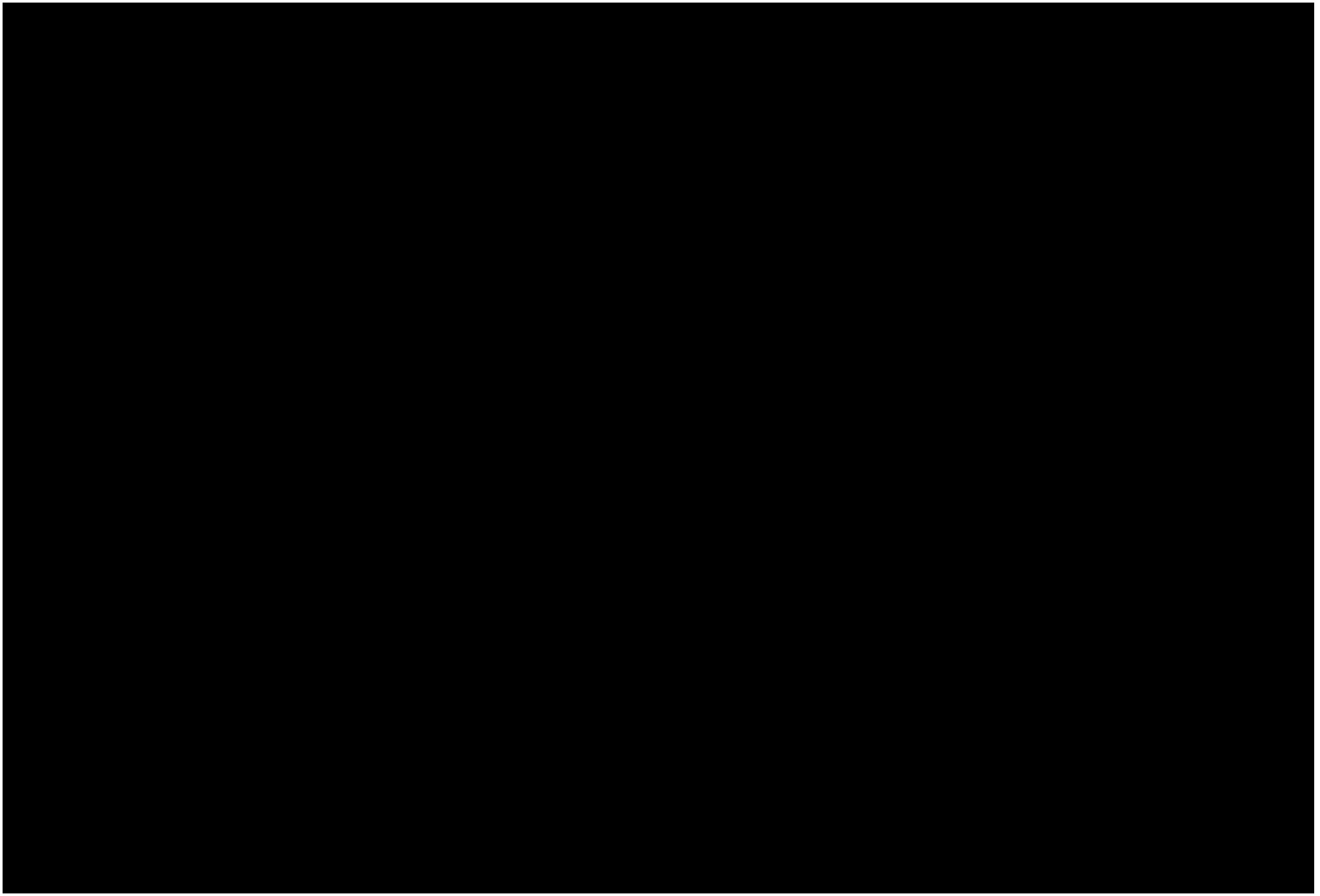
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Central New Mexico Electric Cooperative, Inc.

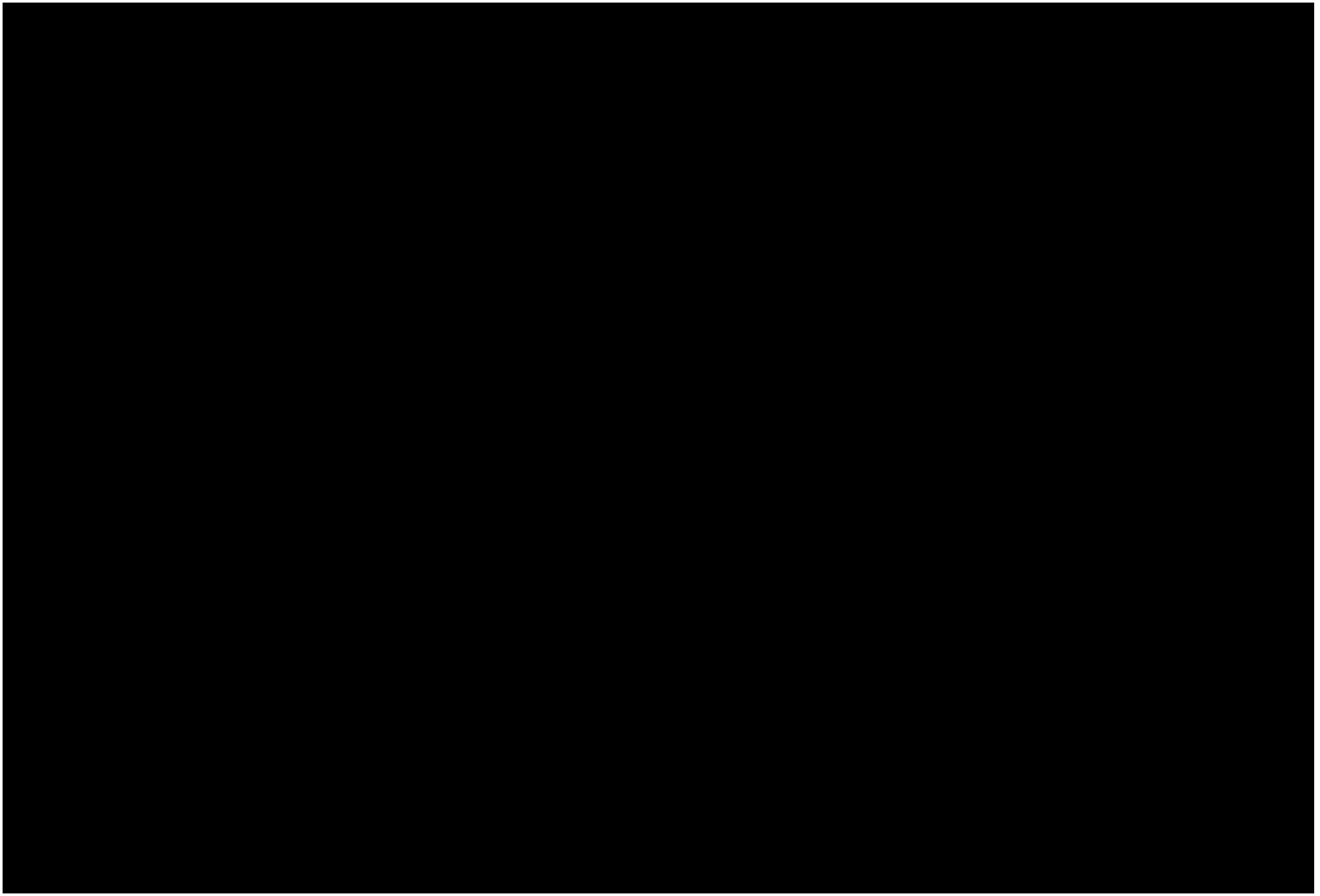
Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Central New Mexico Electric Cooperative, Inc.

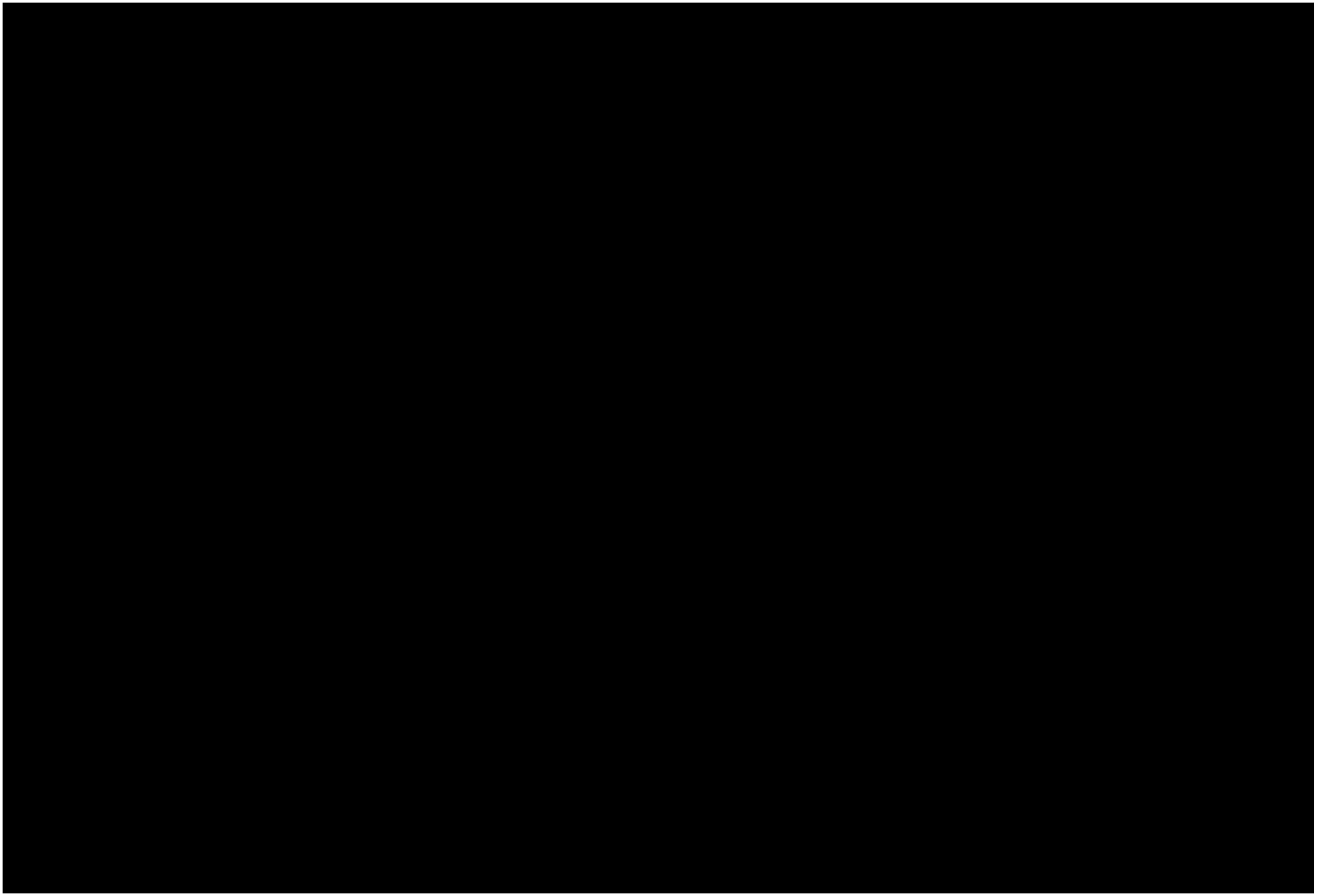
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Central New Mexico Electric Cooperative, Inc.

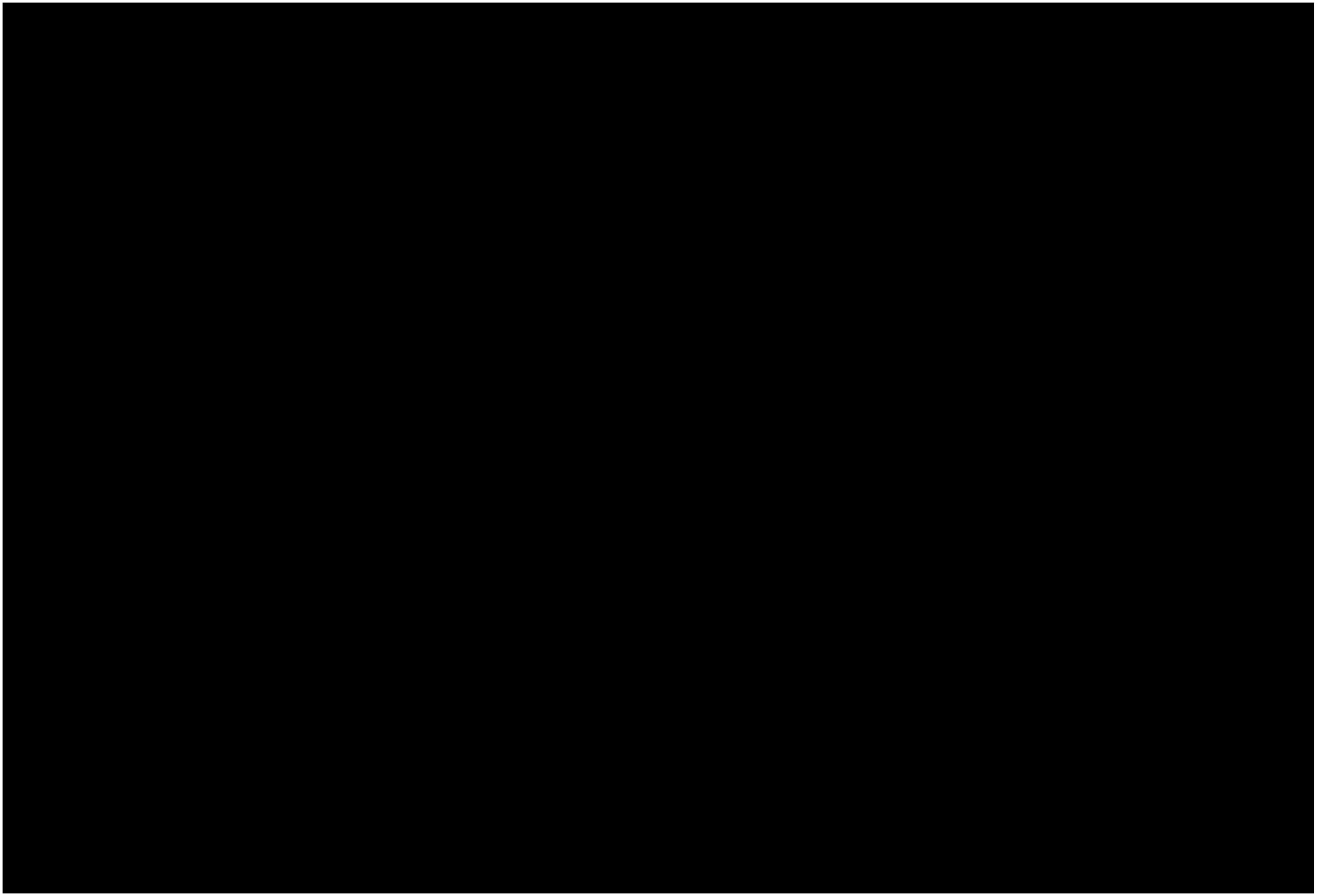
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Central New Mexico Electric Cooperative, Inc.

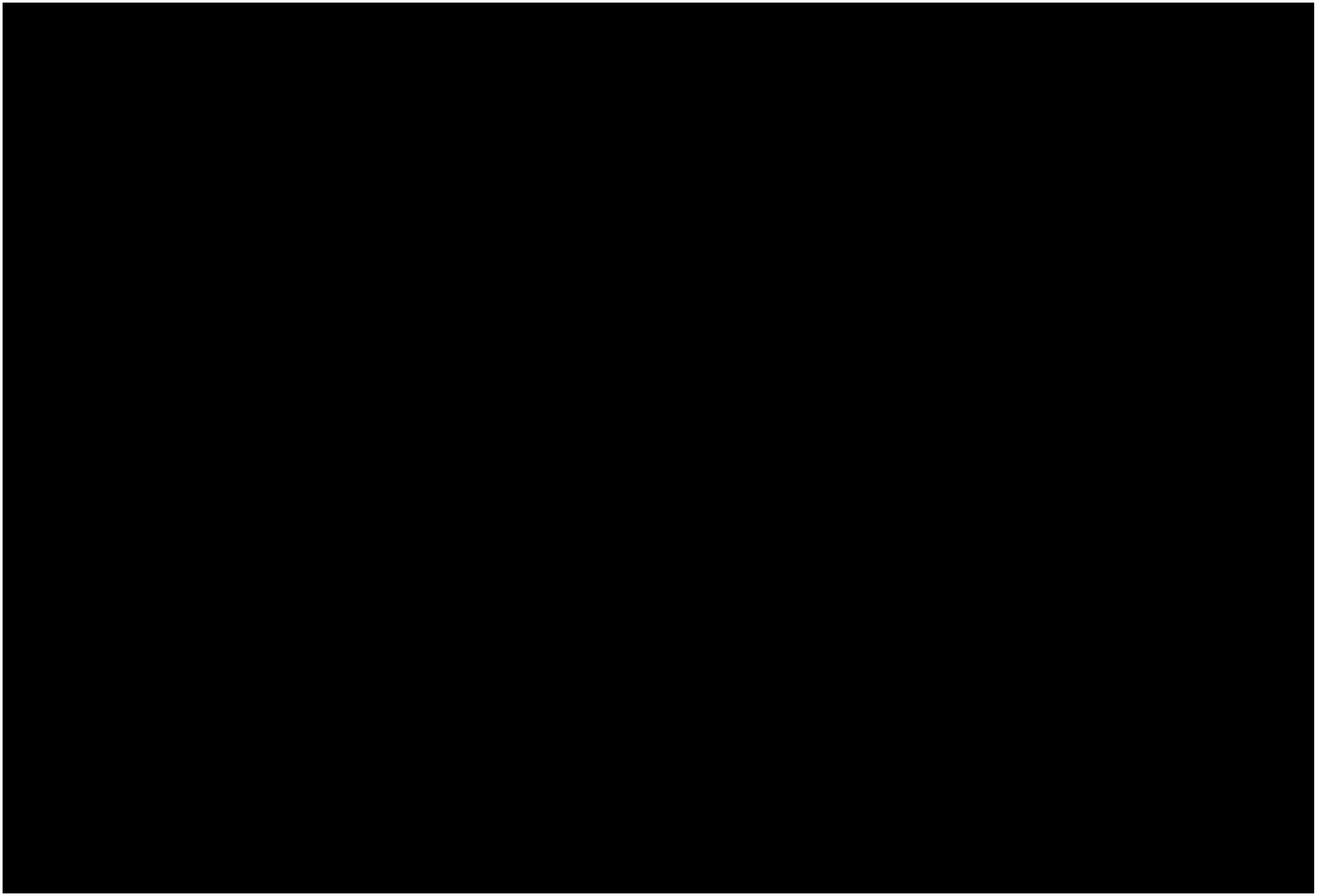
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

Central New Mexico Electric Cooperative, Inc.

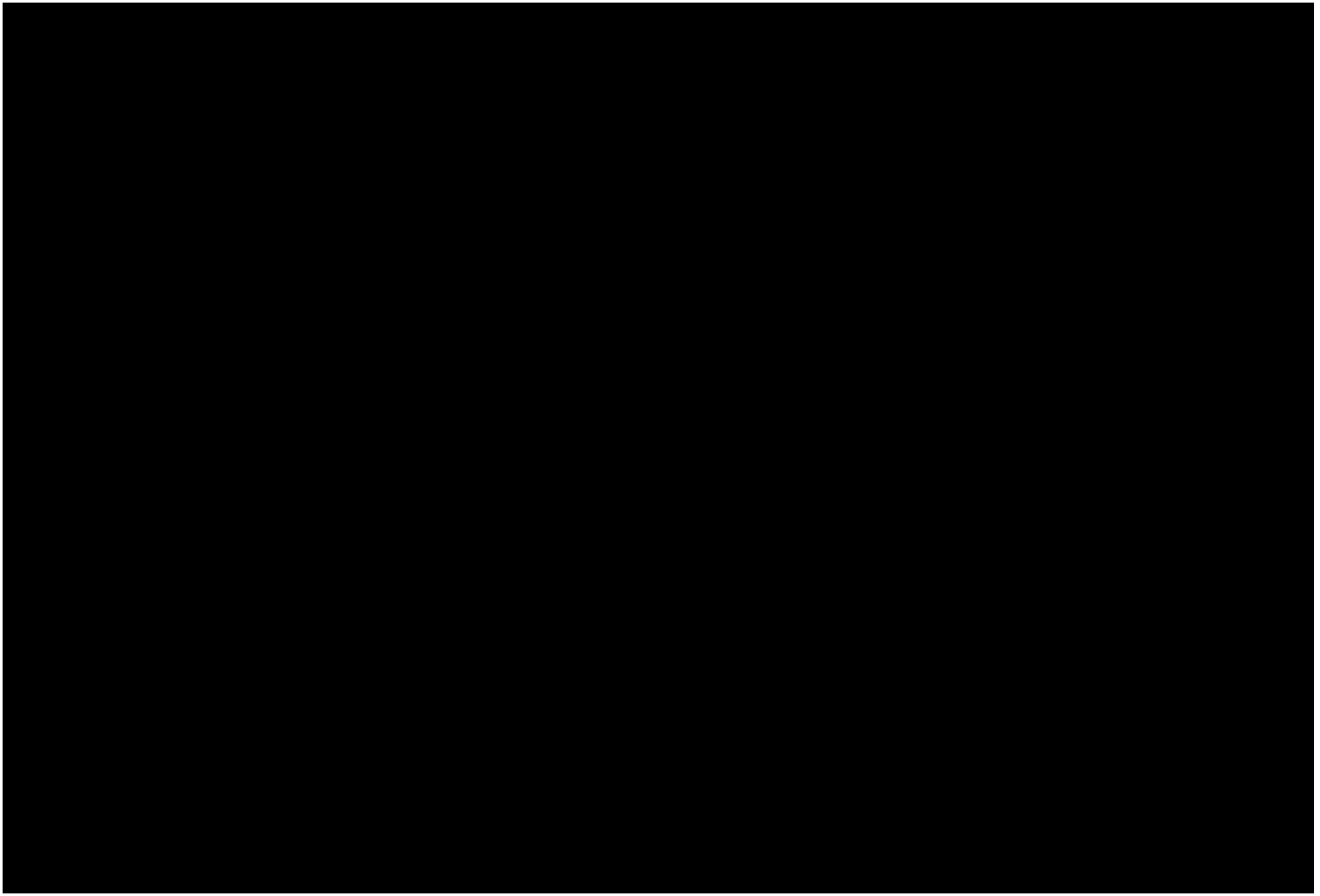
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Central New Mexico Electric Cooperative, Inc.

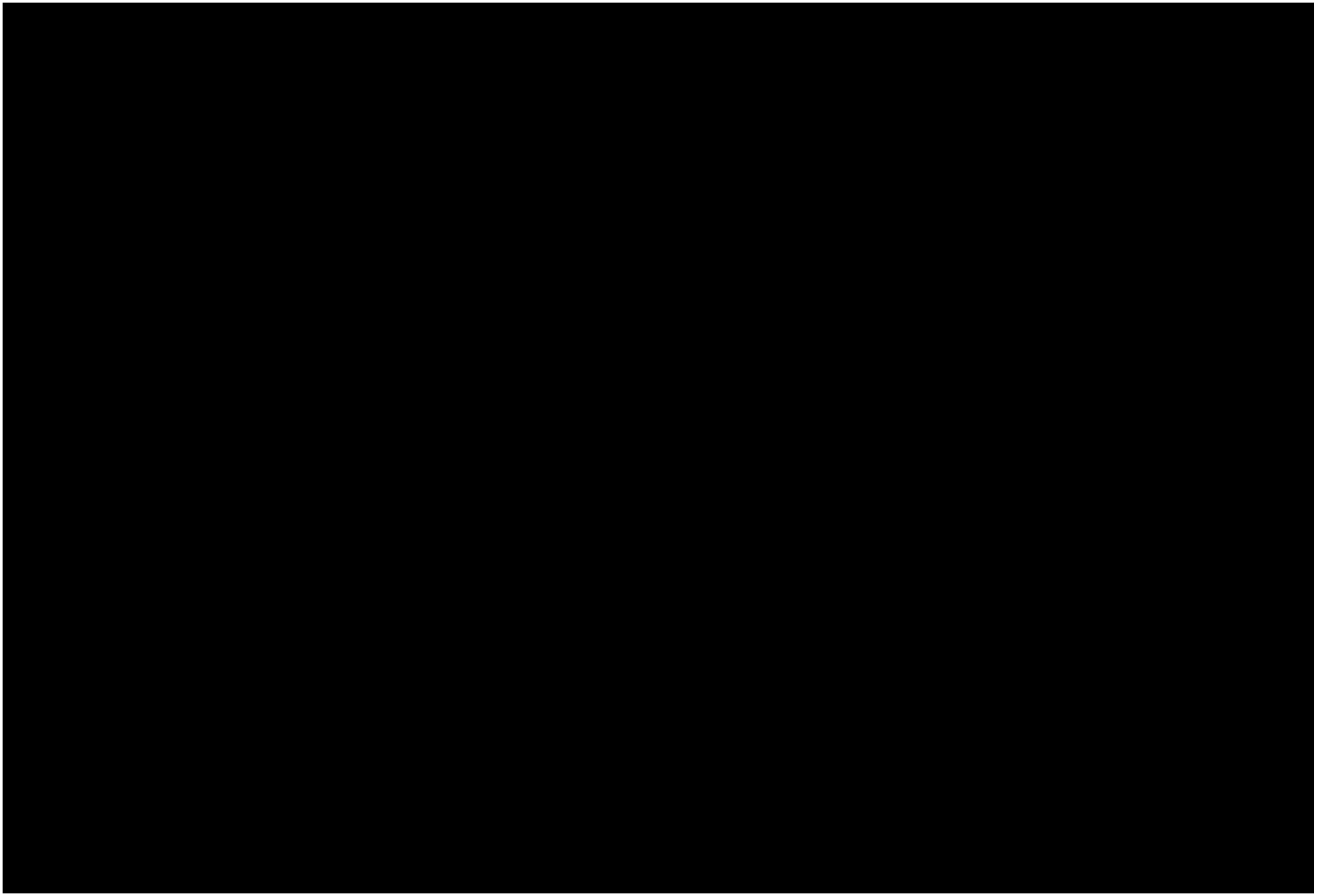
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Central New Mexico Electric Cooperative, Inc.

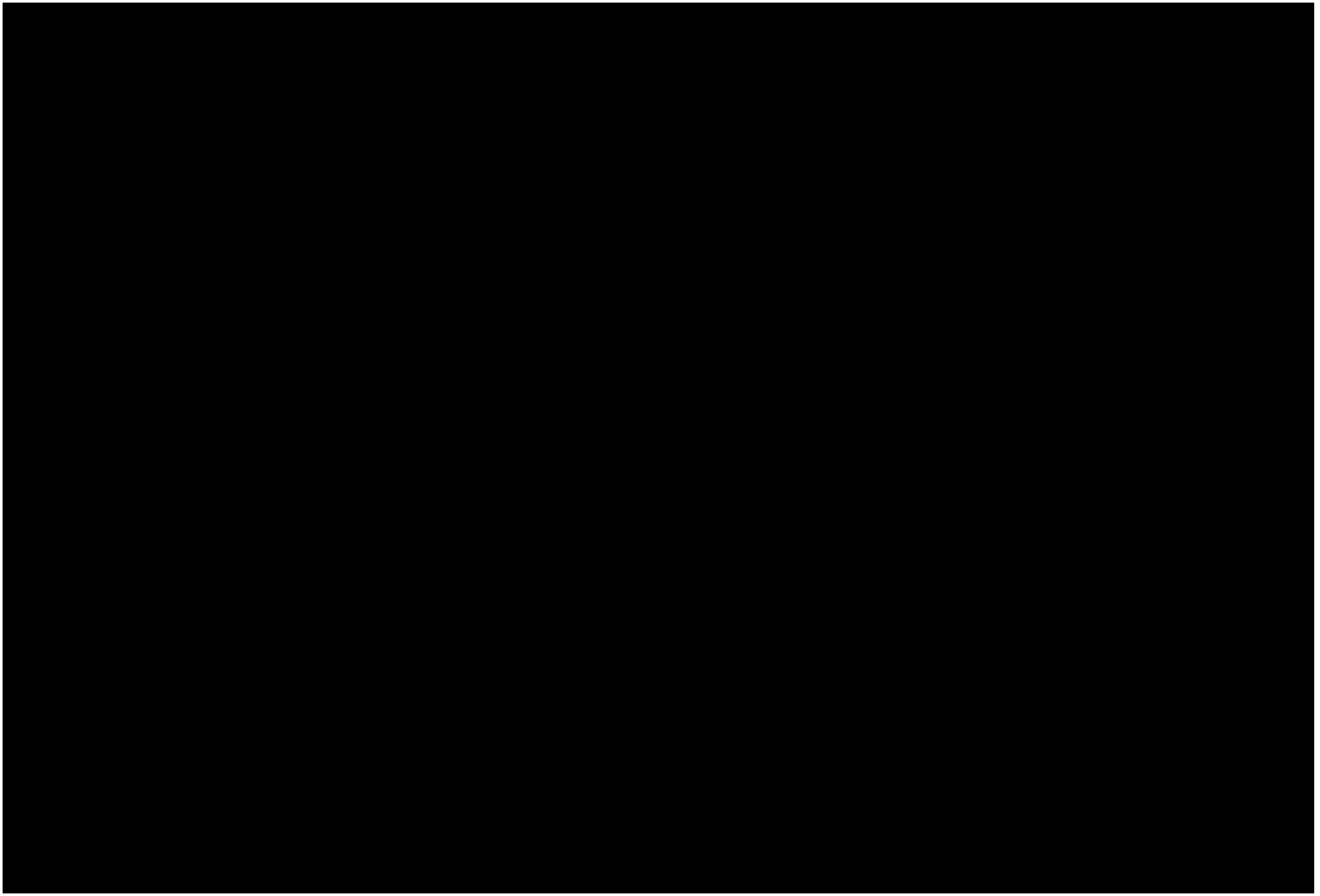
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Central New Mexico Electric Cooperative, Inc.

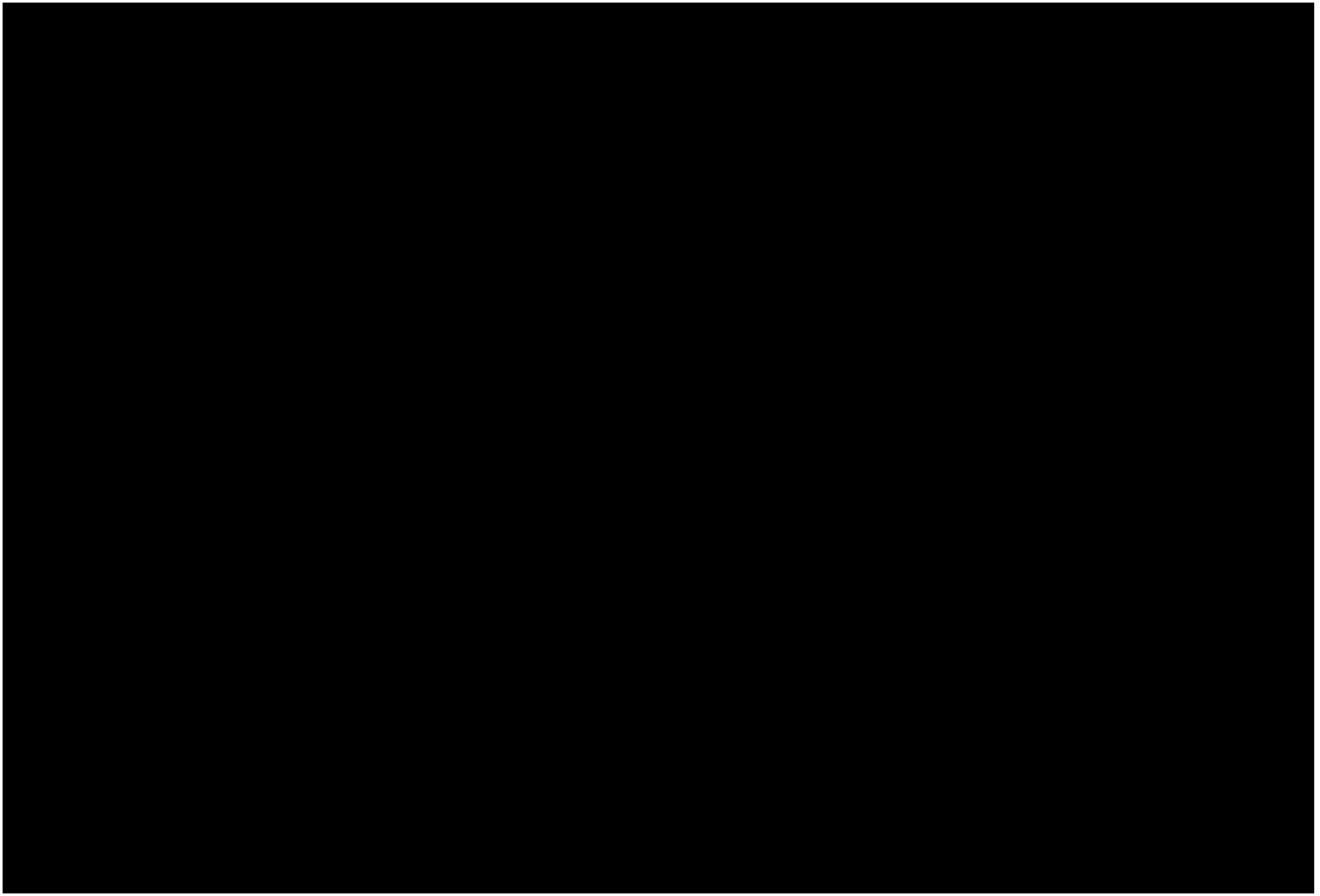
Date of On Peak Day - 11/14/2021



Member Forecasted On Peak Demand Day for December 2021

Central New Mexico Electric Cooperative, Inc.

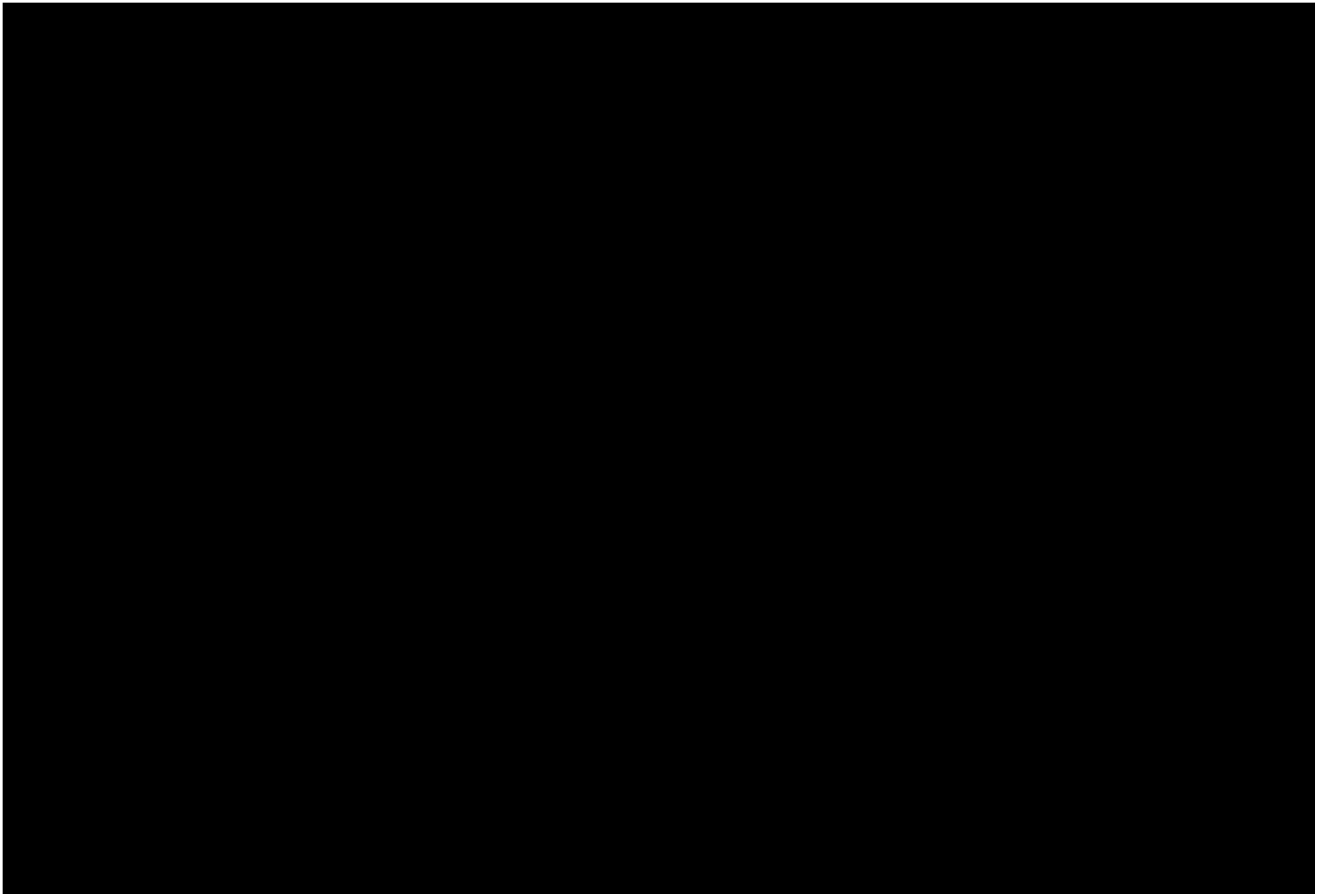
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Chimney Rock Public Power District

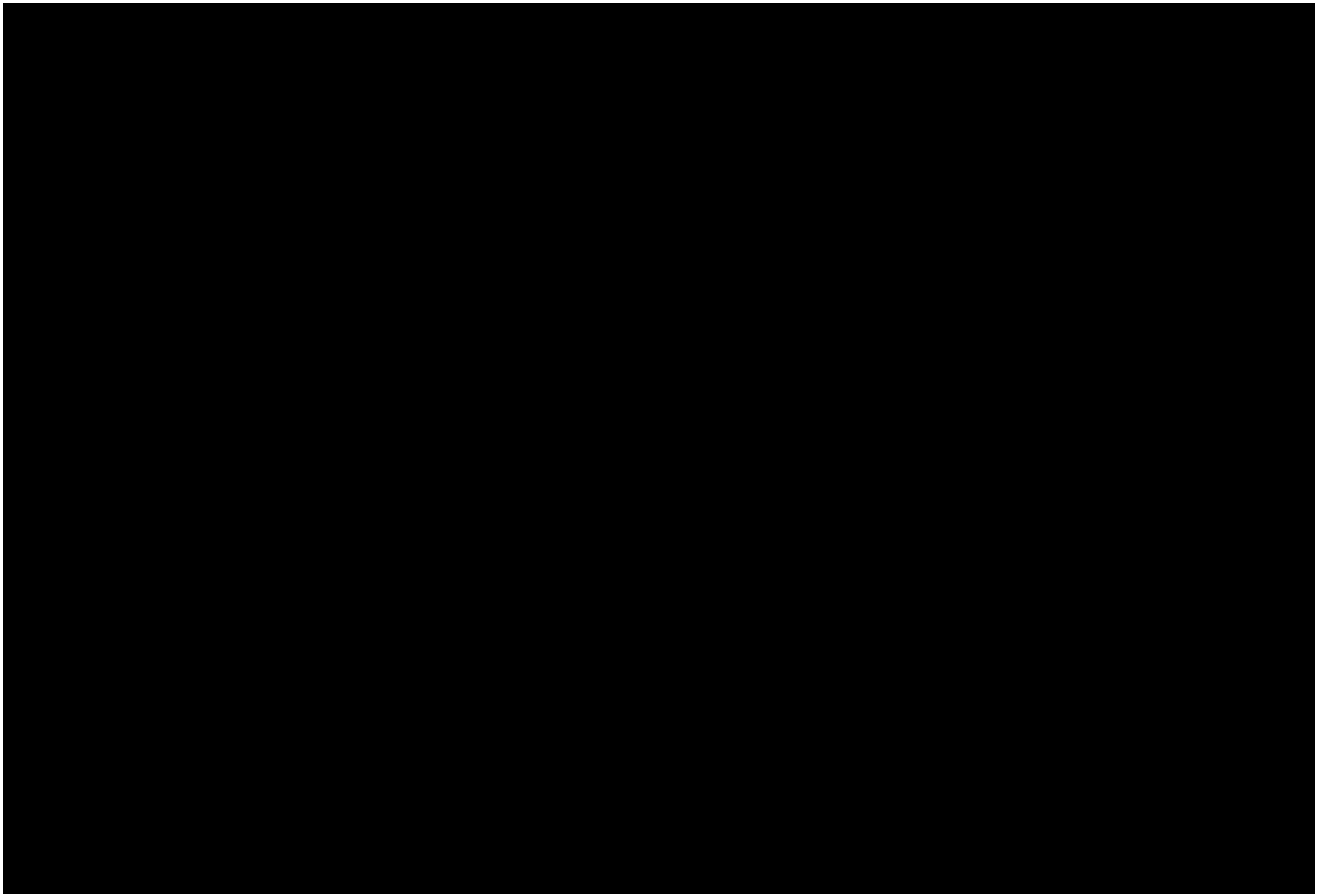
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Chimney Rock Public Power District

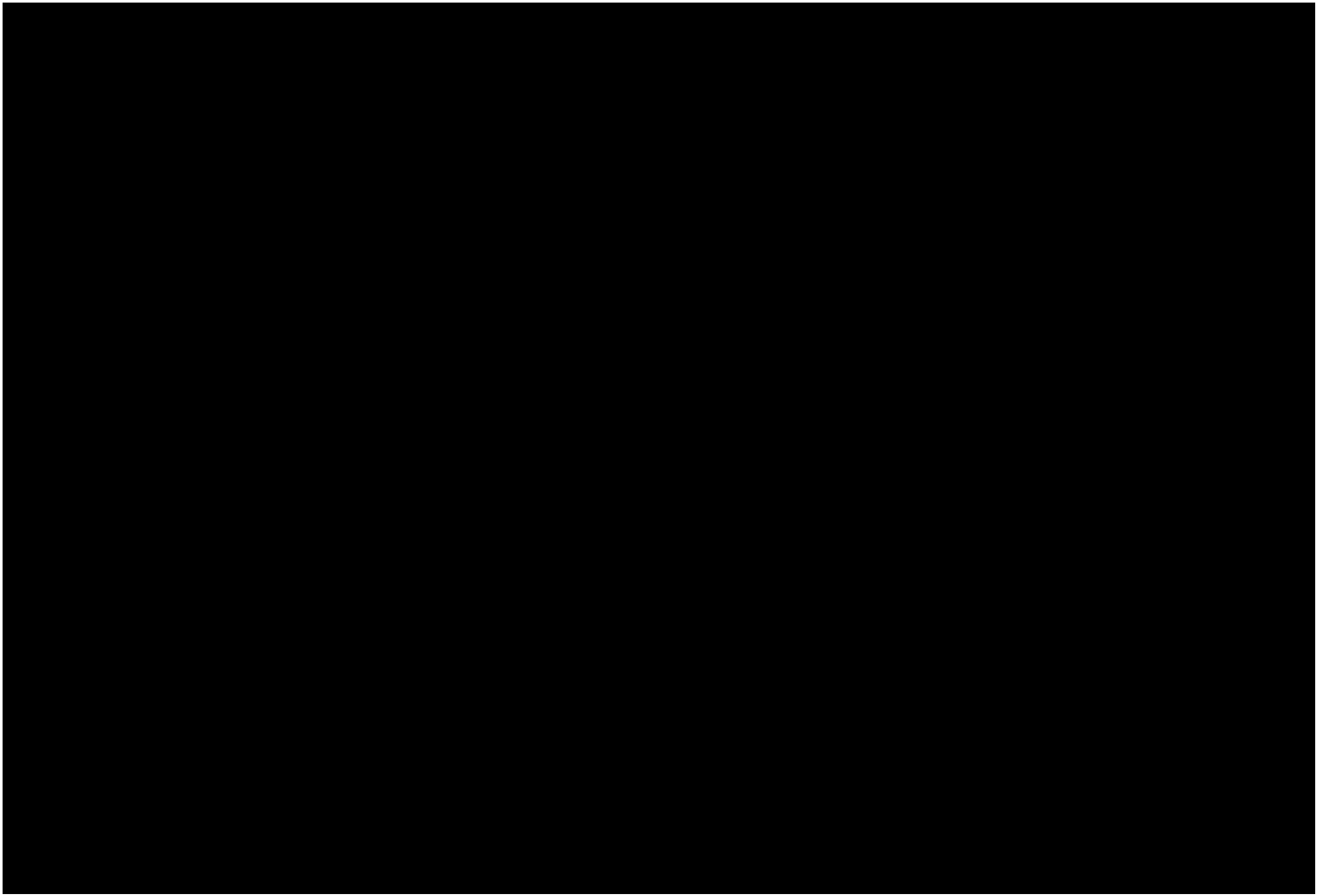
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Chimney Rock Public Power District

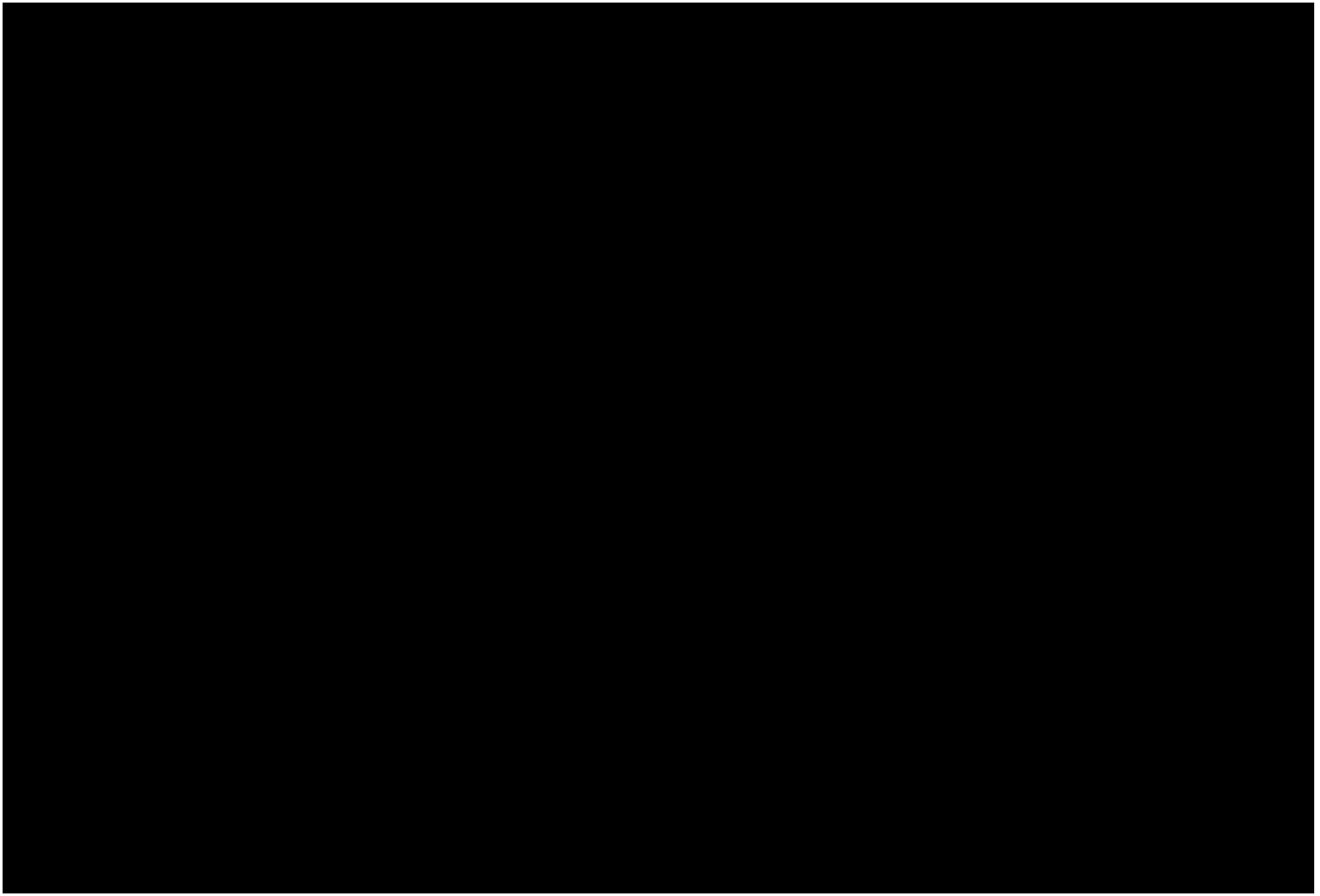
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Chimney Rock Public Power District

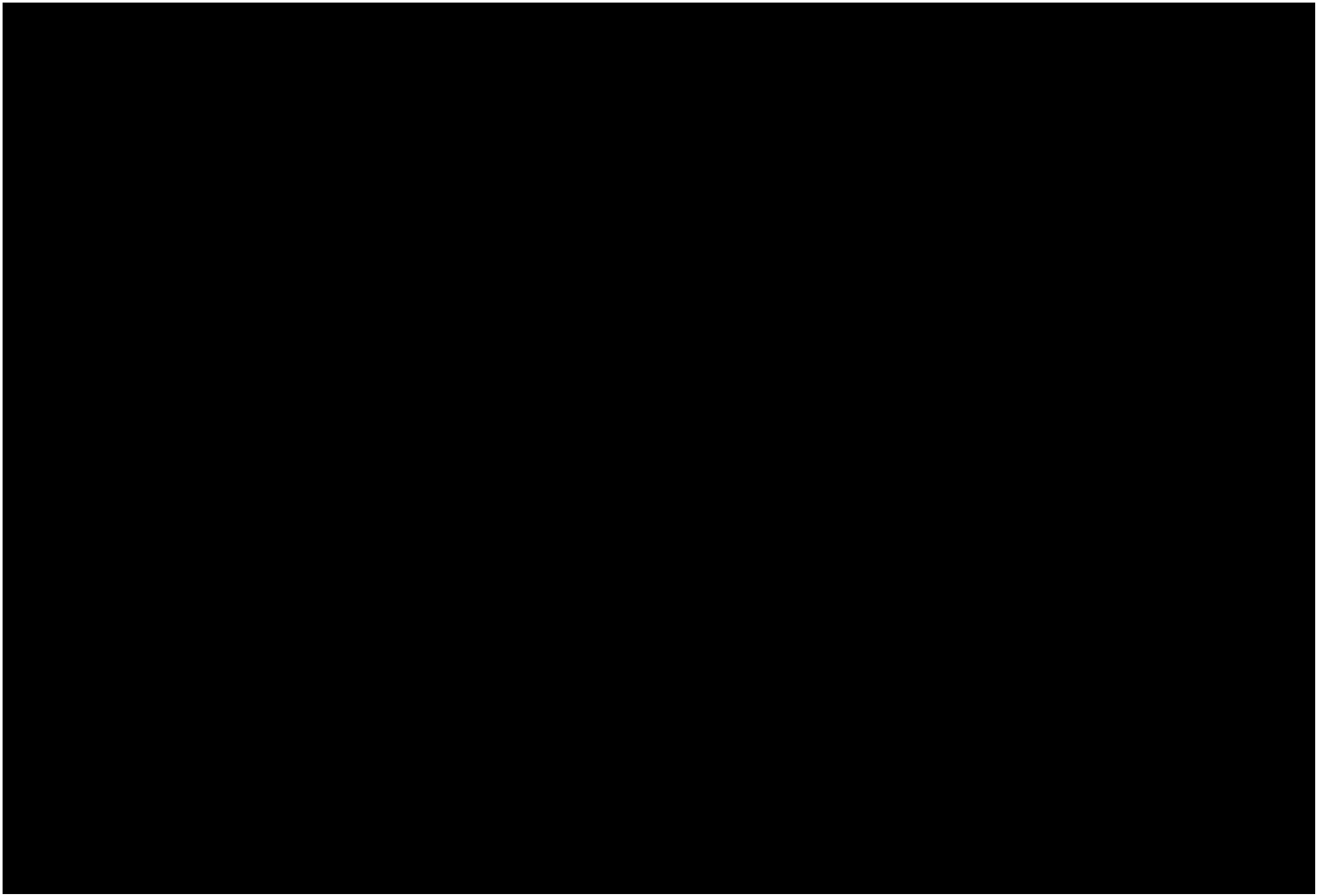
Date of On Peak Day - 04/05/2021



Member Forecasted On Peak Demand Day for May 2021

Chimney Rock Public Power District

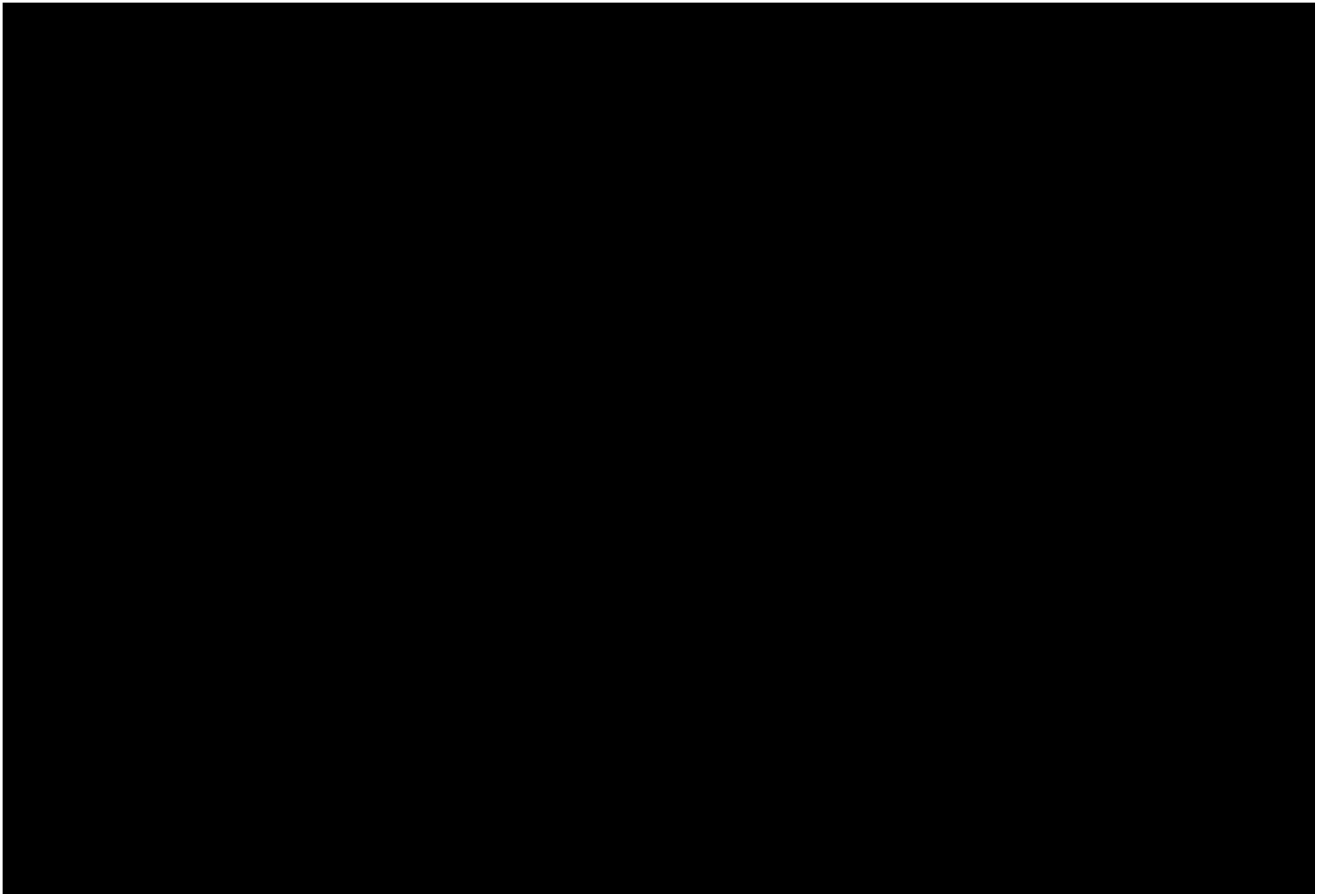
Date of On Peak Day - 05/16/2021



Member Forecasted On Peak Demand Day for June 2021

Chimney Rock Public Power District

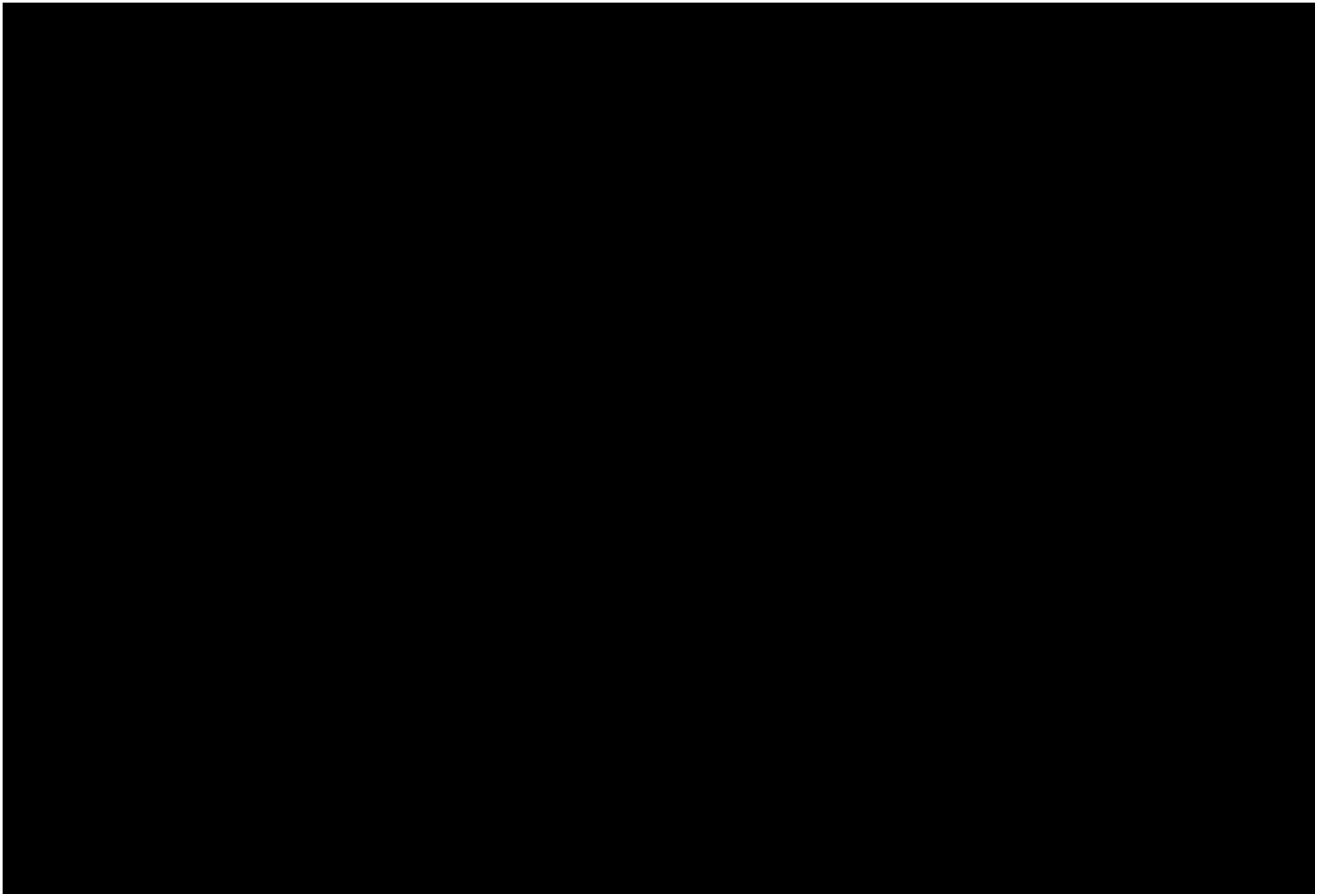
Date of On Peak Day - 06/26/2021



Member Forecasted On Peak Demand Day for July 2021

Chimney Rock Public Power District

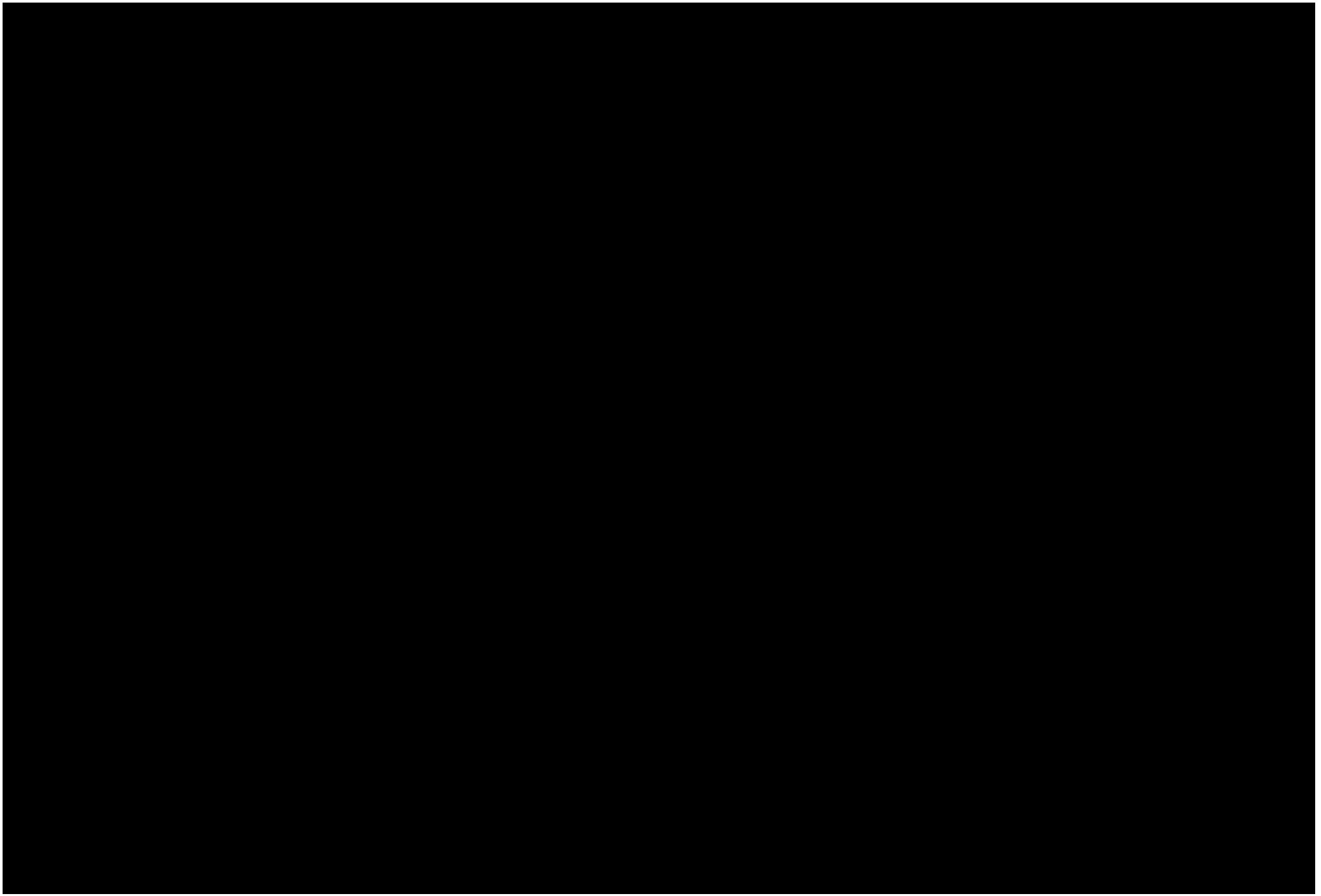
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Chimney Rock Public Power District

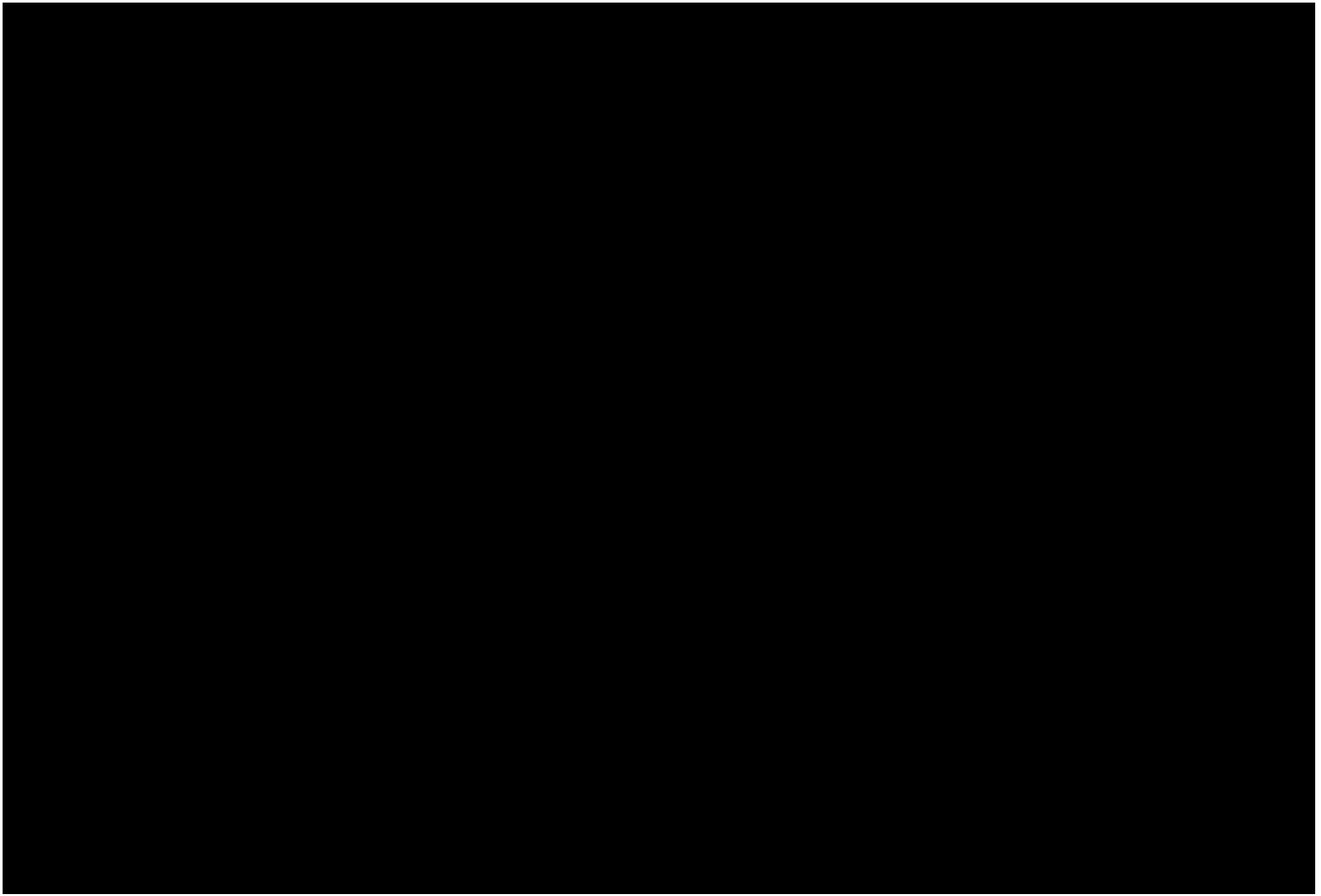
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Chimney Rock Public Power District

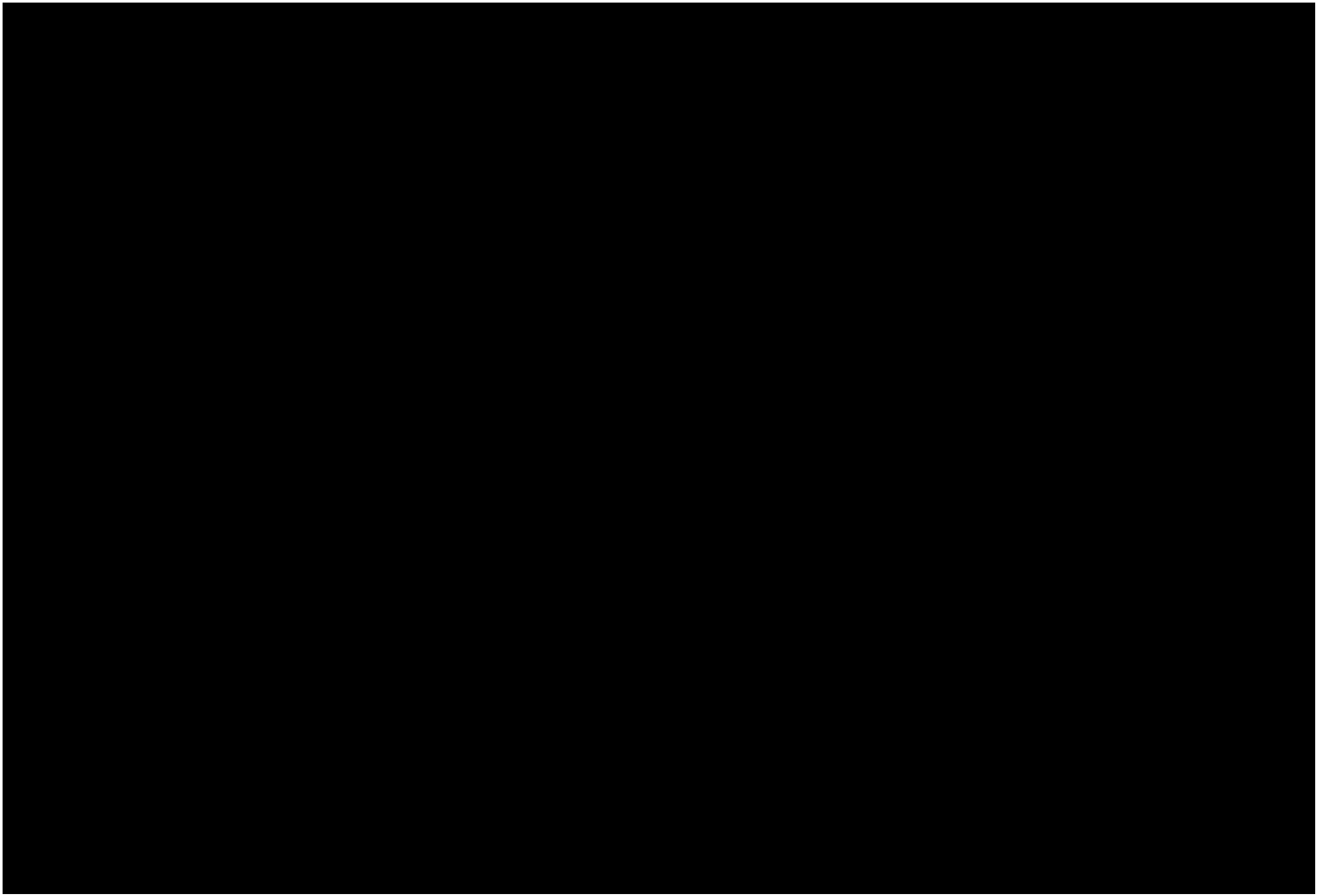
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Chimney Rock Public Power District

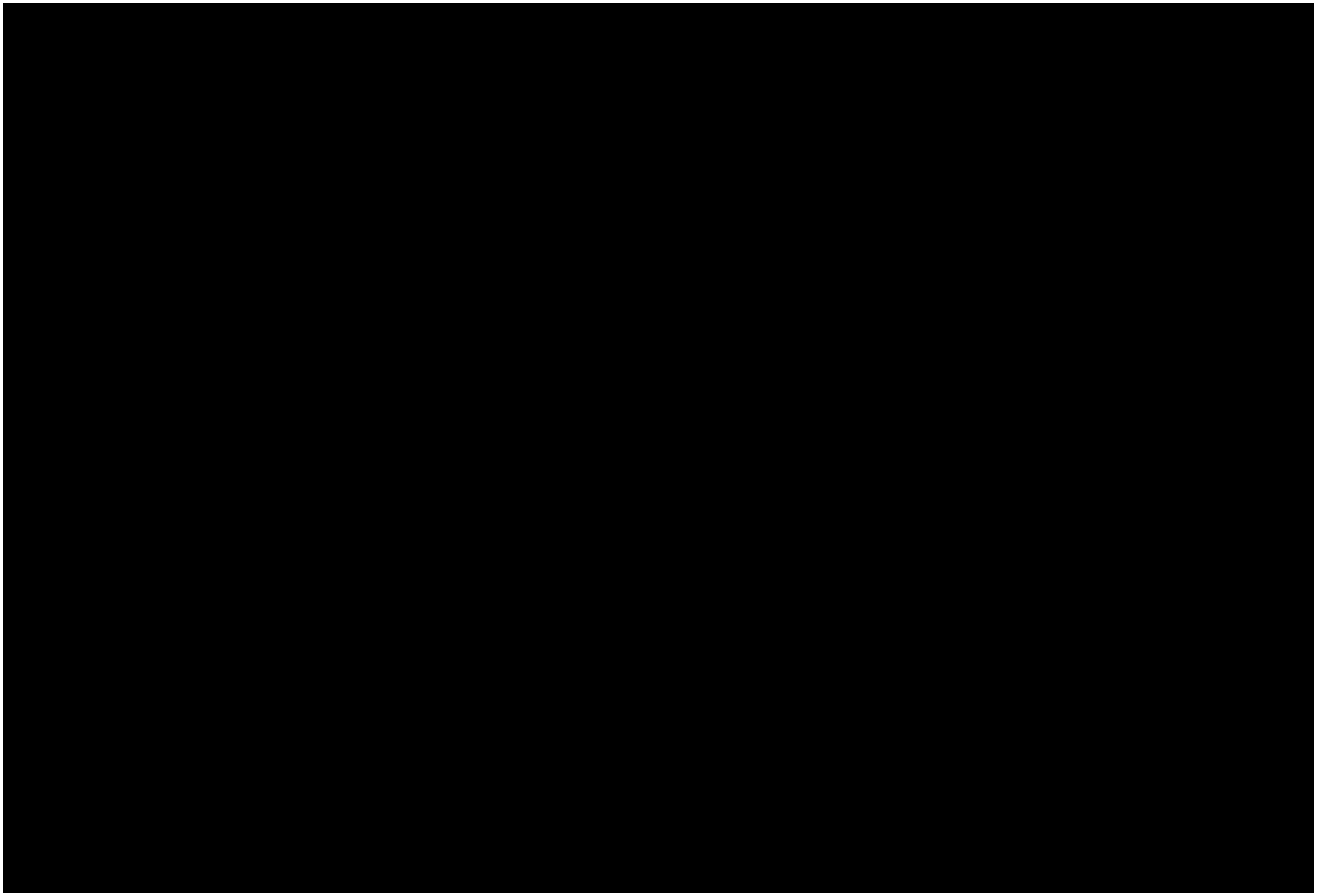
Date of On Peak Day - 10/29/2021



Member Forecasted On Peak Demand Day for November 2021

Chimney Rock Public Power District

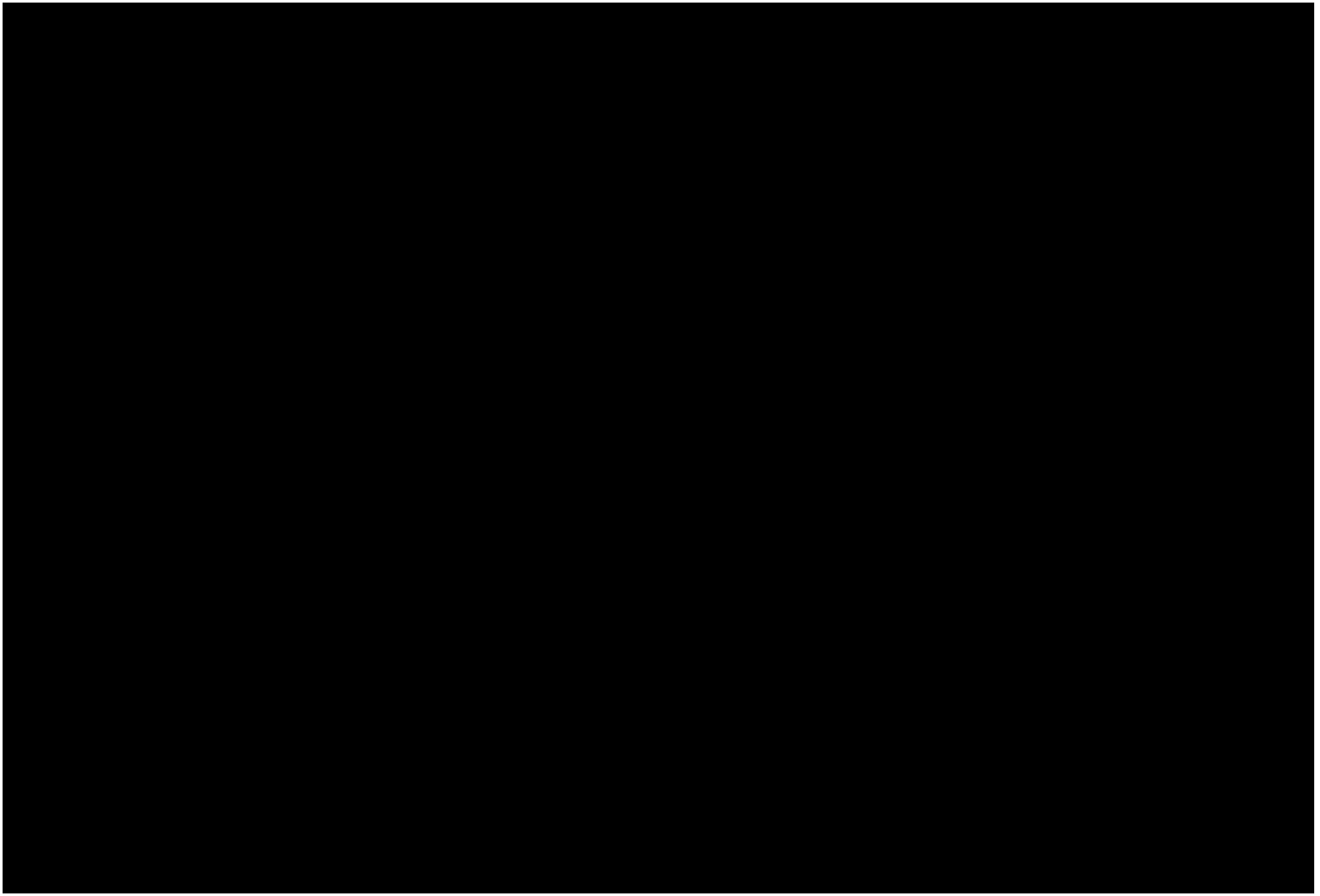
Date of On Peak Day - 11/27/2021



Member Forecasted On Peak Demand Day for December 2021

Chimney Rock Public Power District

Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Empire Electric Association, Inc.

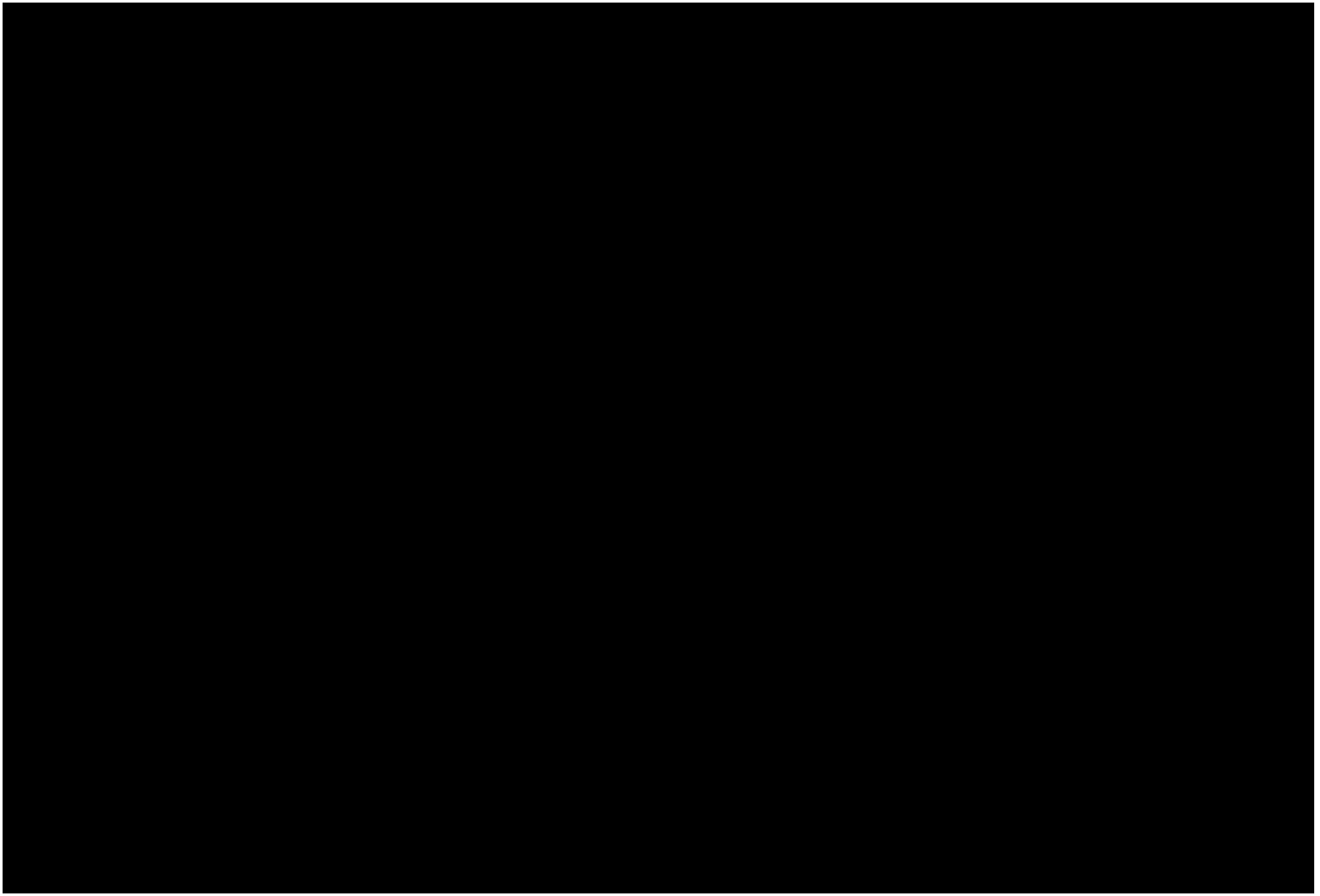
Date of On Peak Day - 01/27/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Empire Electric Association, Inc.

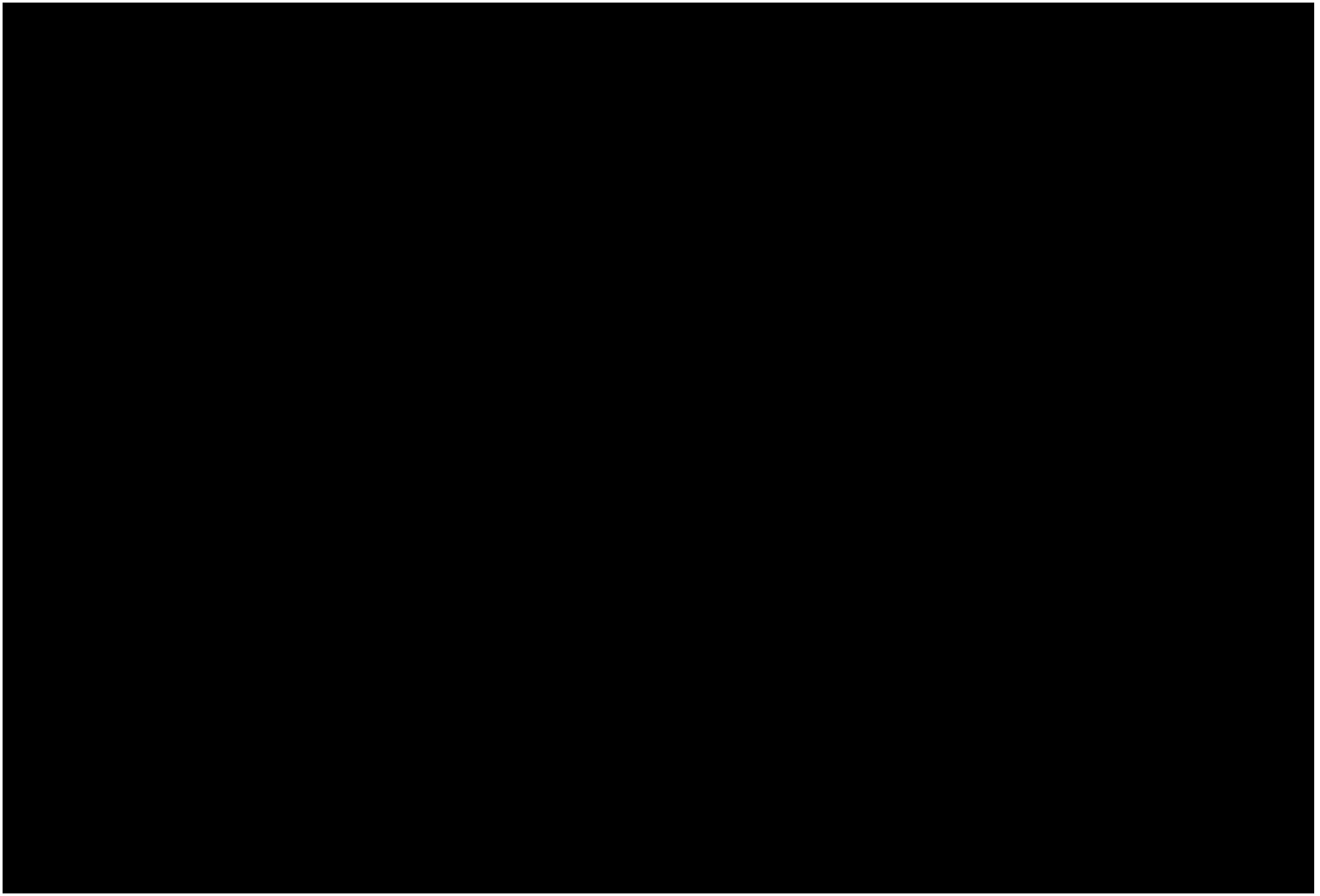
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Empire Electric Association, Inc.

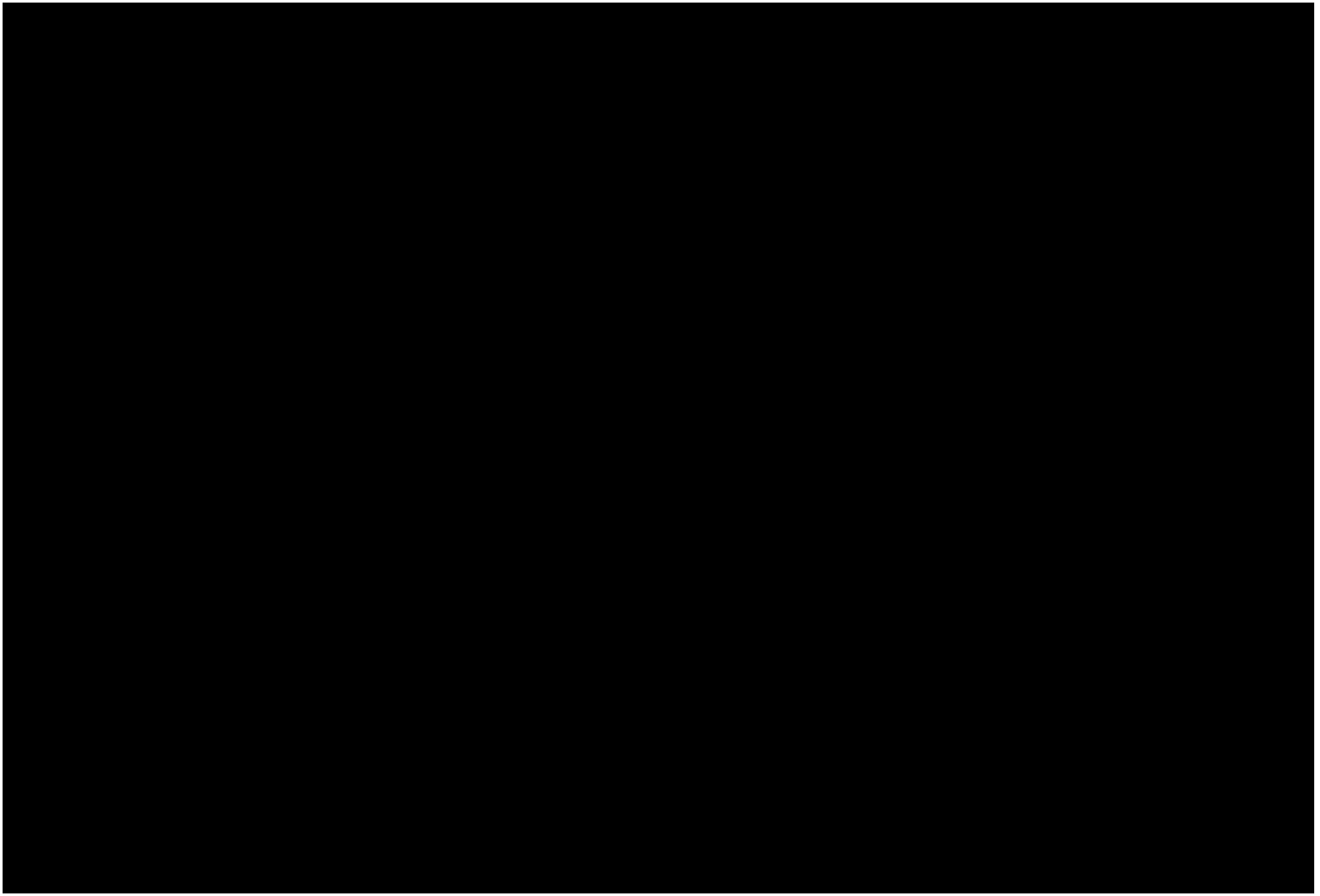
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Empire Electric Association, Inc.

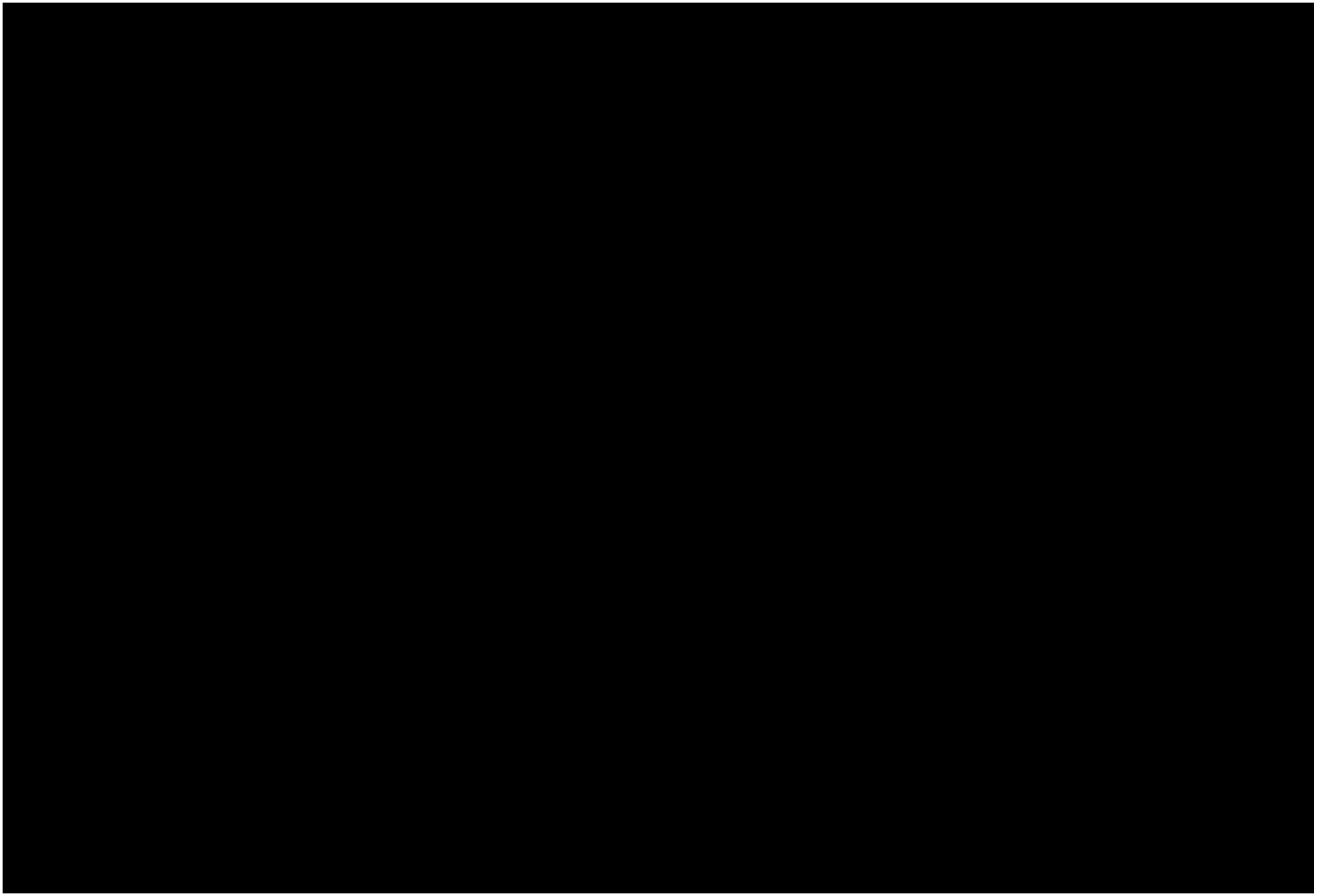
Date of On Peak Day - 04/15/2021



Member Forecasted On Peak Demand Day for May 2021

Empire Electric Association, Inc.

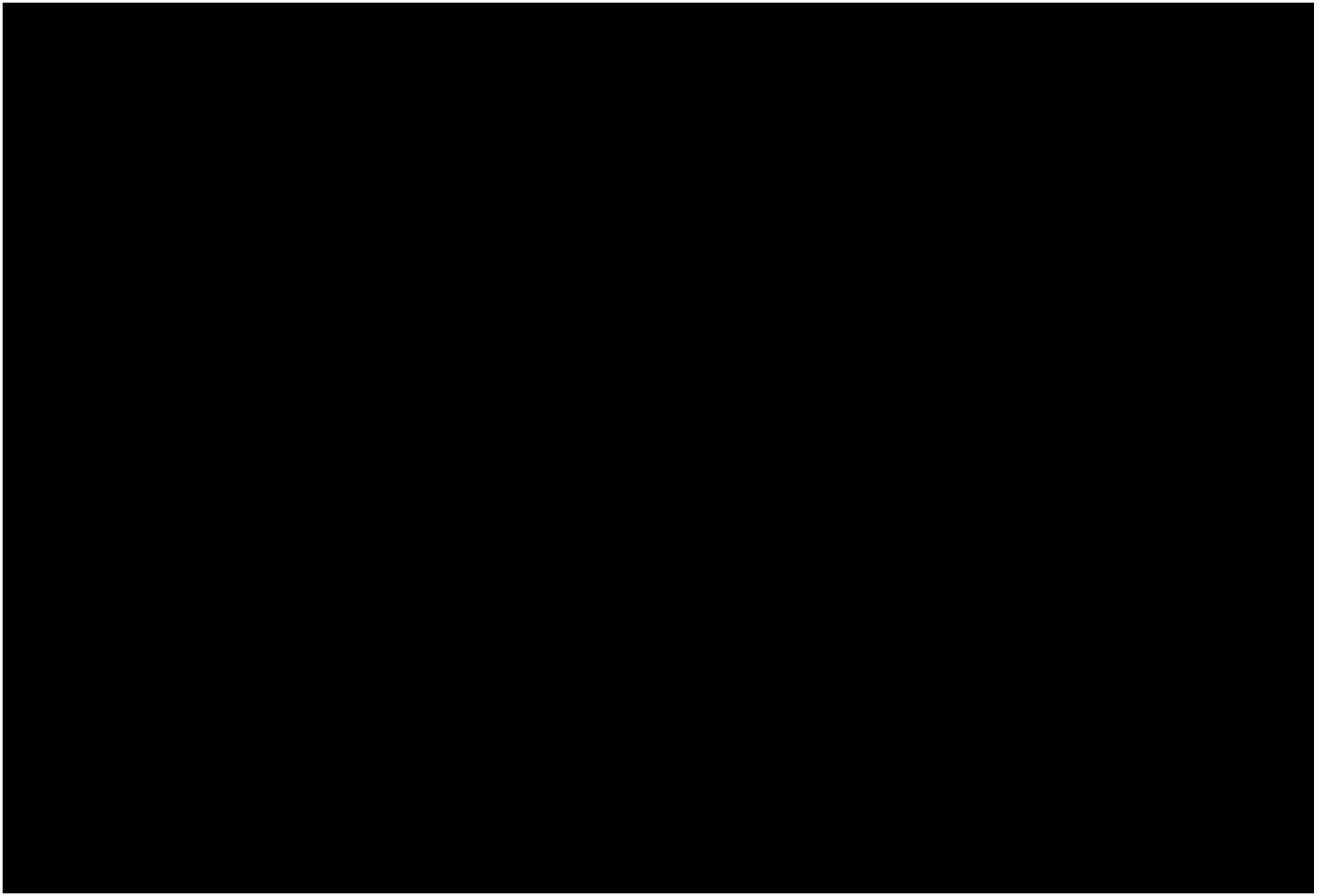
Date of On Peak Day - 05/05/2021



Member Forecasted On Peak Demand Day for June 2021

Empire Electric Association, Inc.

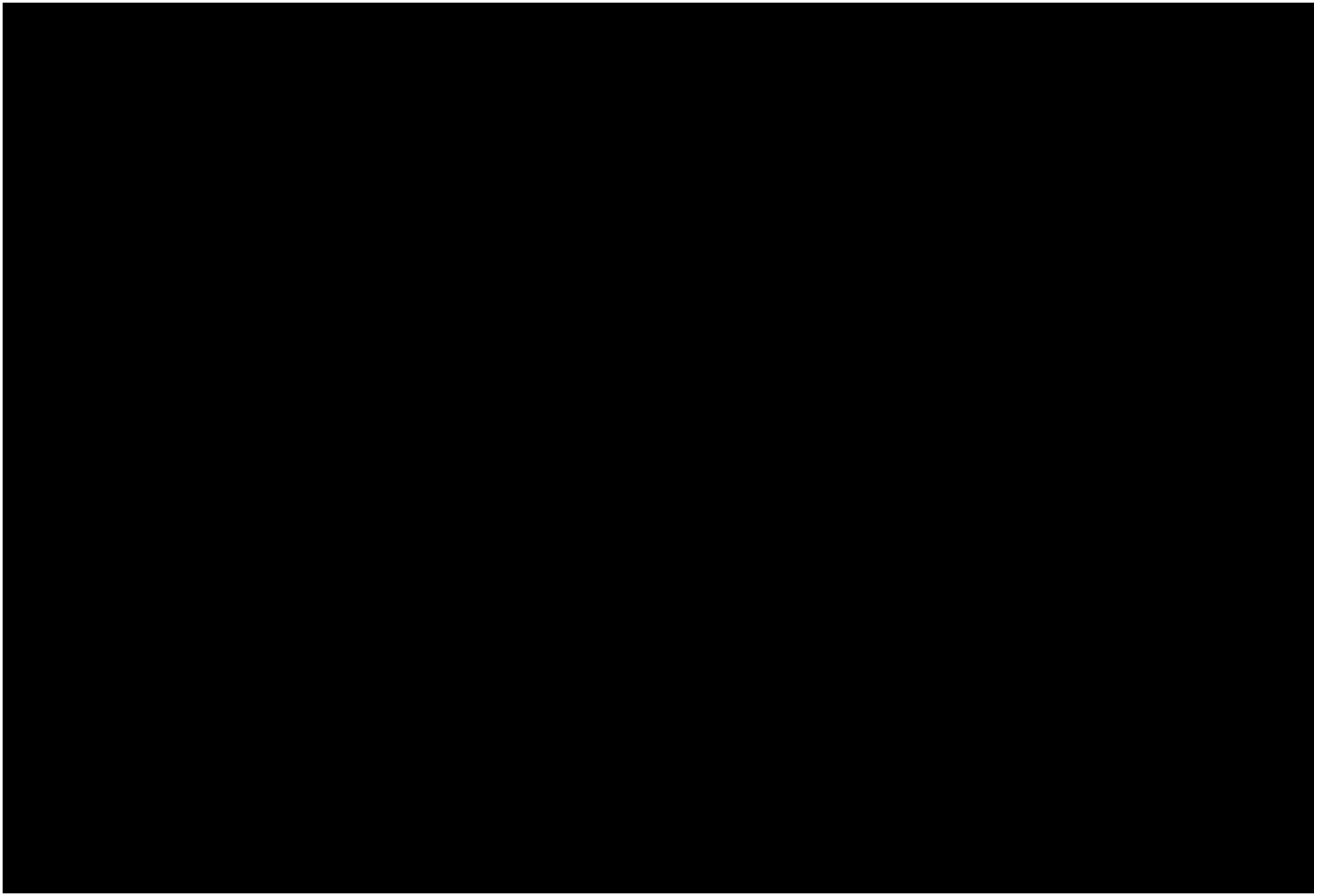
Date of On Peak Day - 06/03/2021



Member Forecasted On Peak Demand Day for July 2021

Empire Electric Association, Inc.

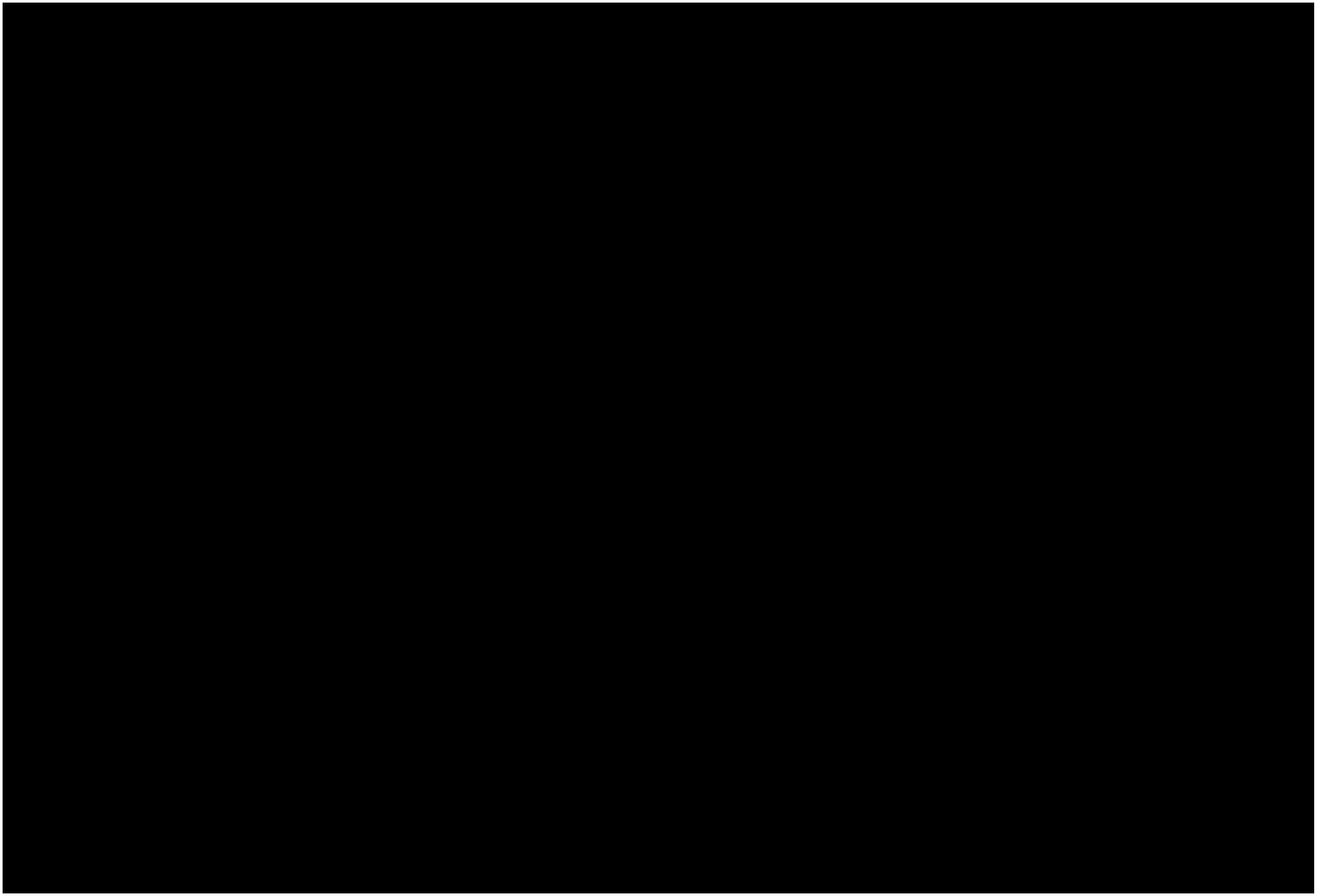
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Empire Electric Association, Inc.

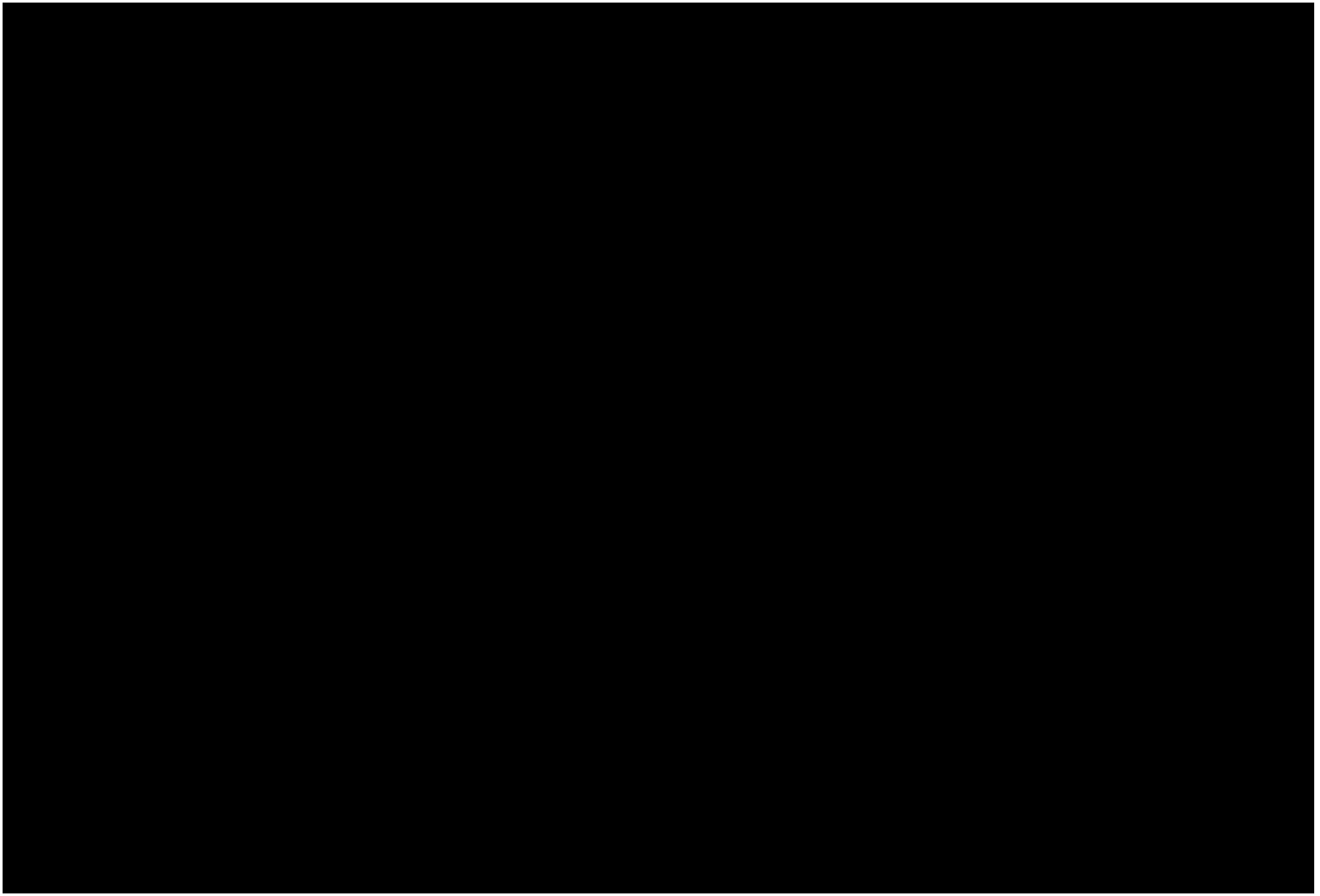
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Empire Electric Association, Inc.

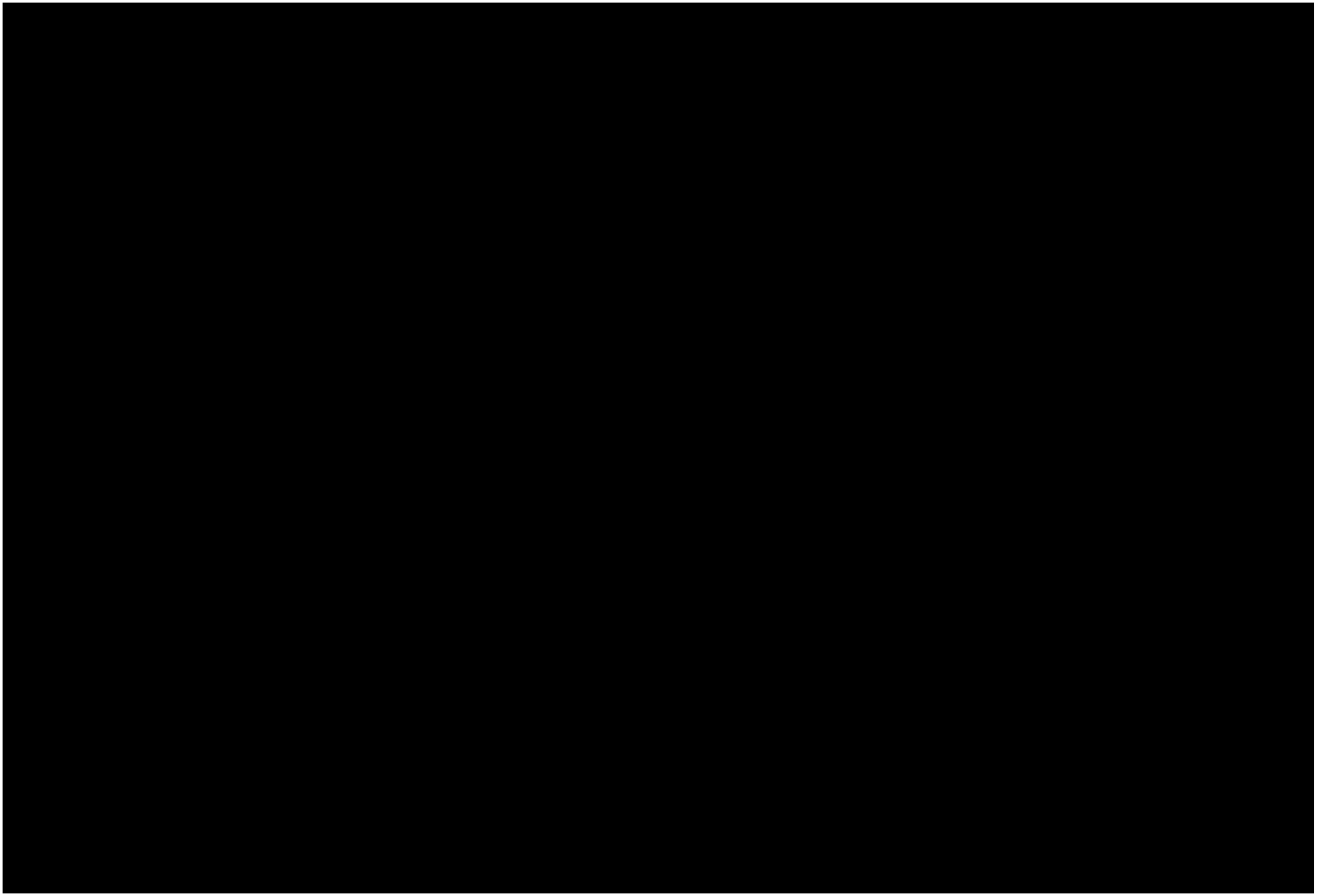
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Empire Electric Association, Inc.

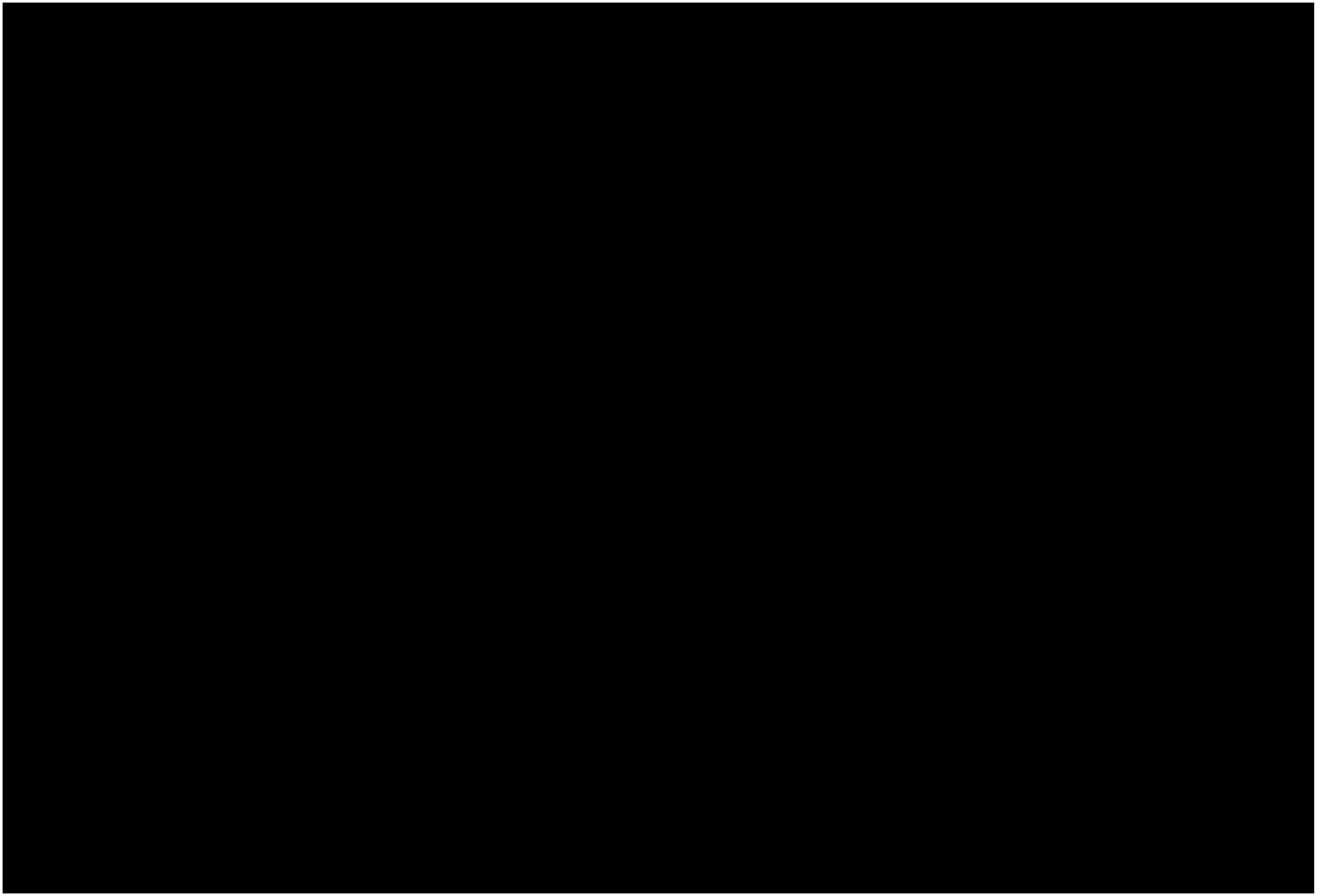
Date of On Peak Day - 10/18/2021



Member Forecasted On Peak Demand Day for November 2021

Empire Electric Association, Inc.

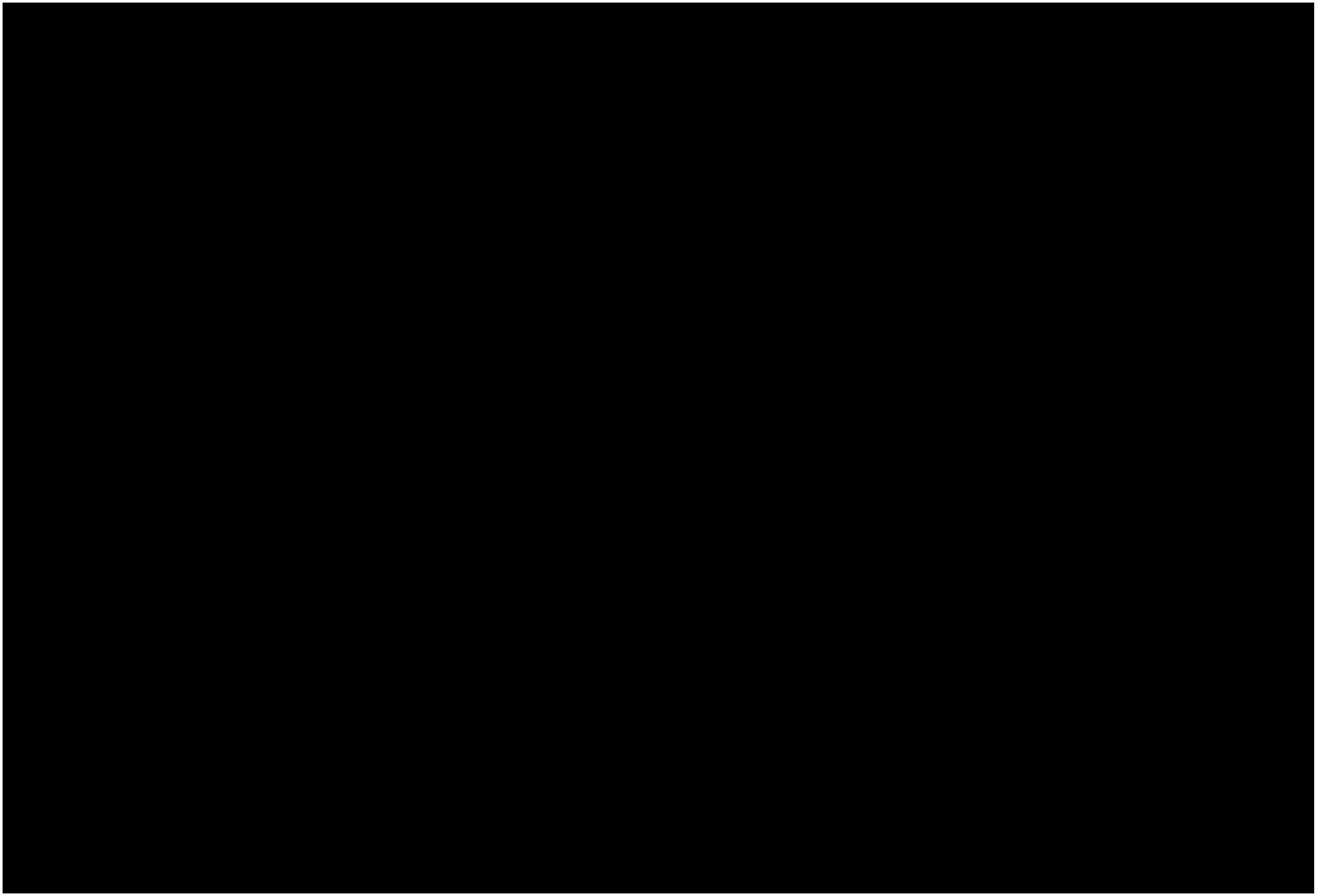
Date of On Peak Day - 11/29/2021



Member Forecasted On Peak Demand Day for December 2021

Empire Electric Association, Inc.

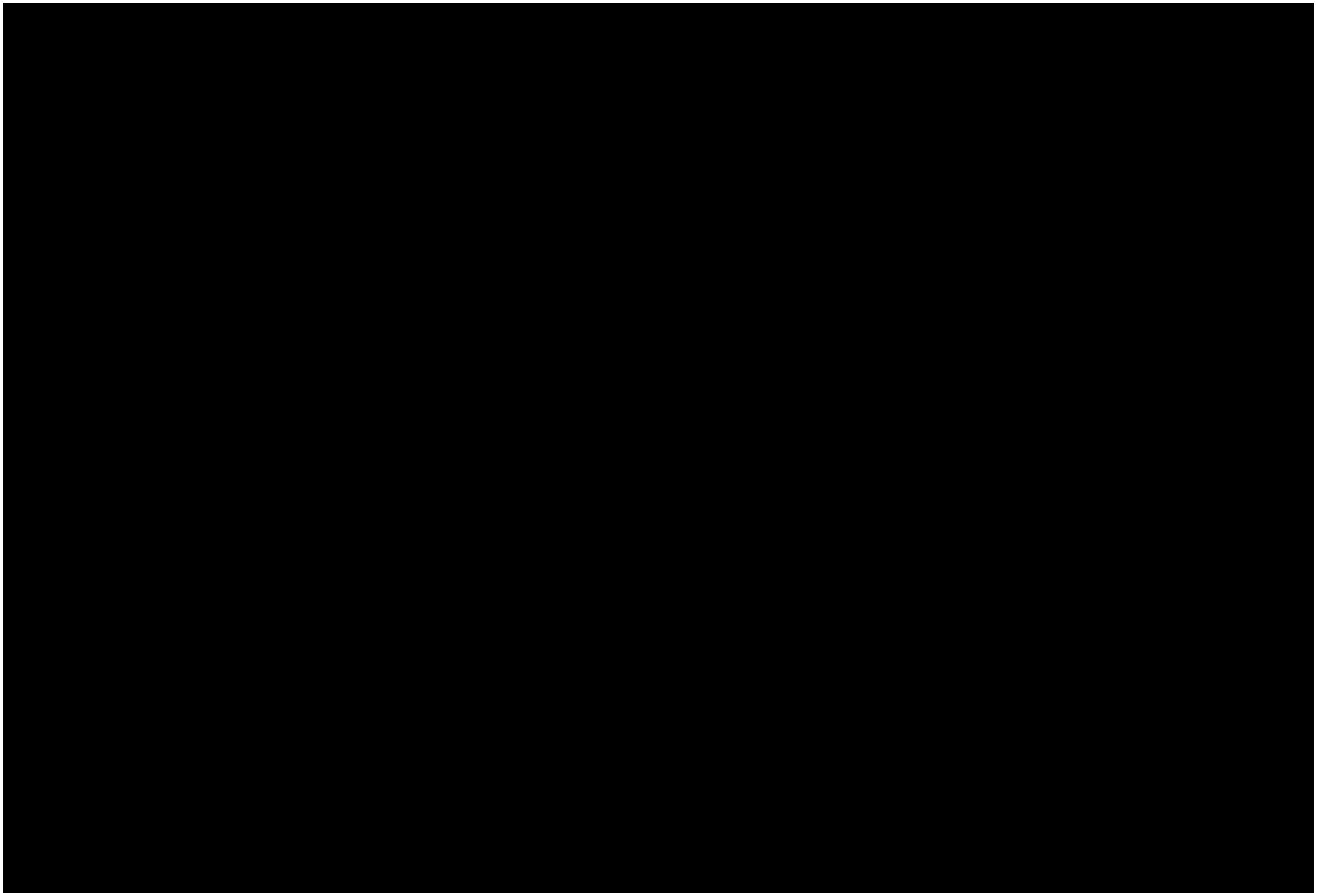
Date of On Peak Day - 12/15/2021



Member Forecasted On Peak Demand Day for January 2021

Gunnison County Electric Association, Inc.

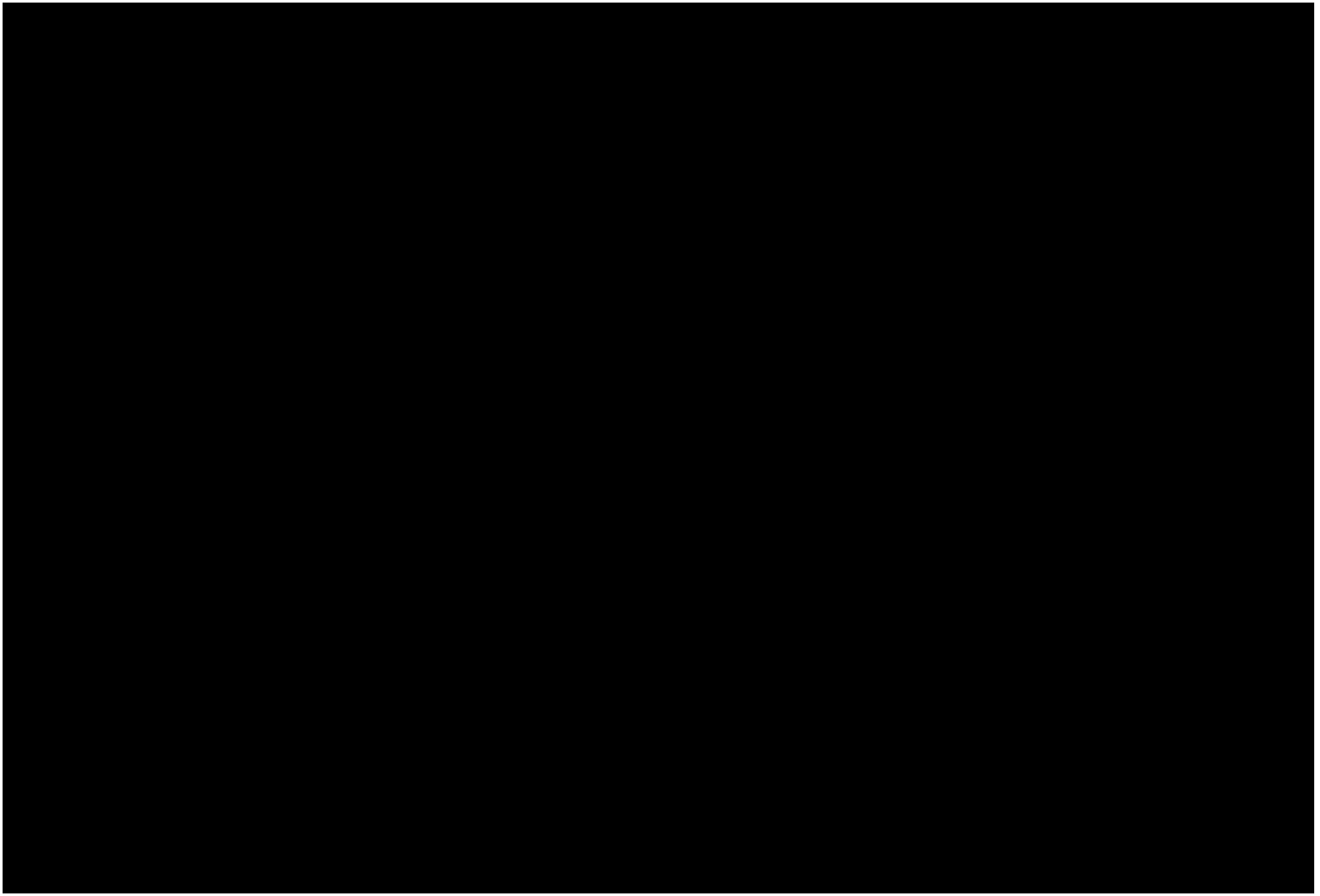
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Gunnison County Electric Association, Inc.

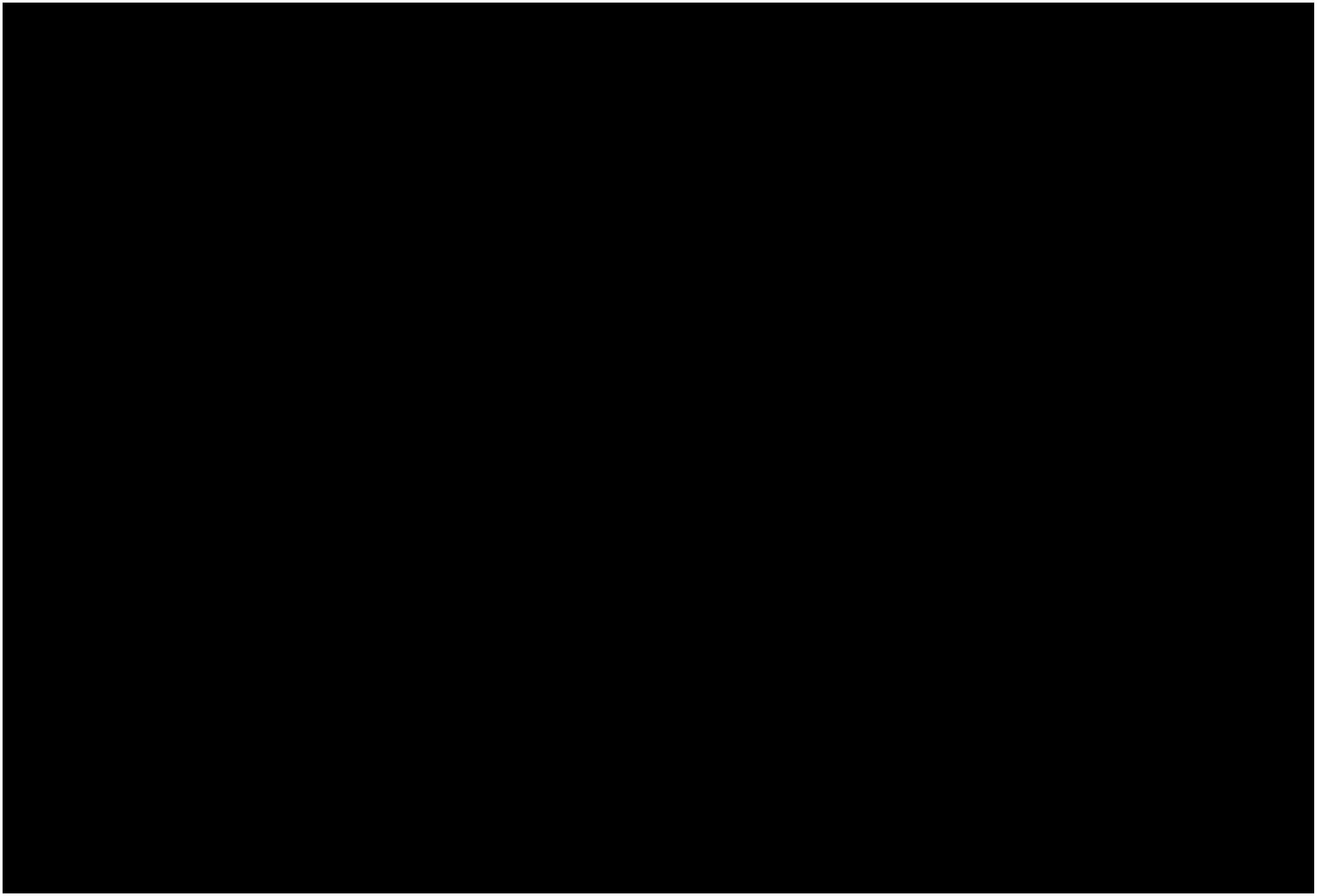
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Gunnison County Electric Association, Inc.

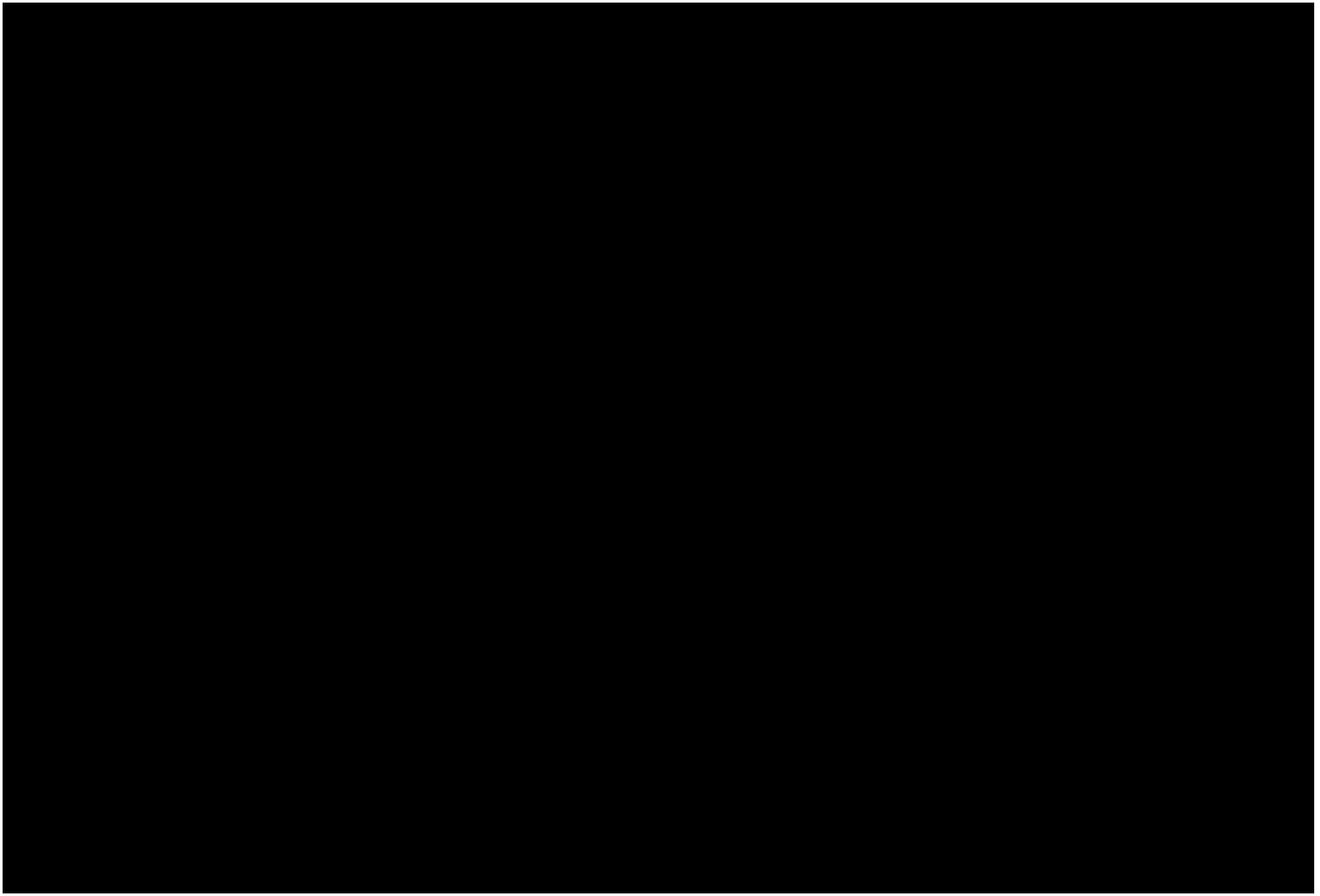
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Gunnison County Electric Association, Inc.

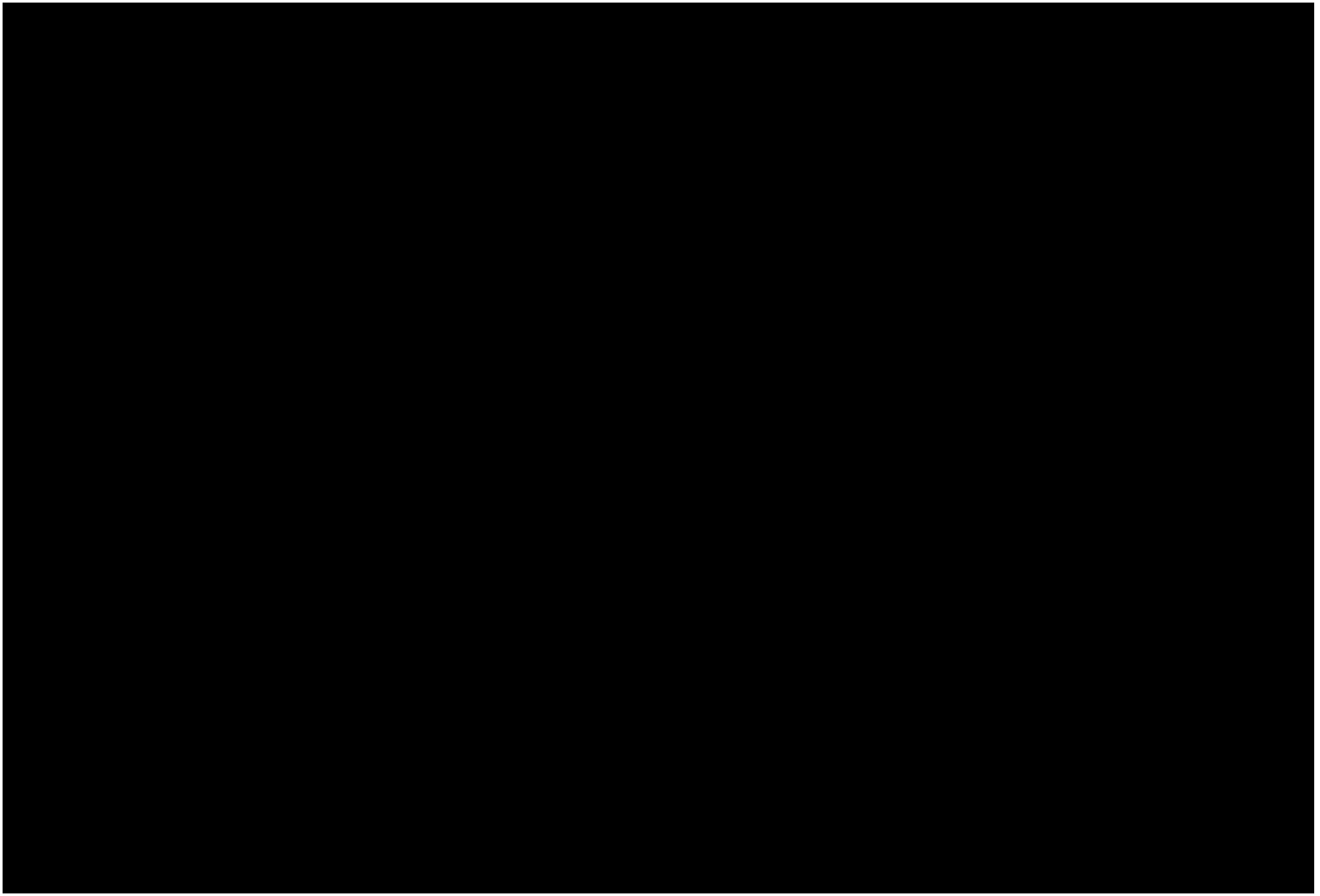
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

Gunnison County Electric Association, Inc.

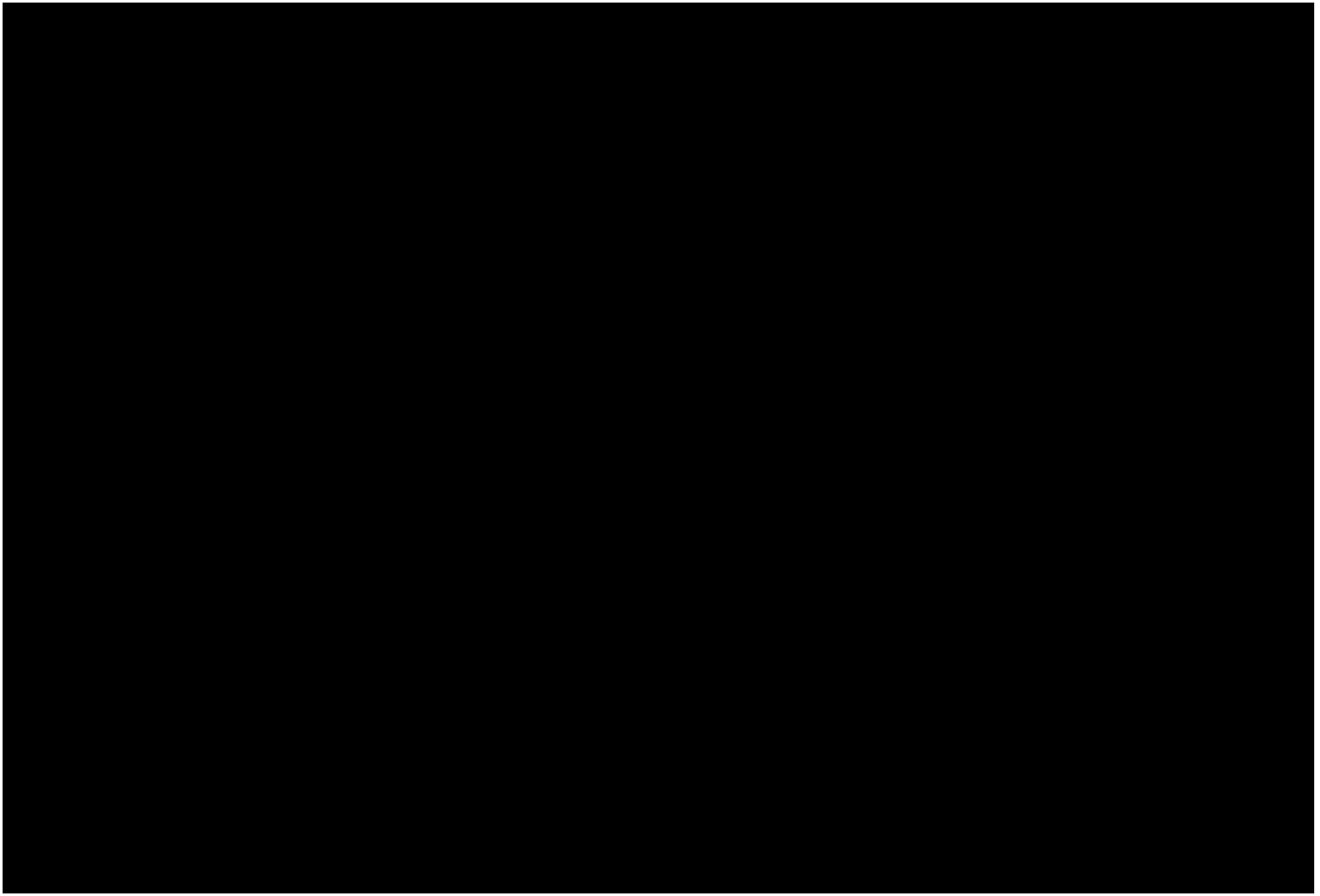
Date of On Peak Day - 05/20/2021



Member Forecasted On Peak Demand Day for June 2021

Gunnison County Electric Association, Inc.

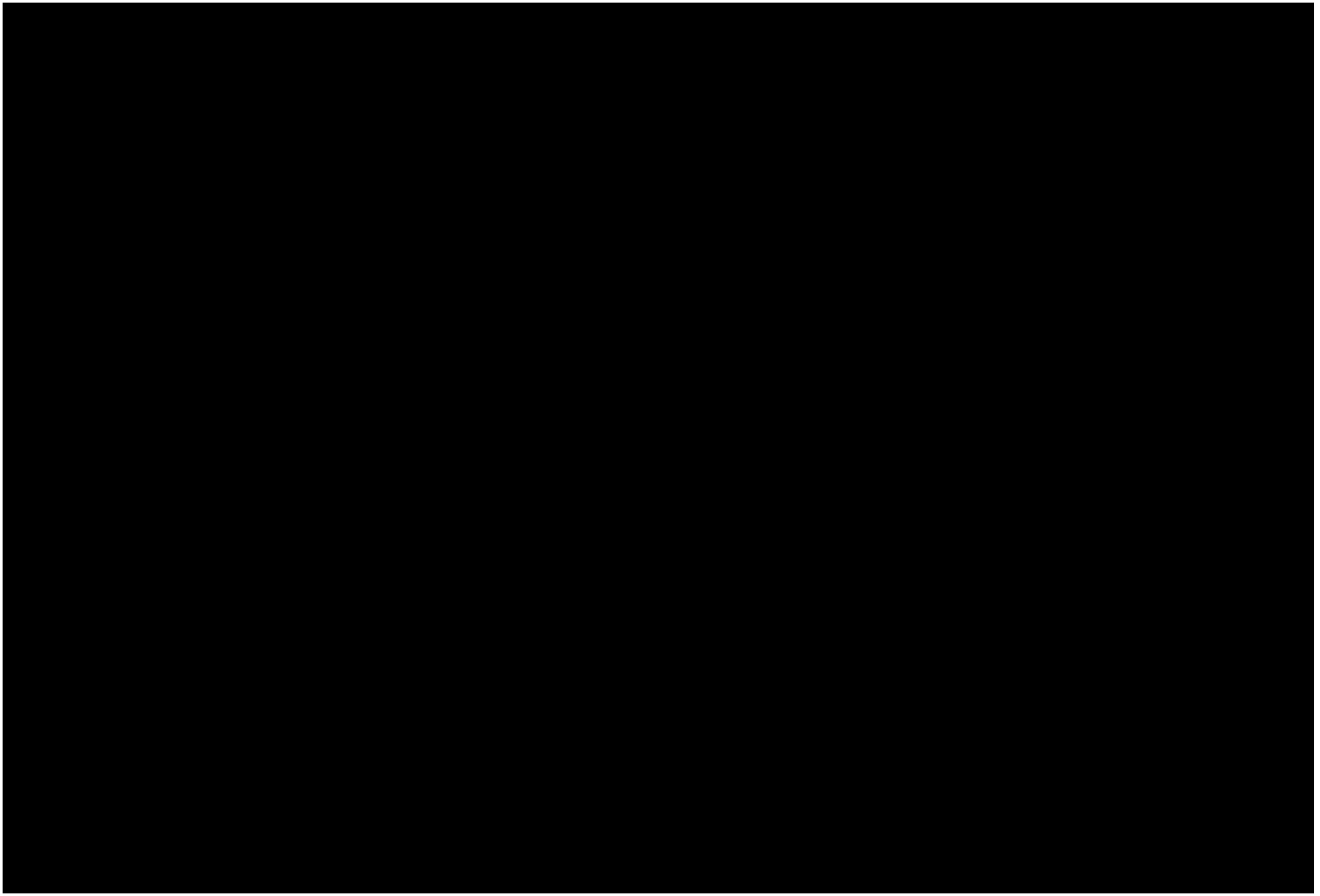
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Gunnison County Electric Association, Inc.

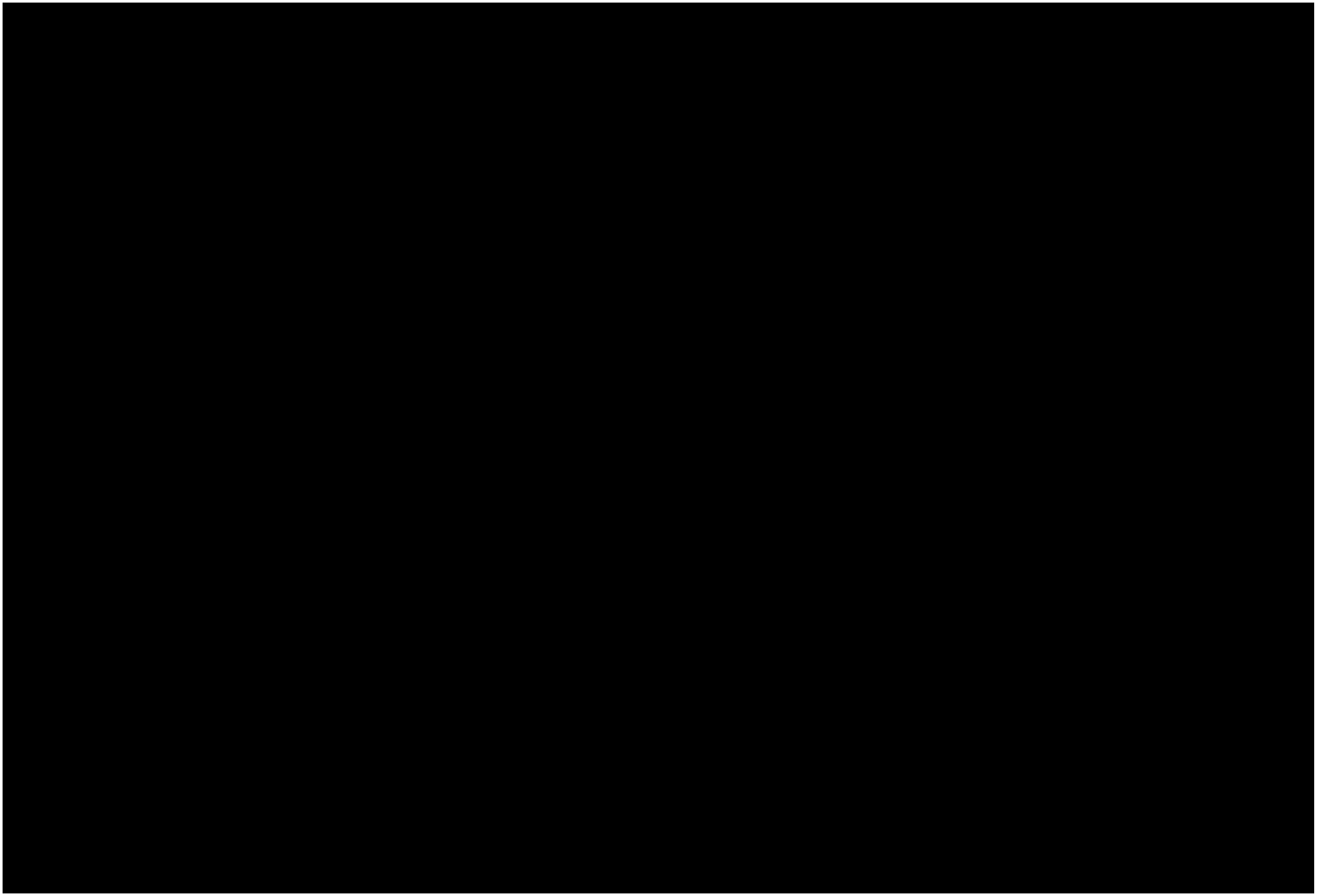
Date of On Peak Day - 07/02/2021



Member Forecasted On Peak Demand Day for August 2021

Gunnison County Electric Association, Inc.

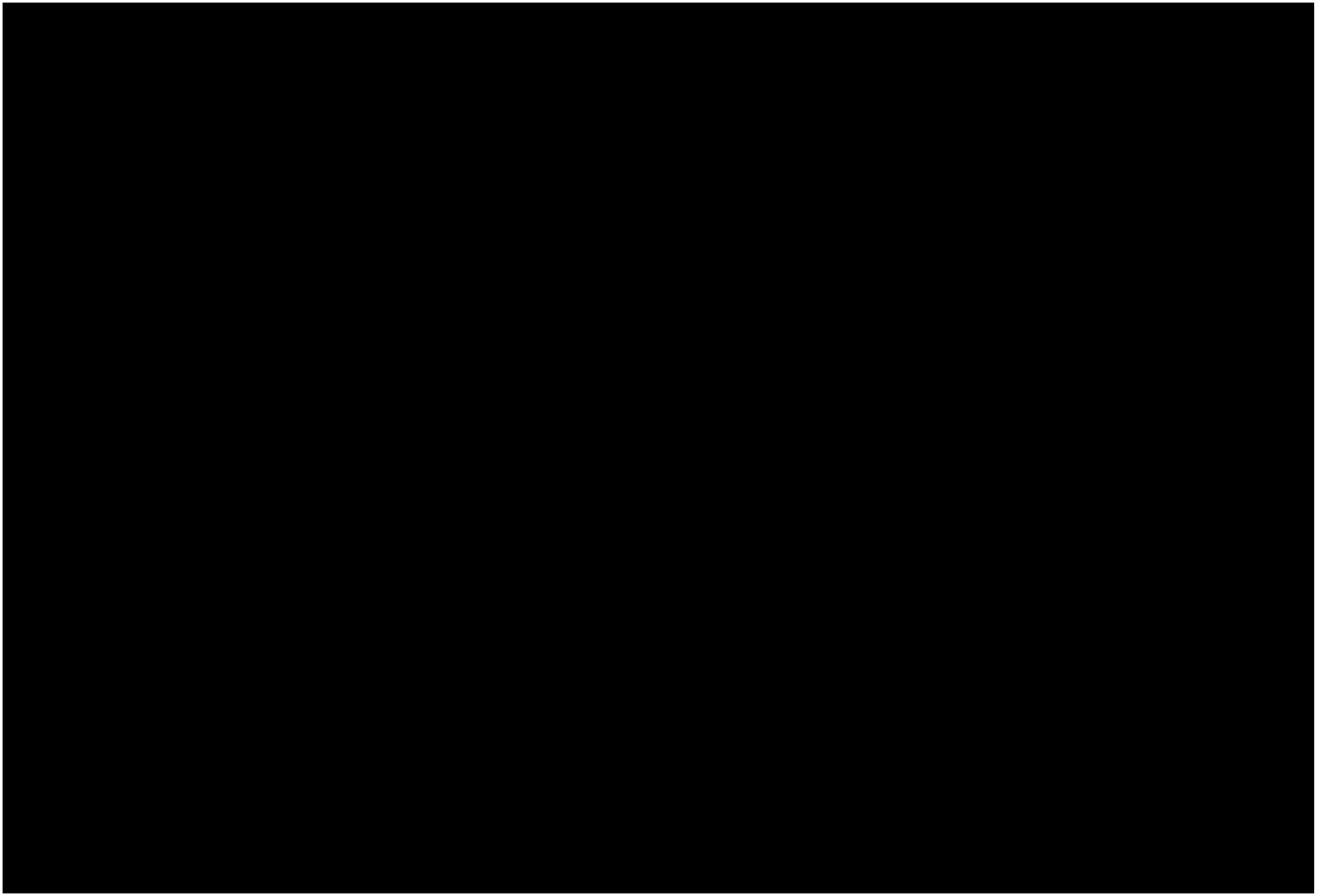
Date of On Peak Day - 08/05/2021



Member Forecasted On Peak Demand Day for September 2021

Gunnison County Electric Association, Inc.

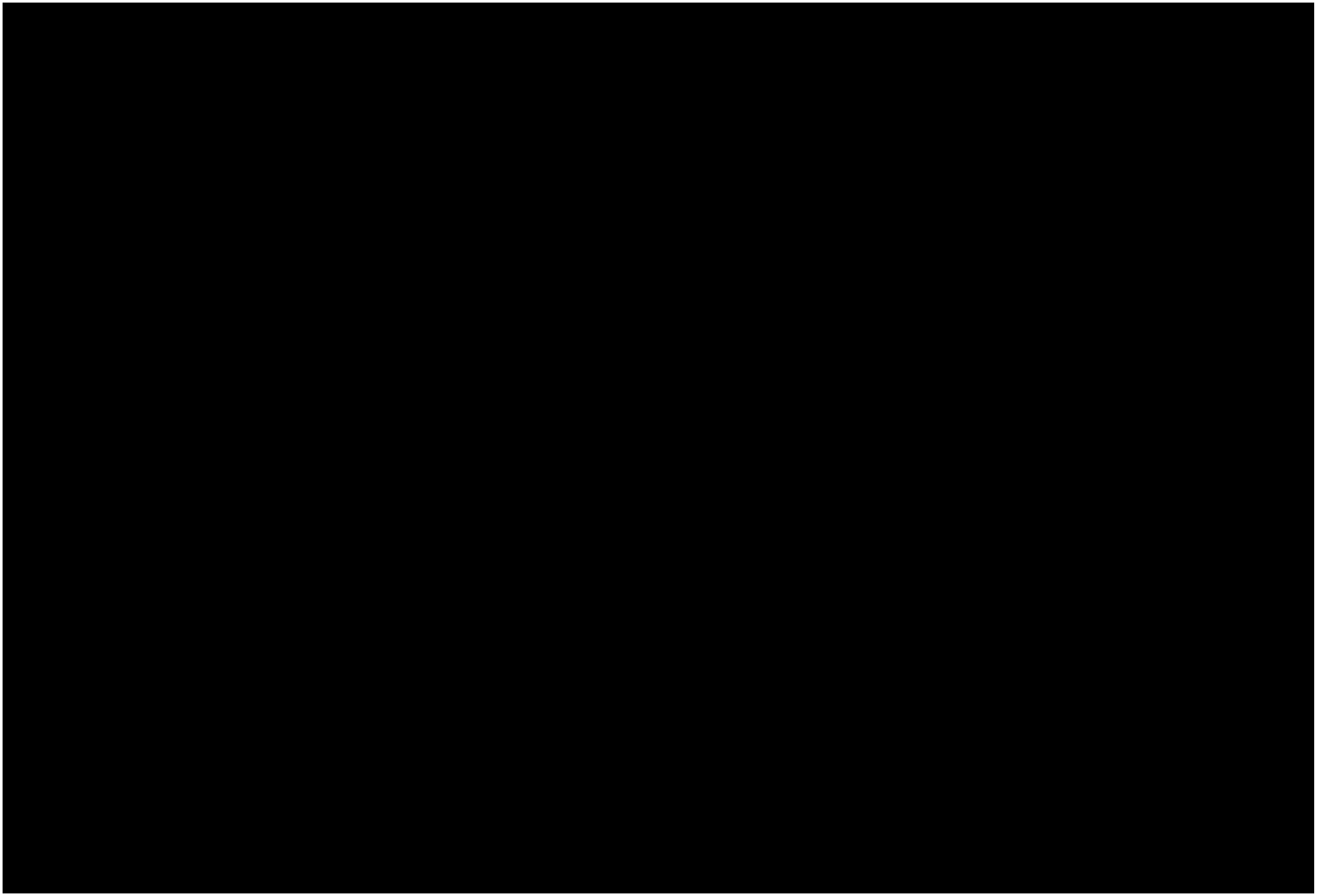
Date of On Peak Day - 09/19/2021



Member Forecasted On Peak Demand Day for October 2021

Gunnison County Electric Association, Inc.

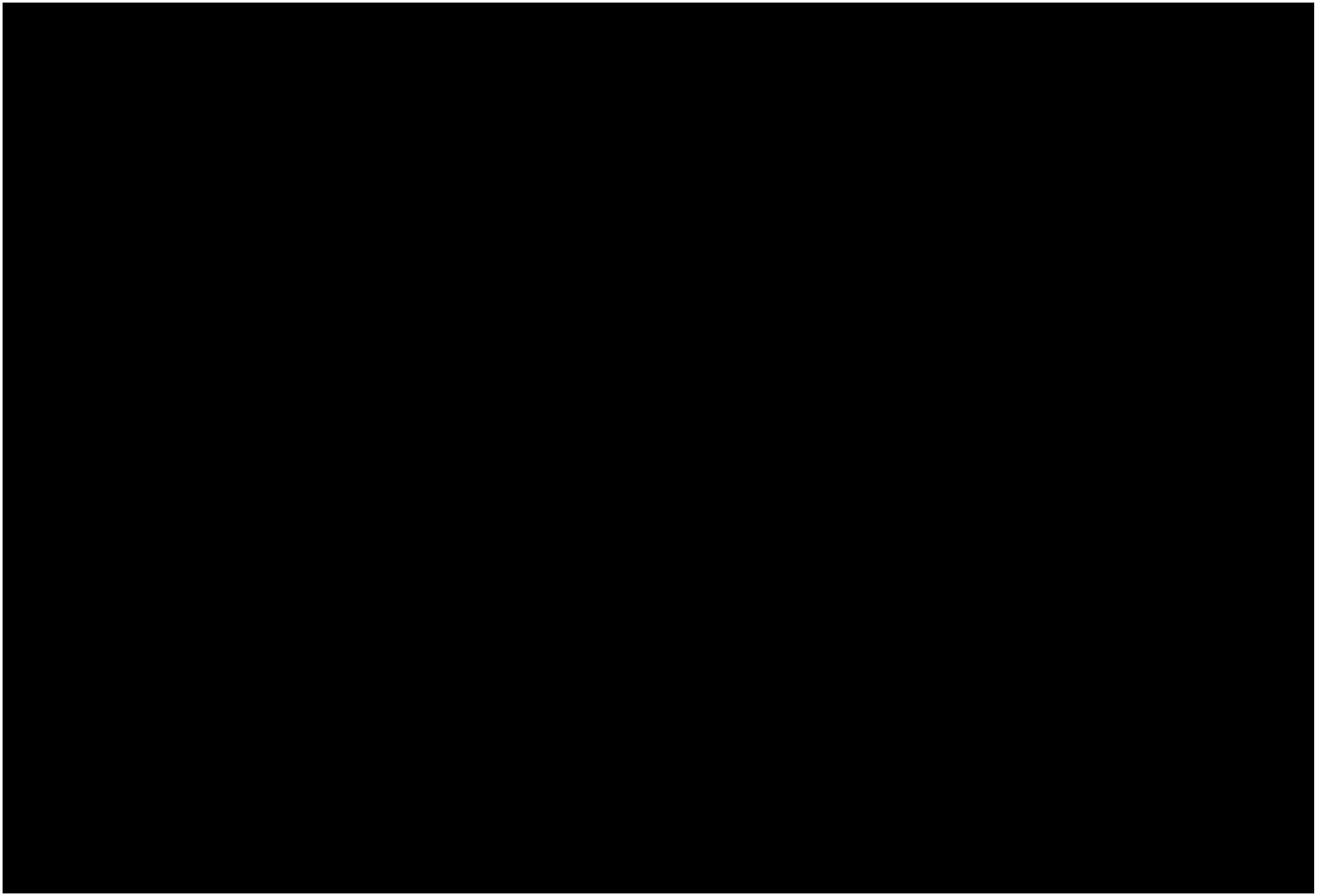
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Gunnison County Electric Association, Inc.

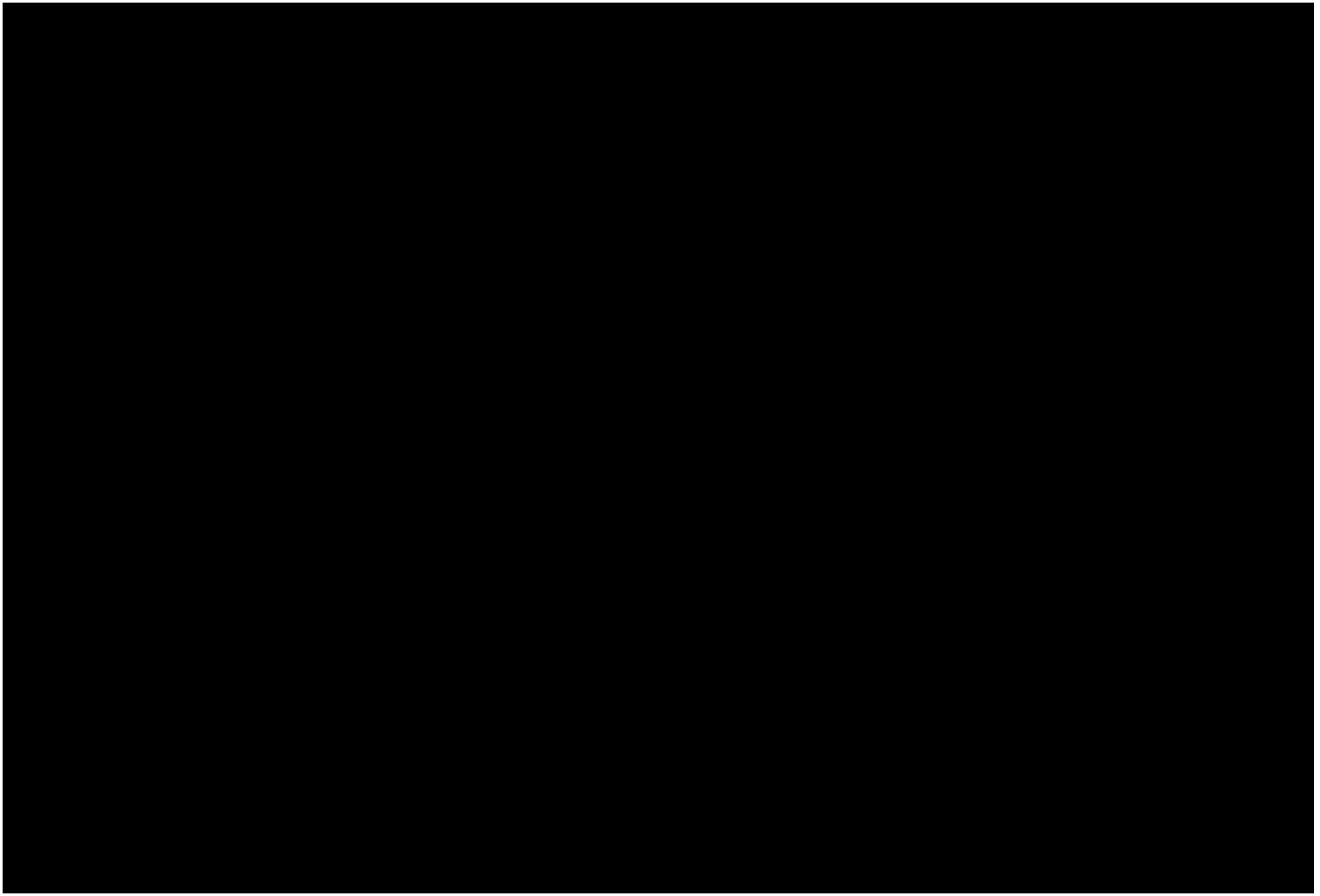
Date of On Peak Day - 11/10/2021



Member Forecasted On Peak Demand Day for December 2021

Gunnison County Electric Association, Inc.

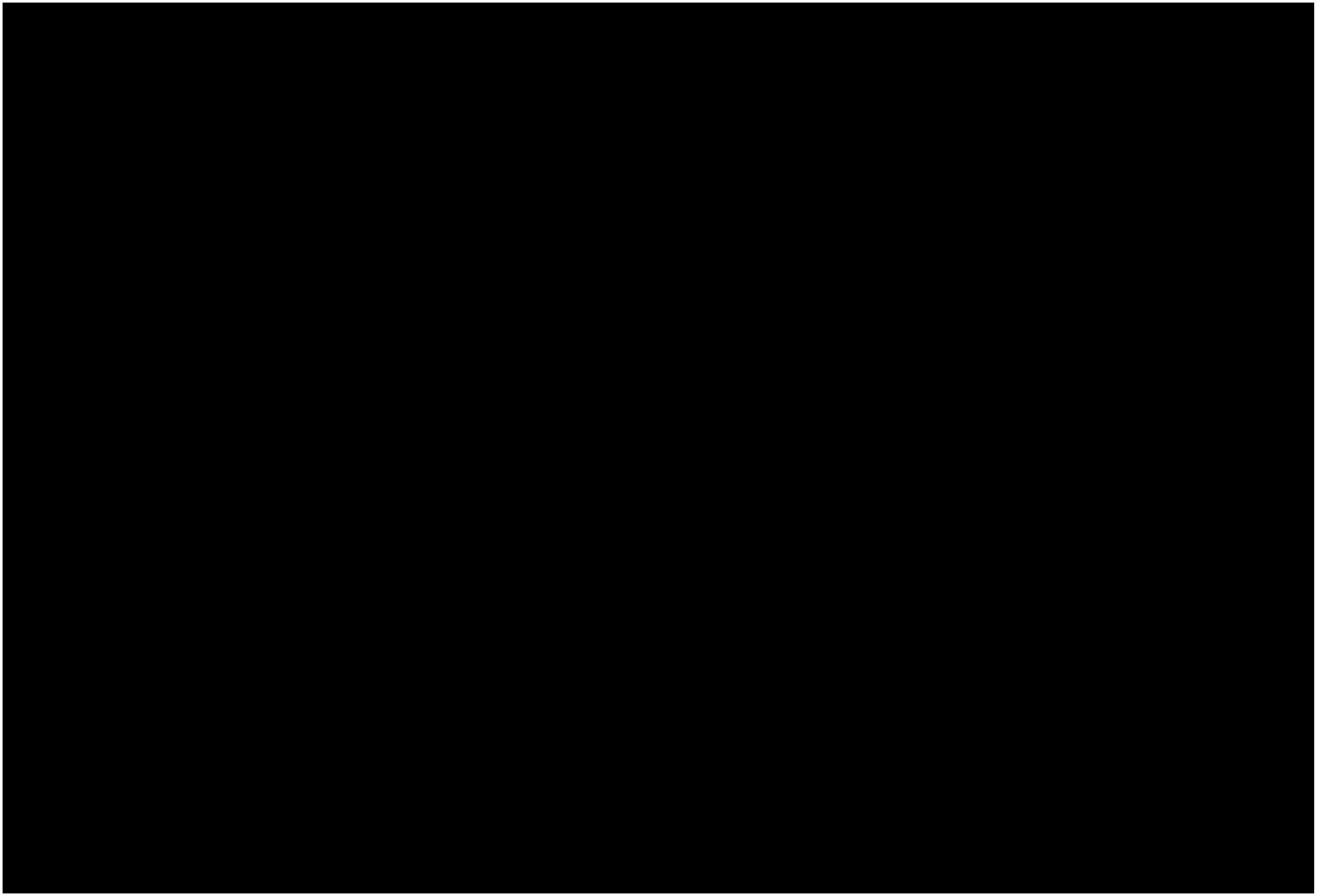
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Garland Light and Power Company

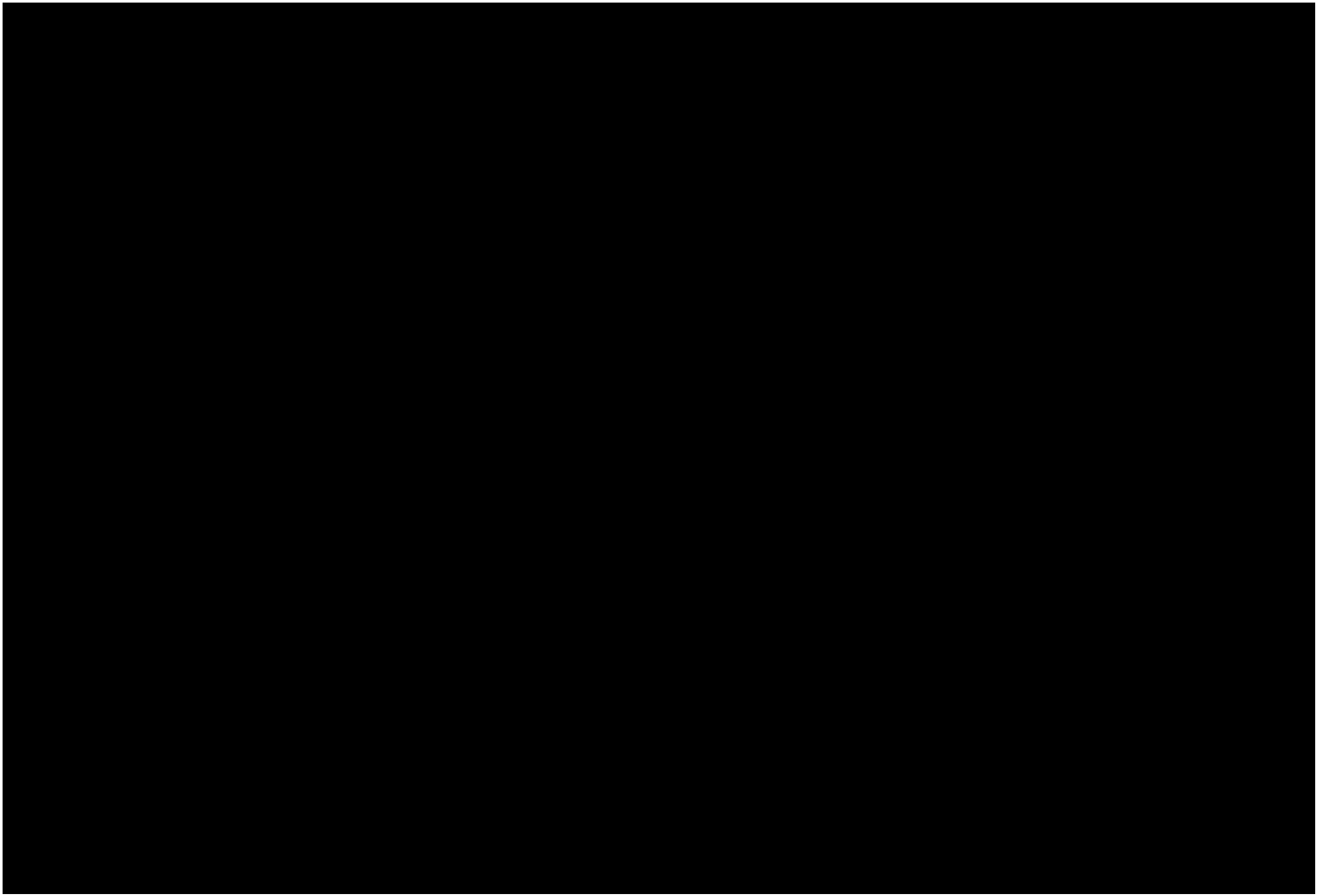
Date of On Peak Day - 01/03/2021



Member Forecasted On Peak Demand Day for February 2021

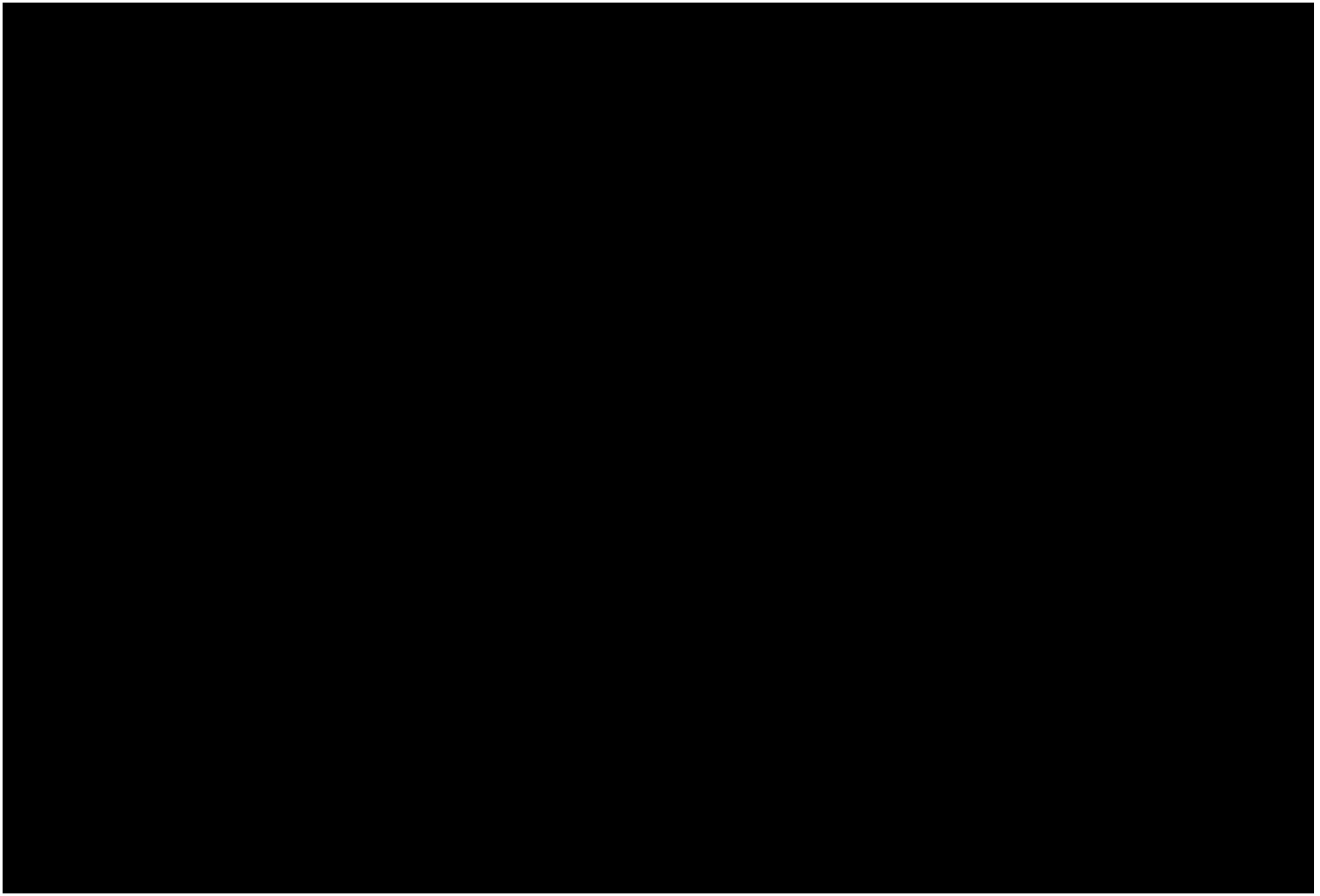
Garland Light and Power Company

Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

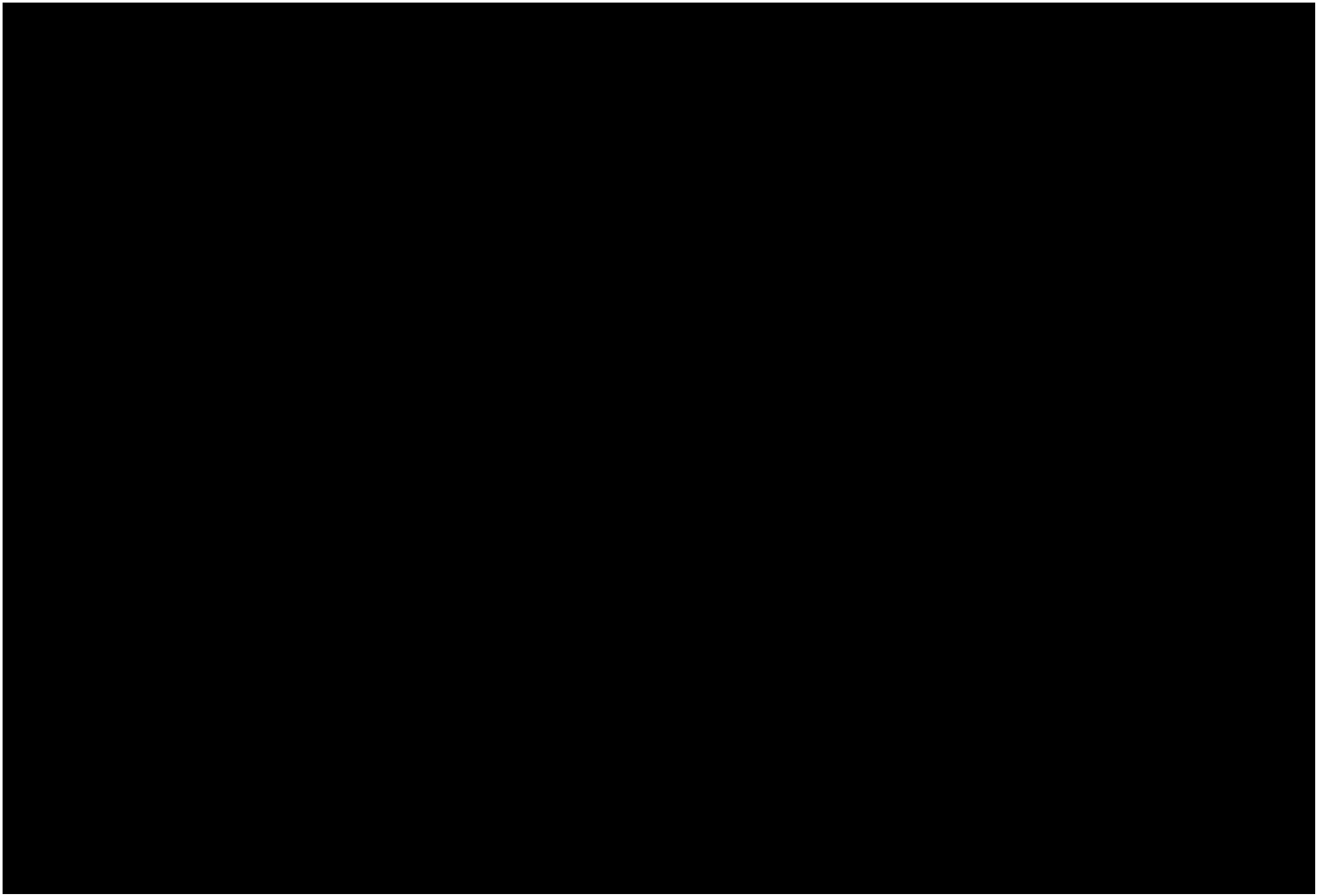
Garland Light and Power Company
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Garland Light and Power Company

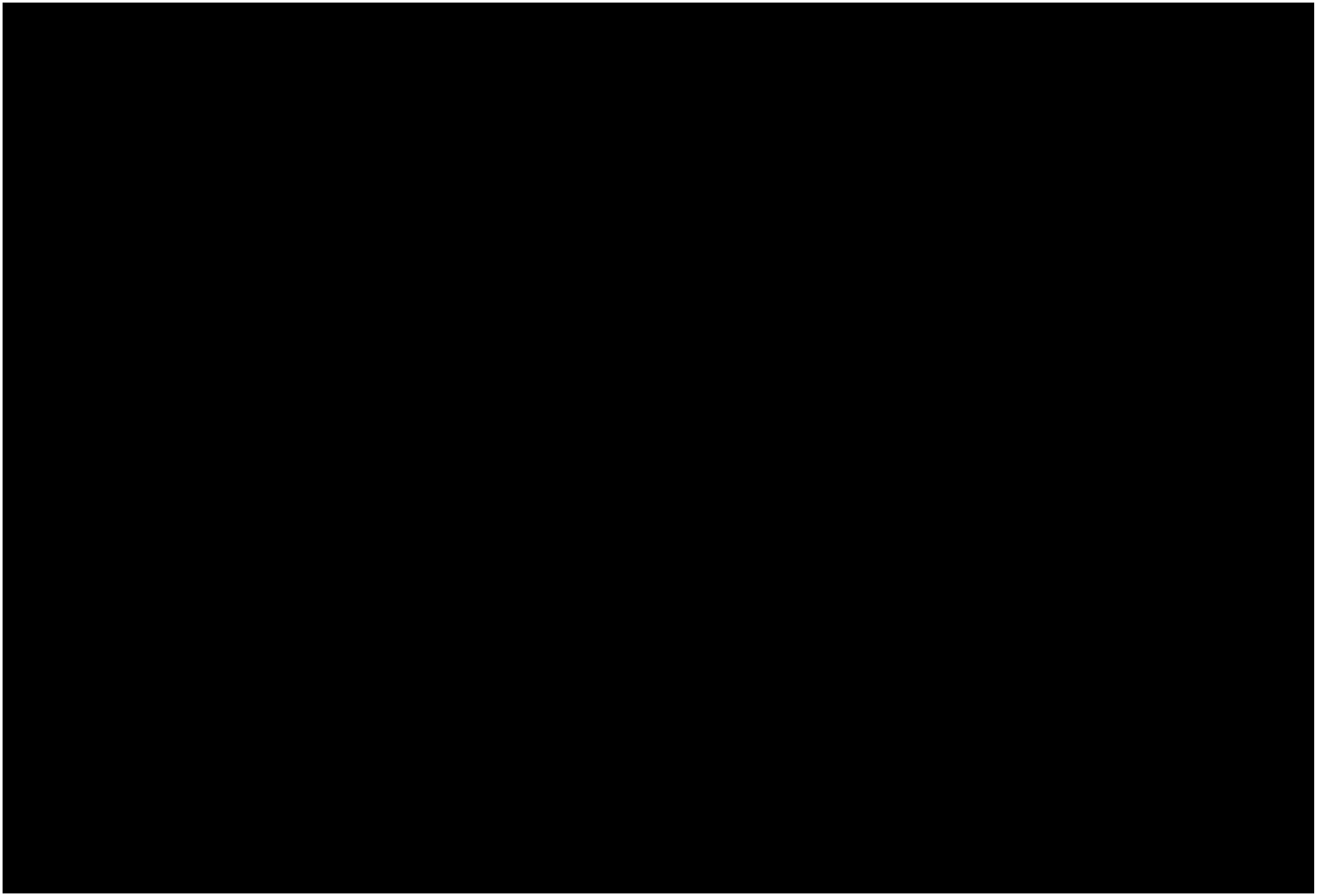
Date of On Peak Day - 04/07/2021



Member Forecasted On Peak Demand Day for May 2021

Garland Light and Power Company

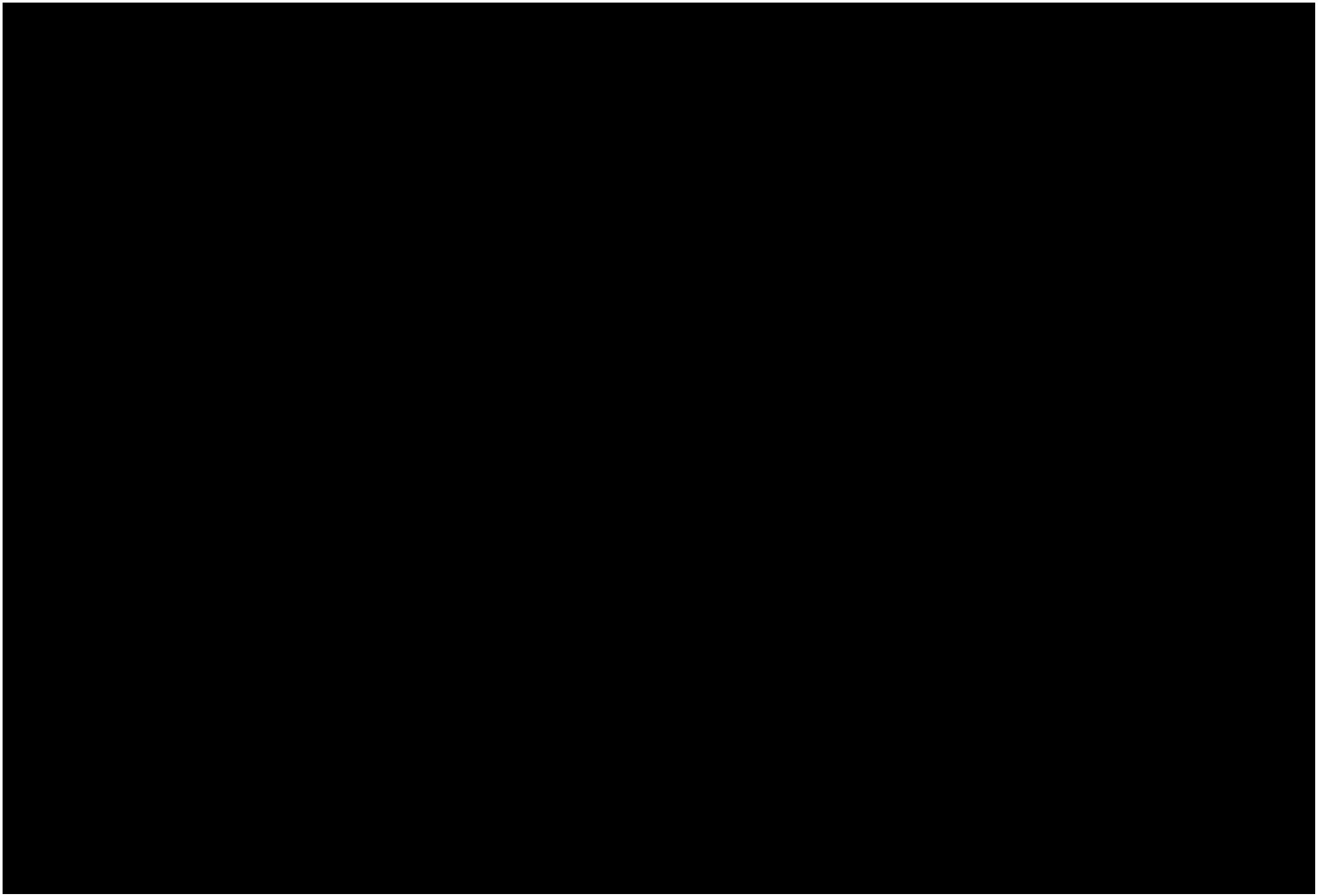
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Garland Light and Power Company

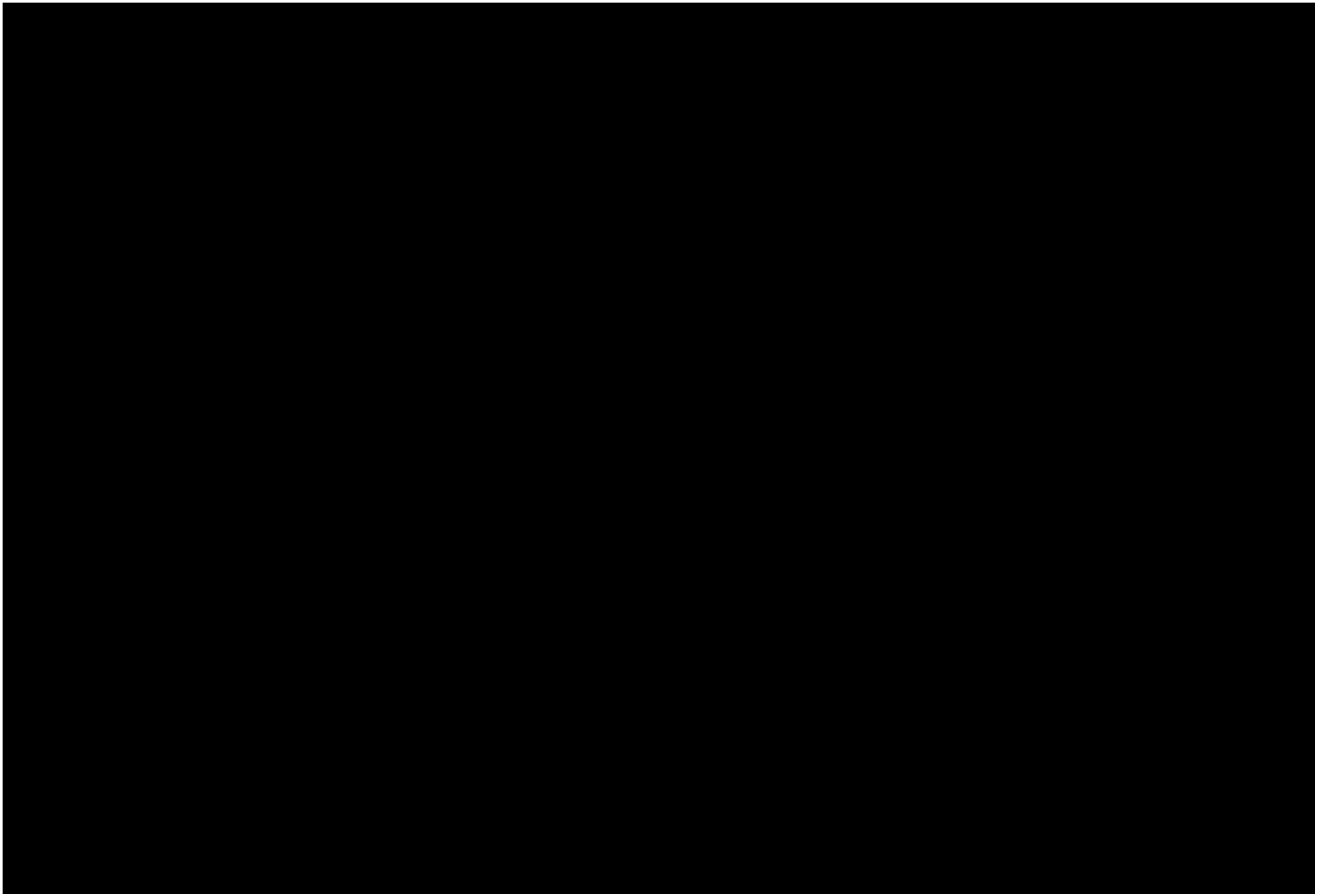
Date of On Peak Day - 06/09/2021



Member Forecasted On Peak Demand Day for July 2021

Garland Light and Power Company

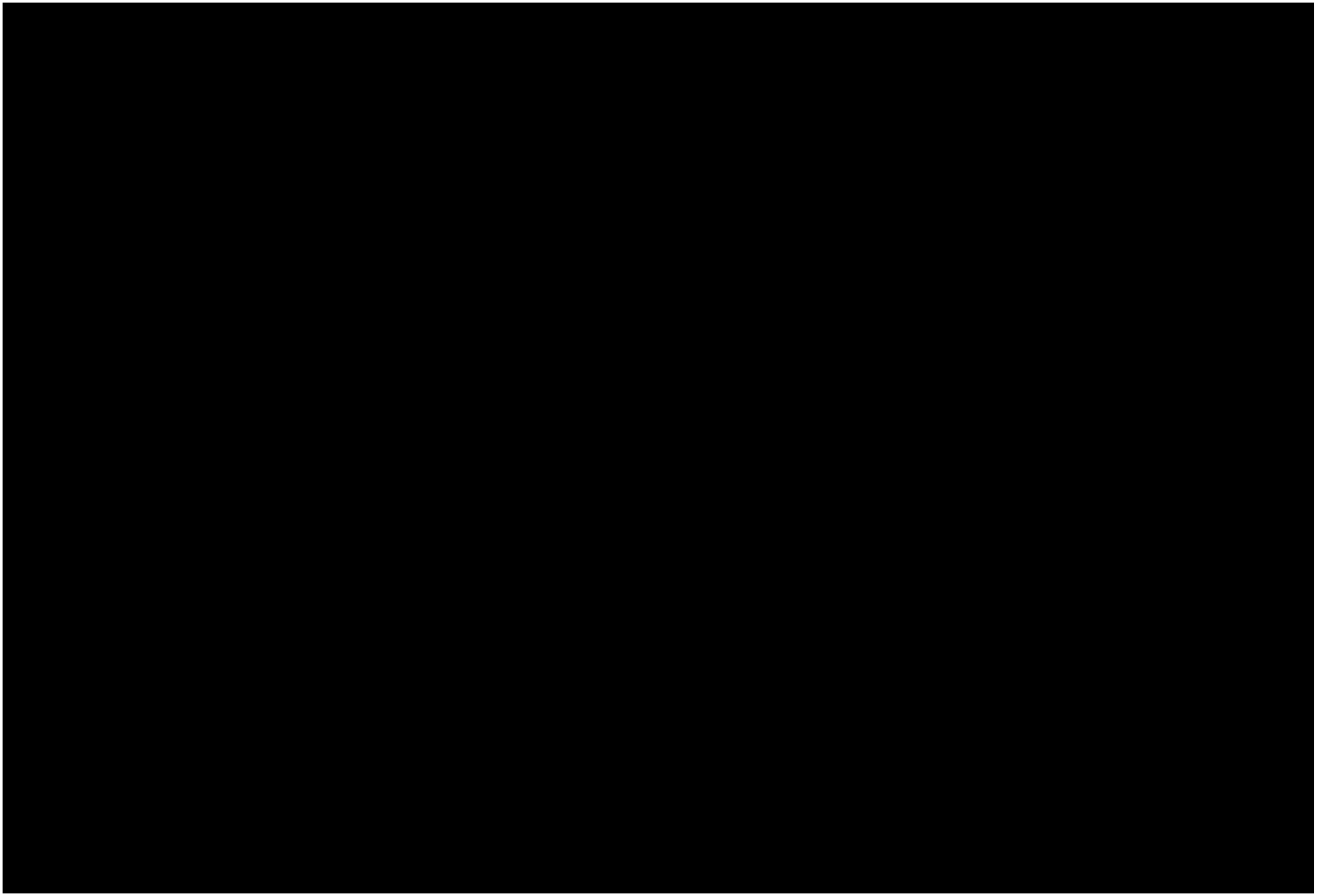
Date of On Peak Day - 07/25/2021



Member Forecasted On Peak Demand Day for August 2021

Garland Light and Power Company

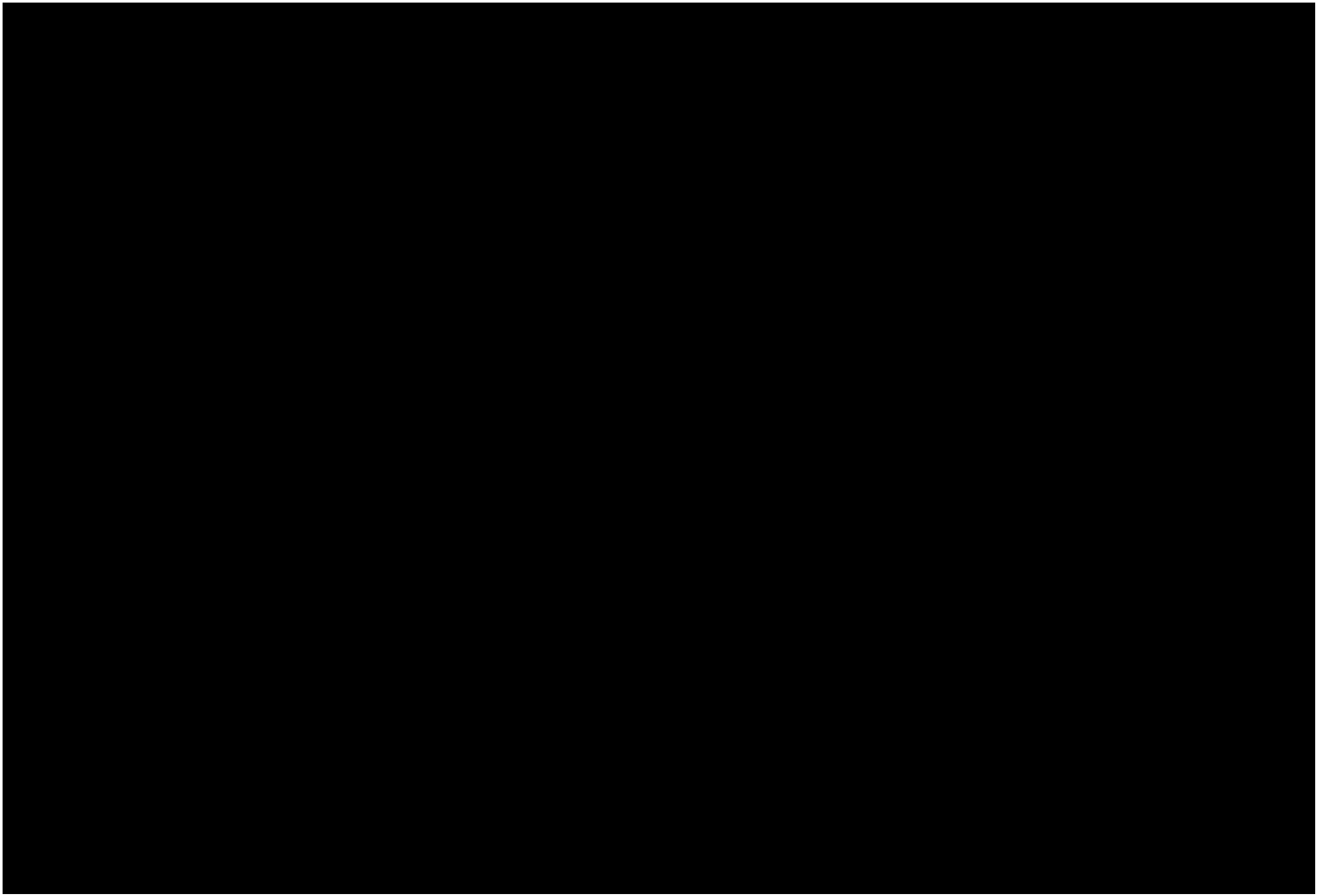
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Garland Light and Power Company

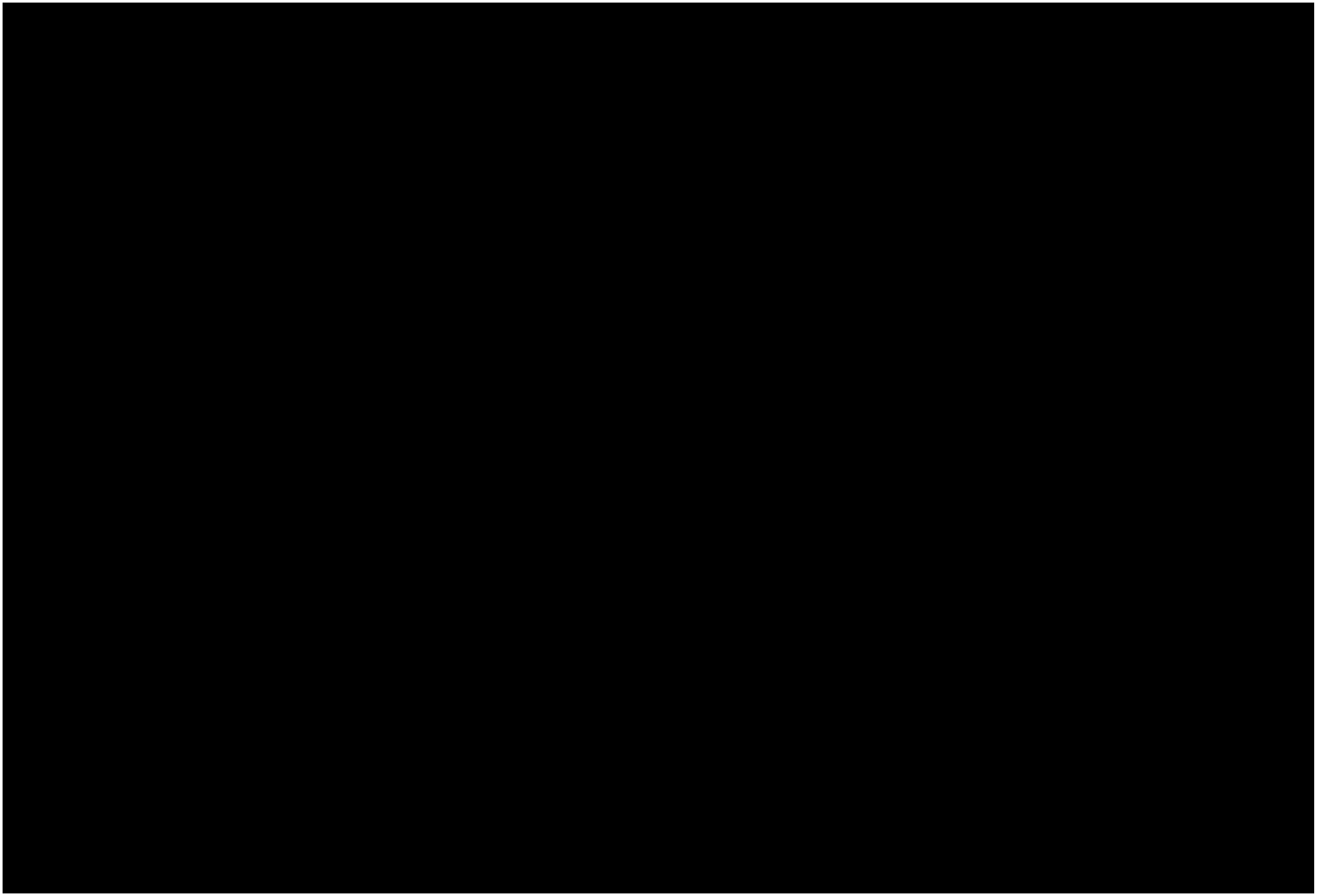
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Garland Light and Power Company

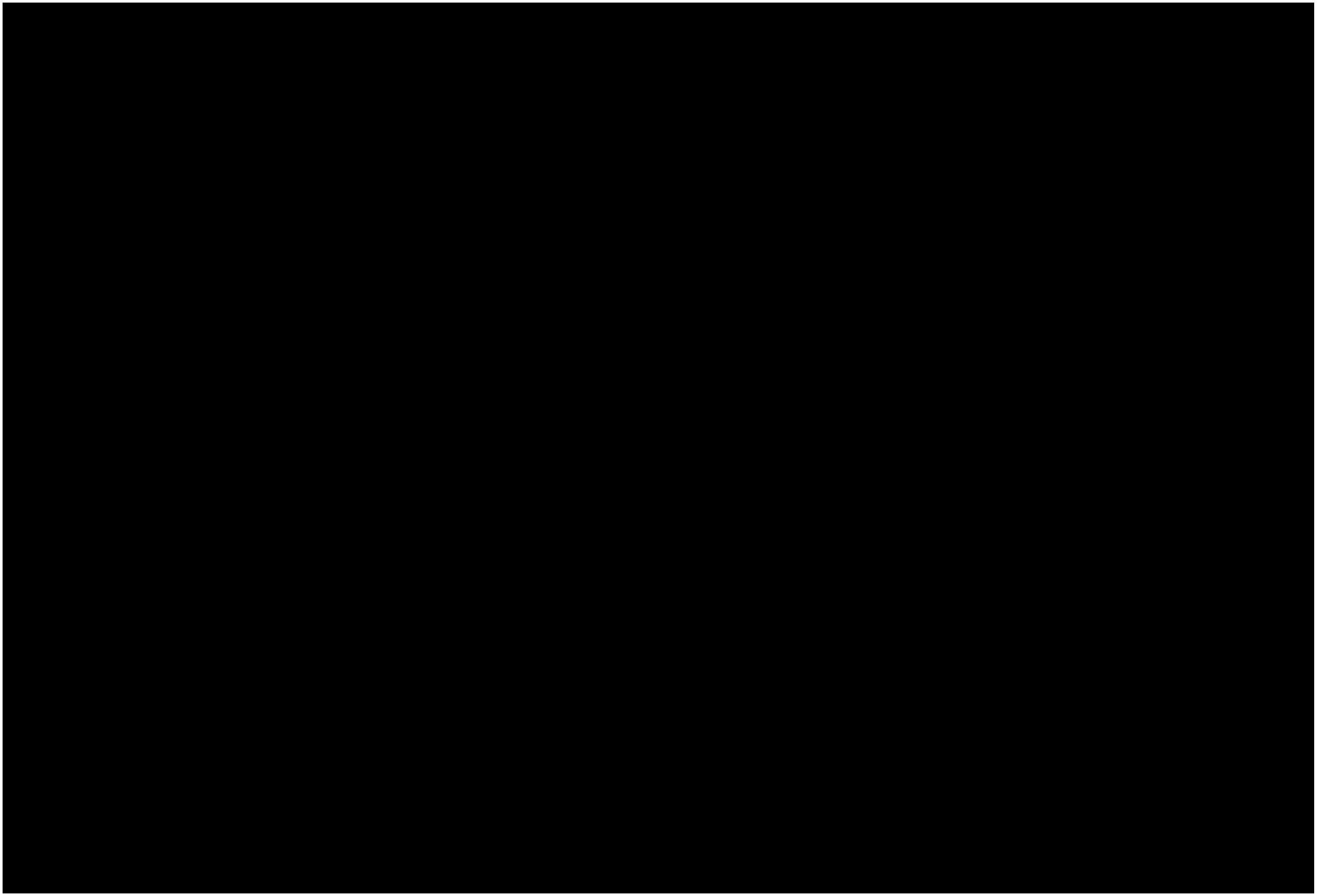
Date of On Peak Day - 10/12/2021



Member Forecasted On Peak Demand Day for November 2021

Garland Light and Power Company

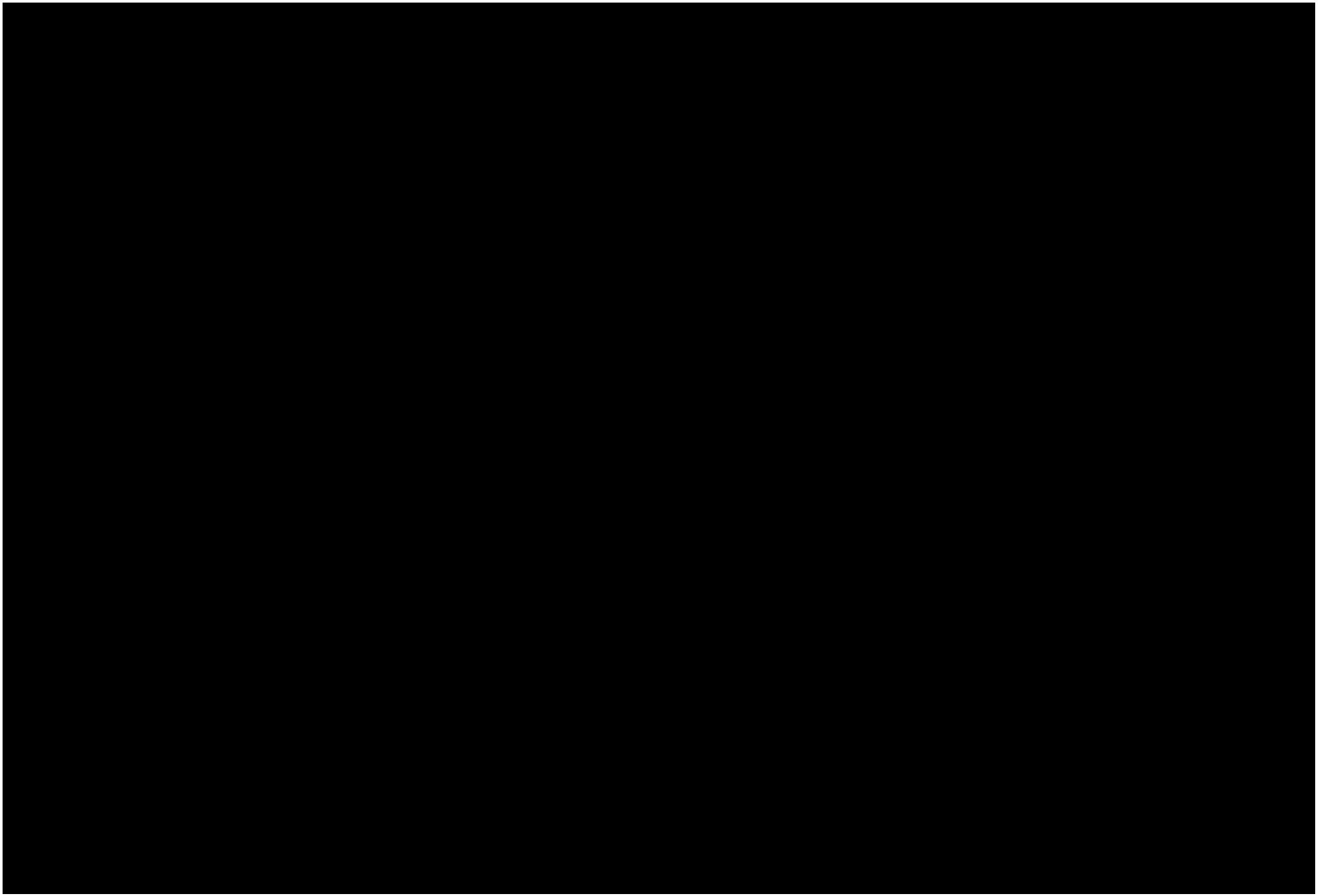
Date of On Peak Day - 11/07/2021



Member Forecasted On Peak Demand Day for December 2021

Garland Light and Power Company

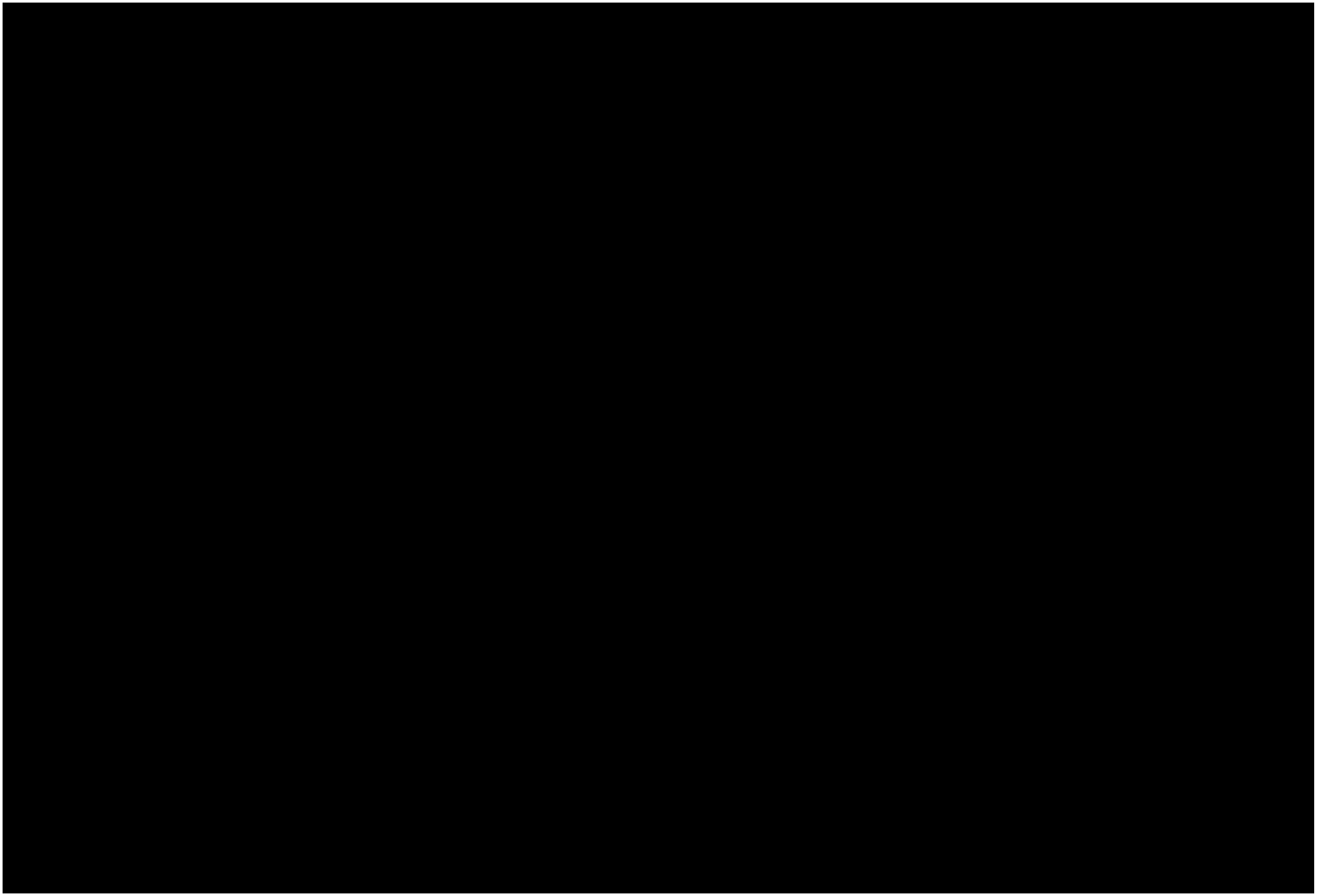
Date of On Peak Day - 12/02/2021



Member Forecasted On Peak Demand Day for January 2021

Highline Electric Association

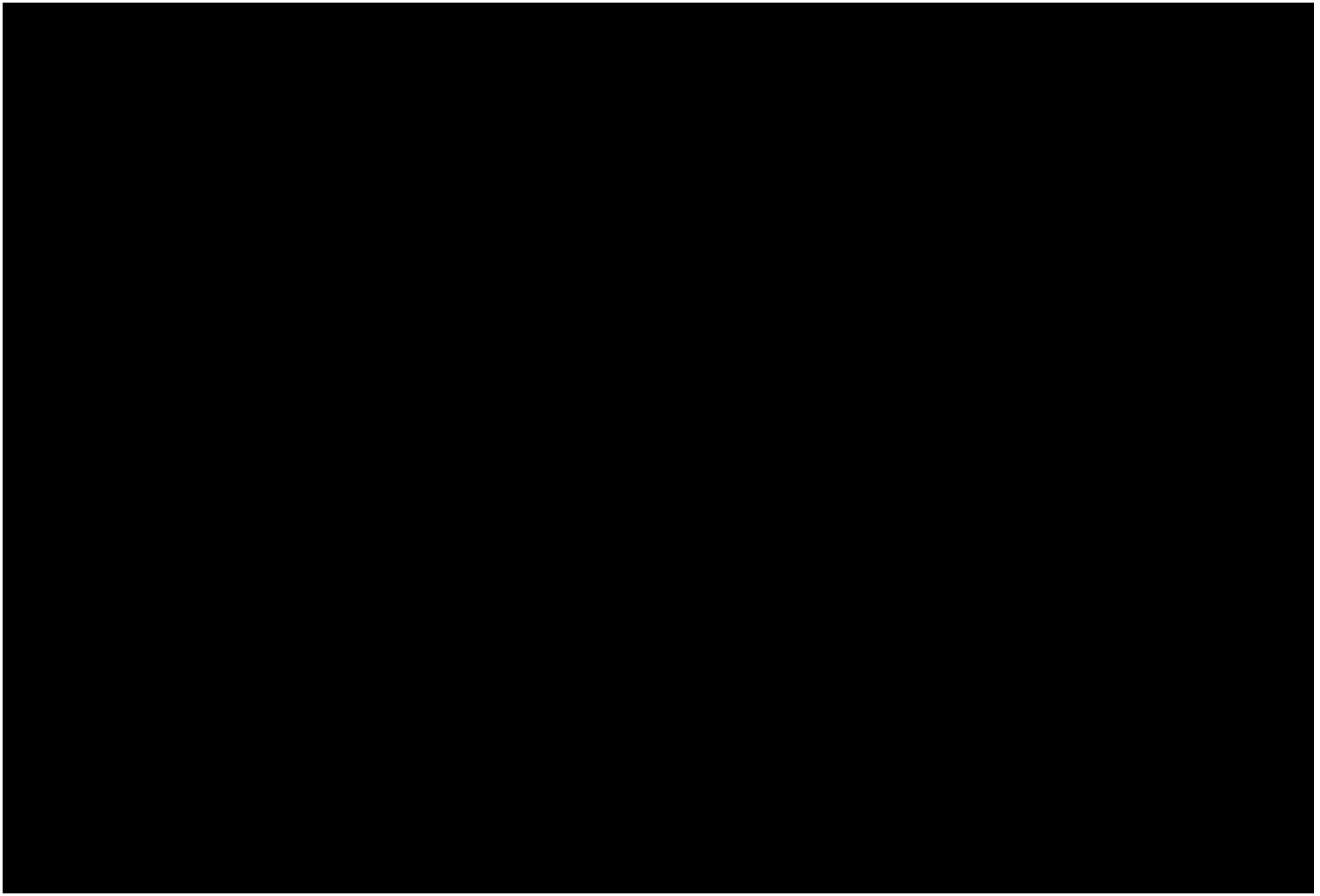
Date of On Peak Day - 01/30/2021



Member Forecasted On Peak Demand Day for February 2021

Highline Electric Association

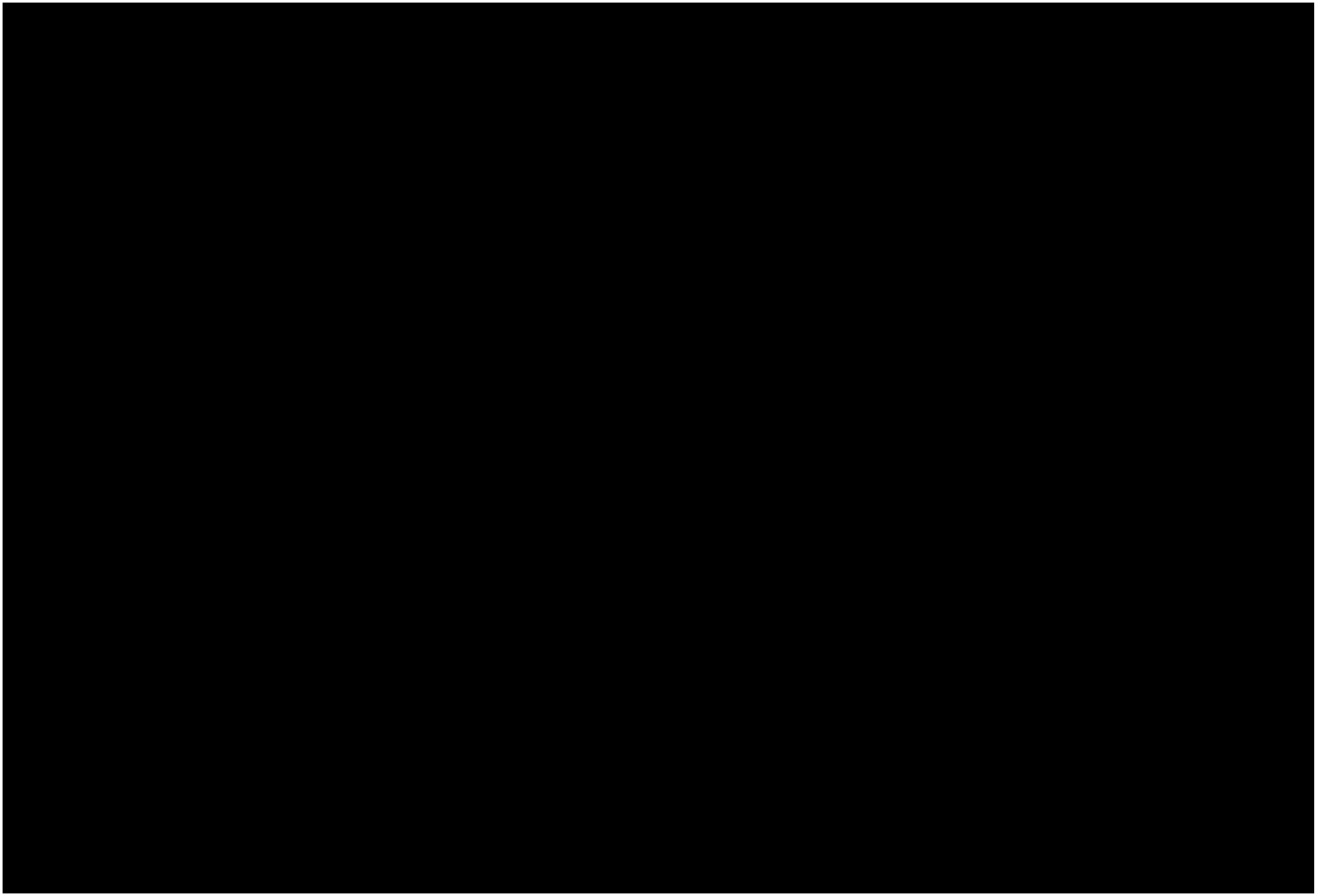
Date of On Peak Day - 02/26/2021



Member Forecasted On Peak Demand Day for March 2021

Highline Electric Association

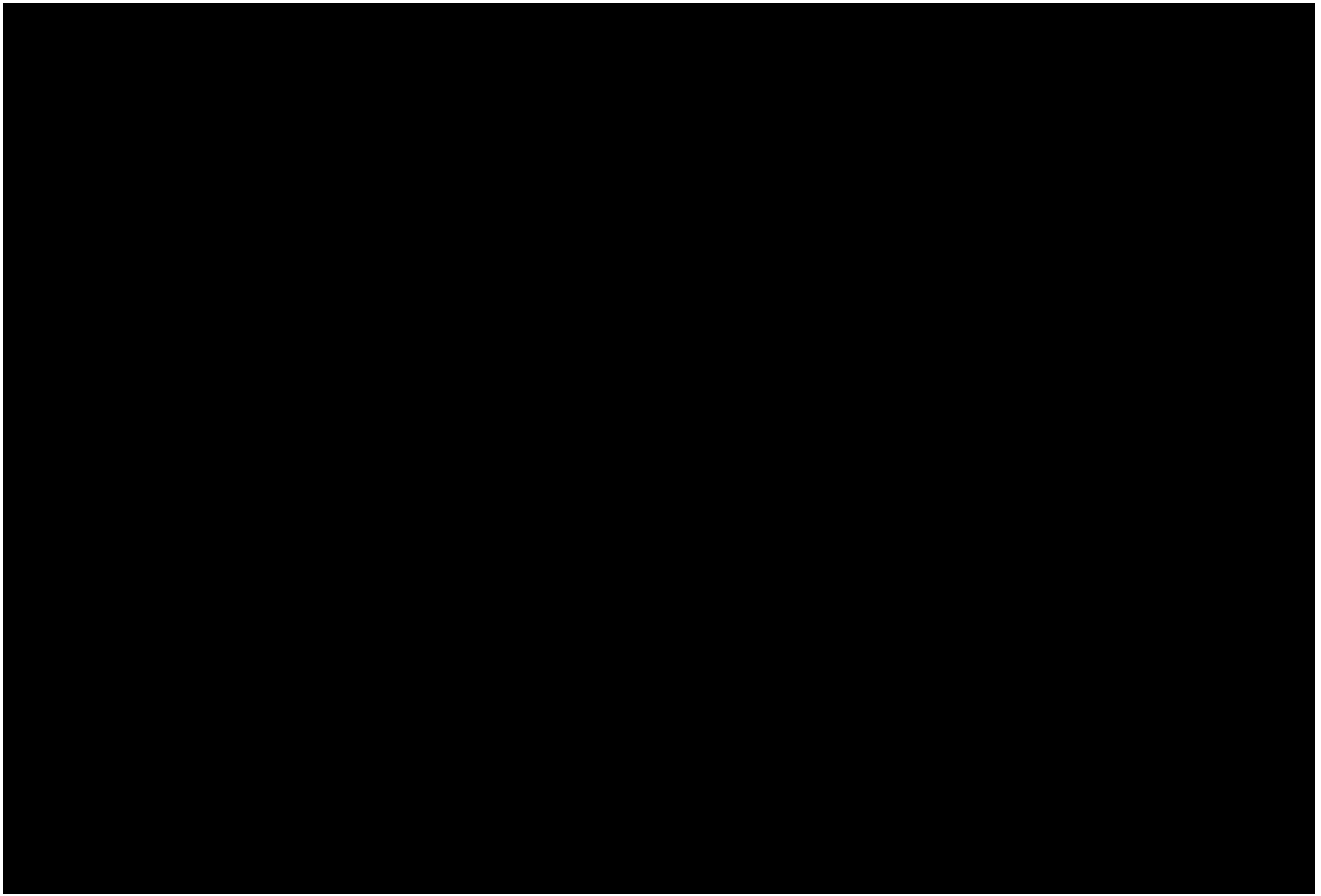
Date of On Peak Day - 03/19/2021



Member Forecasted On Peak Demand Day for April 2021

Highline Electric Association

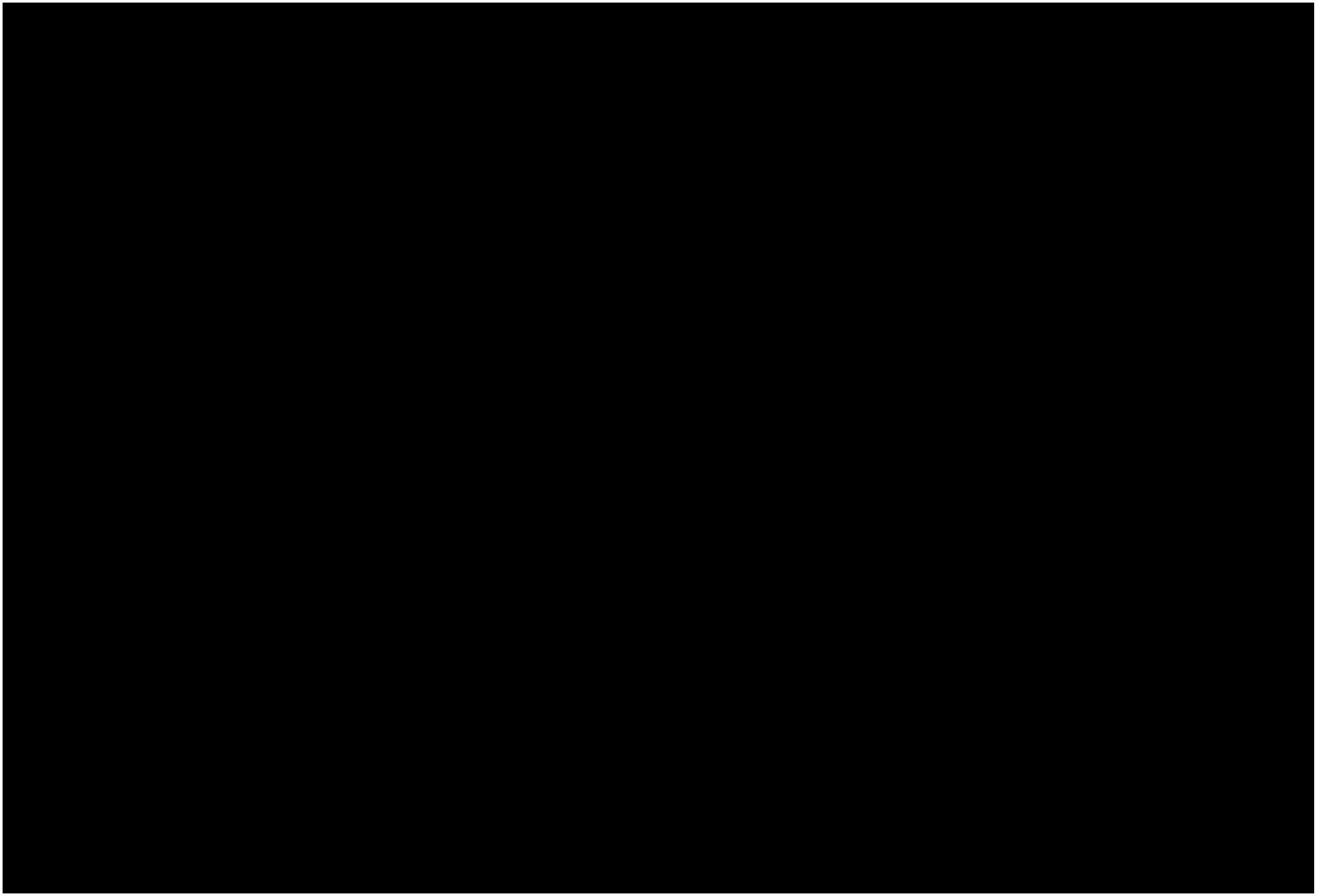
Date of On Peak Day - 04/30/2021



Member Forecasted On Peak Demand Day for May 2021

Highline Electric Association

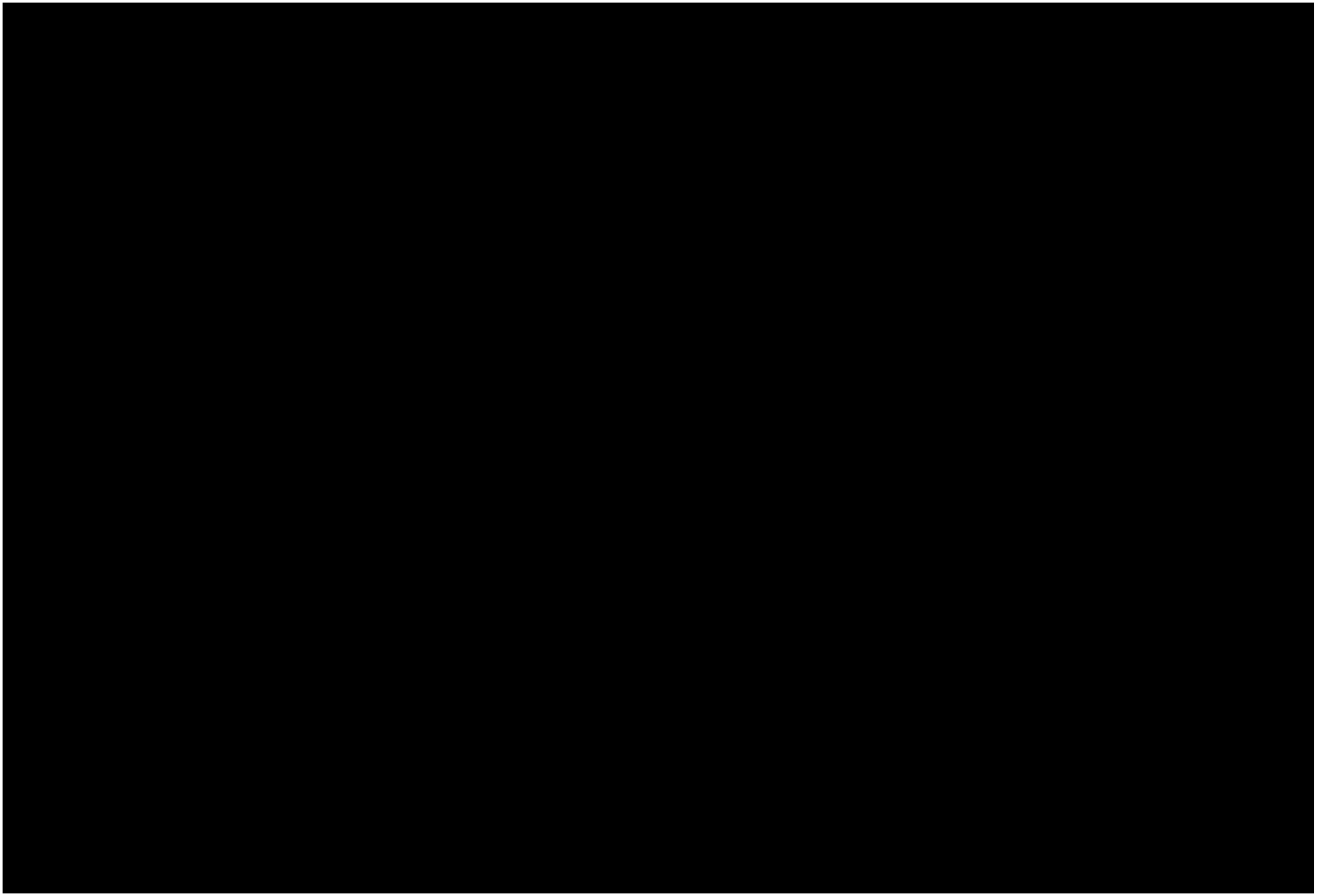
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Highline Electric Association

Date of On Peak Day - 06/11/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
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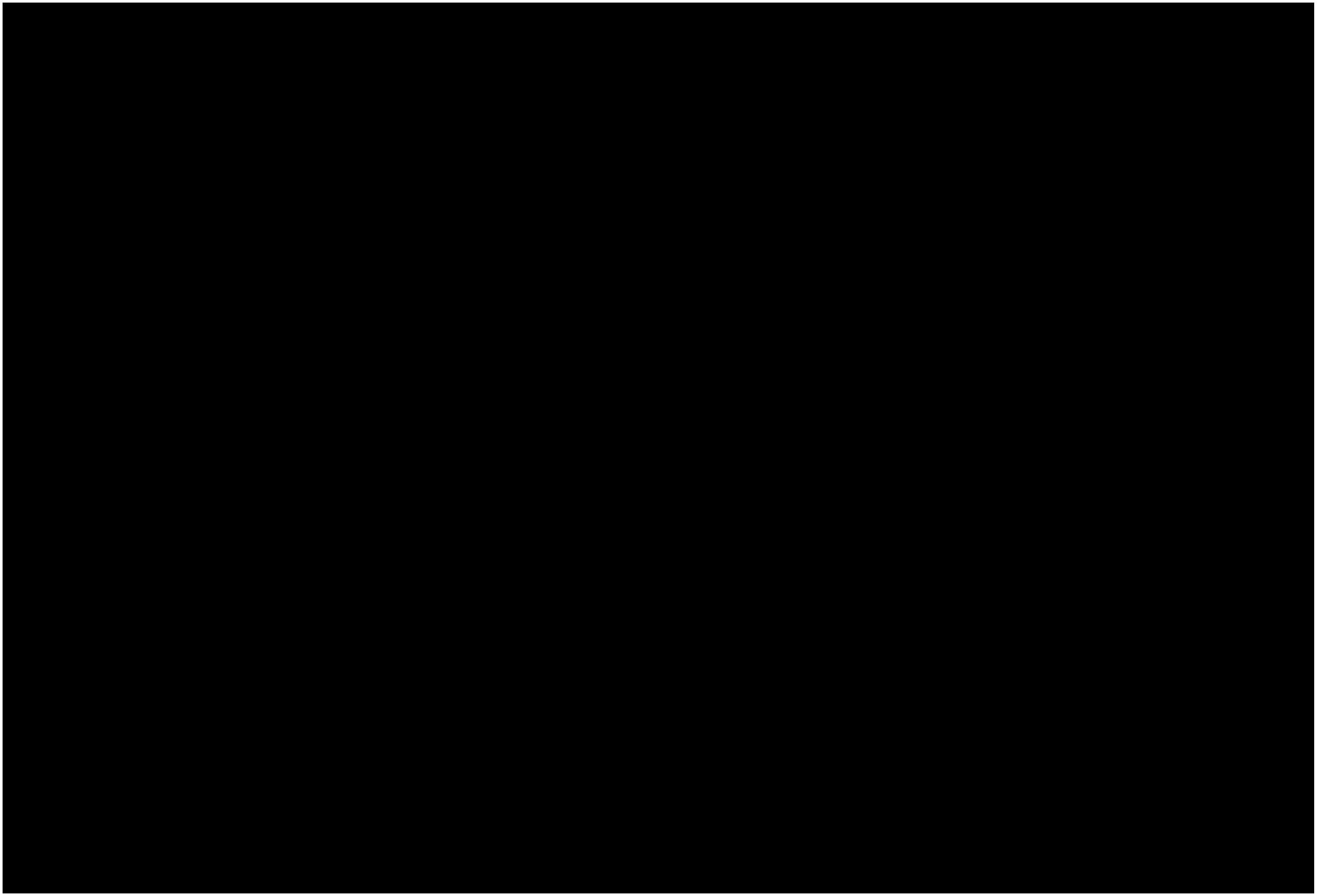
Member Forecasted On Peak Demand Day for July 2021

Highline Electric Association

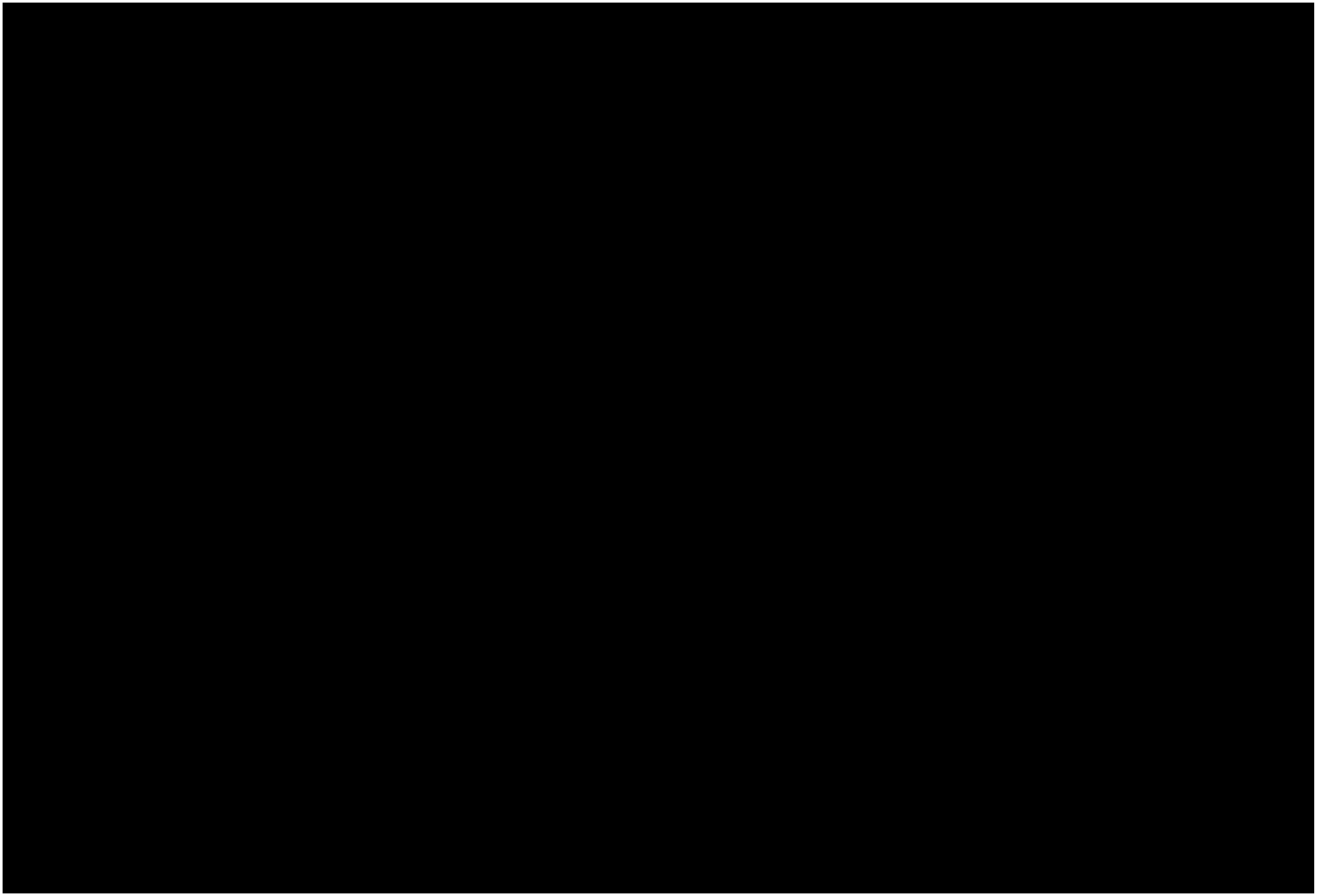
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Highline Electric Association

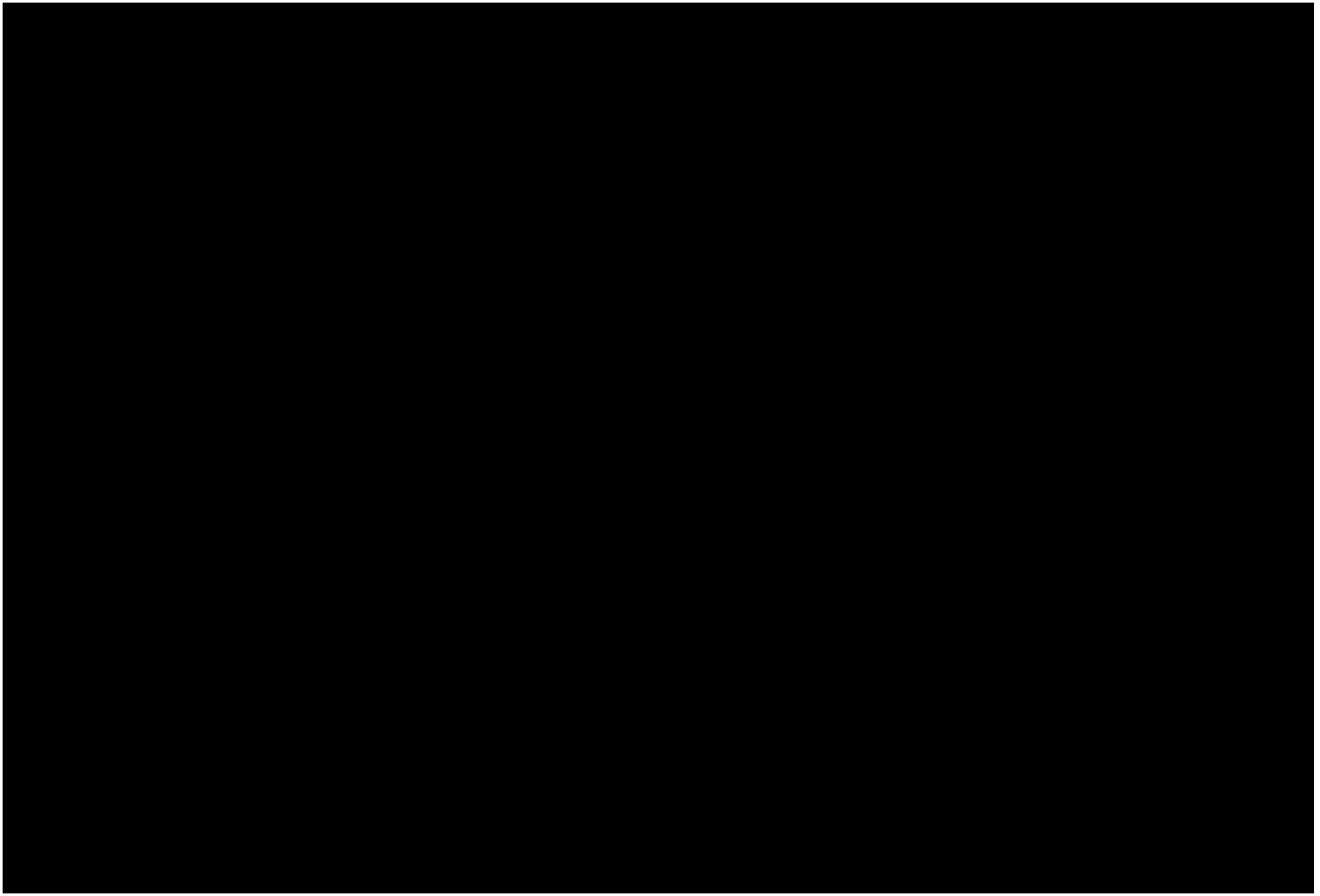
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Highline Electric Association

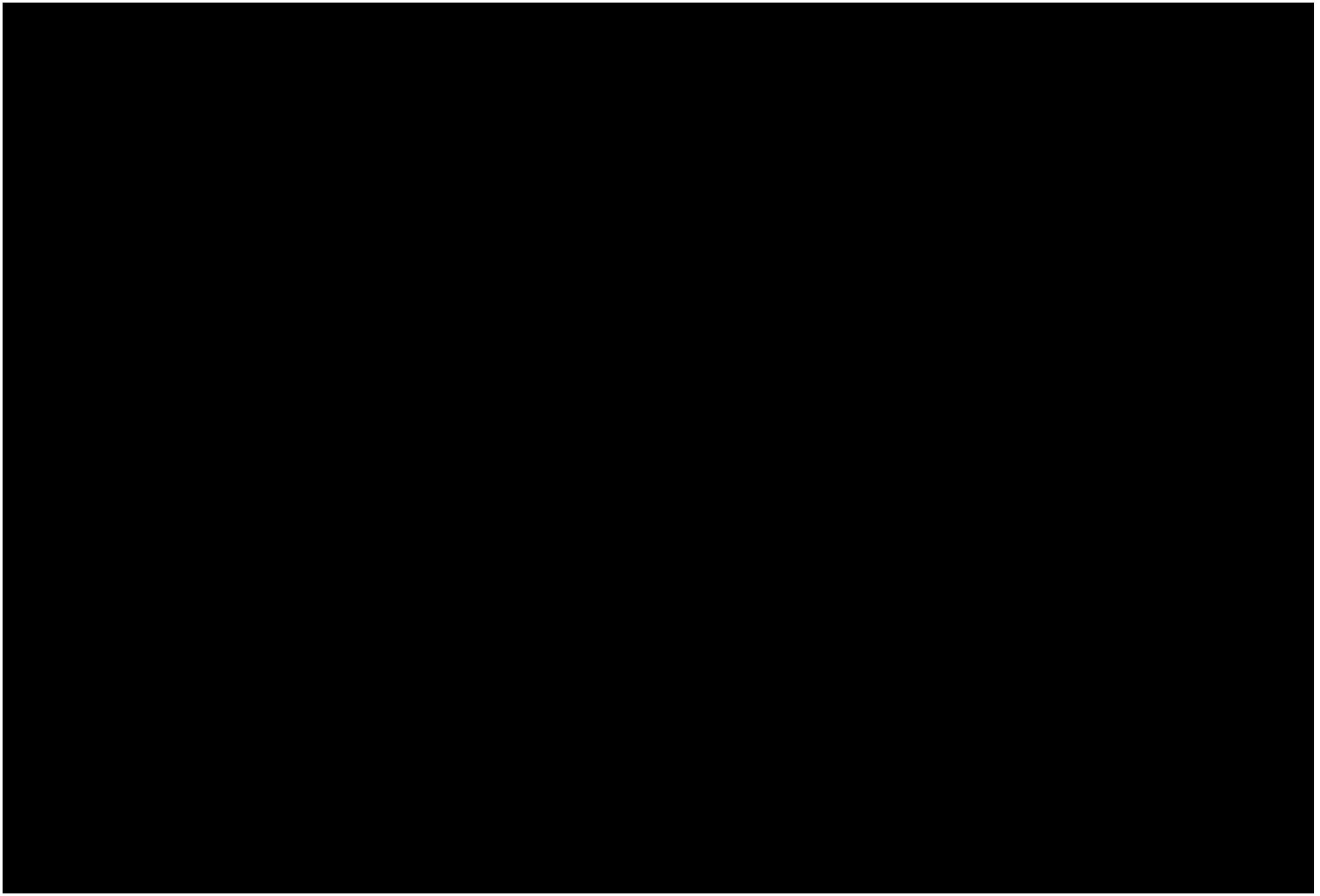
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Highline Electric Association

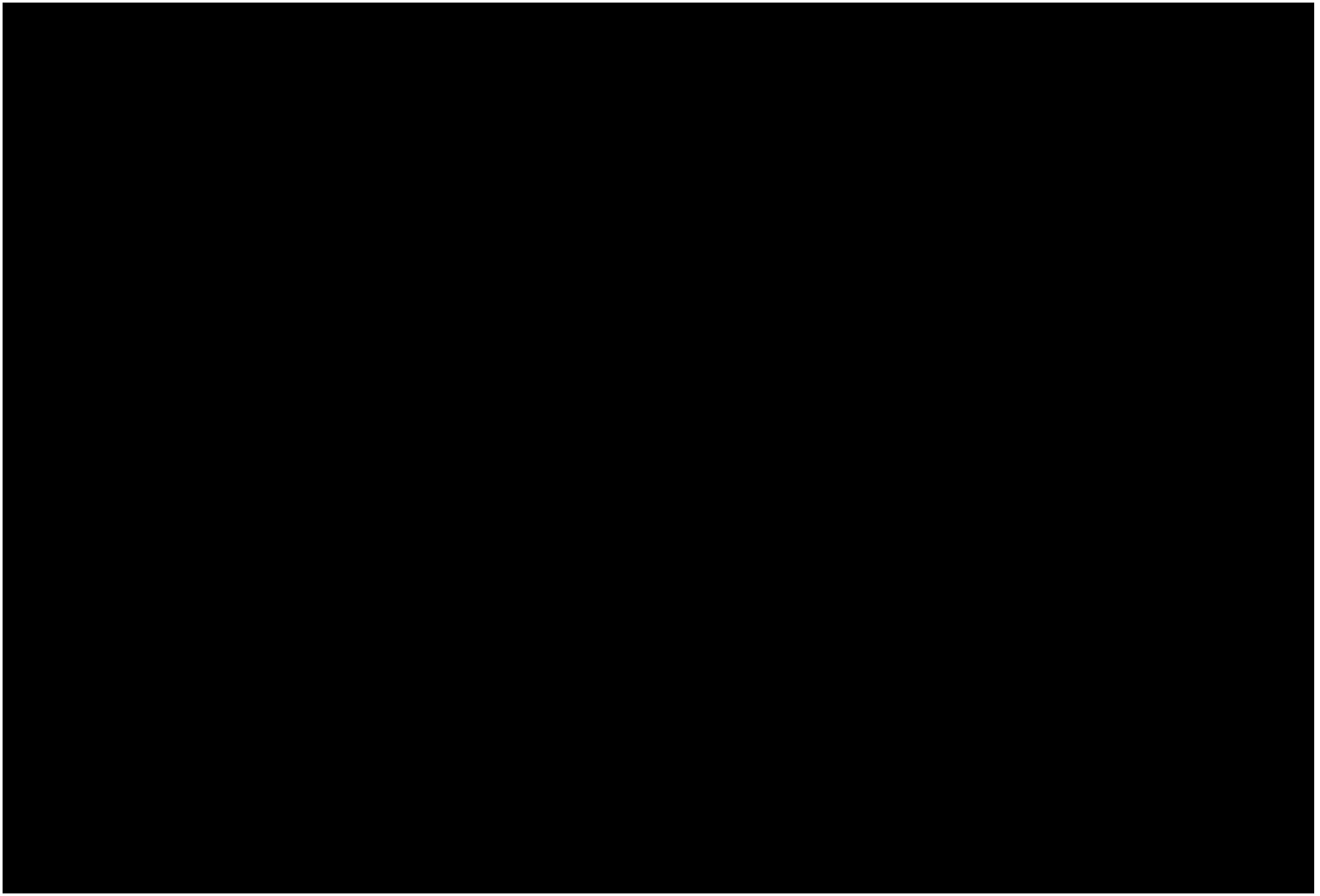
Date of On Peak Day - 10/17/2021



Member Forecasted On Peak Demand Day for November 2021

Highline Electric Association

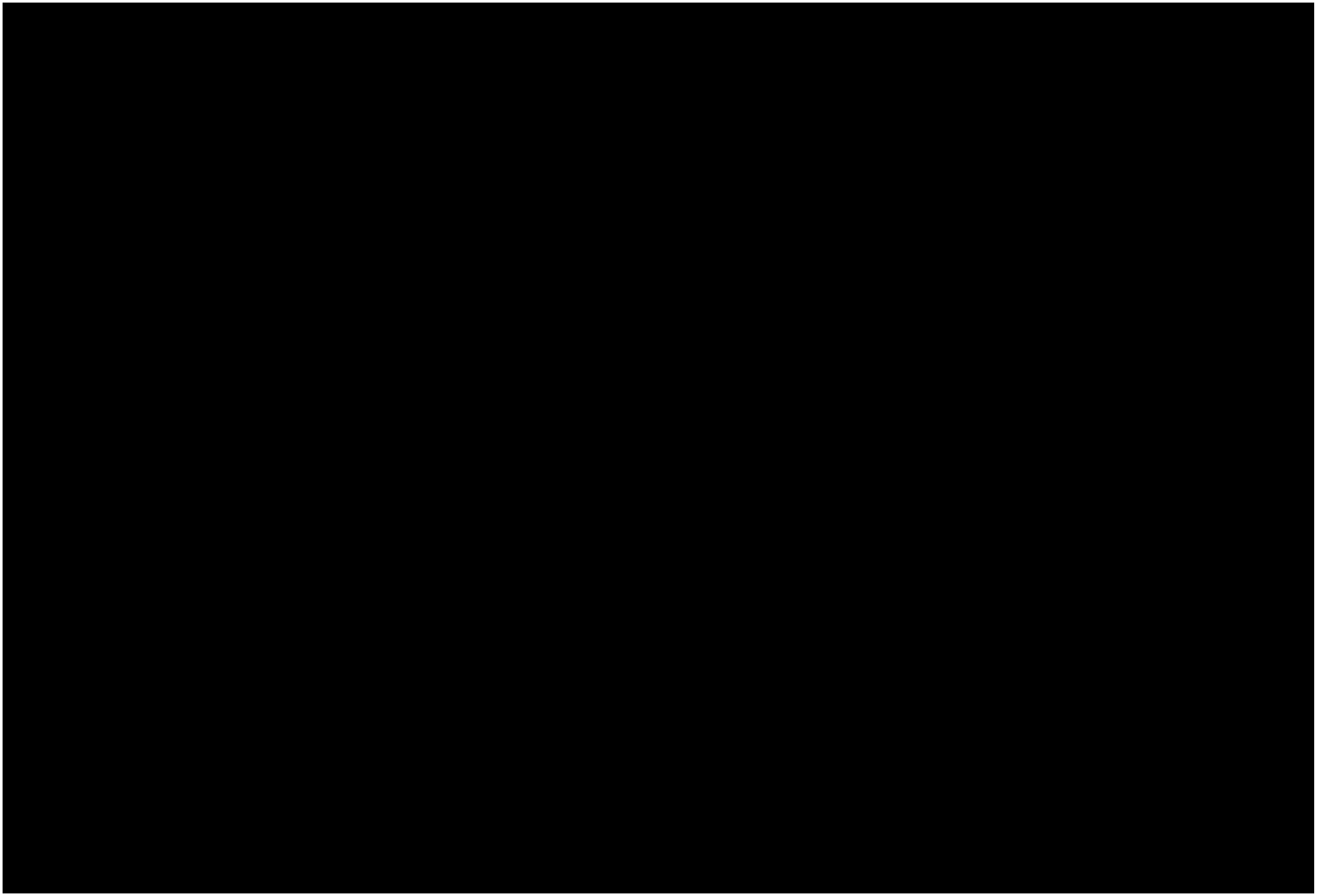
Date of On Peak Day - 11/17/2021



Member Forecasted On Peak Demand Day for December 2021

Highline Electric Association

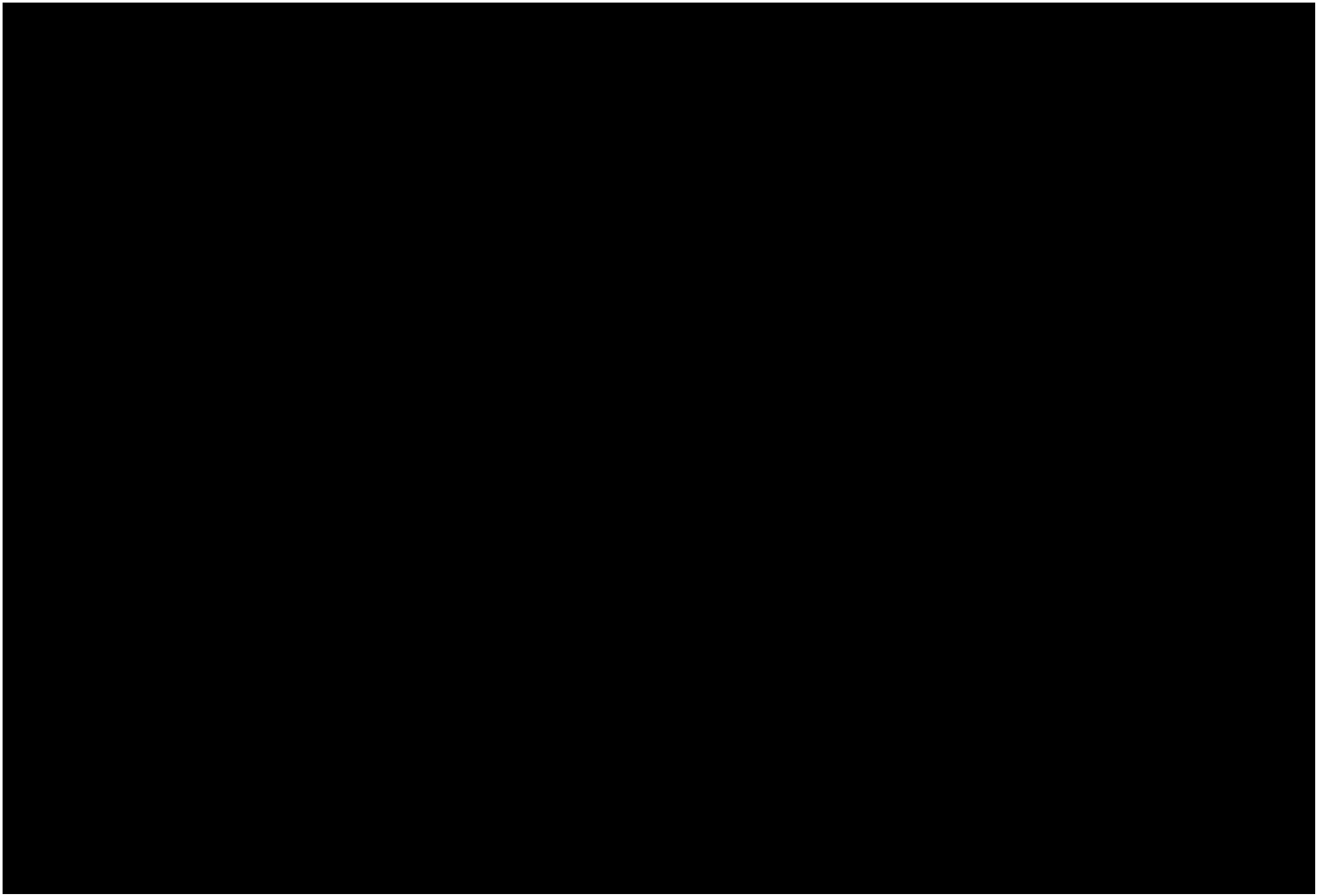
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

High Plains Power, Inc.

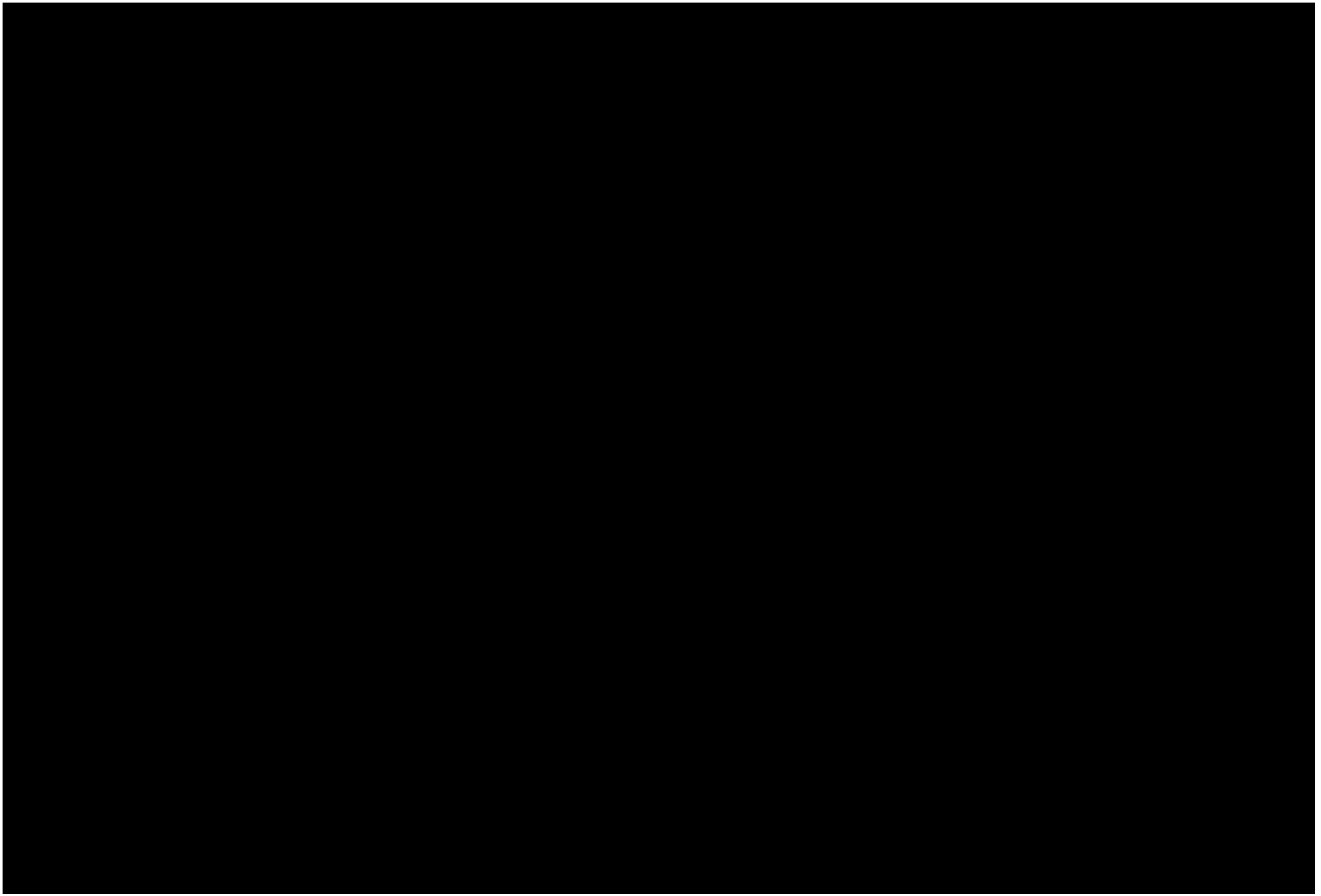
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

High Plains Power, Inc.

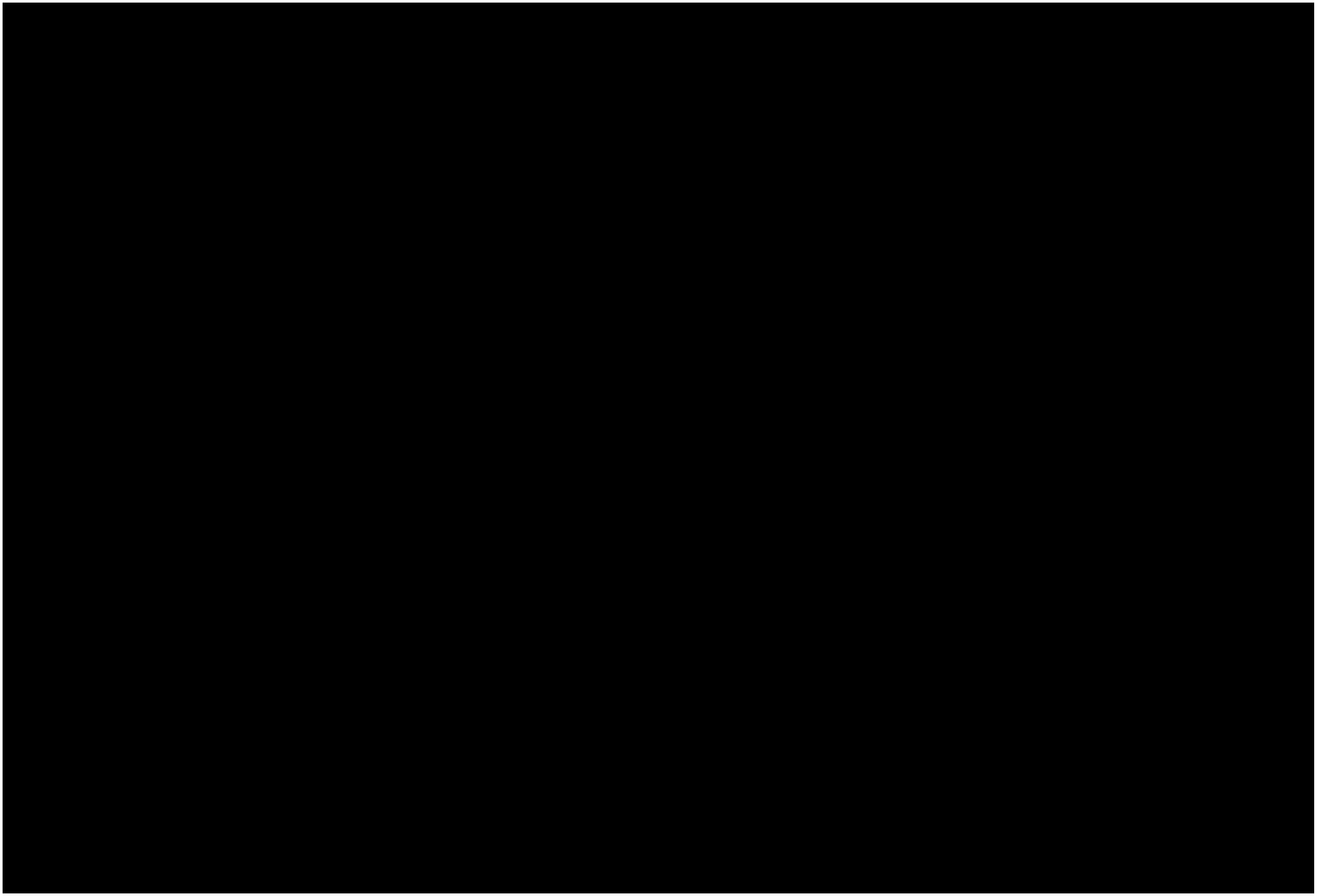
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

High Plains Power, Inc.

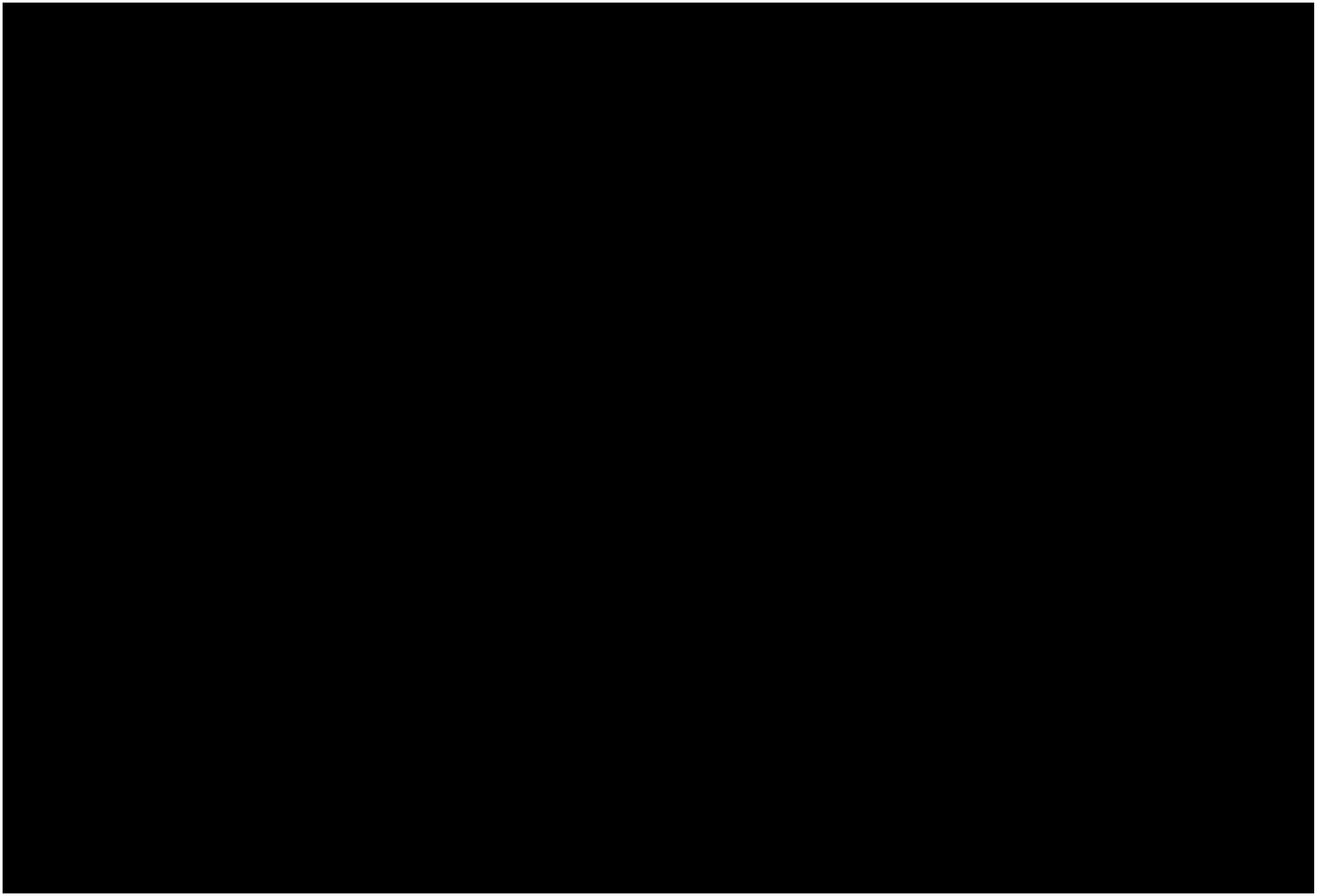
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

High Plains Power, Inc.

Date of On Peak Day - 04/09/2021



Member Forecasted On Peak Demand Day for May 2021

High Plains Power, Inc.

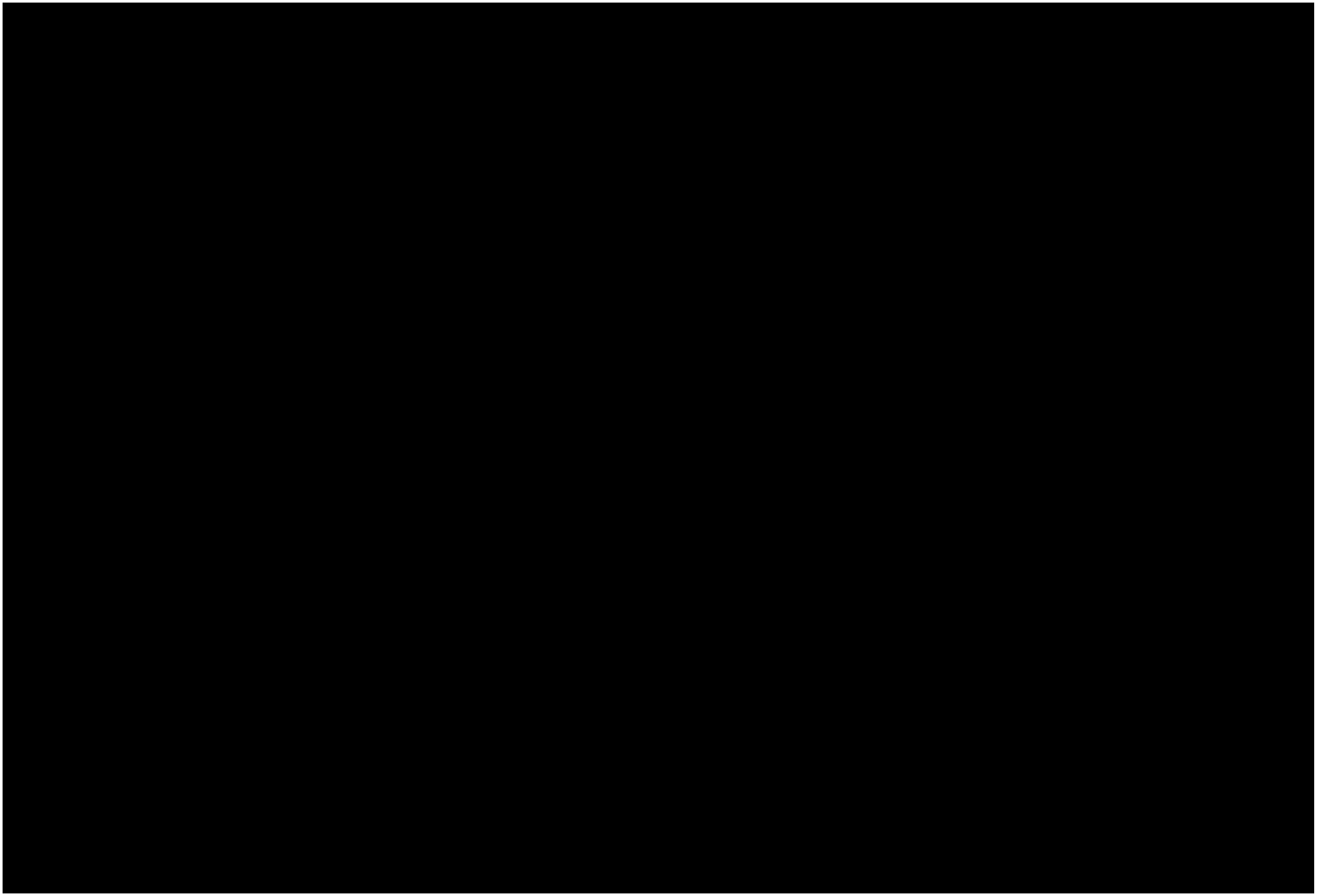
Date of On Peak Day - 05/03/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

High Plains Power, Inc.

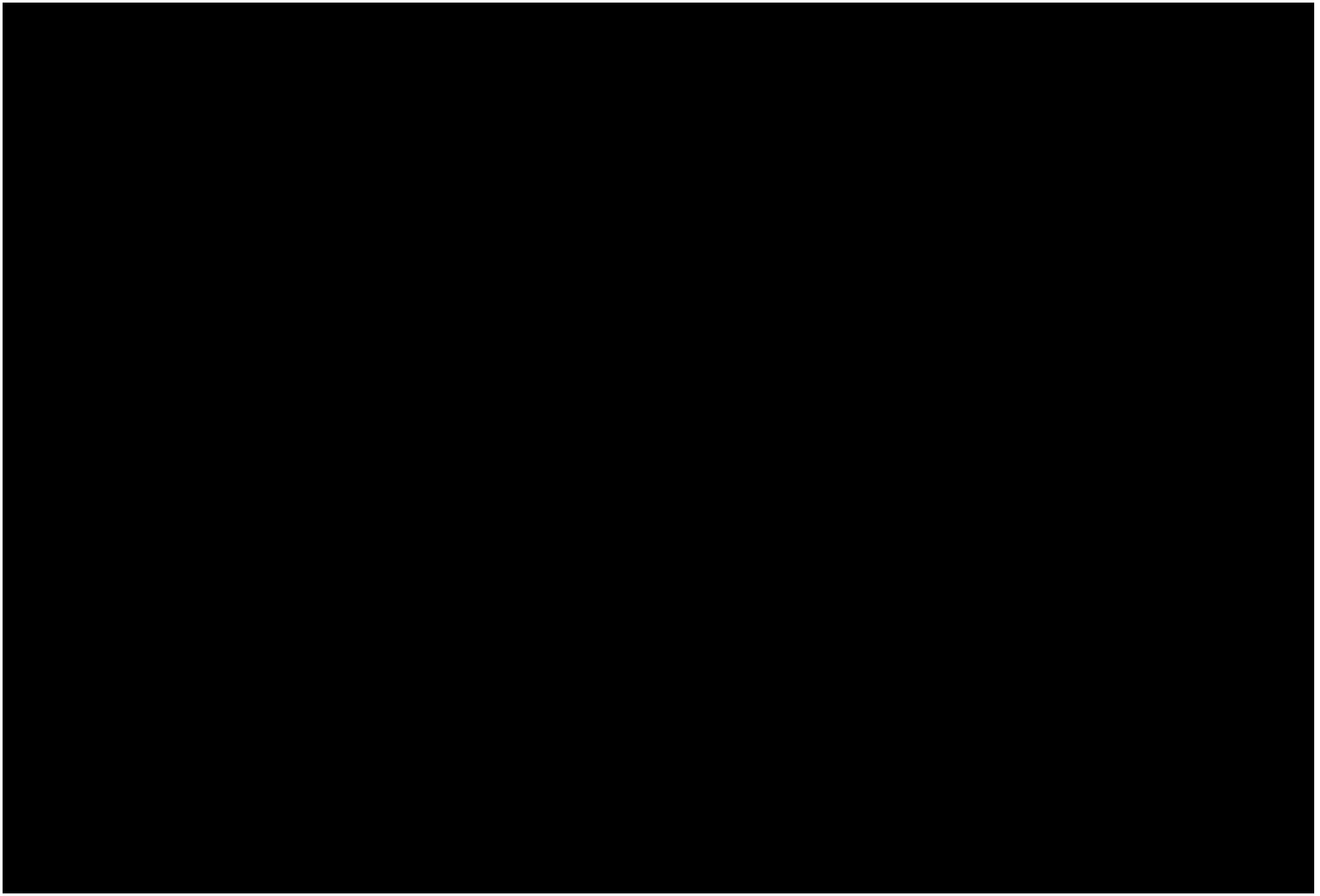
Date of On Peak Day - 06/09/2021



Member Forecasted On Peak Demand Day for July 2021

High Plains Power, Inc.

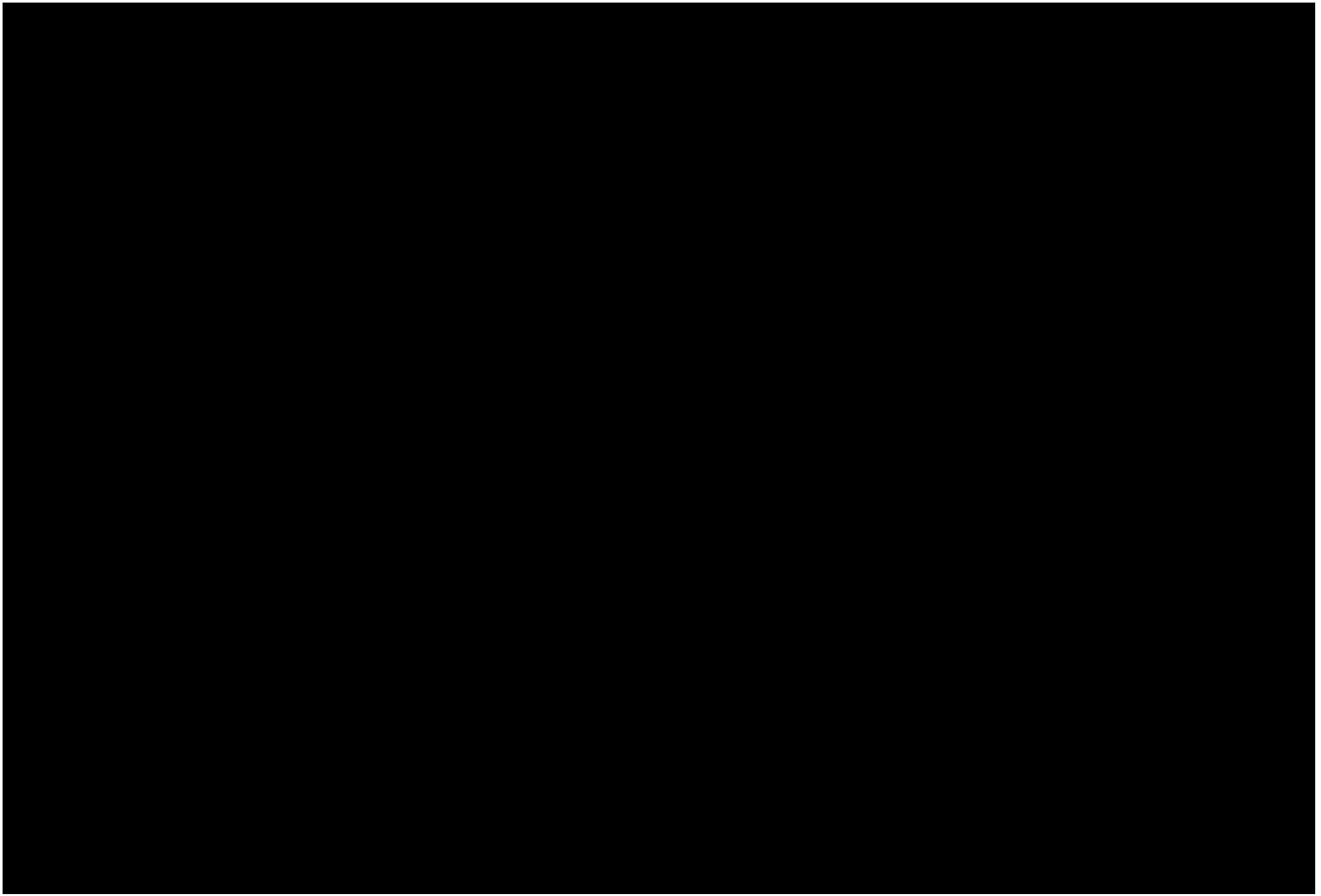
Date of On Peak Day - 07/20/2021



Member Forecasted On Peak Demand Day for August 2021

High Plains Power, Inc.

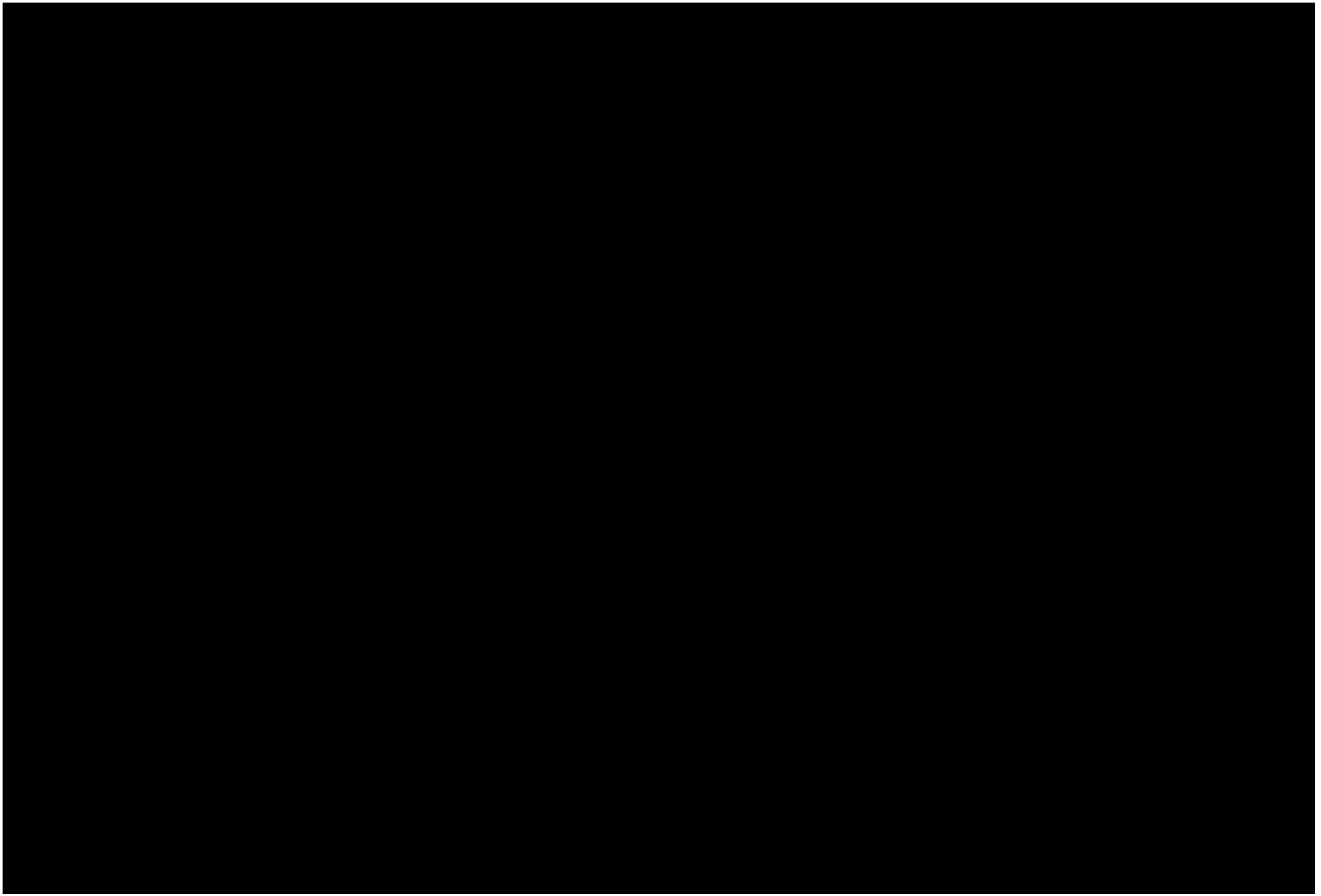
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

High Plains Power, Inc.

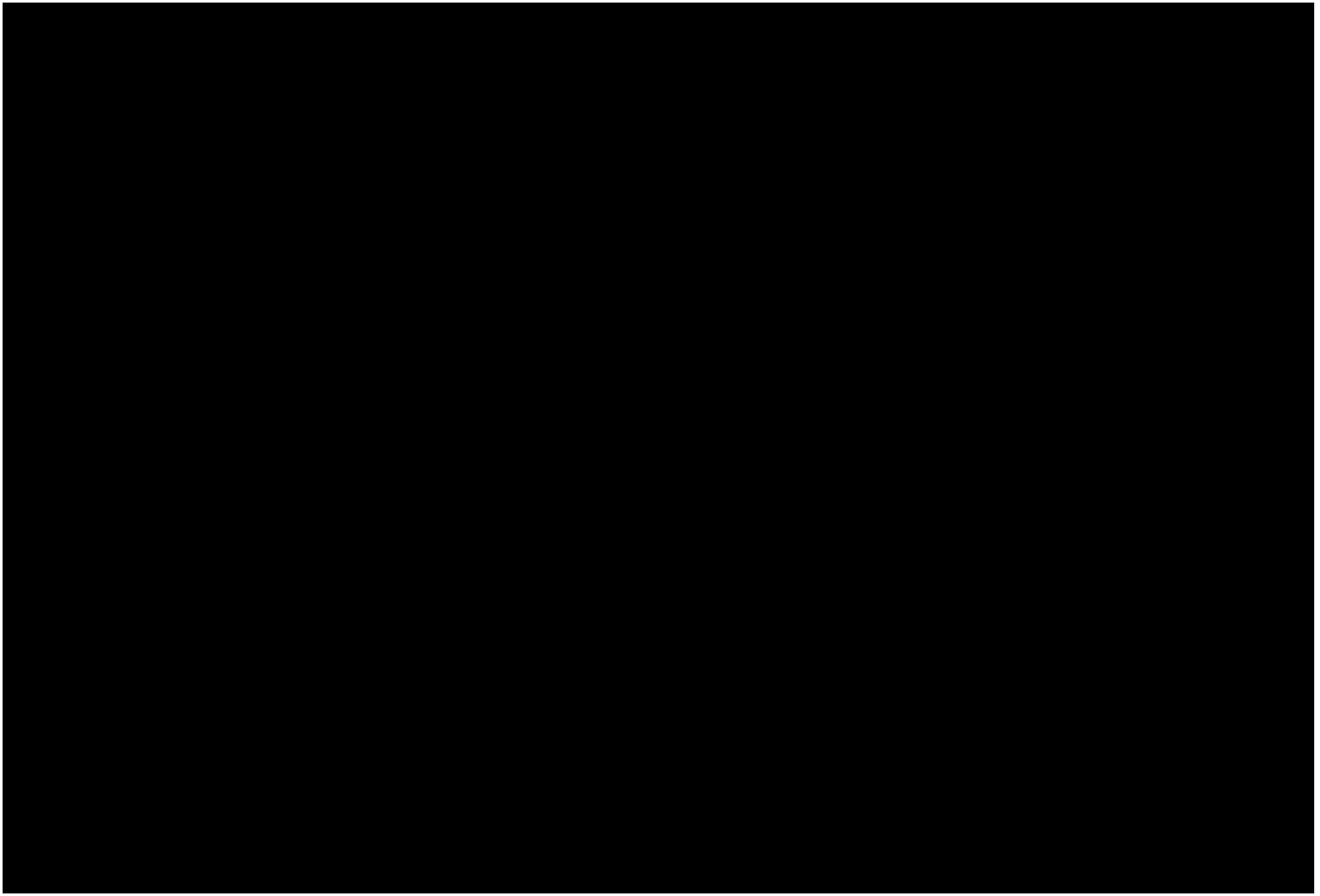
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

High Plains Power, Inc.

Date of On Peak Day - 10/30/2021



Member Forecasted On Peak Demand Day for November 2021

High Plains Power, Inc.

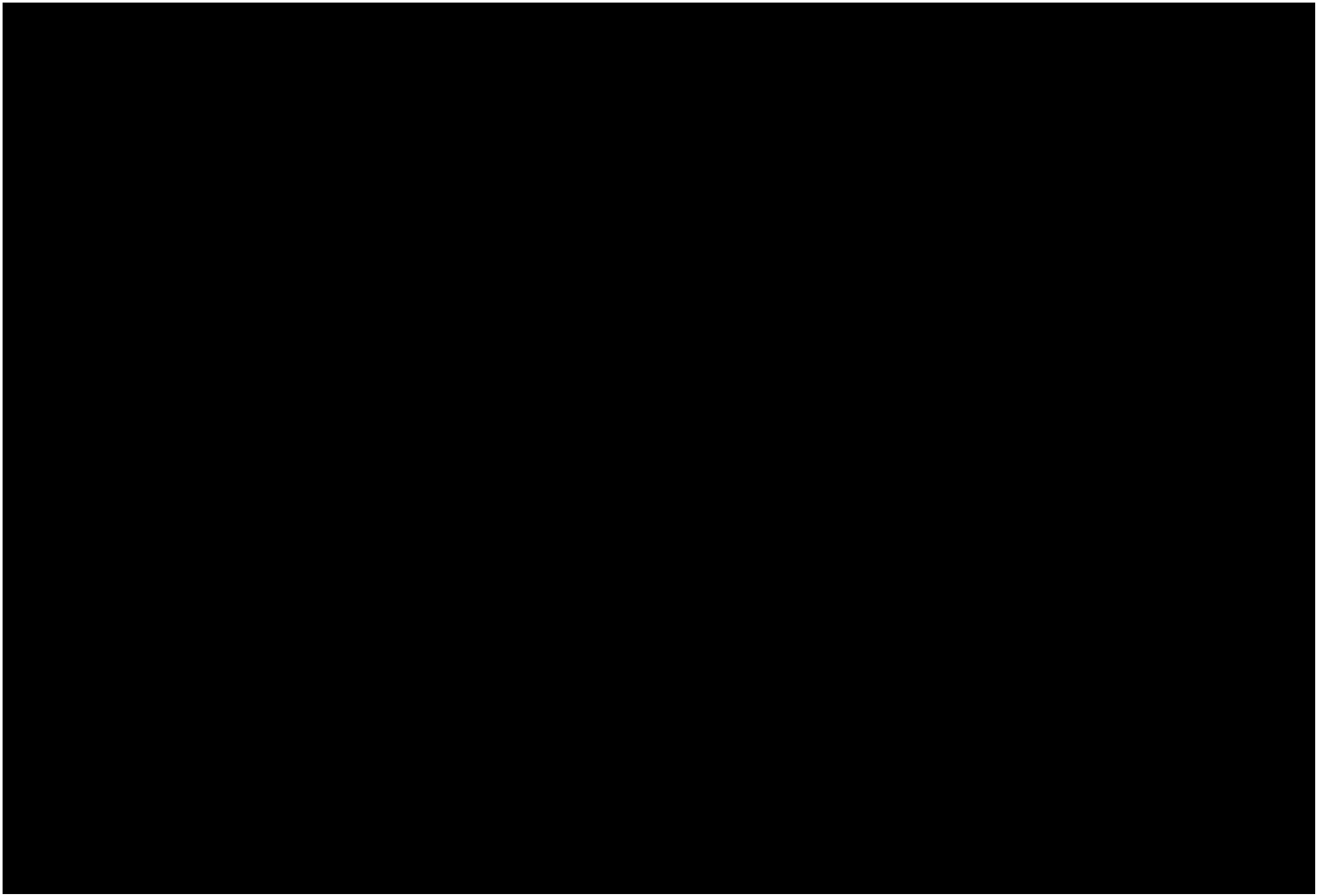
Date of On Peak Day - 11/09/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

High Plains Power, Inc.

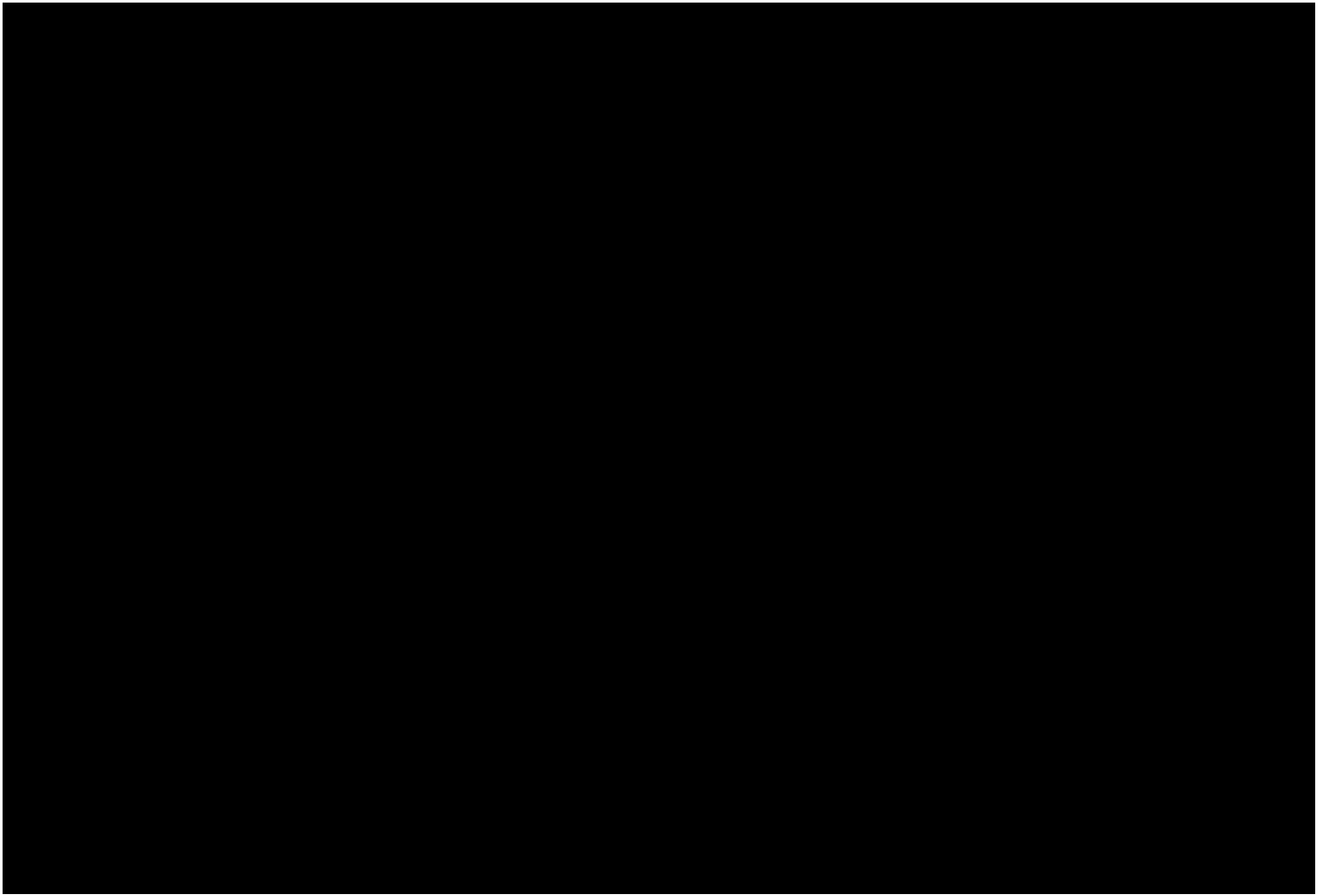
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

High West Energy, Inc.

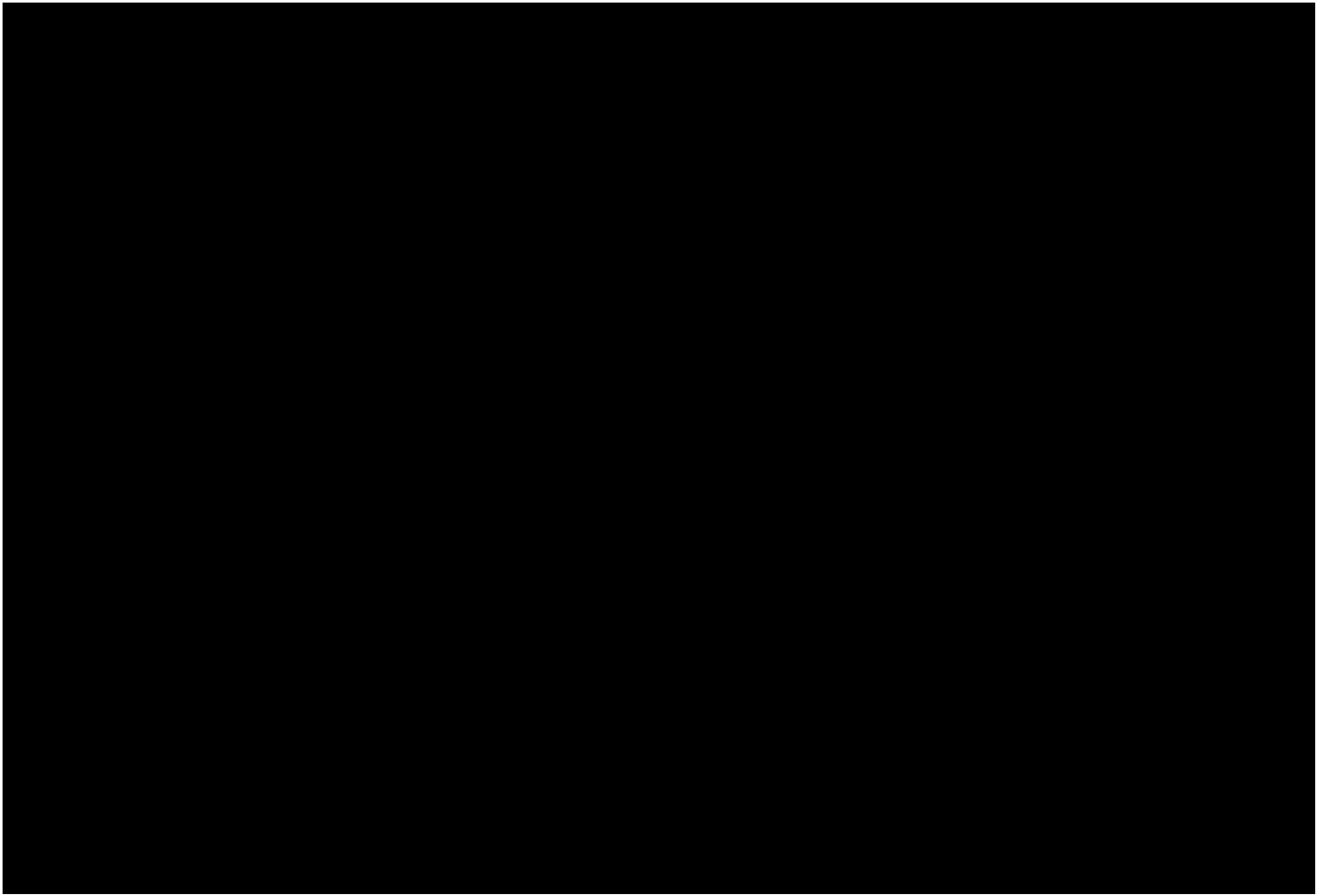
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

High West Energy, Inc.

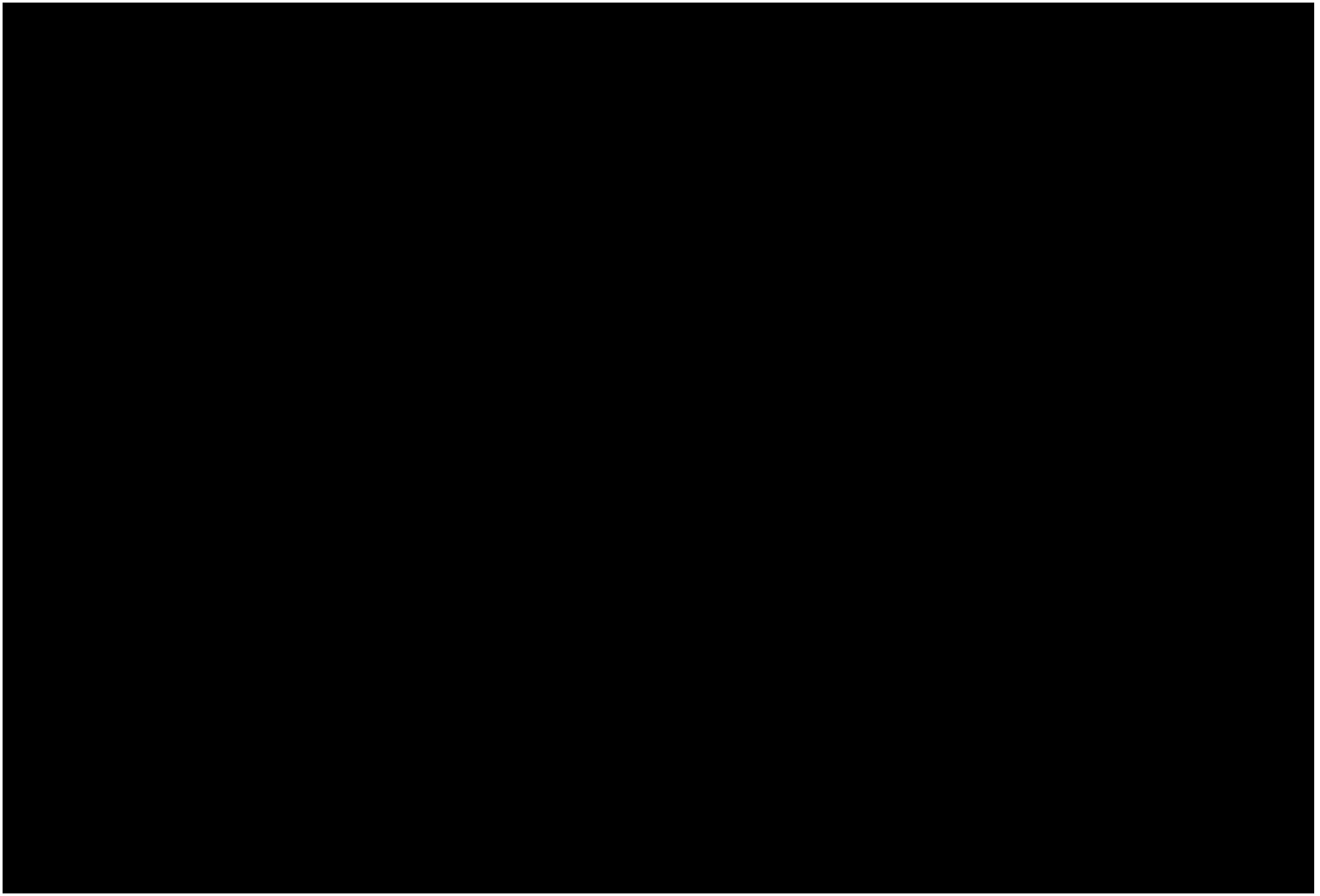
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

High West Energy, Inc.

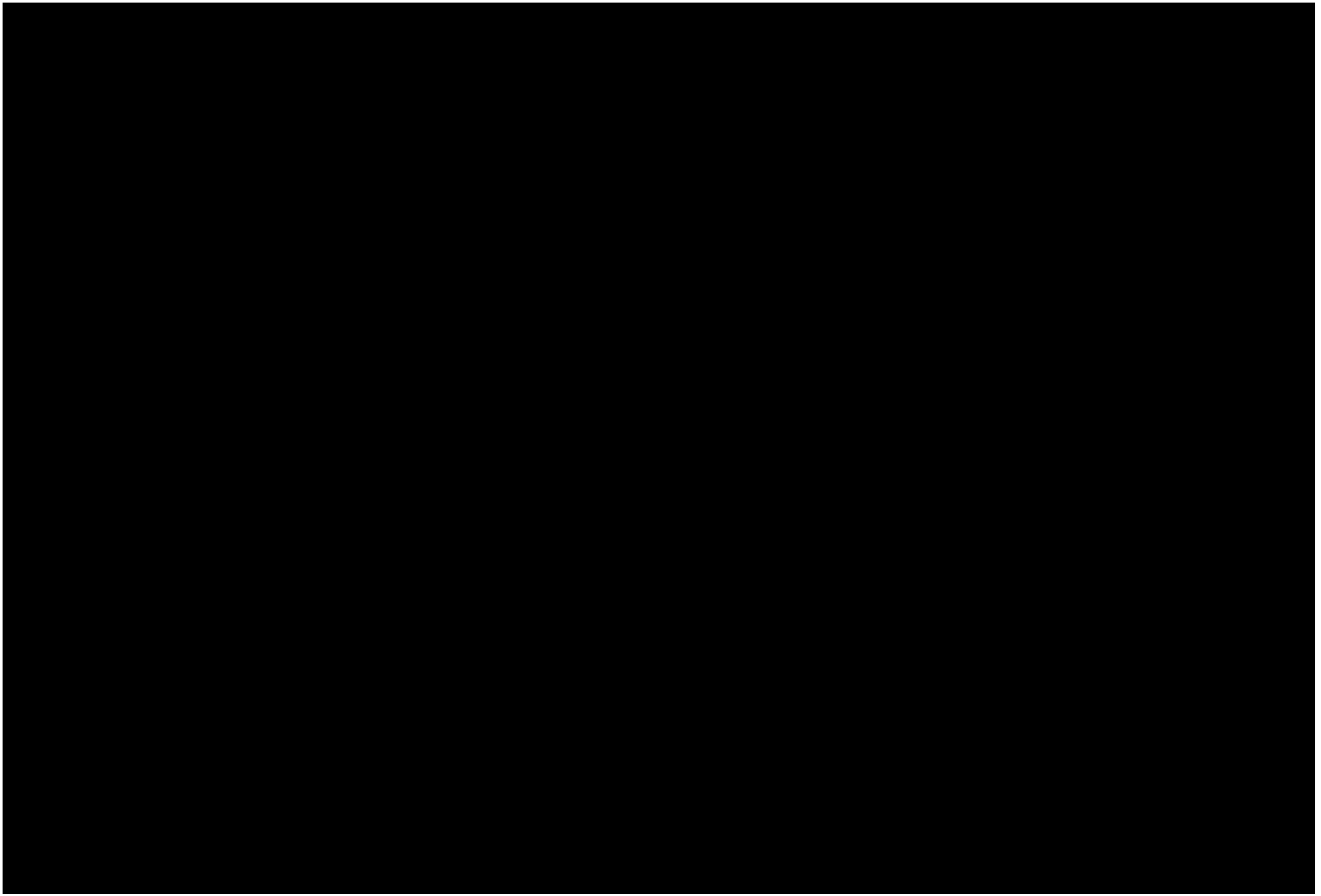
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

High West Energy, Inc.

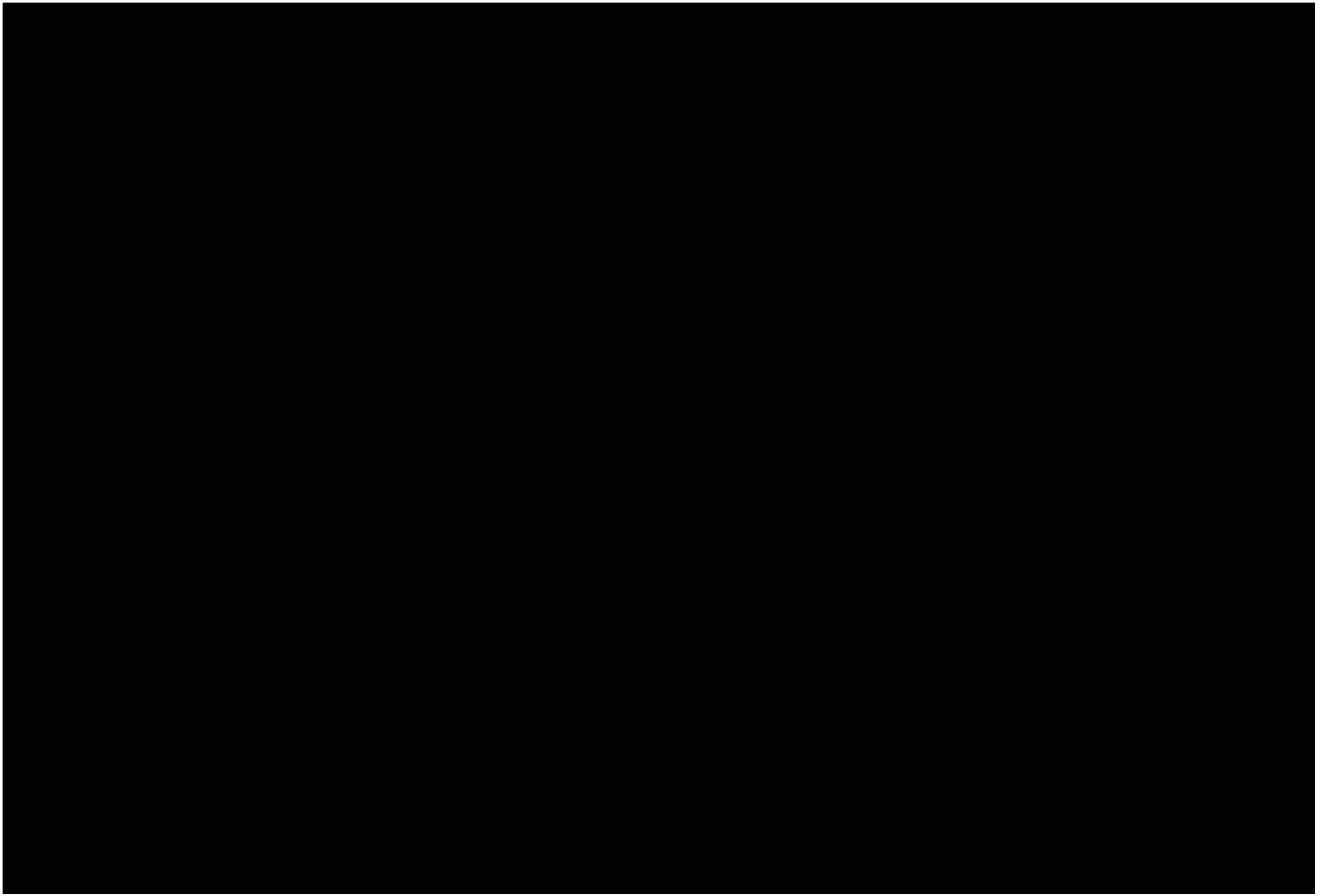
Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

High West Energy, Inc.

Date of On Peak Day - 05/07/2021

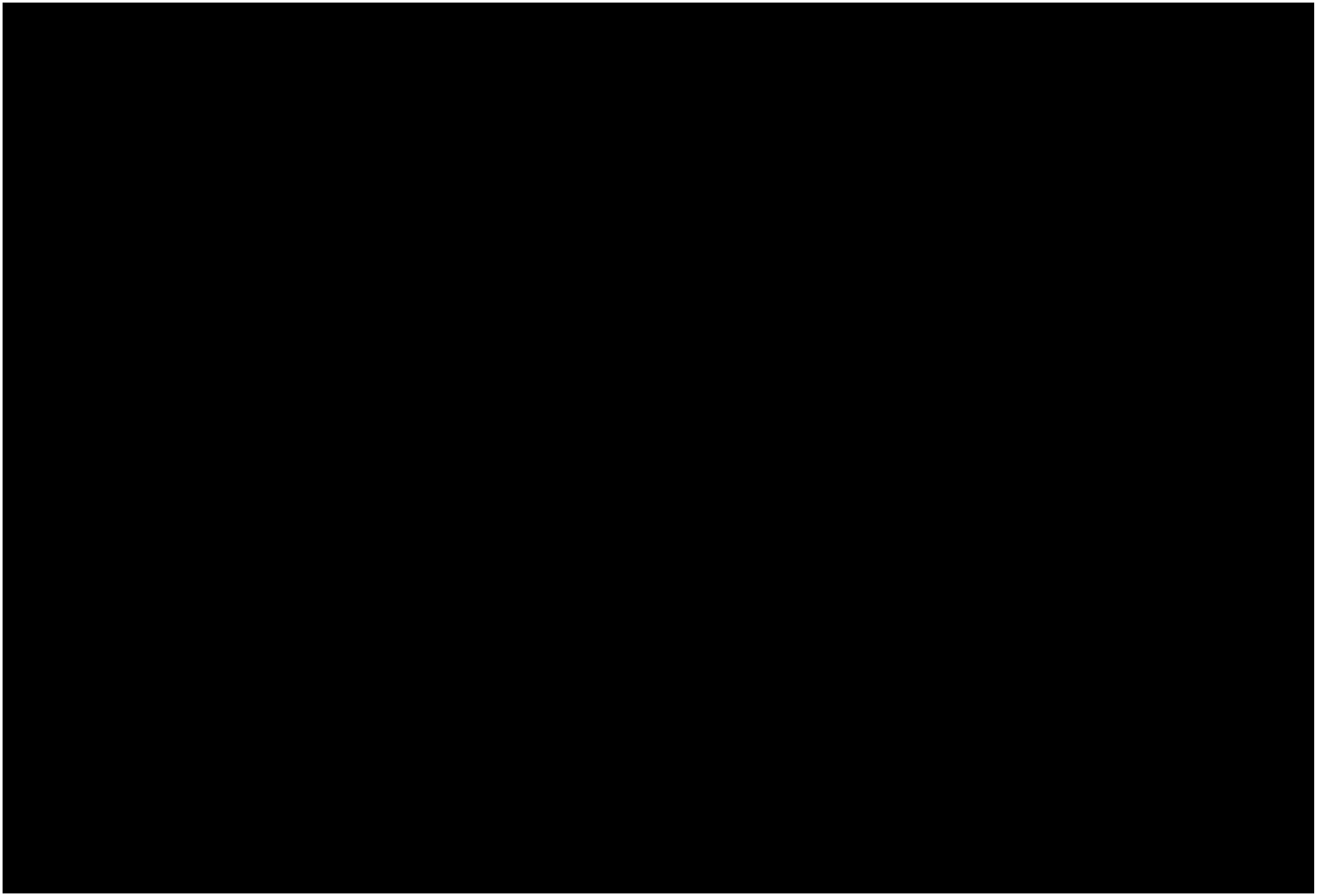


Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
Page 593 of 2886

Member Forecasted On Peak Demand Day for June 2021

High West Energy, Inc.

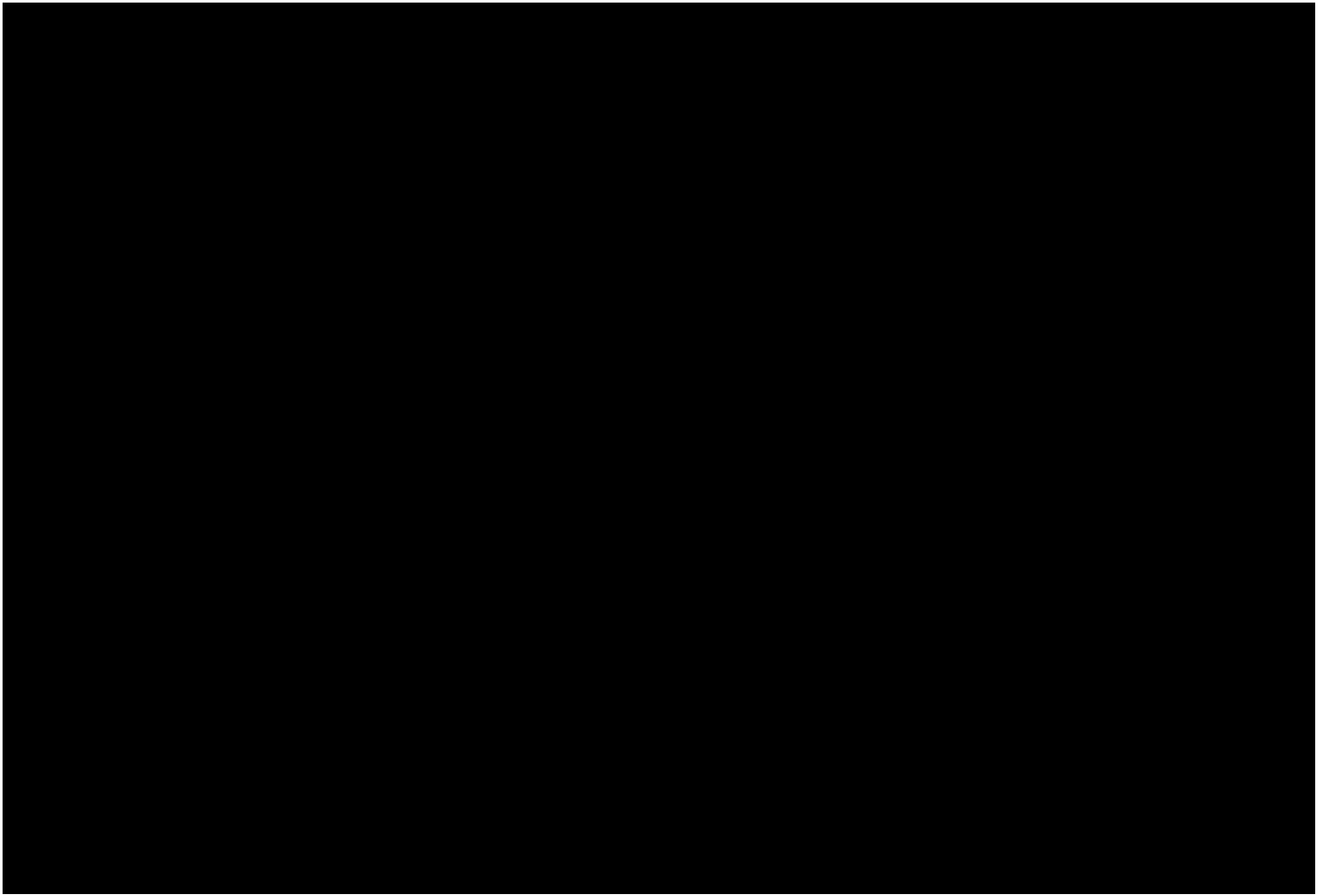
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

High West Energy, Inc.

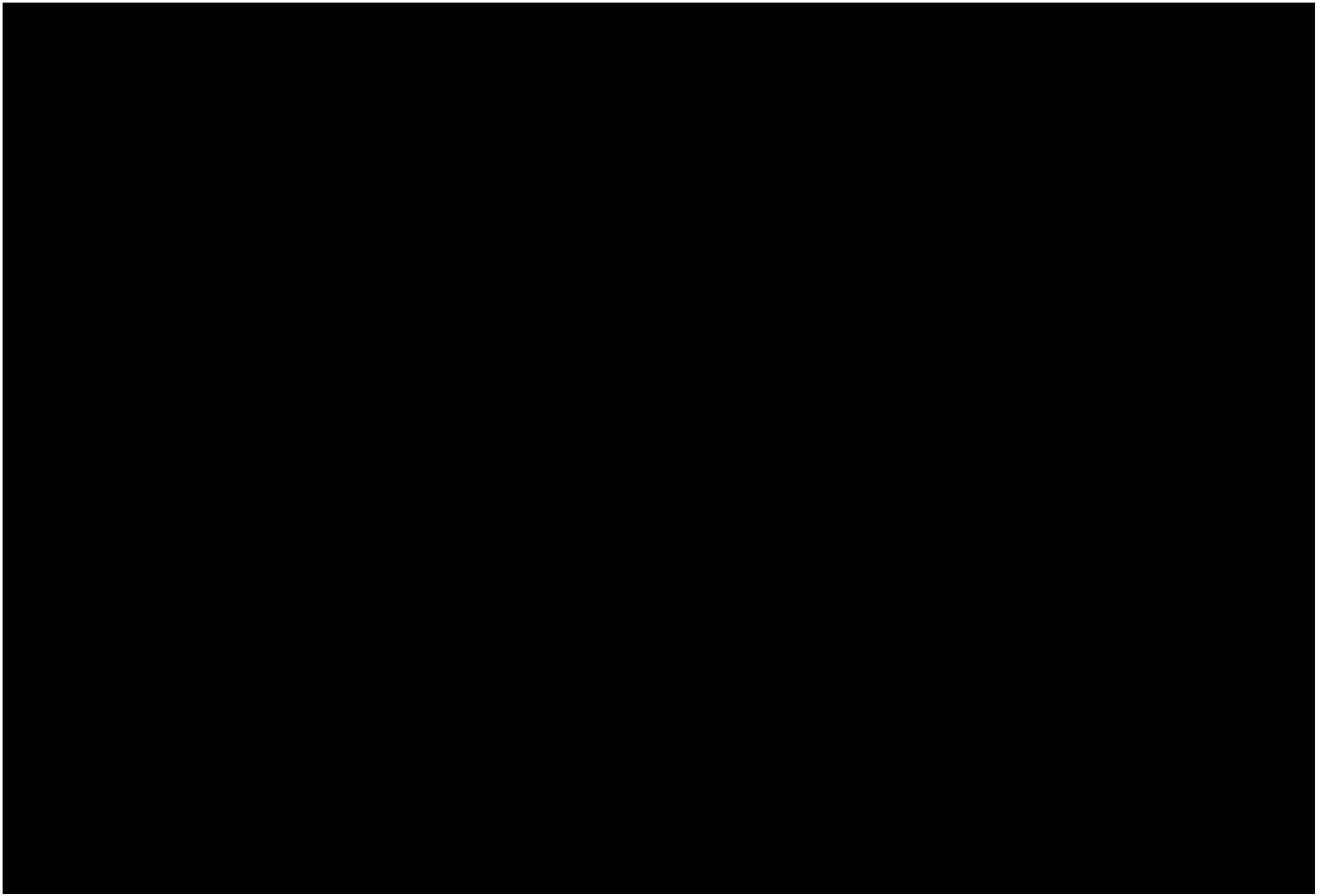
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

High West Energy, Inc.

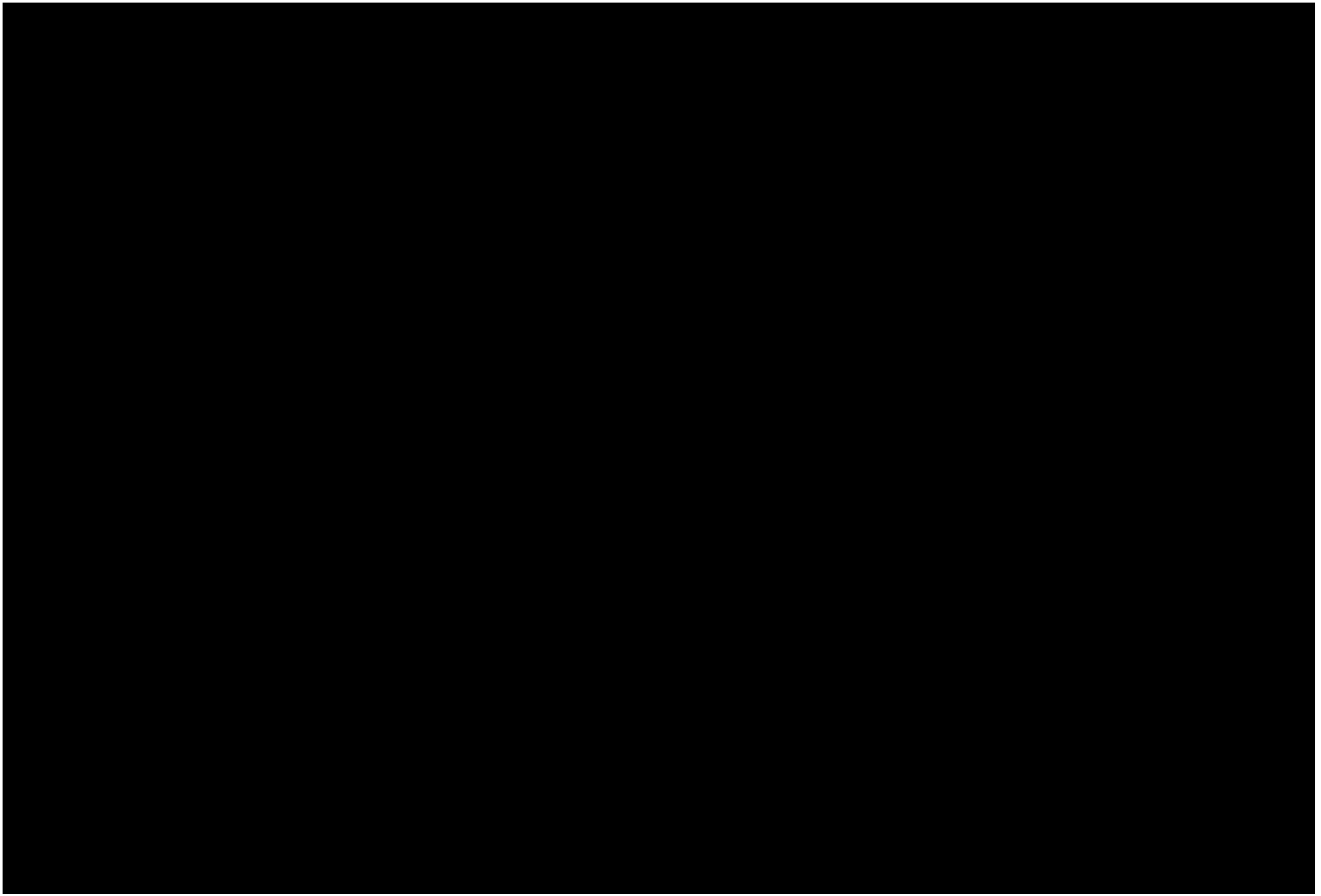
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

High West Energy, Inc.

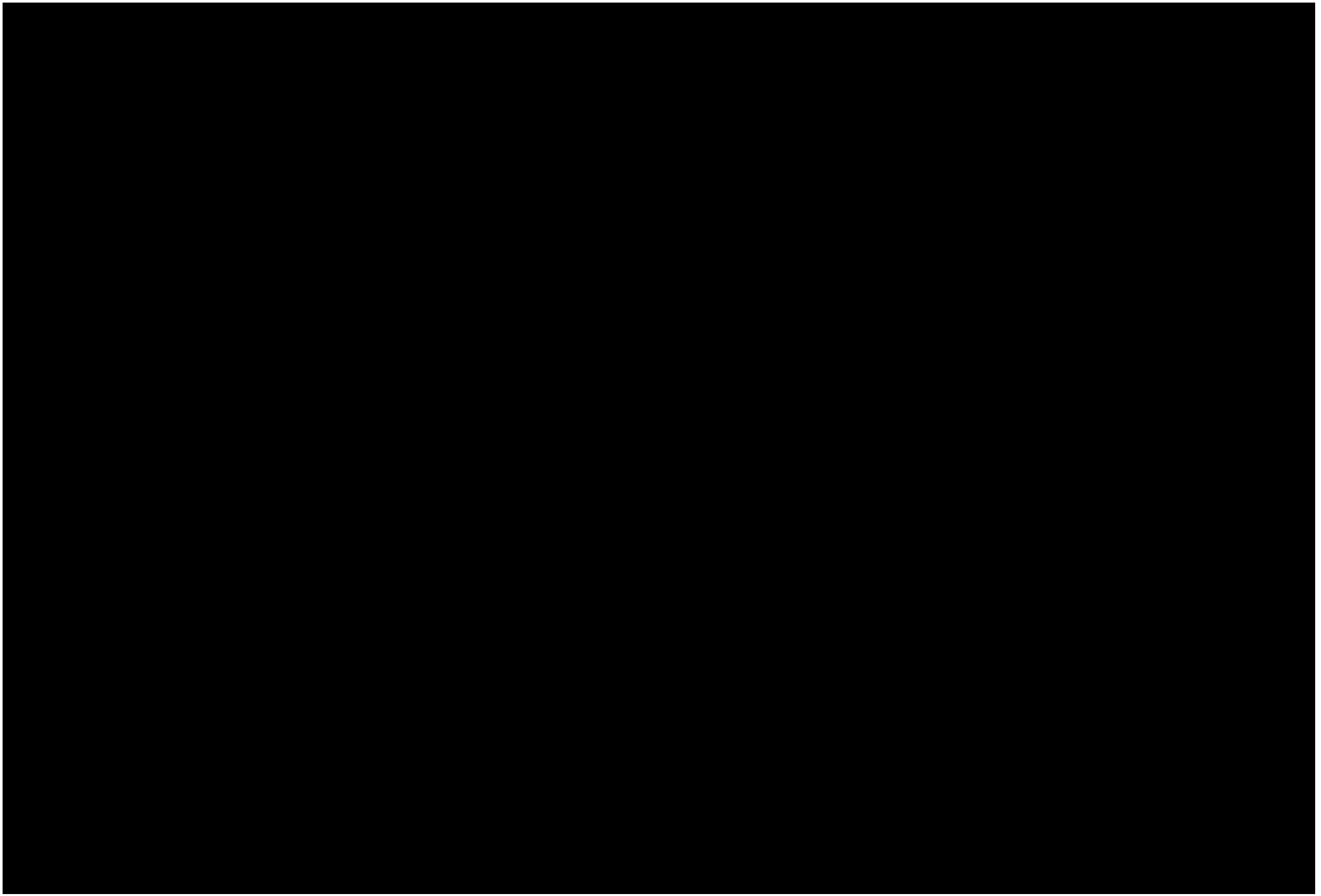
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

High West Energy, Inc.

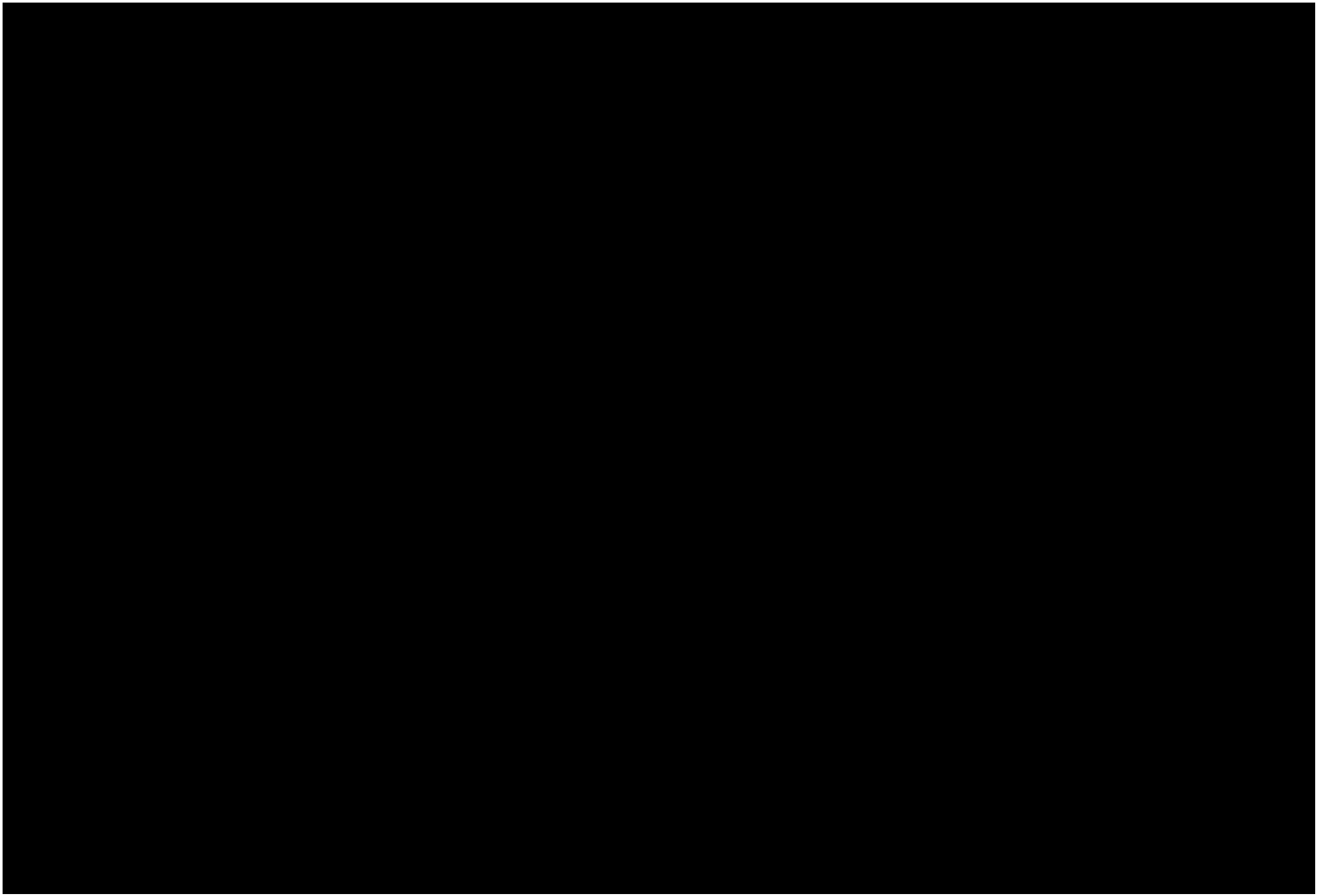
Date of On Peak Day - 10/06/2021



Member Forecasted On Peak Demand Day for November 2021

High West Energy, Inc.

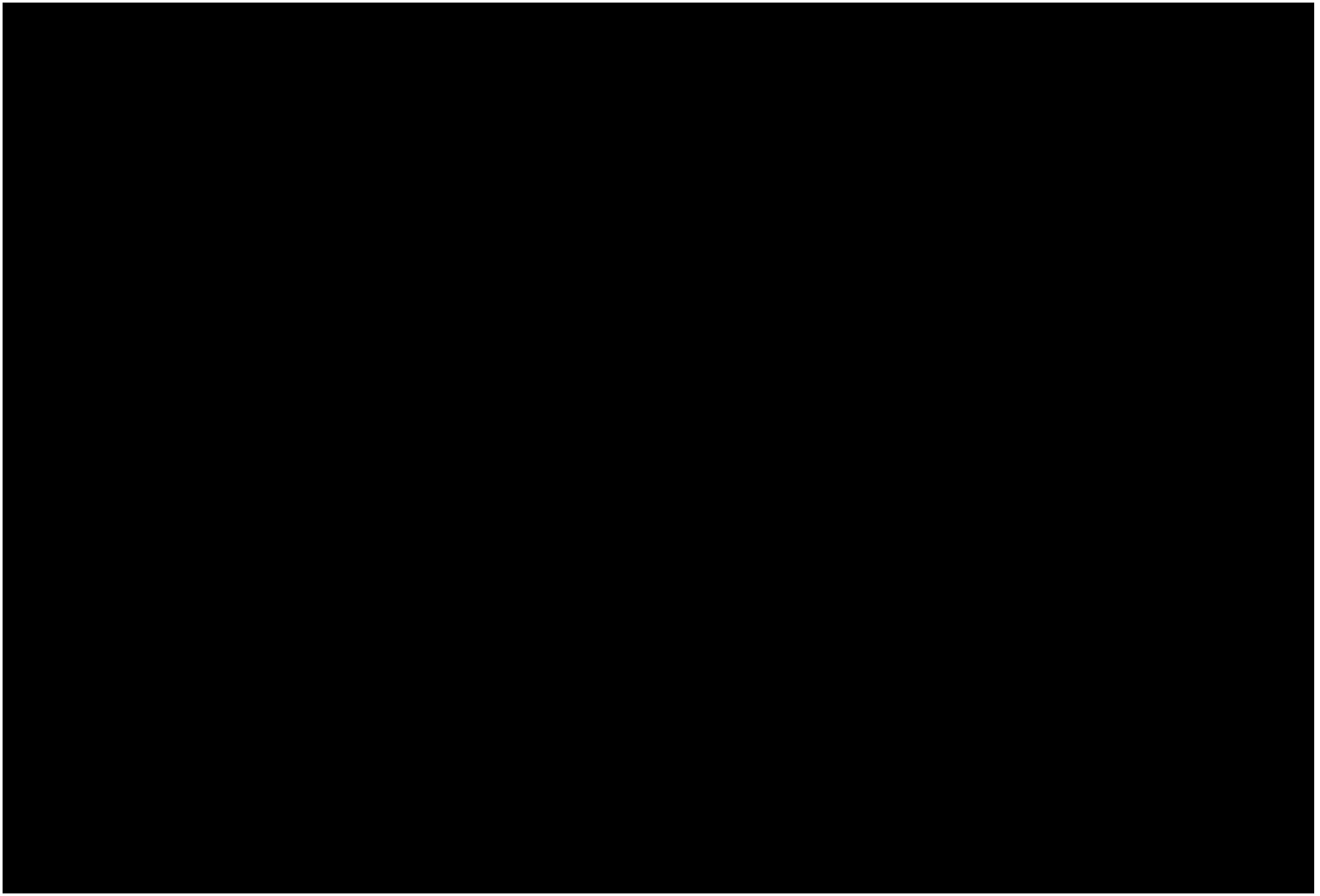
Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

High West Energy, Inc.

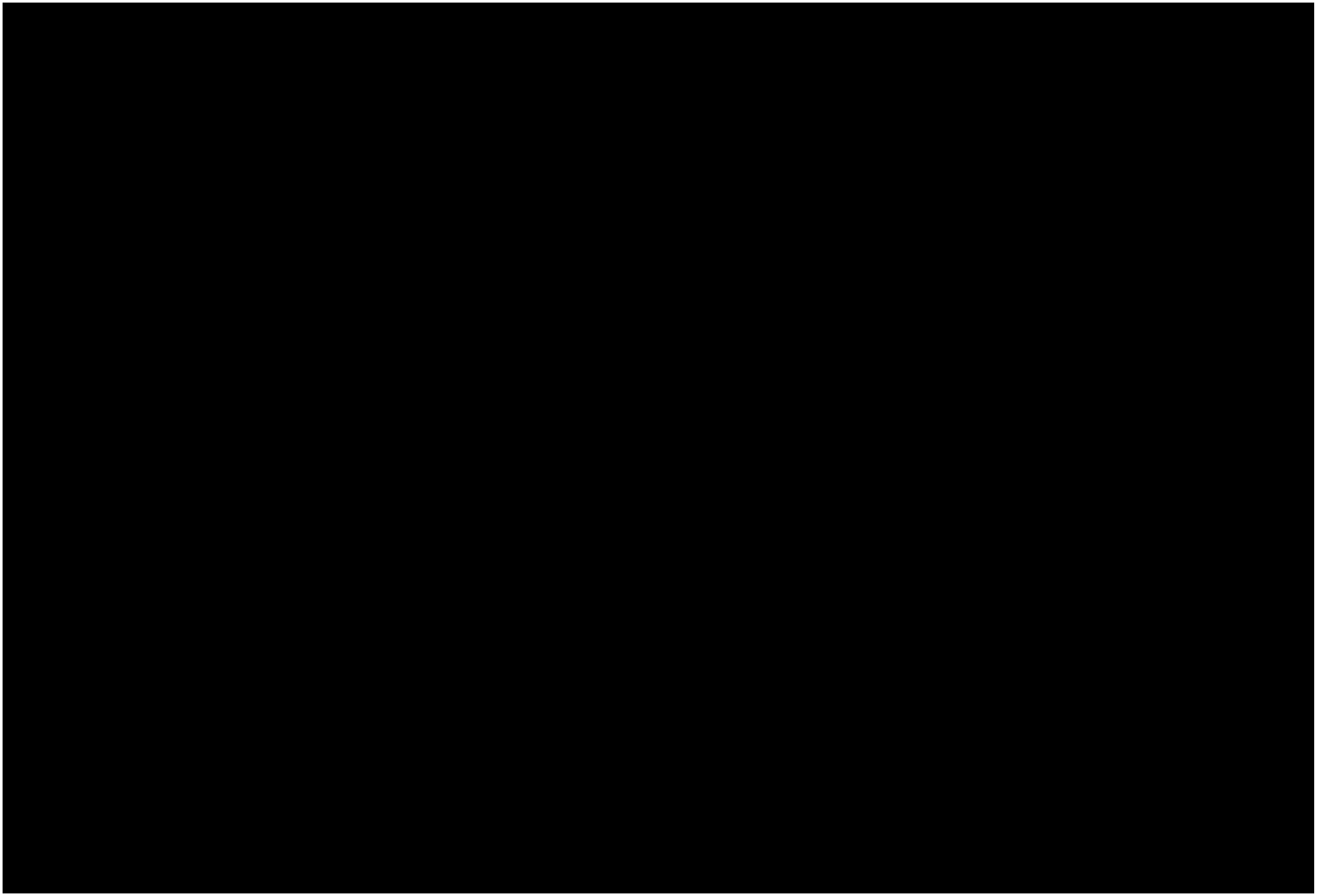
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

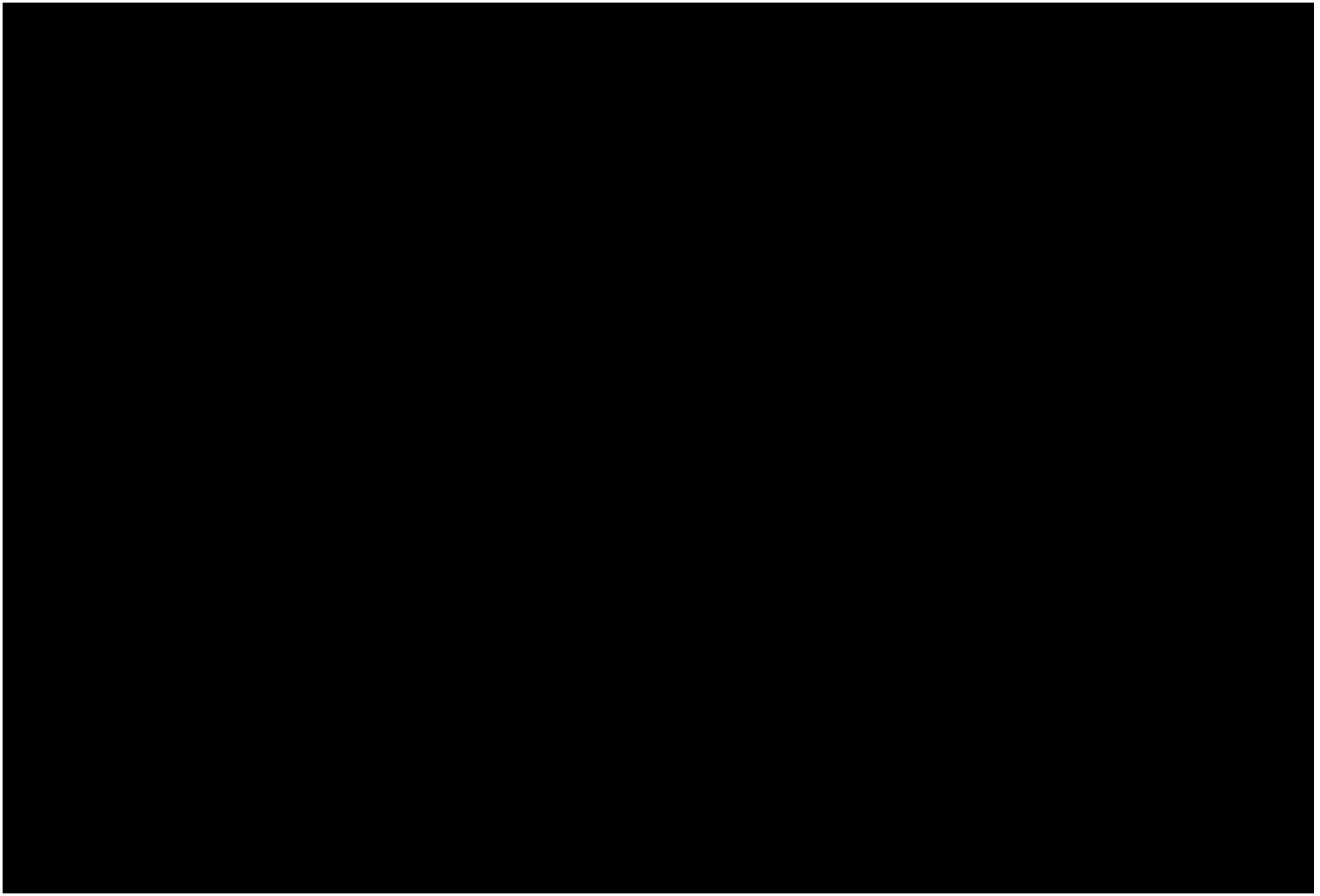
Date of On Peak Day - 01/26/2021



Member Forecasted On Peak Demand Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

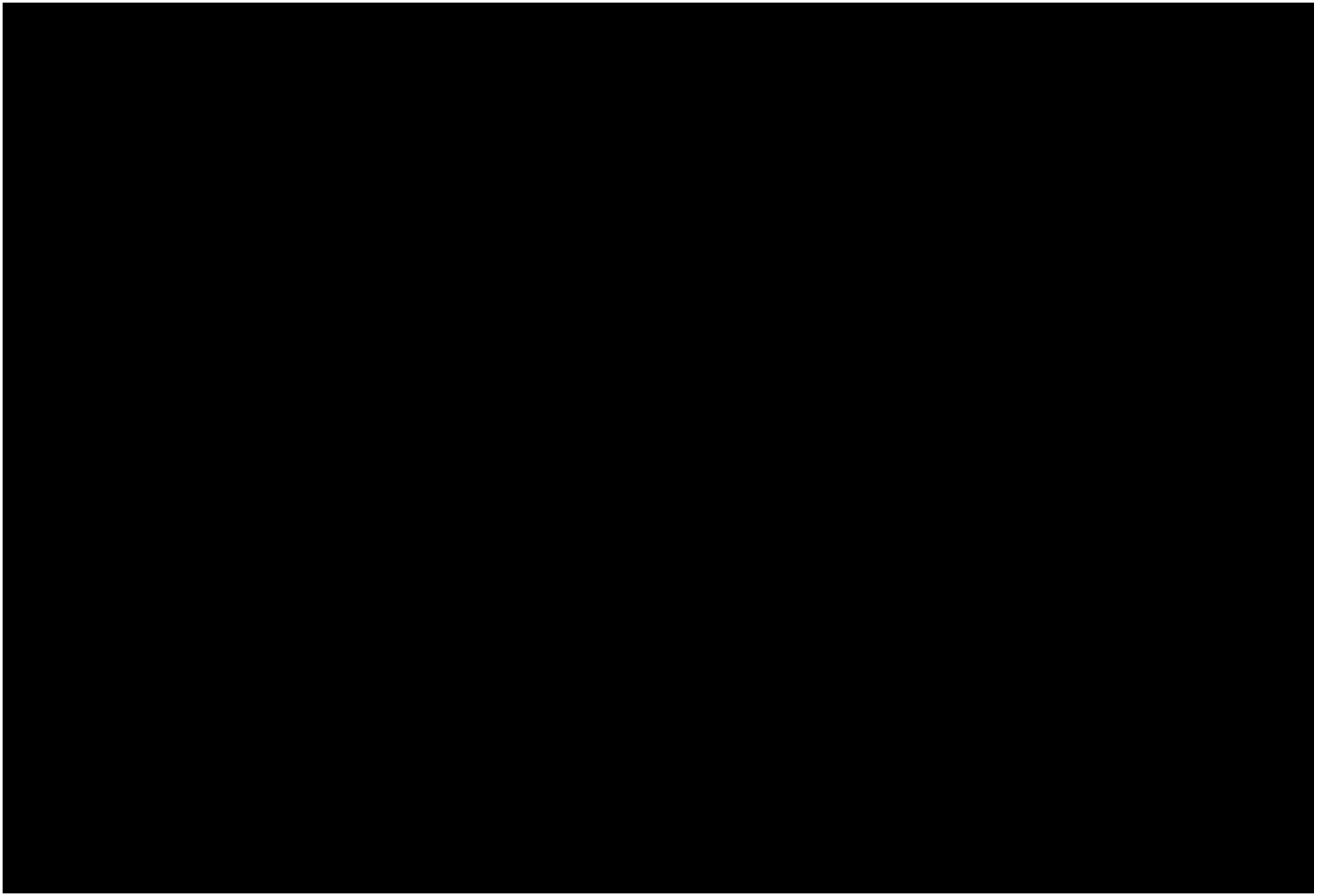
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Jemez Mountains Electric Cooperative, Inc.

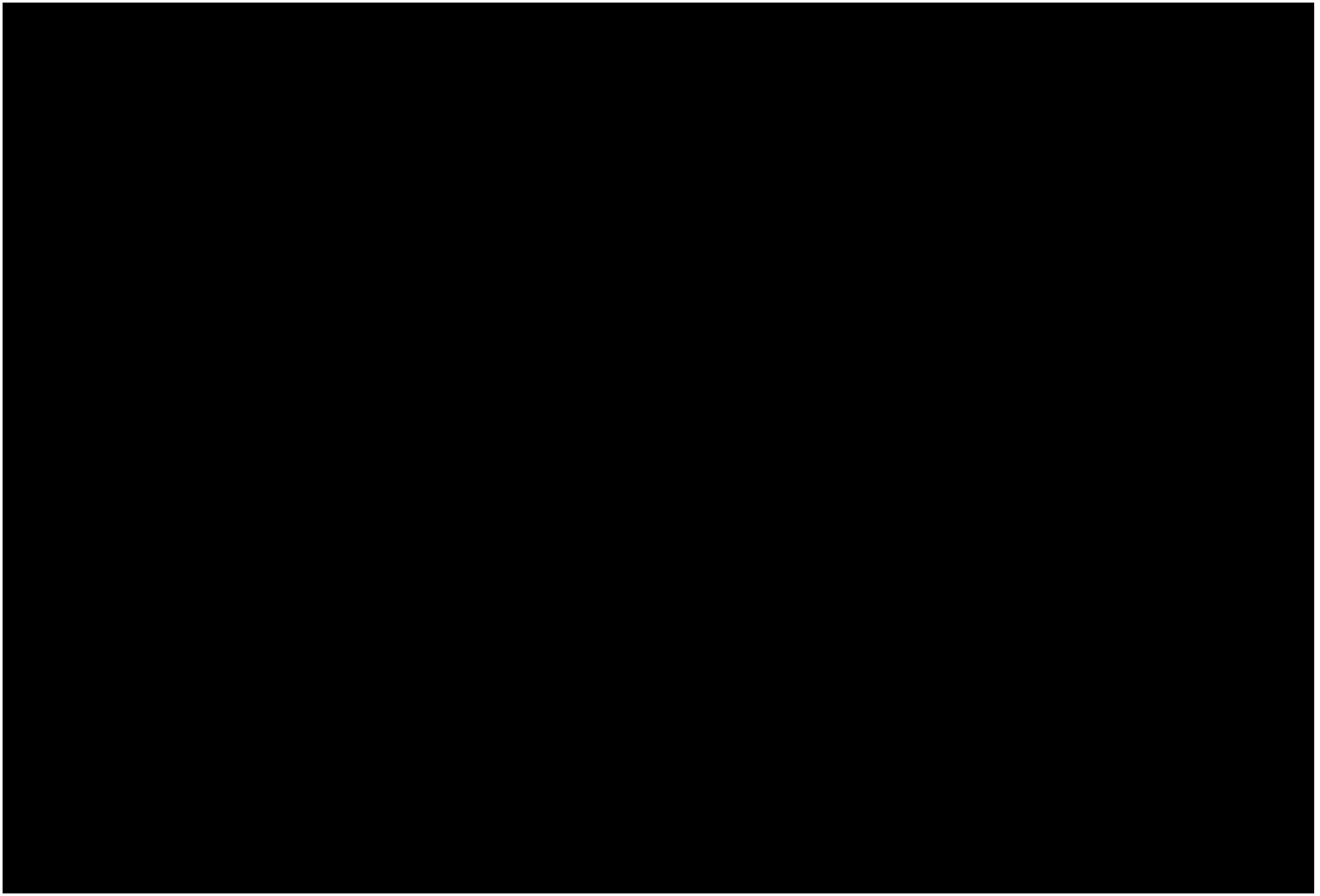
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

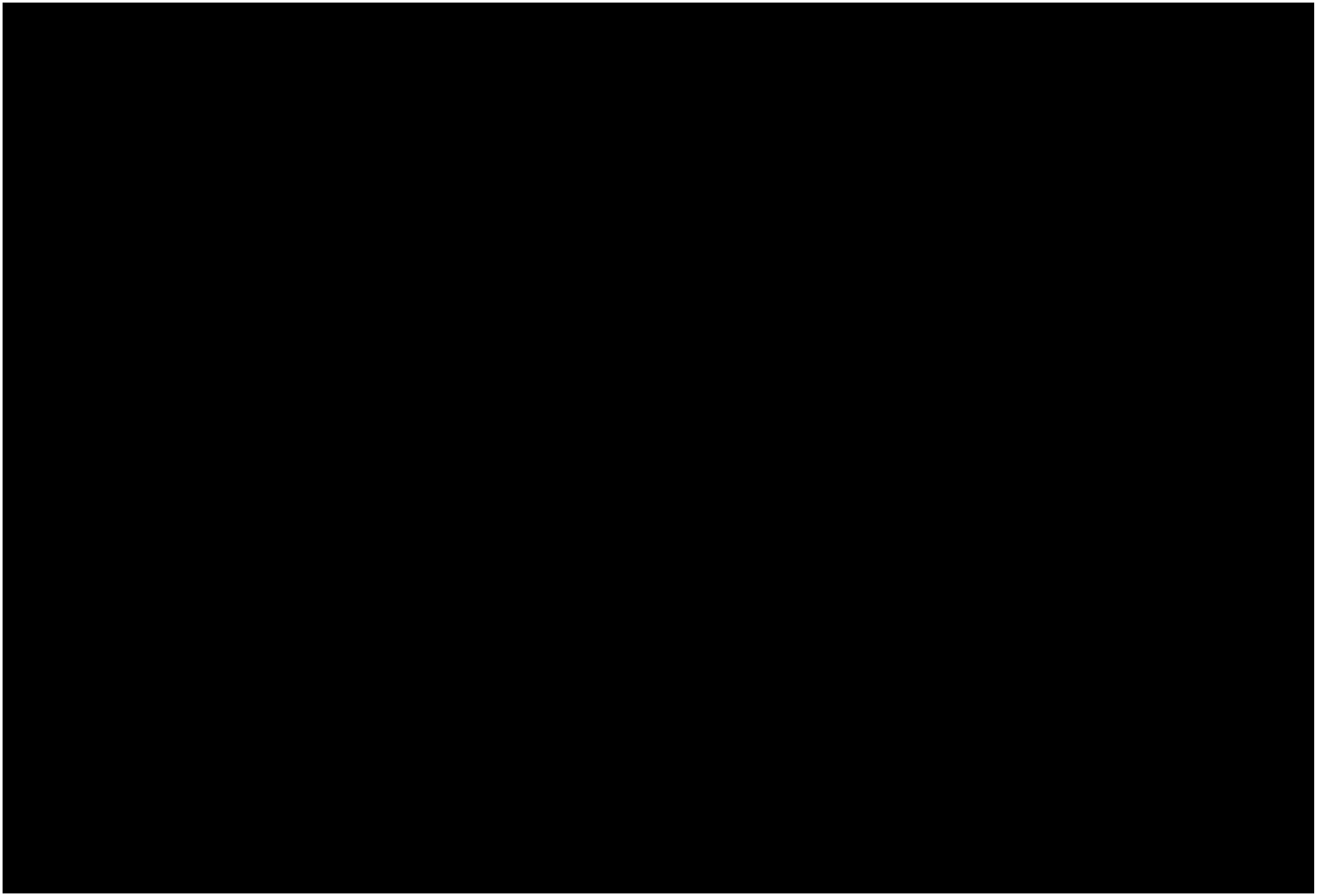
Date of On Peak Day - 04/26/2021



Member Forecasted On Peak Demand Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

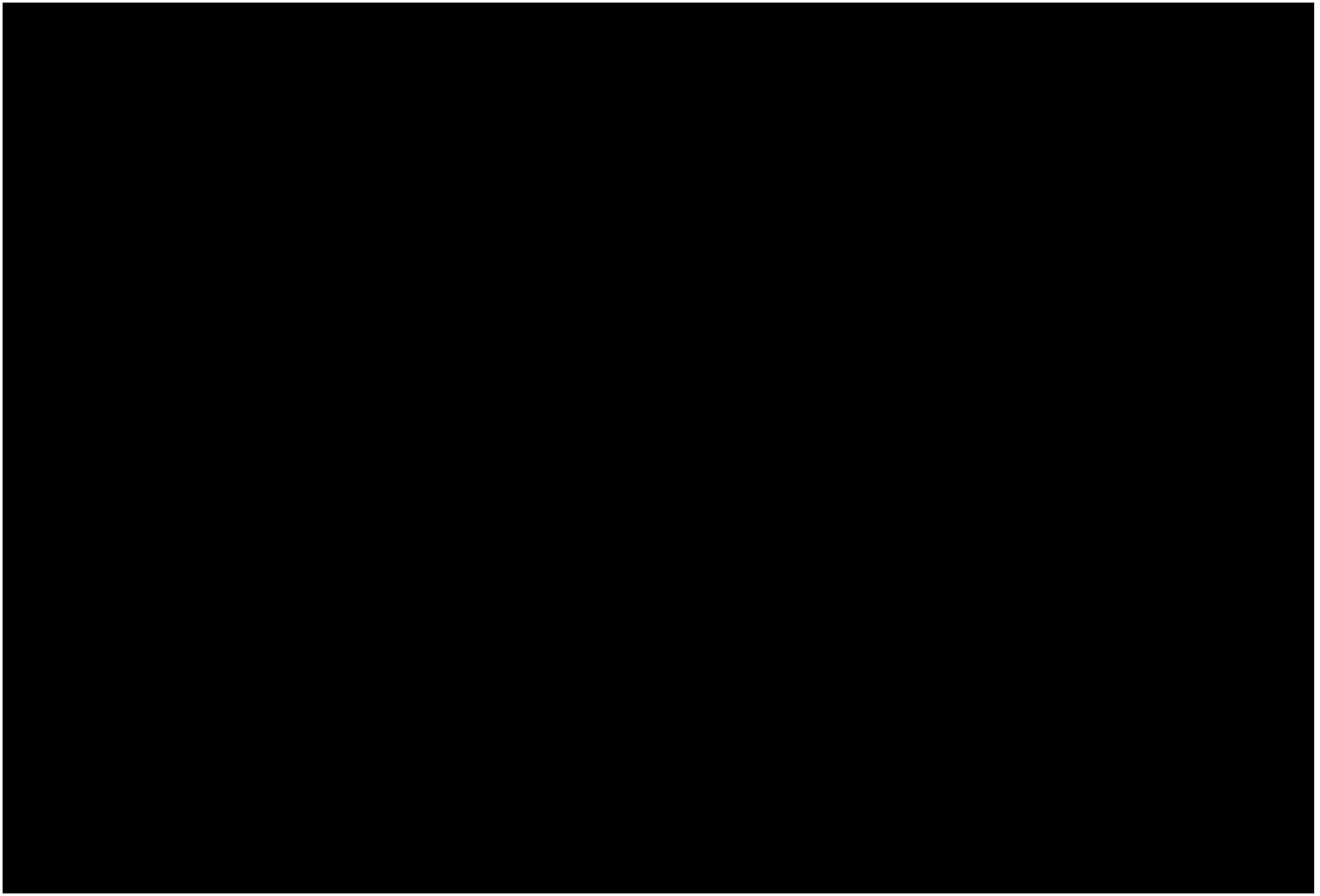
Date of On Peak Day - 05/26/2021



Member Forecasted On Peak Demand Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

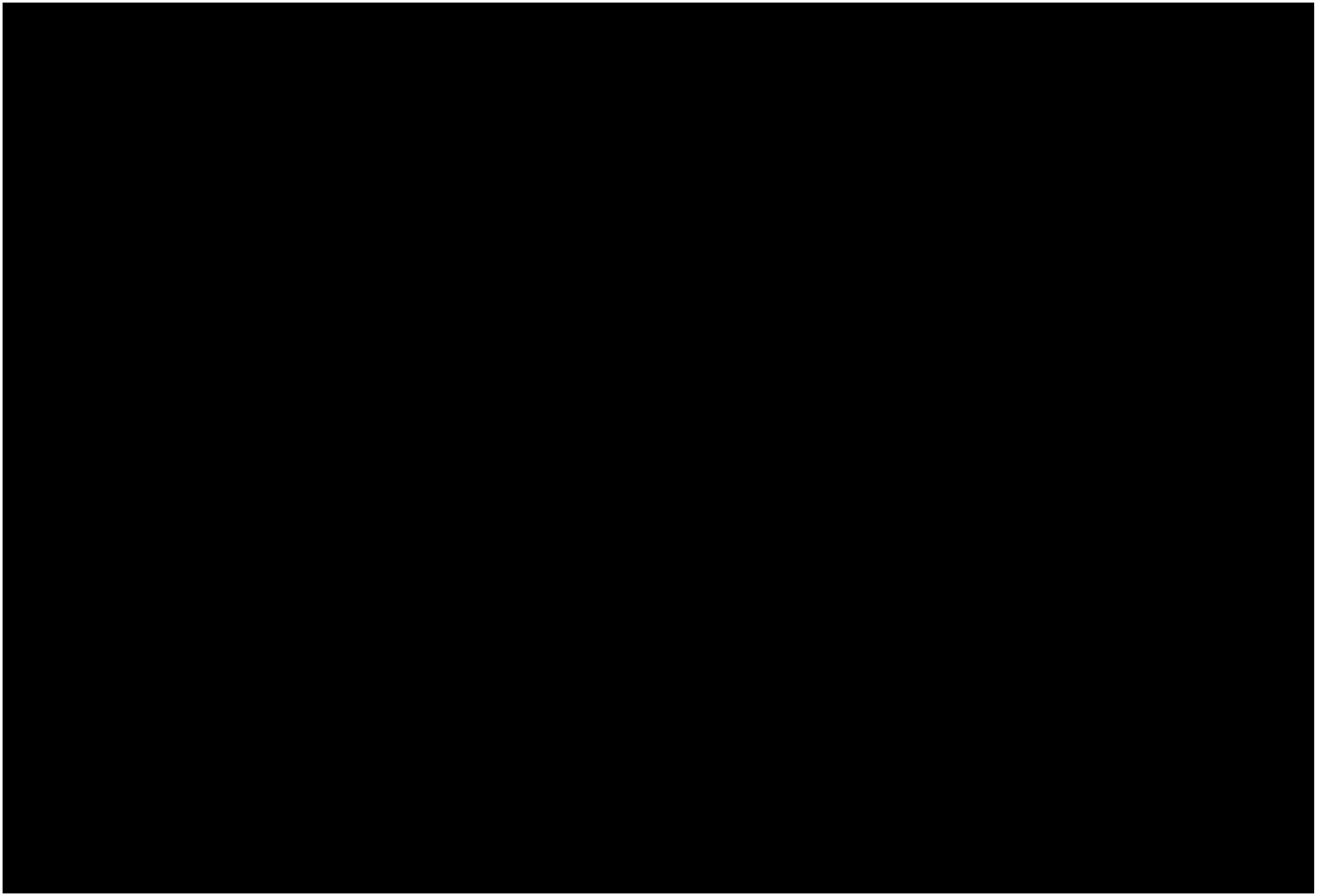
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

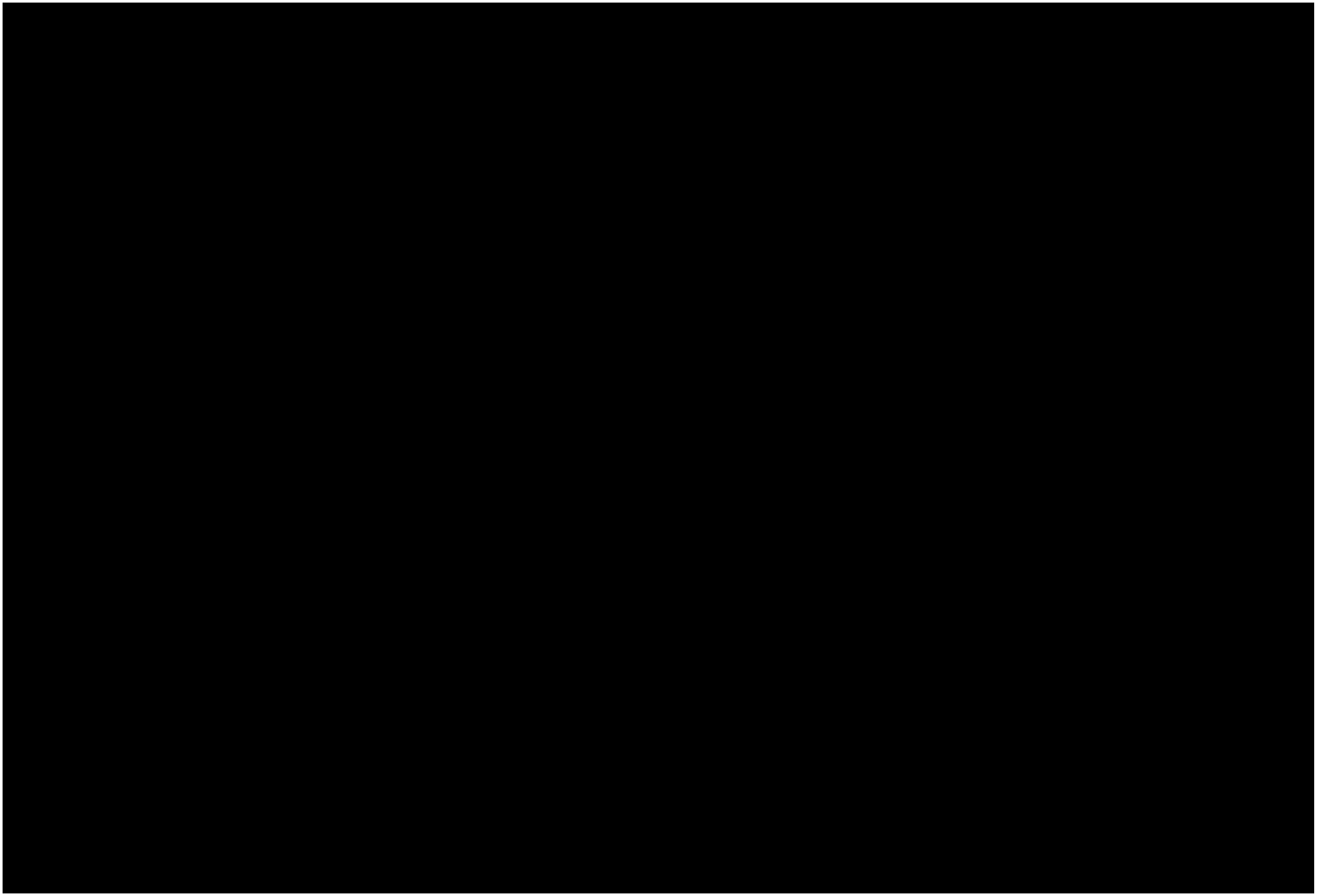
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Jemez Mountains Electric Cooperative, Inc.

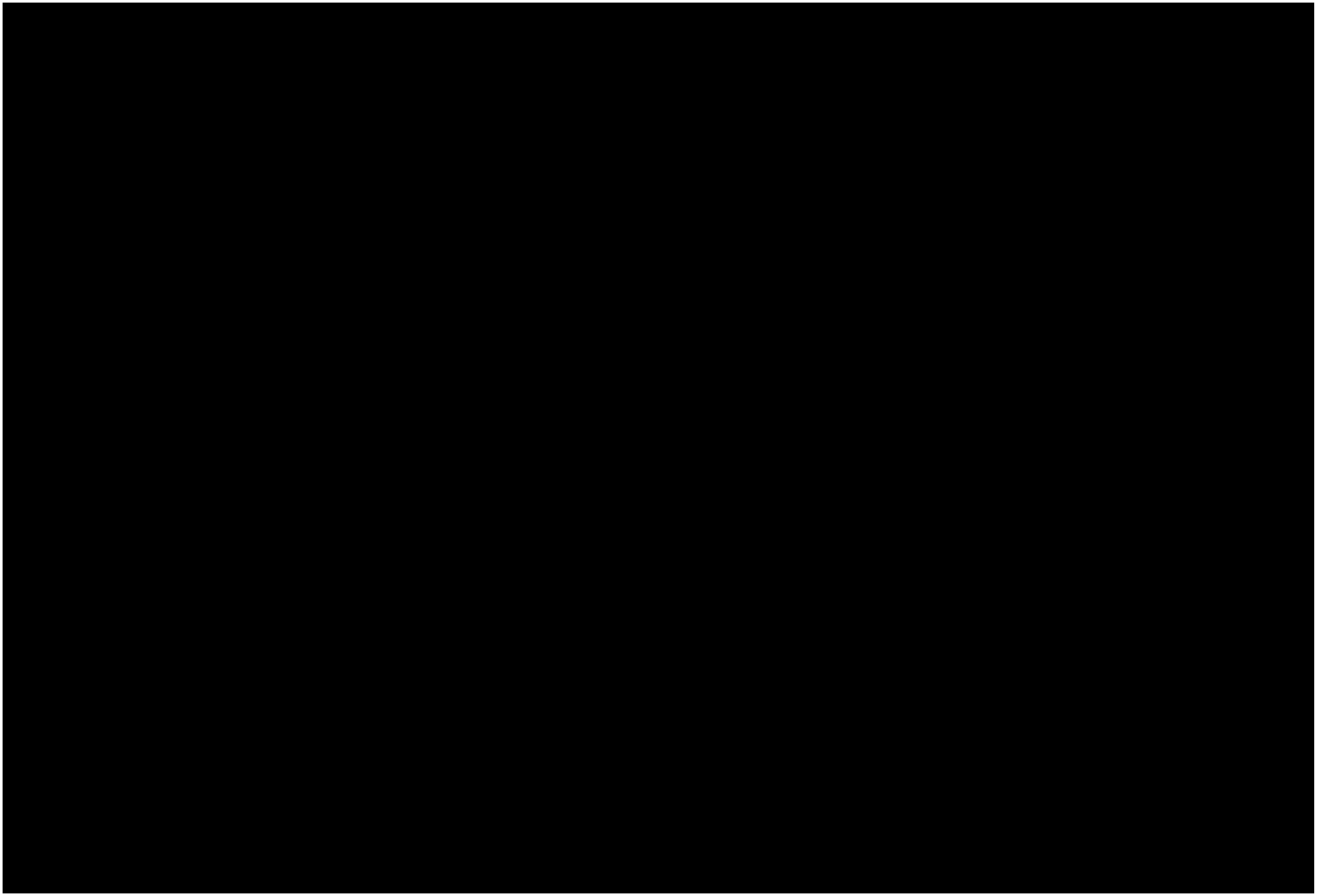
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

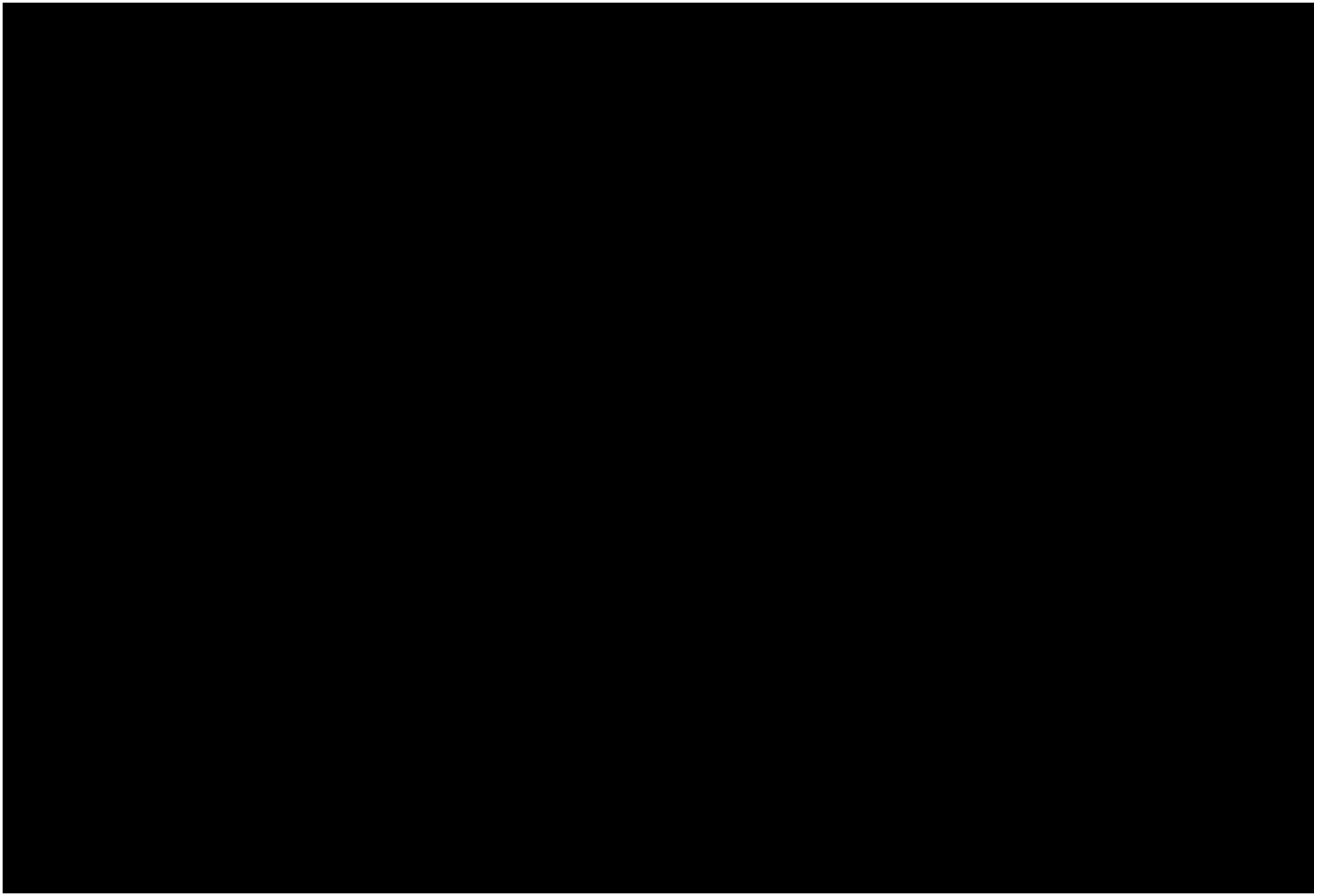
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

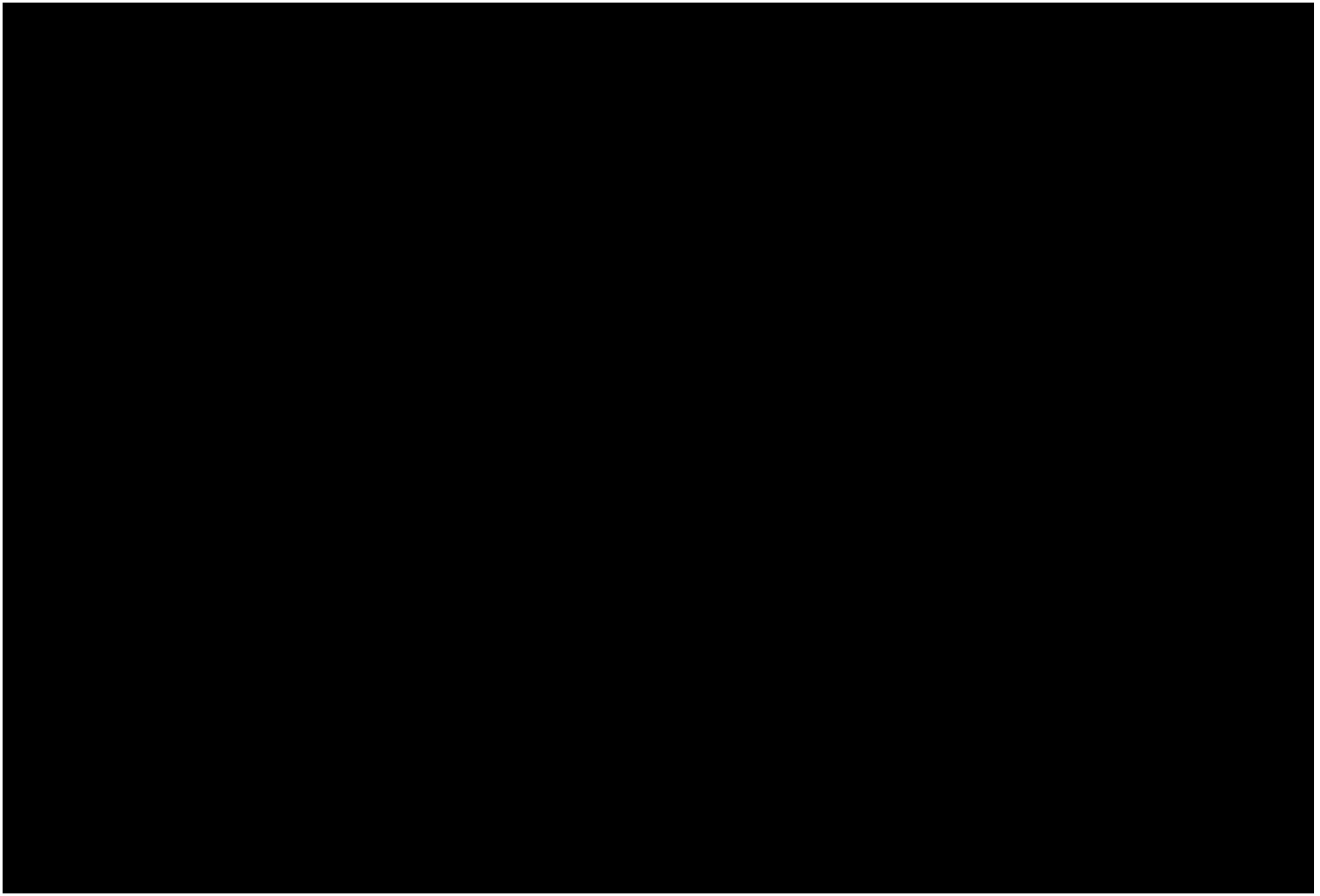
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

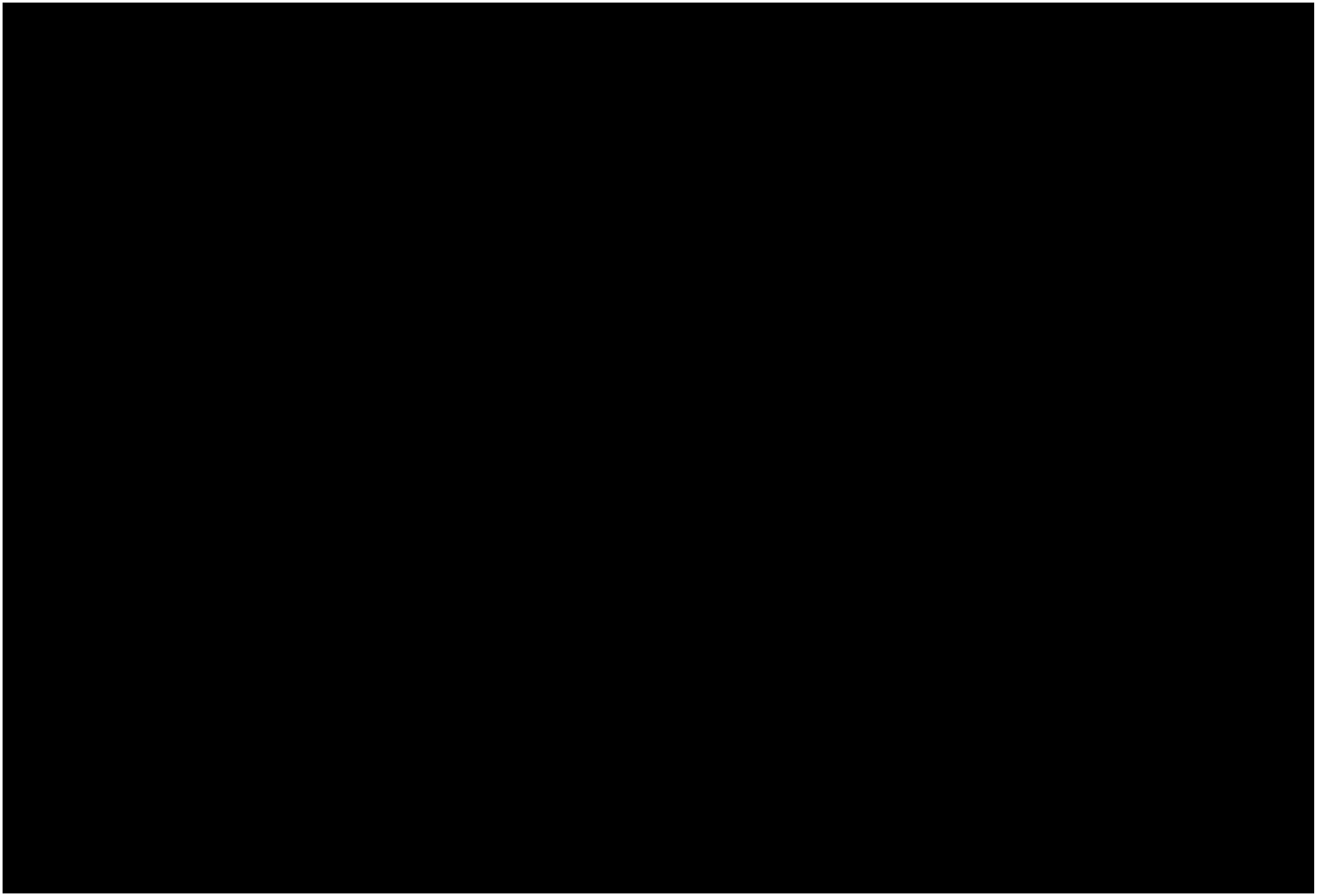
Date of On Peak Day - 11/29/2021



Member Forecasted On Peak Demand Day for December 2021

Jemez Mountains Electric Cooperative, Inc.

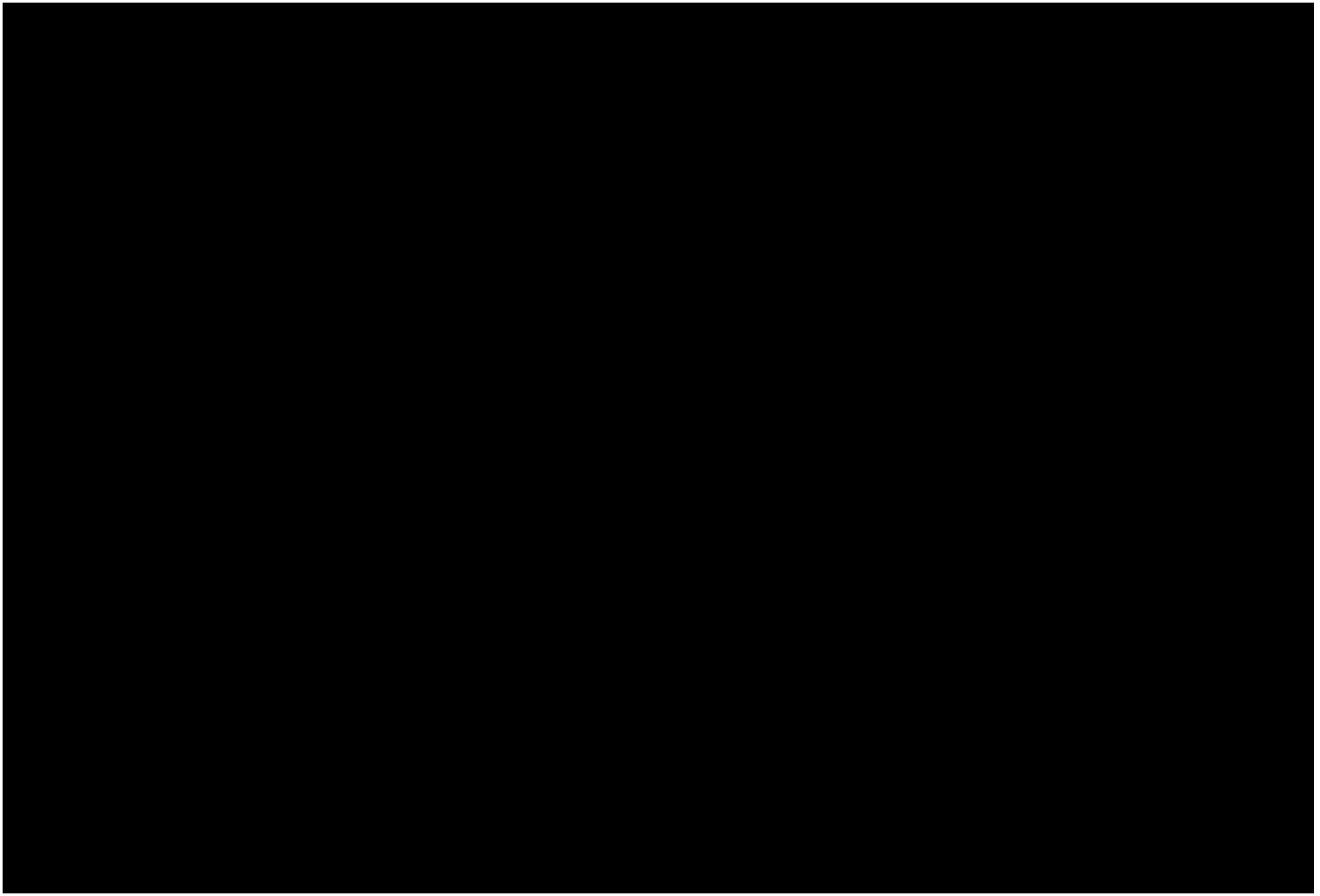
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

K.C. Electric Association, Inc.

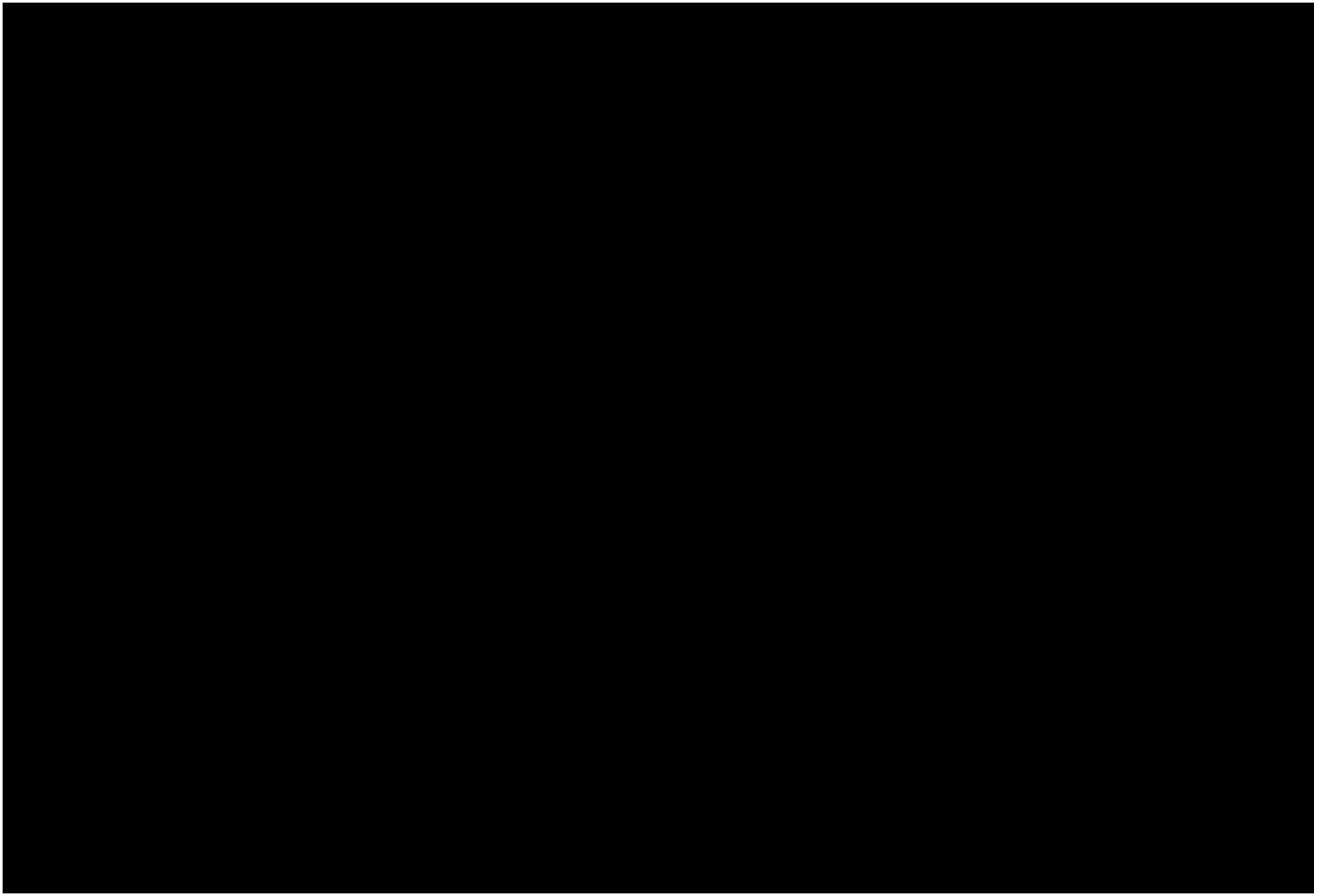
Date of On Peak Day - 01/15/2021



Member Forecasted On Peak Demand Day for February 2021

K.C. Electric Association, Inc.

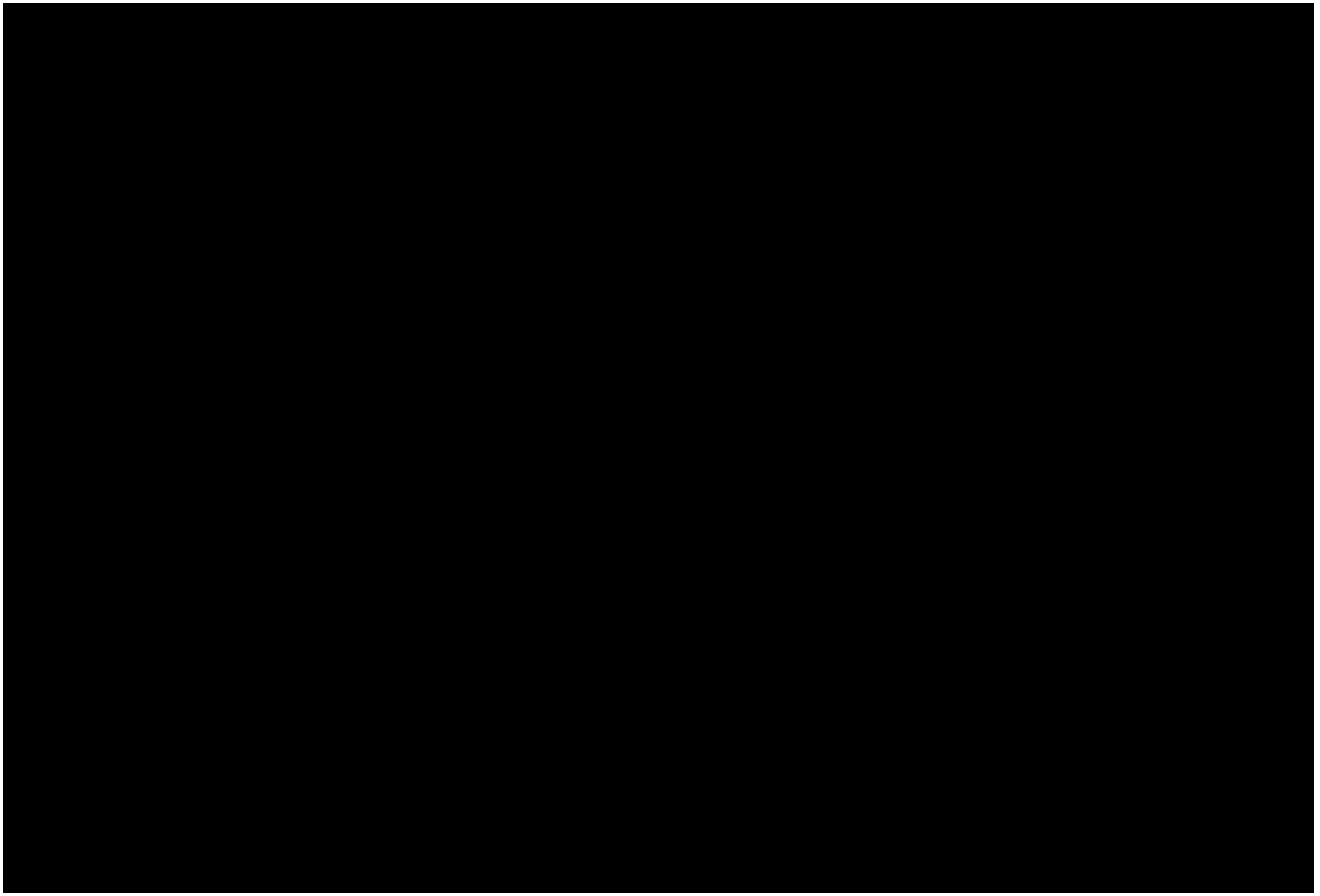
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

K.C. Electric Association, Inc.

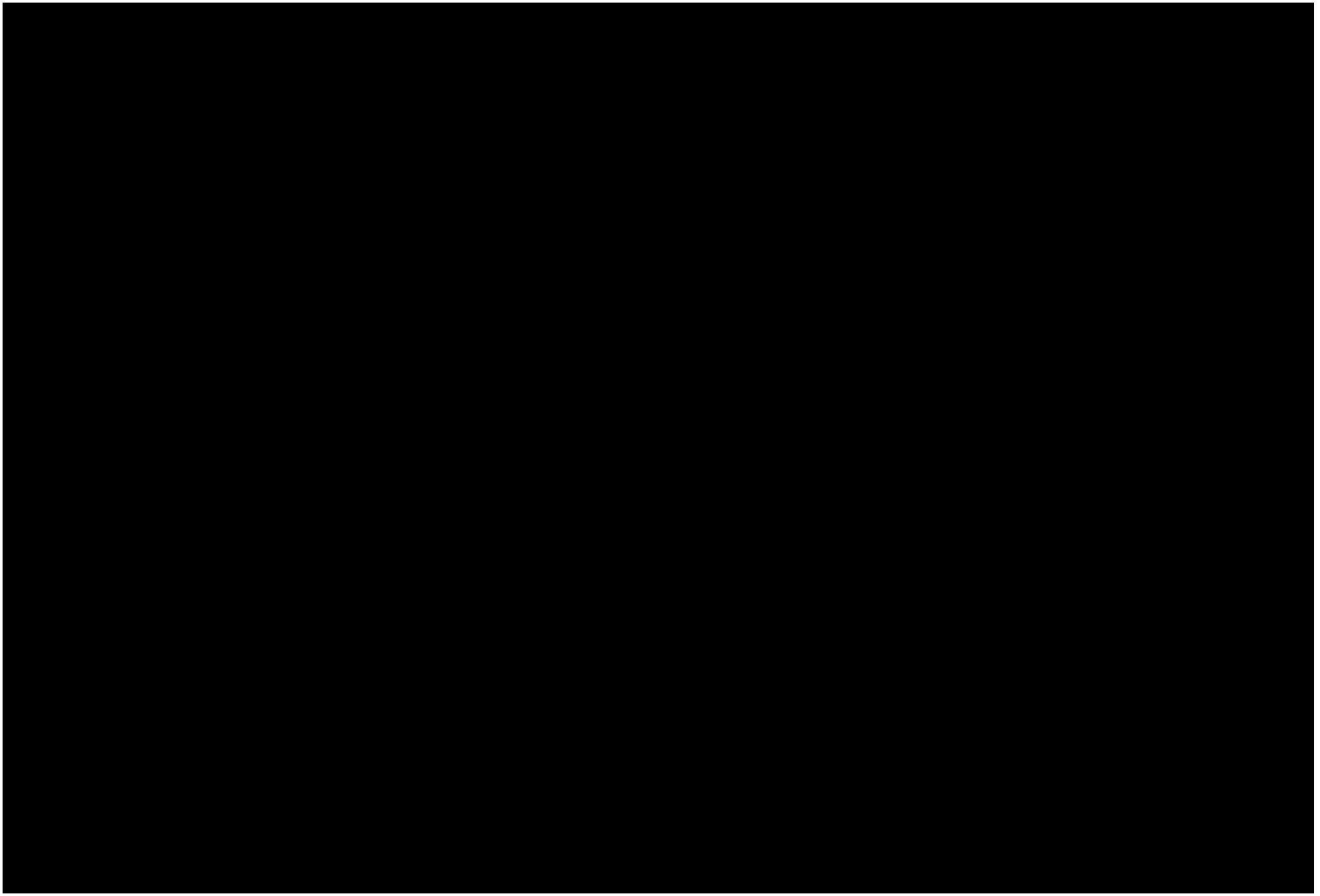
Date of On Peak Day - 03/22/2021



Member Forecasted On Peak Demand Day for April 2021

K.C. Electric Association, Inc.

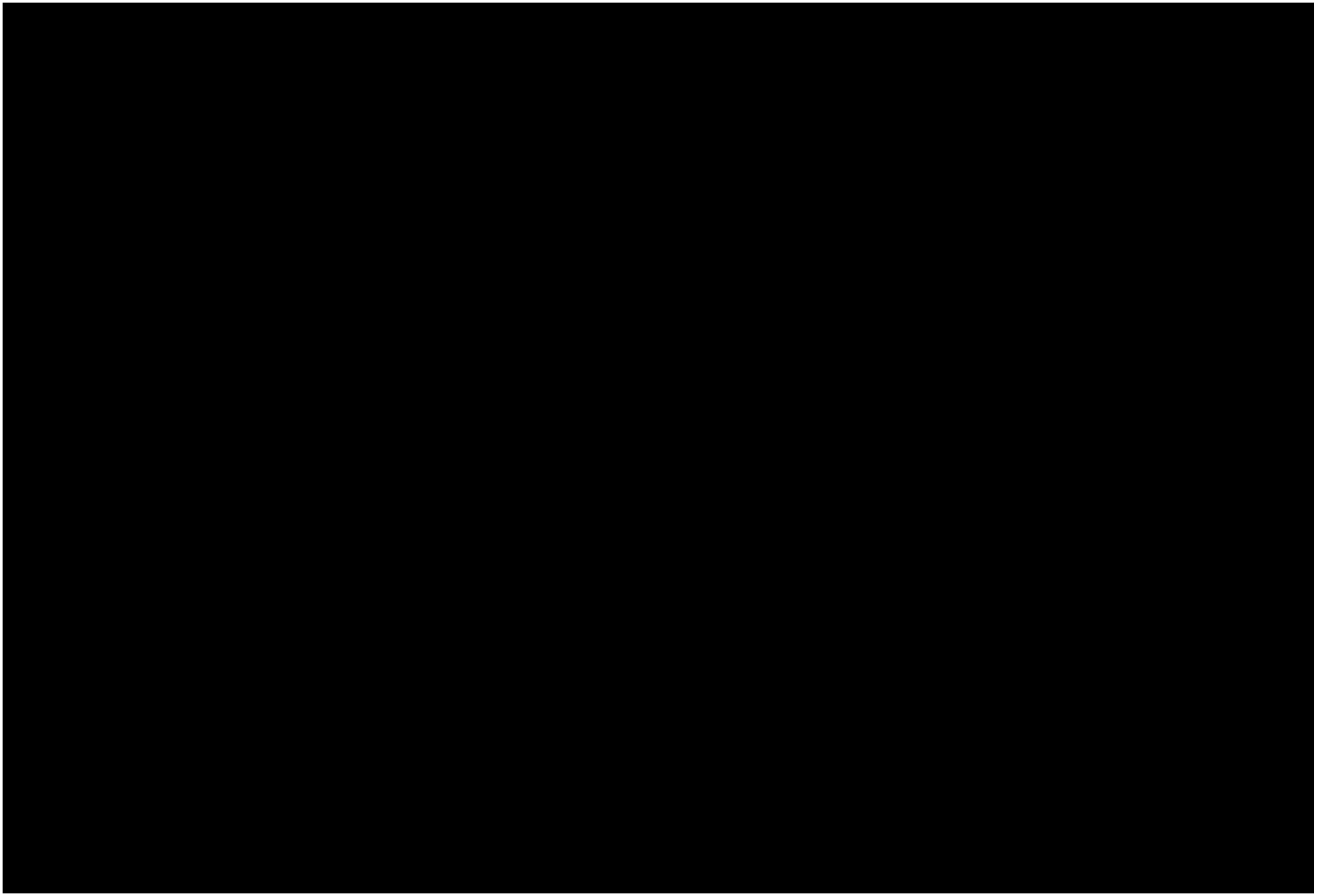
Date of On Peak Day - 04/14/2021



Member Forecasted On Peak Demand Day for May 2021

K.C. Electric Association, Inc.

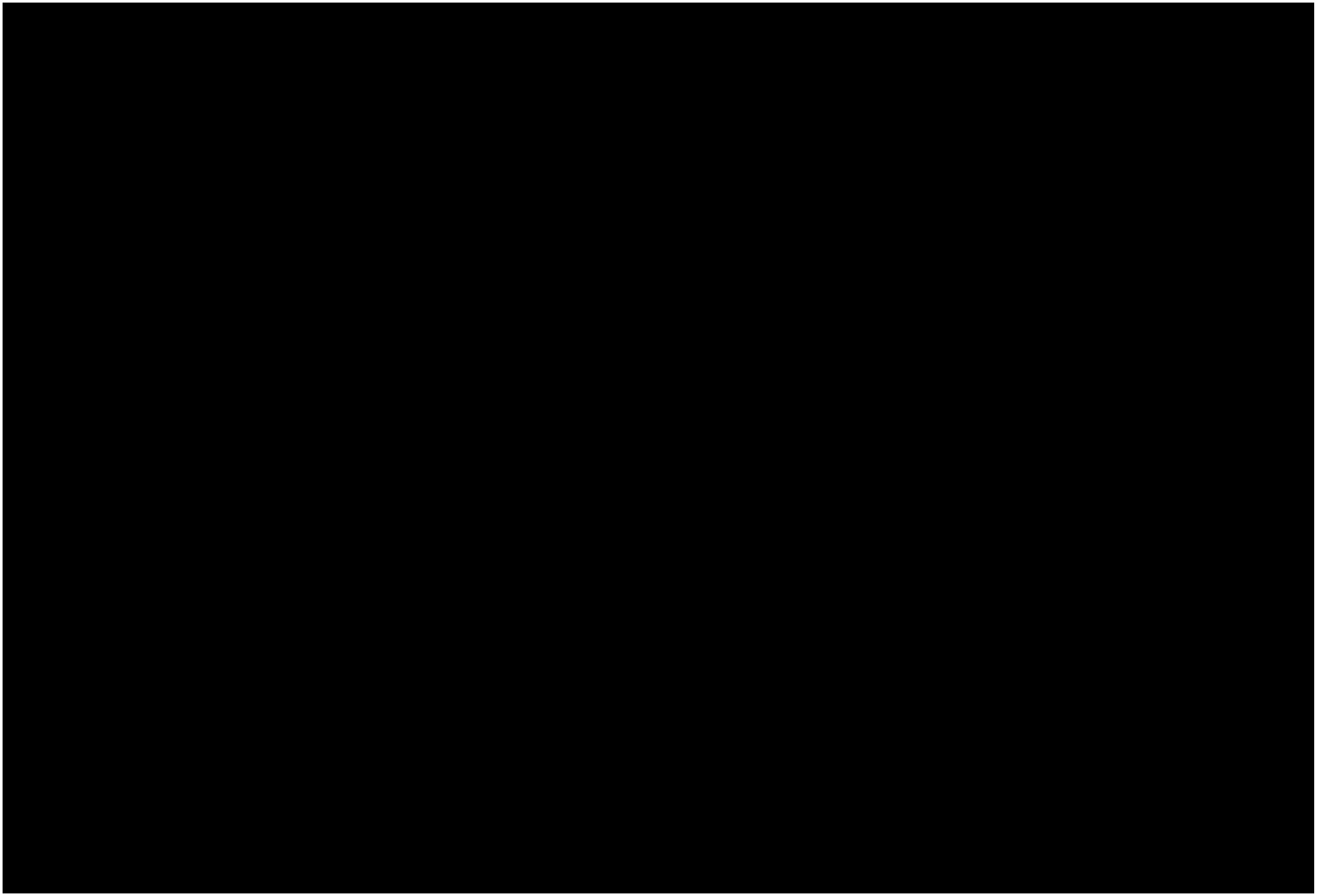
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

K.C. Electric Association, Inc.

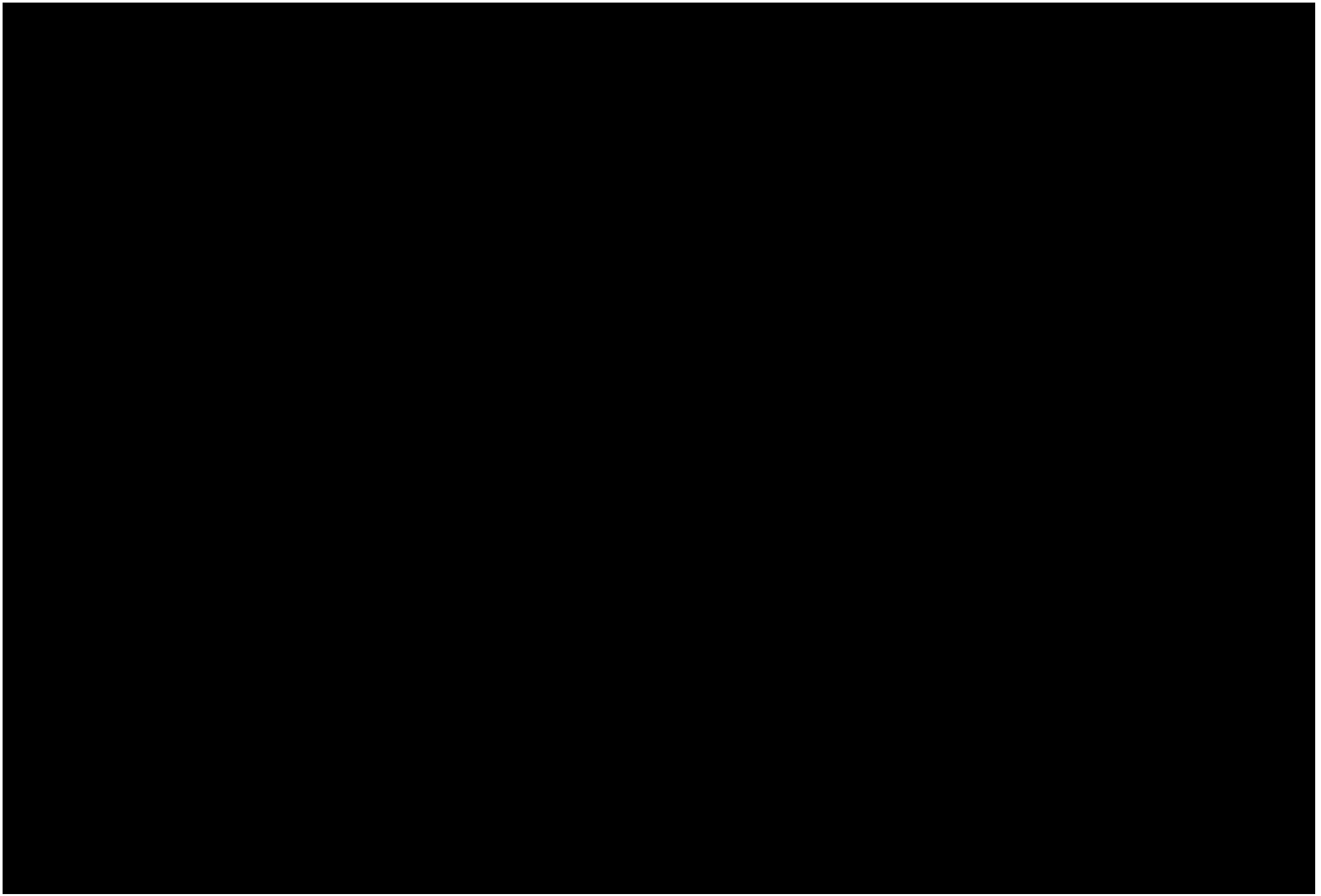
Date of On Peak Day - 06/17/2021



Member Forecasted On Peak Demand Day for July 2021

K.C. Electric Association, Inc.

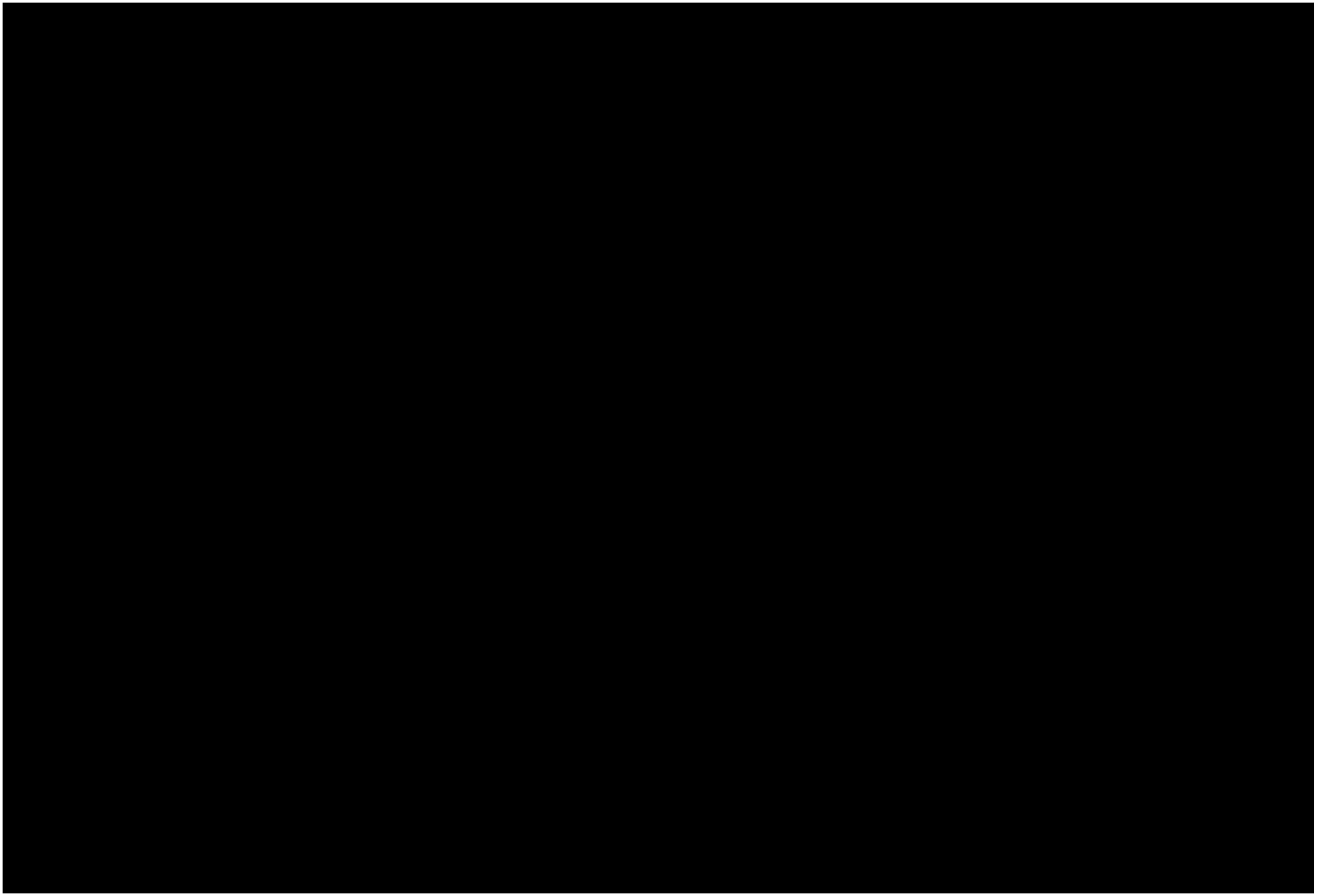
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

K.C. Electric Association, Inc.

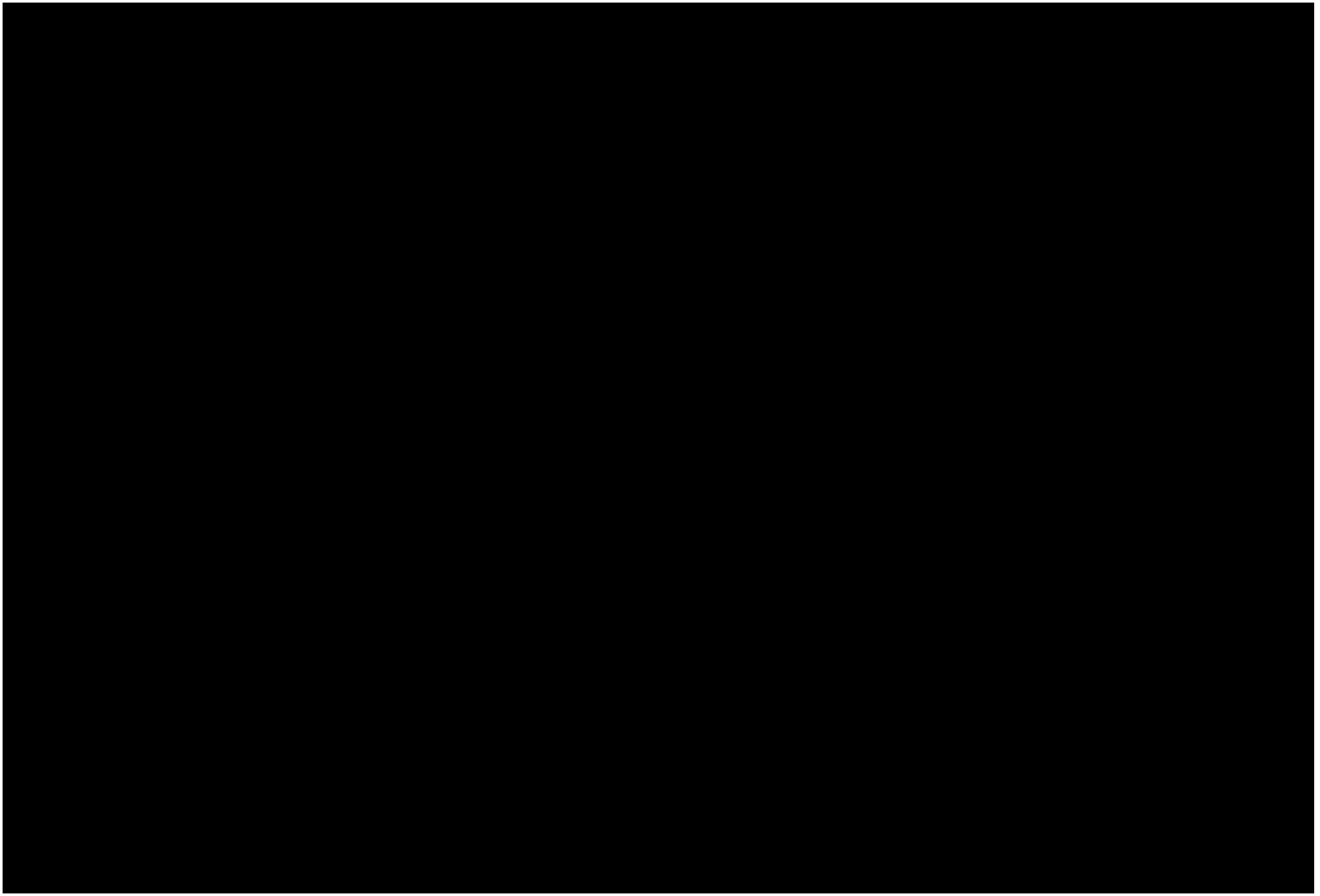
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

K.C. Electric Association, Inc.

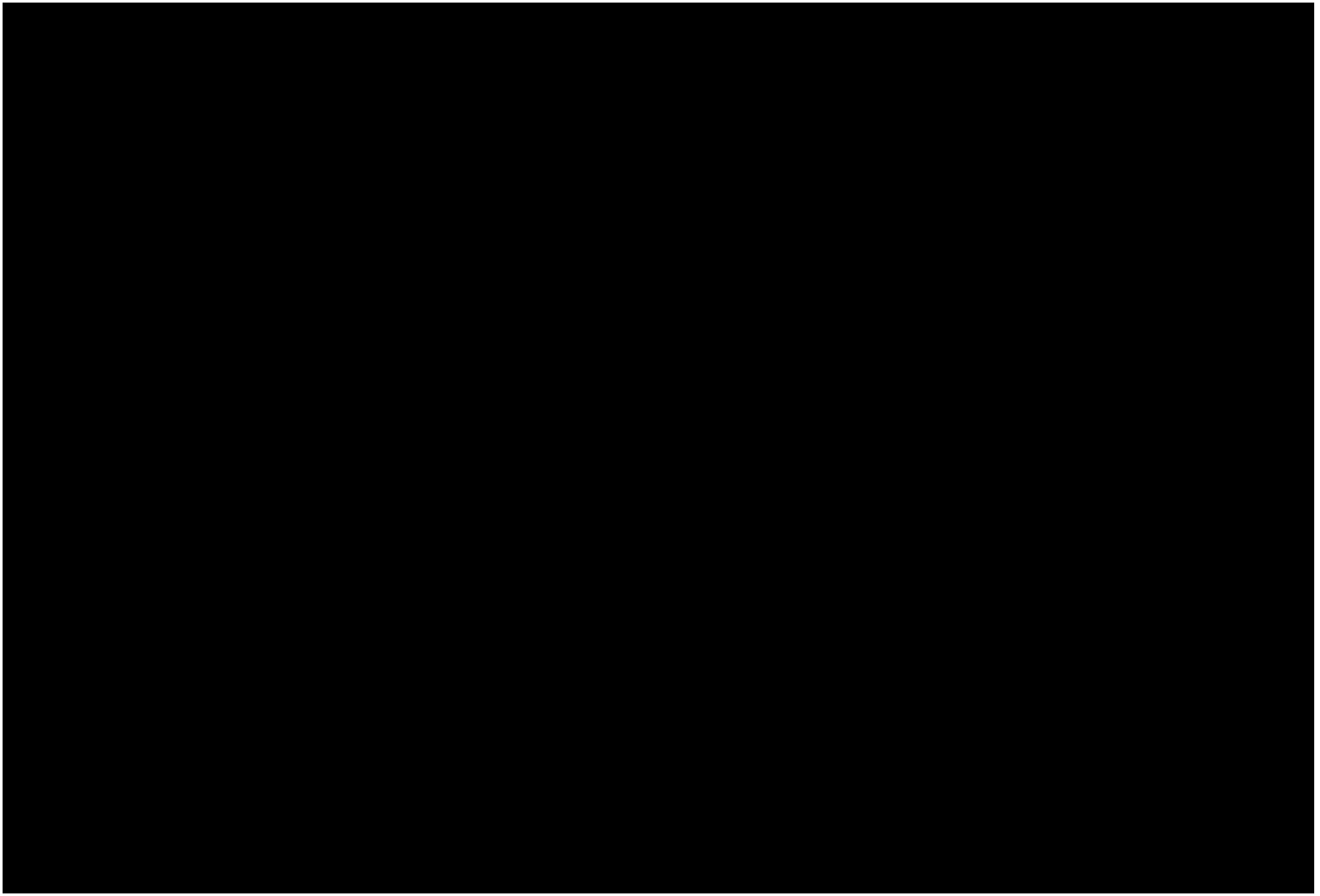
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

K.C. Electric Association, Inc.

Date of On Peak Day - 10/19/2021



Member Forecasted On Peak Demand Day for November 2021

K.C. Electric Association, Inc.

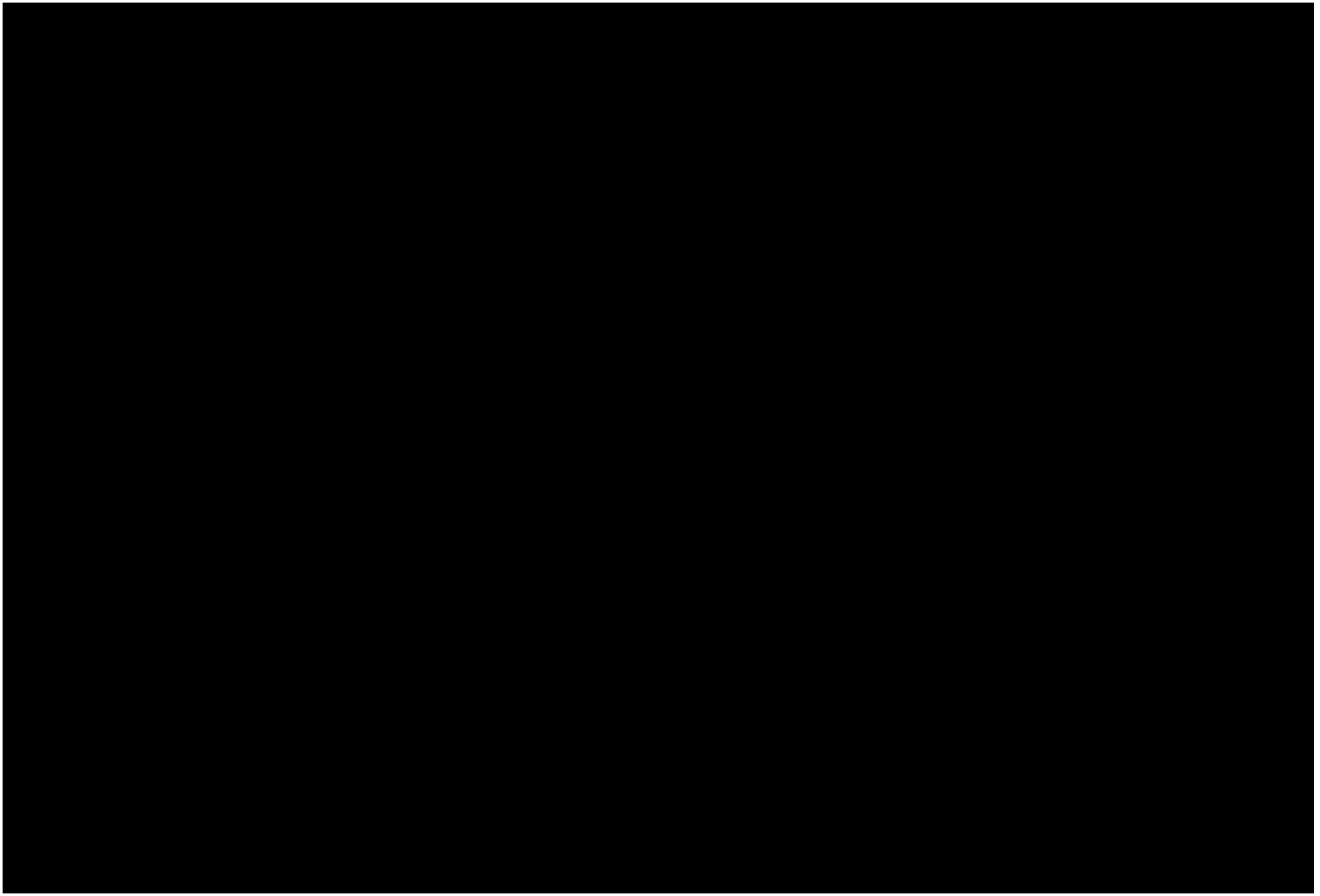
Date of On Peak Day - 11/08/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

K.C. Electric Association, Inc.

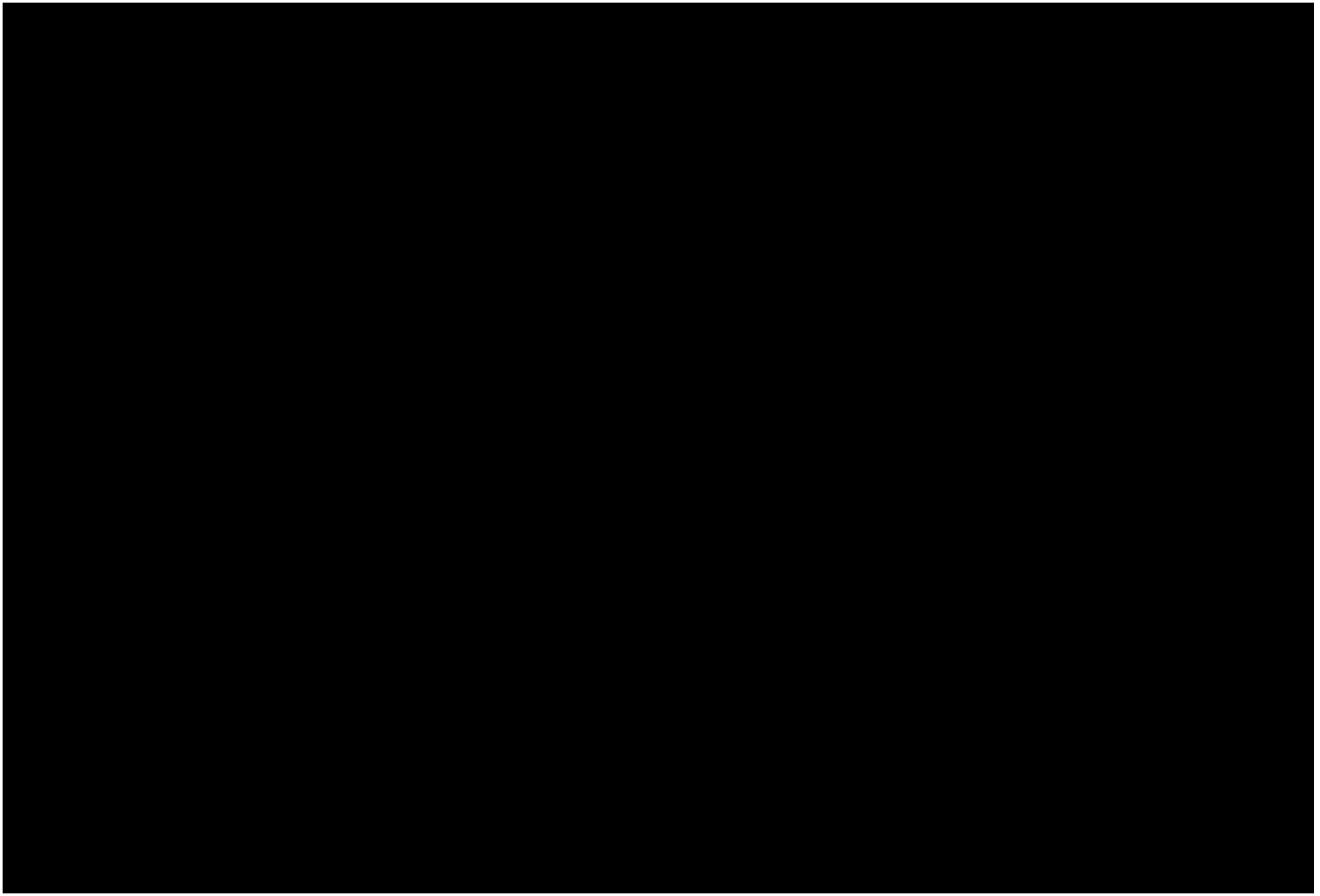
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

La Plata Electric Association, Inc.

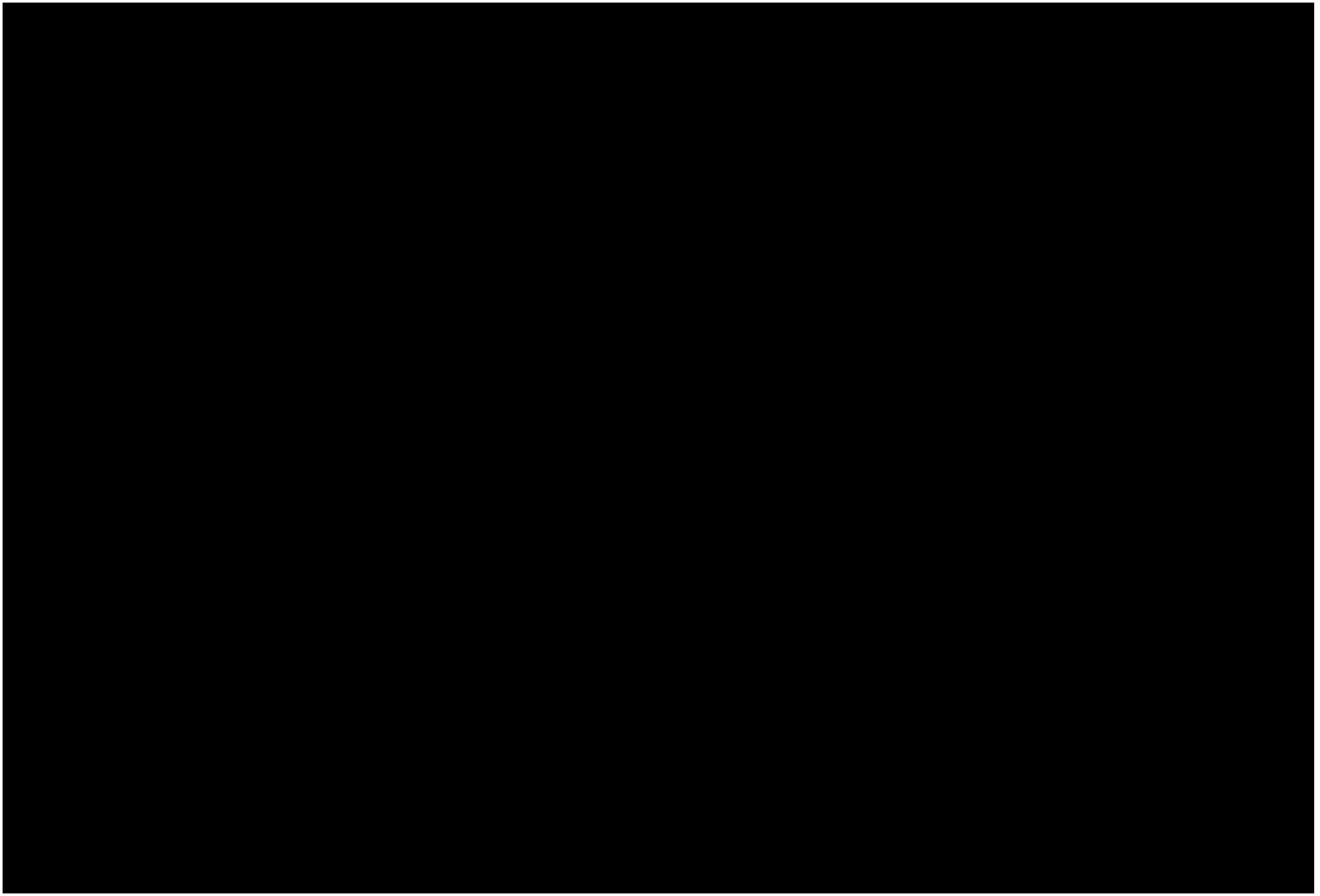
Date of On Peak Day - 01/25/2021



Member Forecasted On Peak Demand Day for February 2021

La Plata Electric Association, Inc.

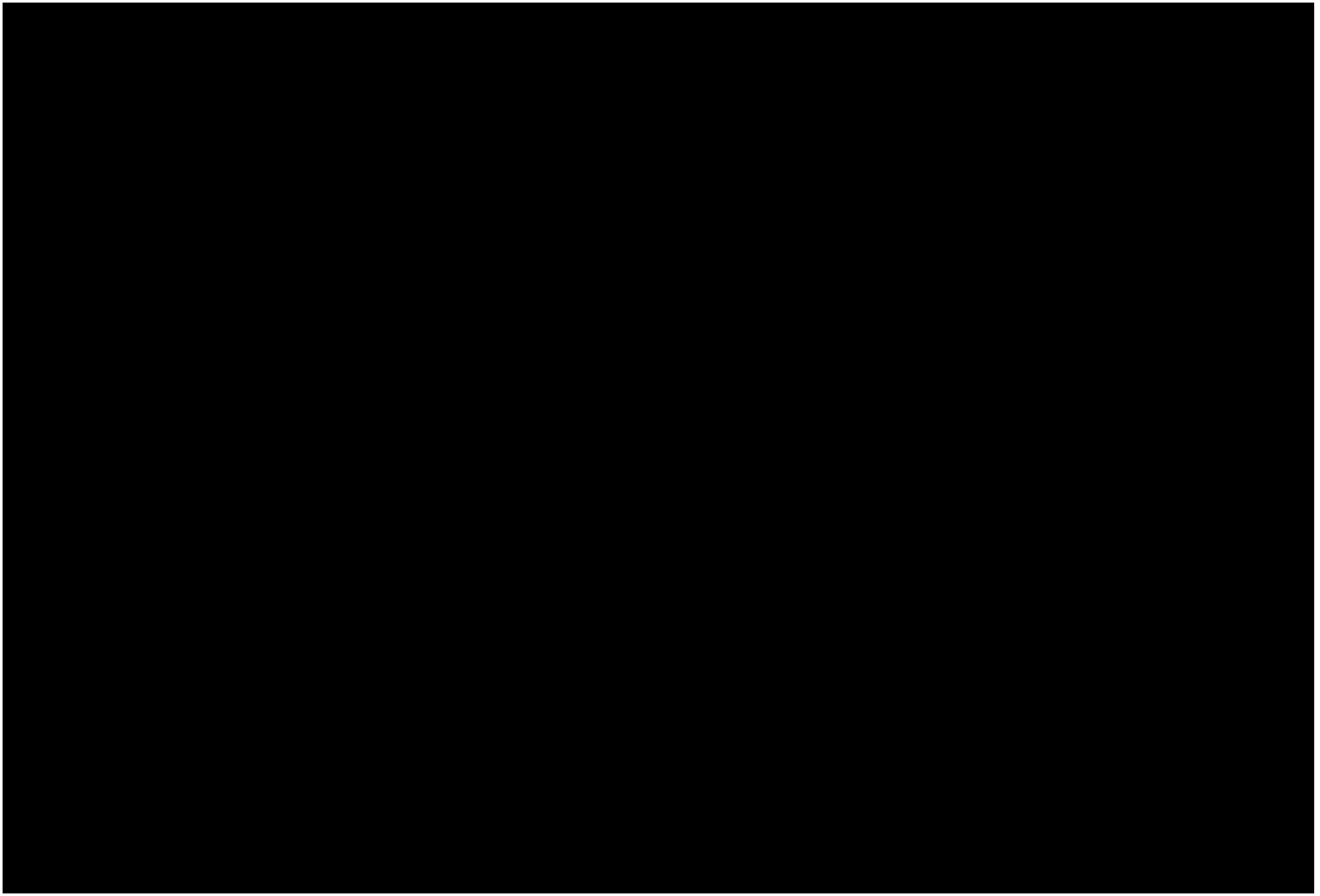
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

La Plata Electric Association, Inc.

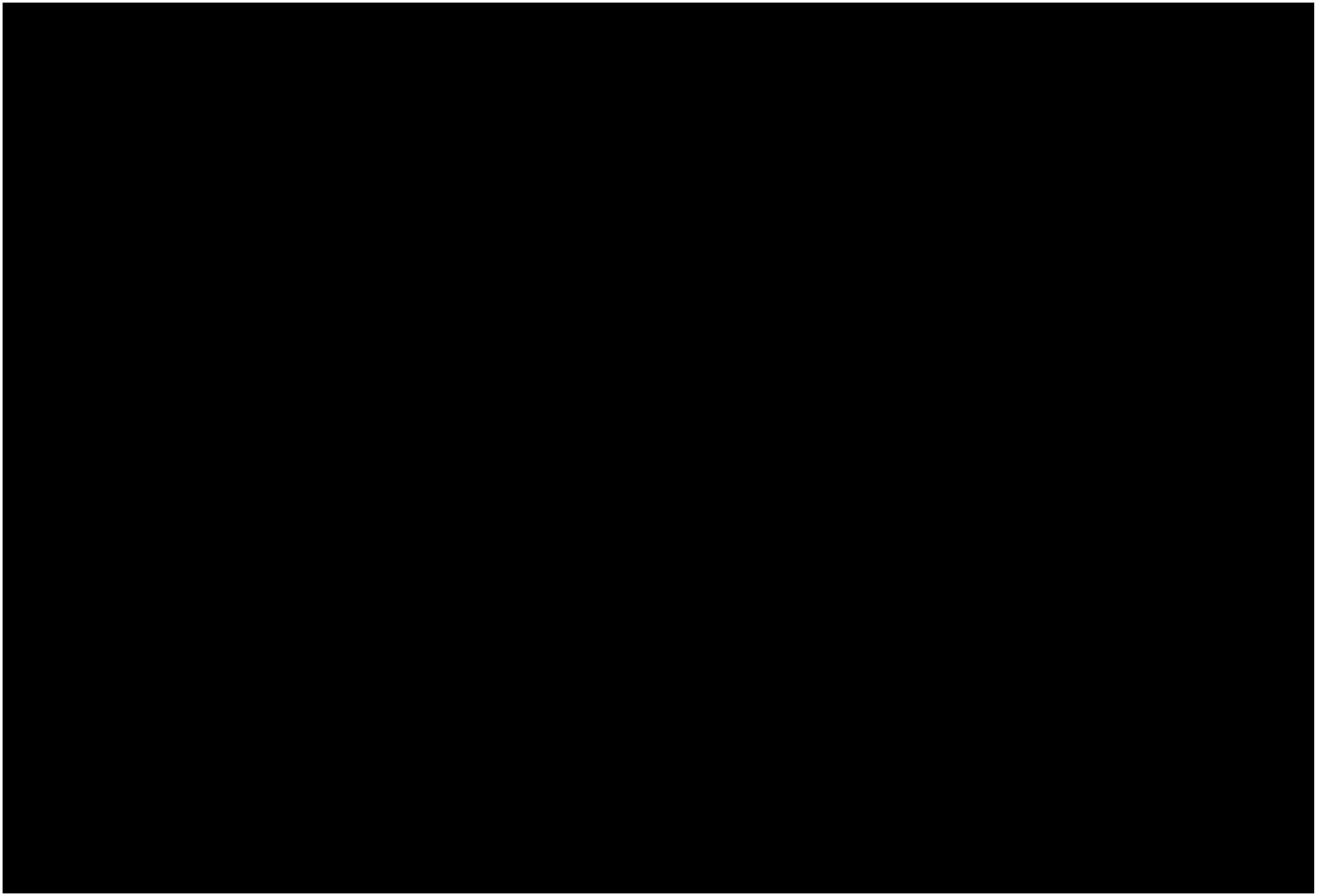
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

La Plata Electric Association, Inc.

Date of On Peak Day - 04/16/2021



Member Forecasted On Peak Demand Day for May 2021

La Plata Electric Association, Inc.

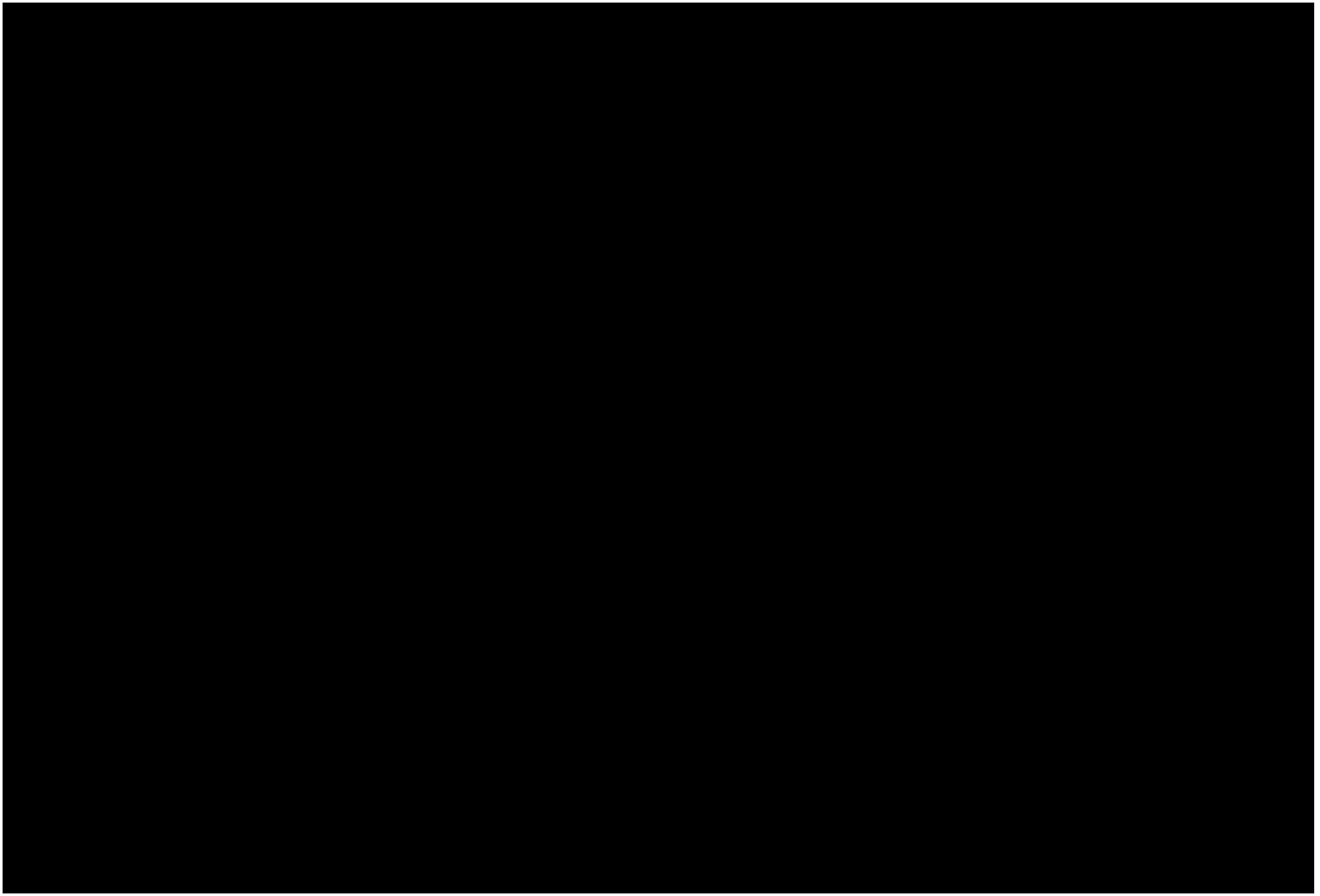
Date of On Peak Day - 05/19/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

La Plata Electric Association, Inc.

Date of On Peak Day - 06/24/2021



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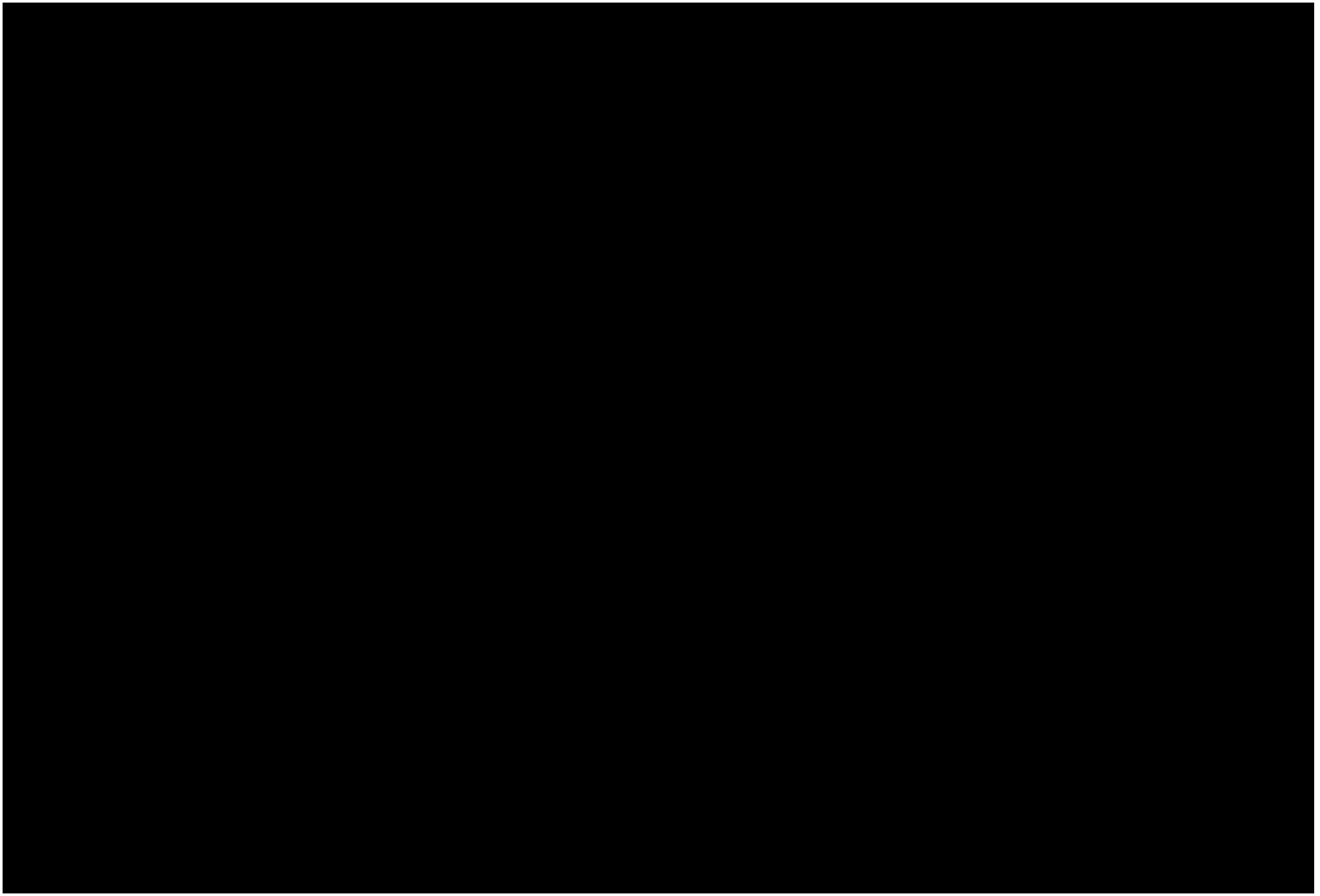
Member Forecasted On Peak Demand Day for July 2021

La Plata Electric Association, Inc.

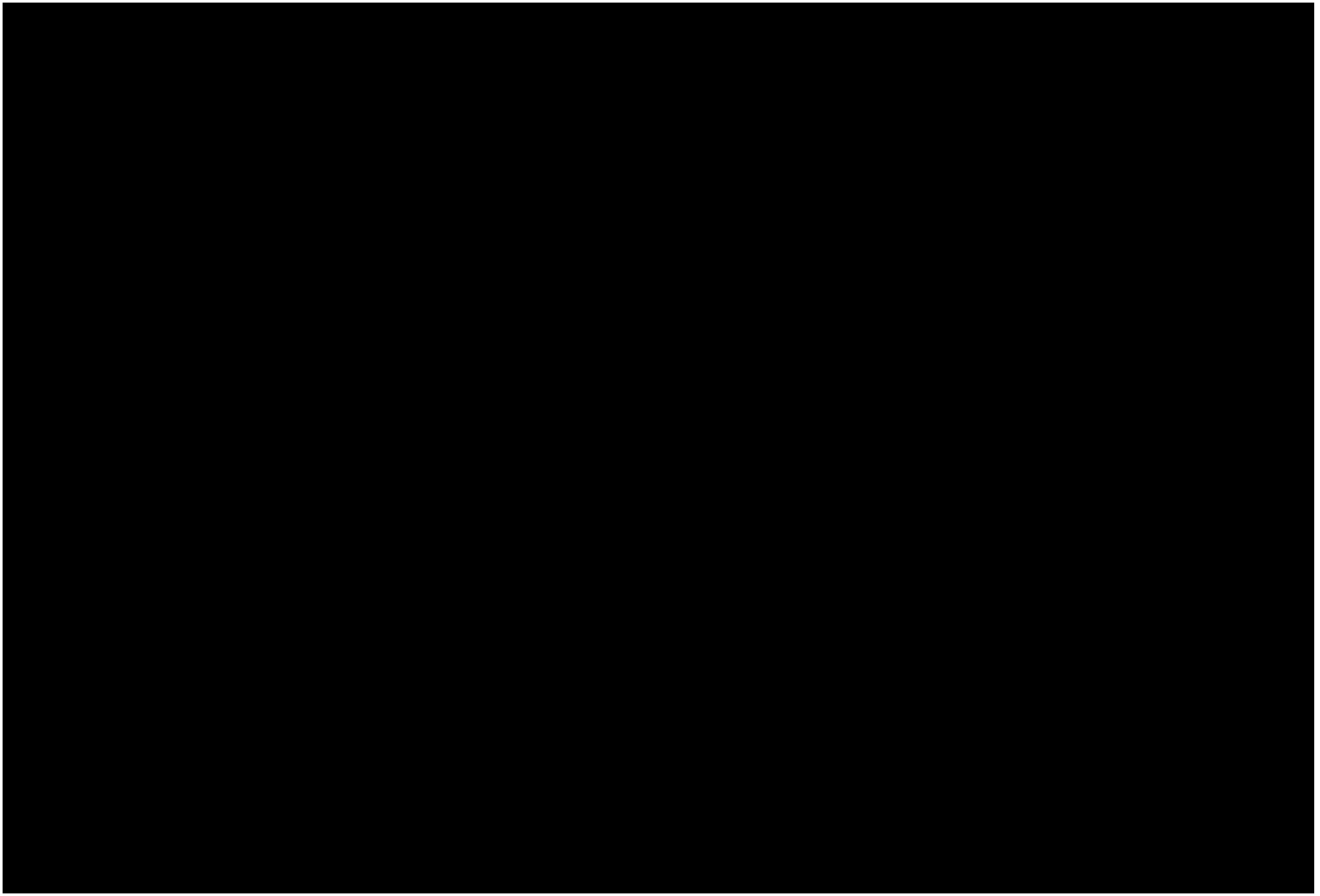
Date of On Peak Day - 07/19/2021



Member Forecasted On Peak Demand Day for August 2021

La Plata Electric Association, Inc.

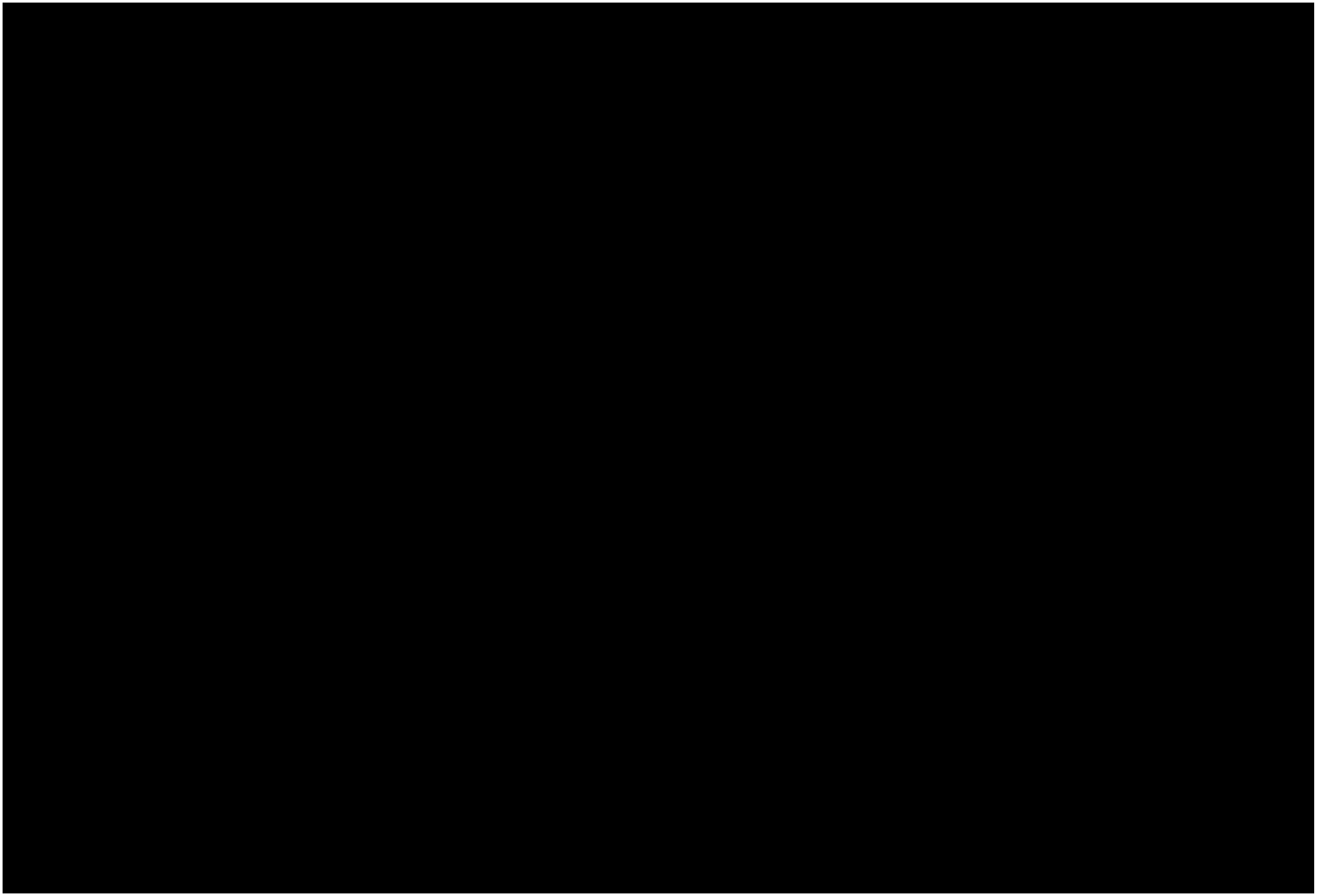
Date of On Peak Day - 08/26/2021



Member Forecasted On Peak Demand Day for September 2021

La Plata Electric Association, Inc.

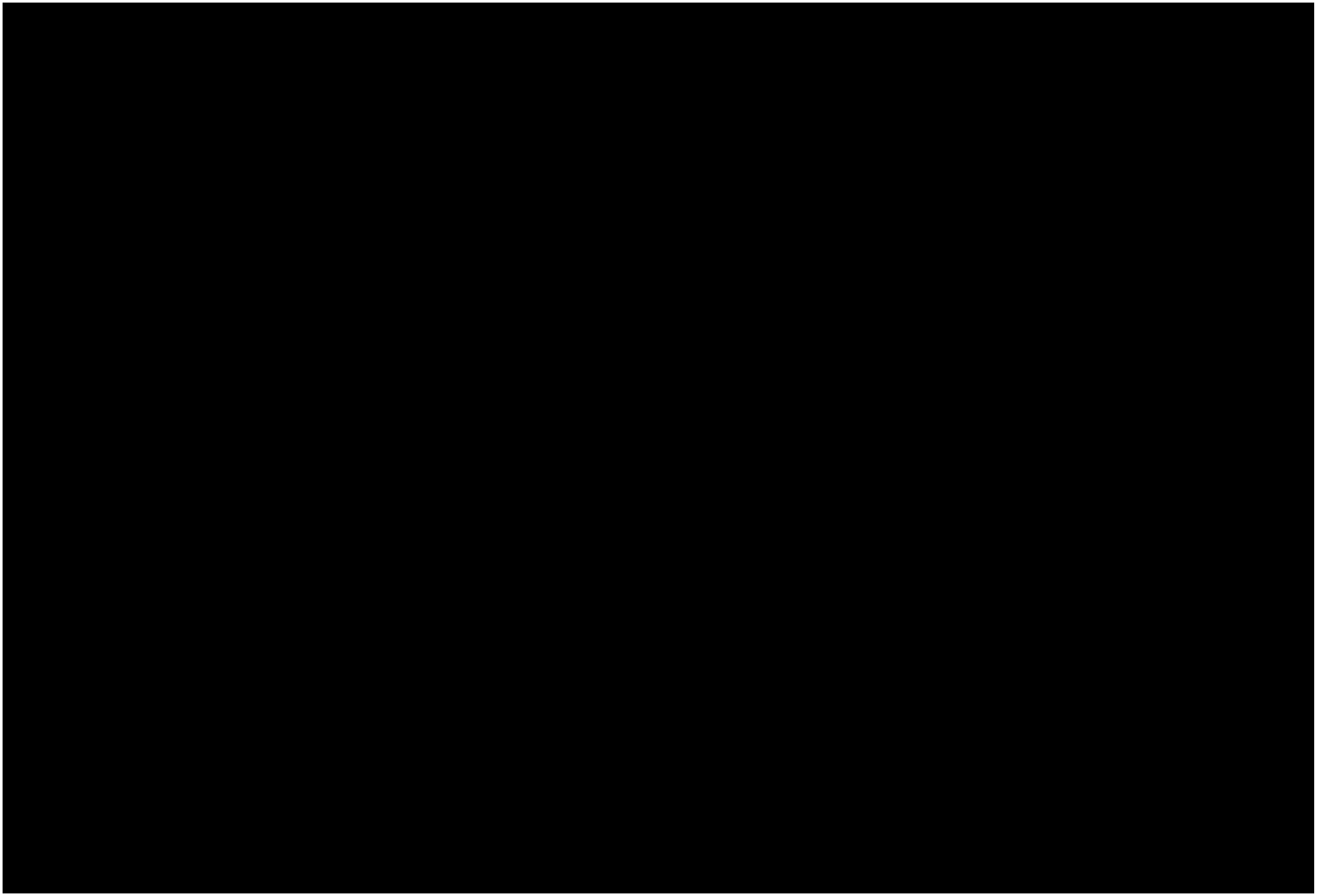
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

La Plata Electric Association, Inc.

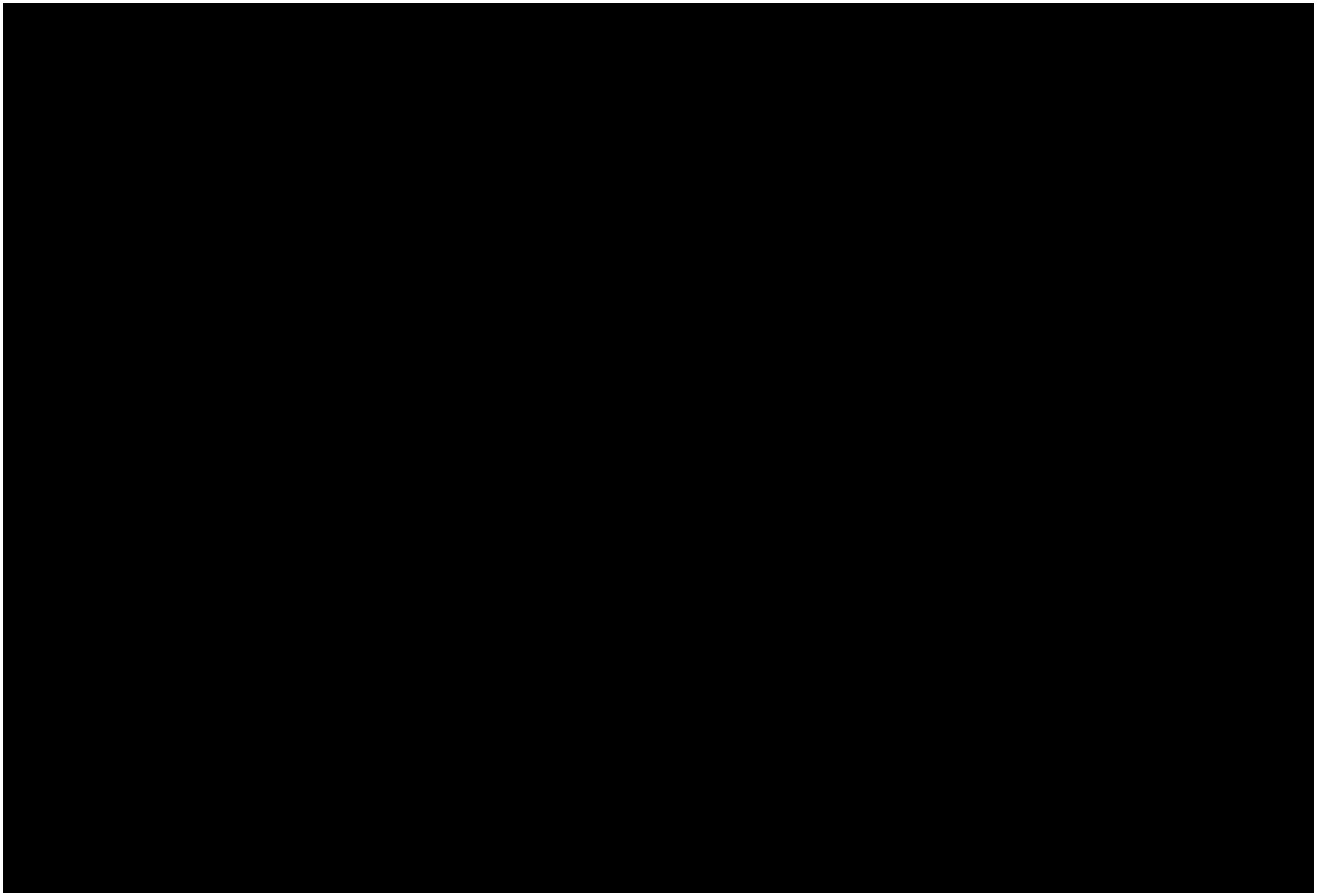
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

La Plata Electric Association, Inc.

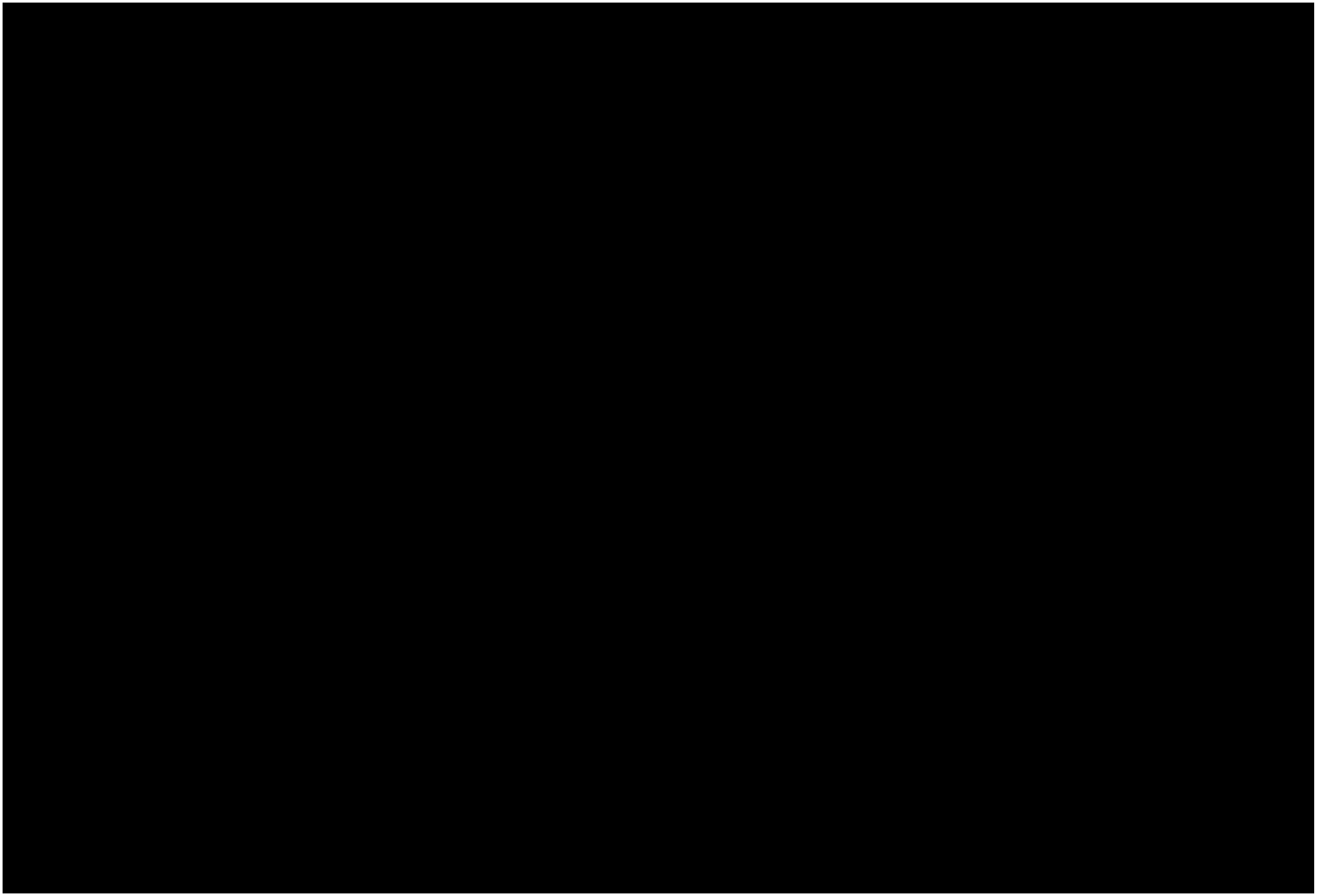
Date of On Peak Day - 11/30/2021



Member Forecasted On Peak Demand Day for December 2021

La Plata Electric Association, Inc.

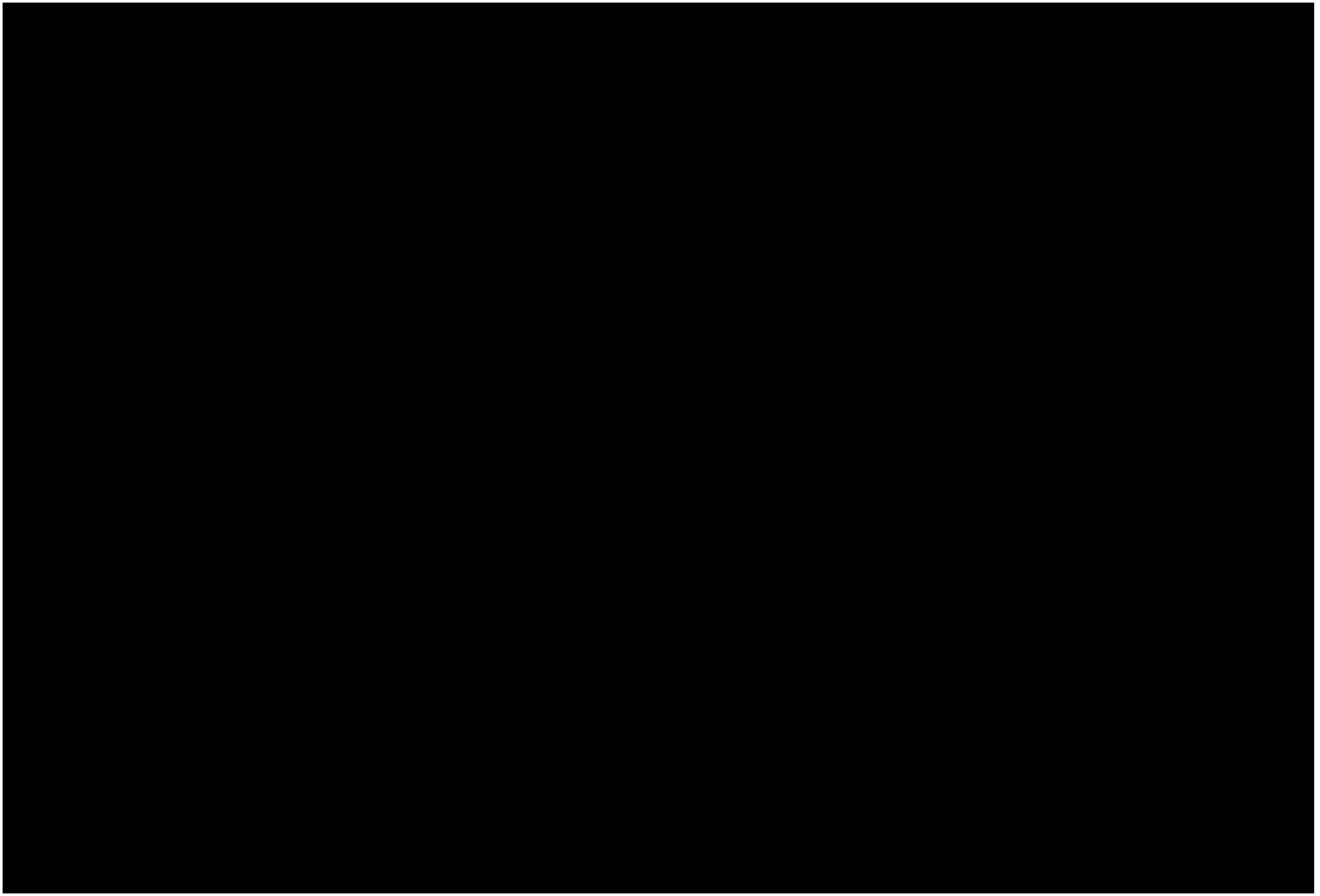
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Morgan County Rural Electric Association

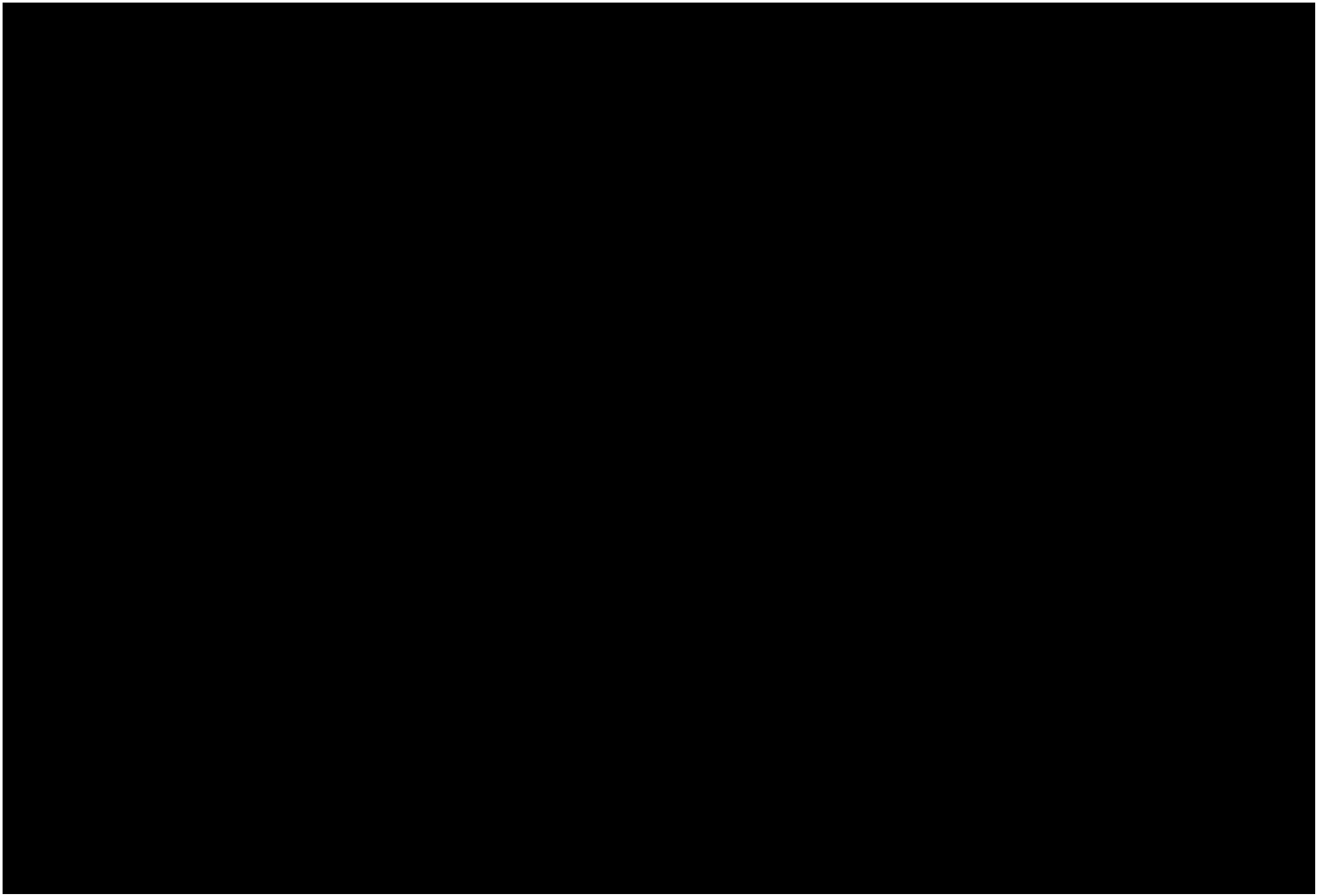
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Morgan County Rural Electric Association

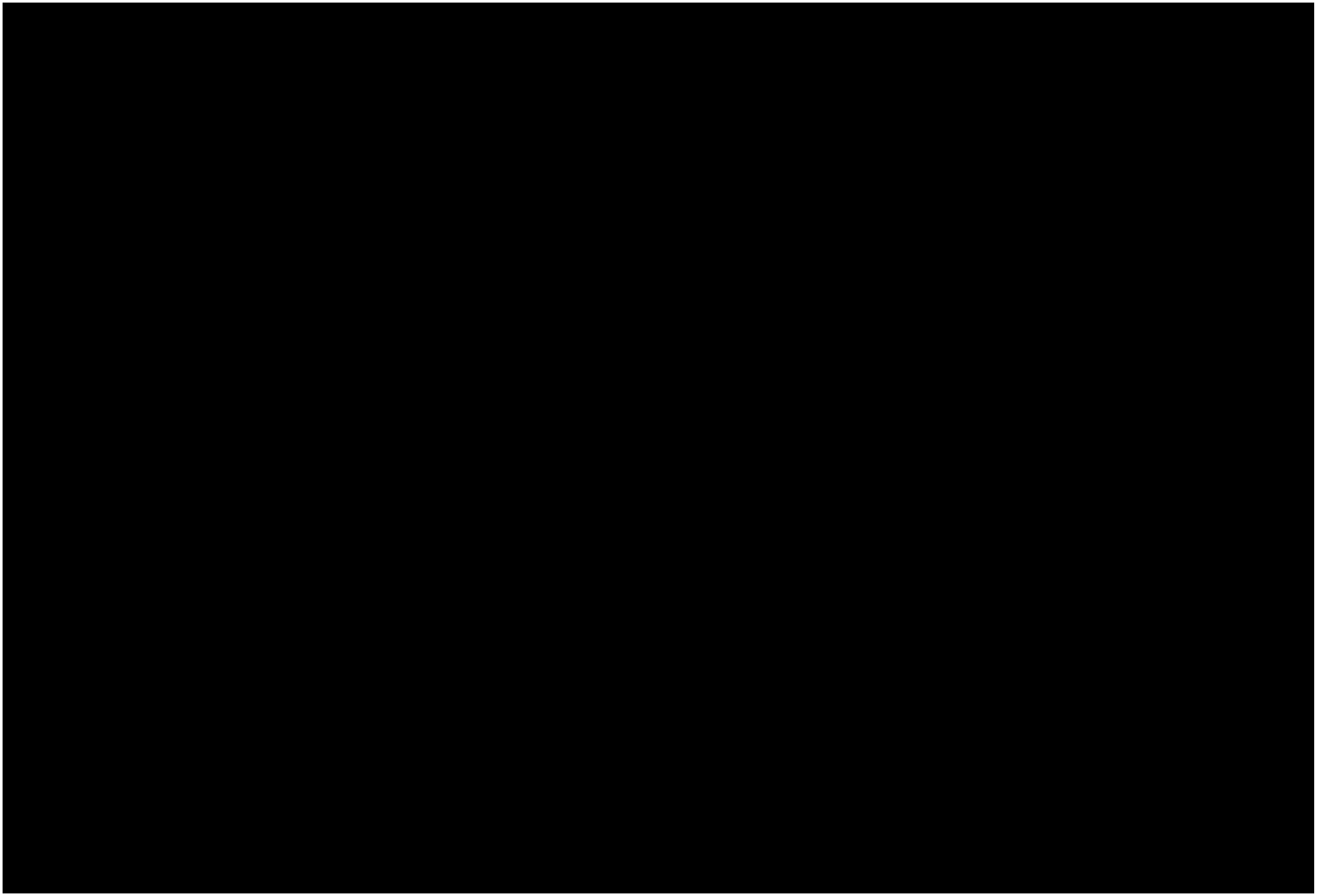
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Morgan County Rural Electric Association

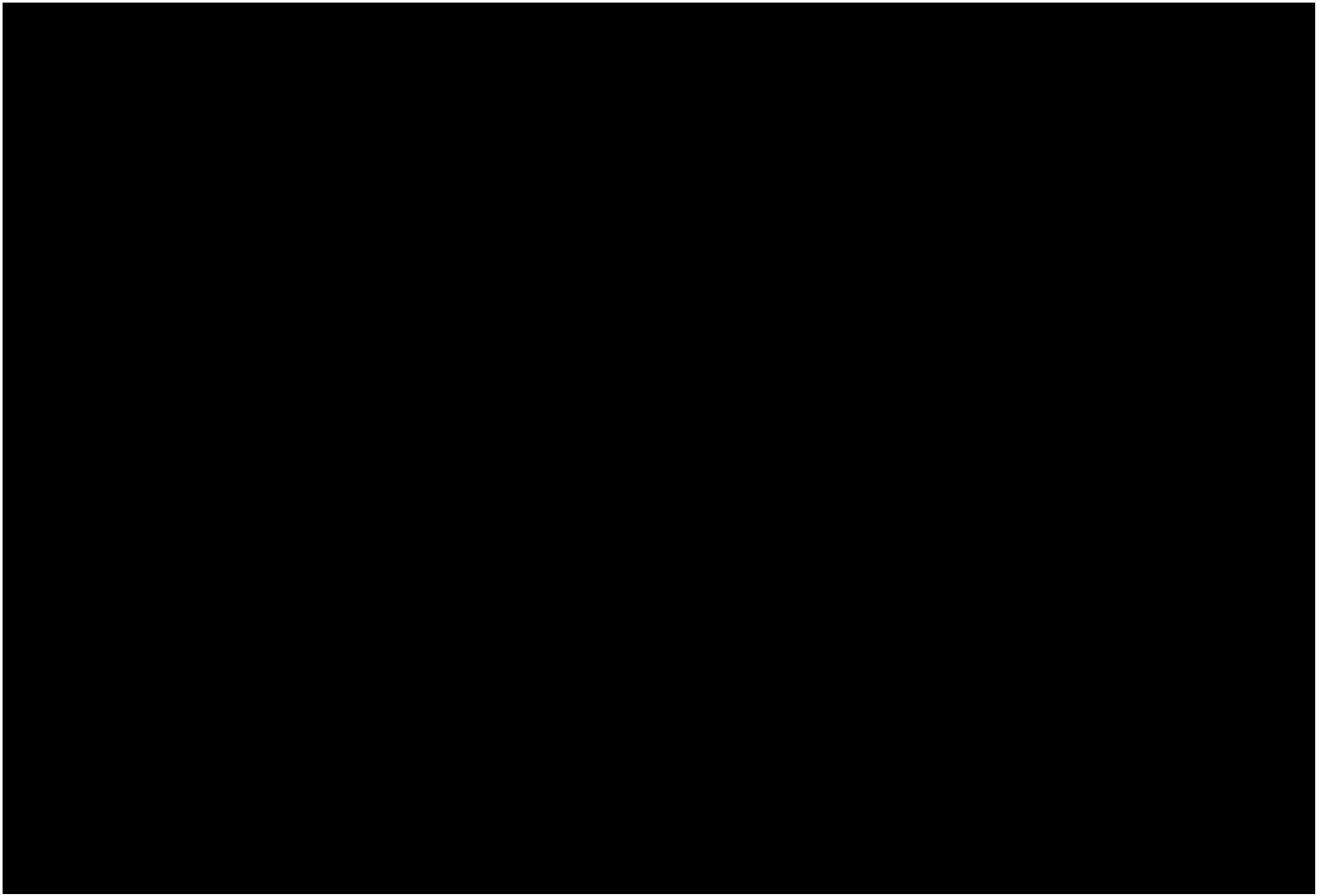
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Morgan County Rural Electric Association

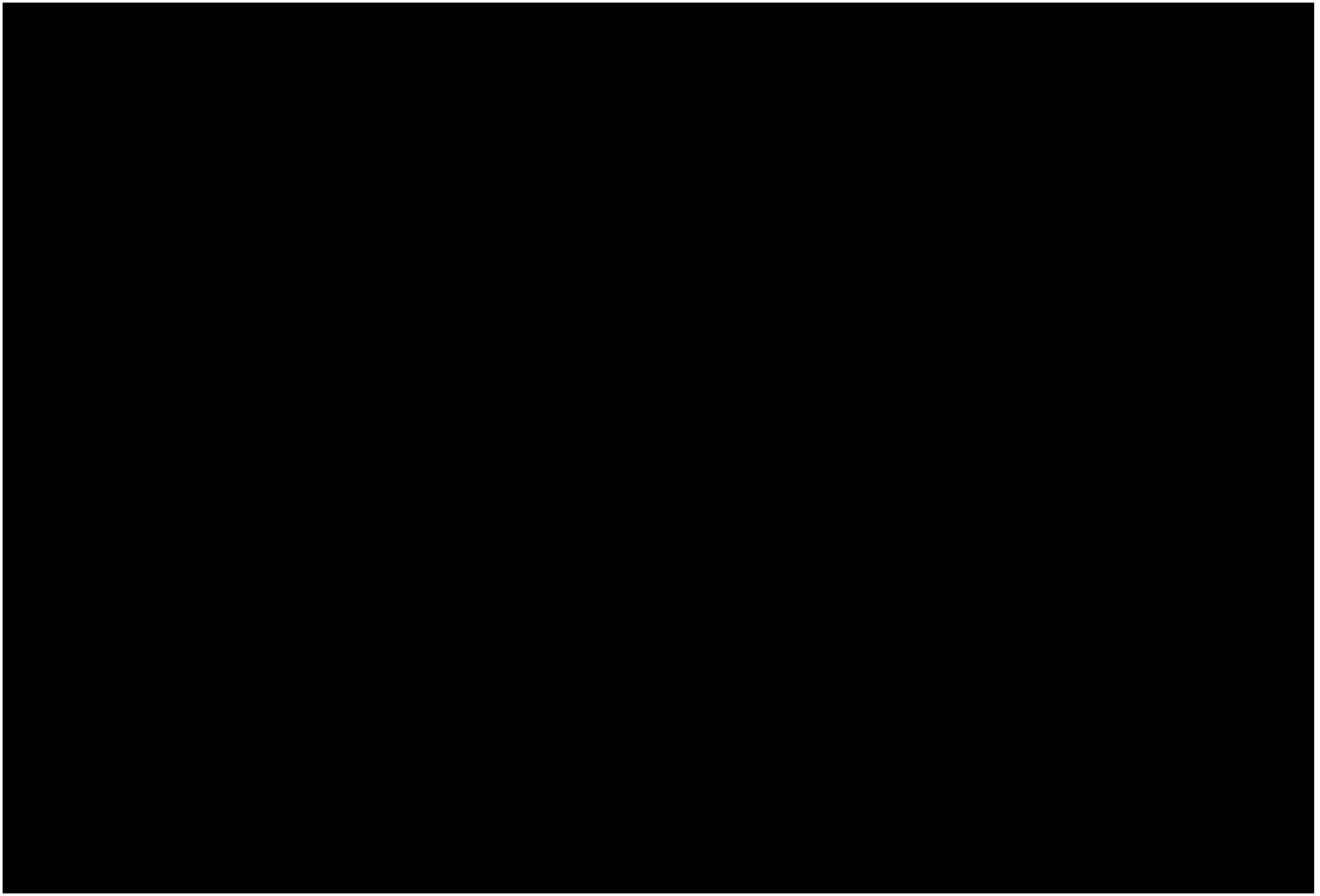
Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

Morgan County Rural Electric Association

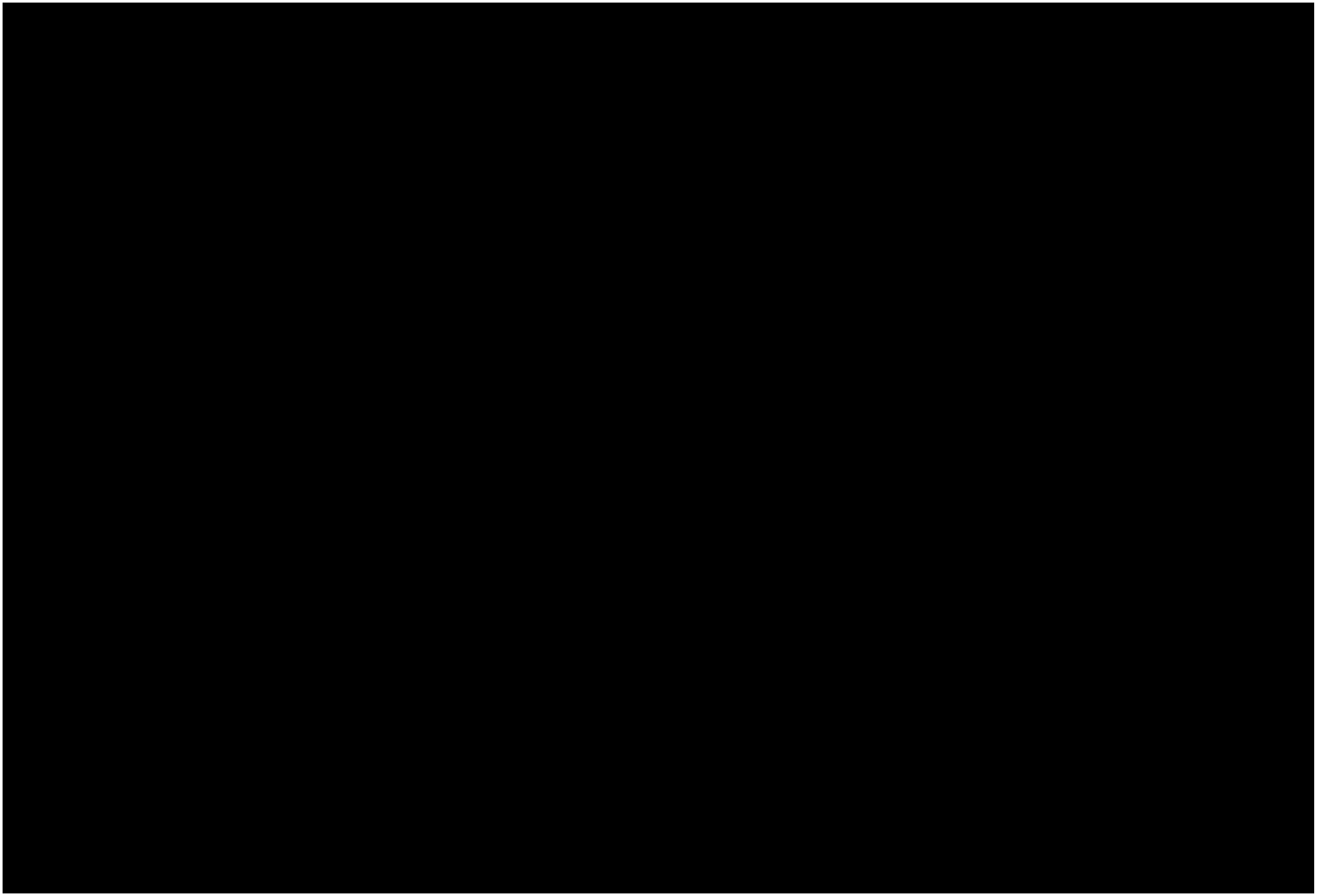
Date of On Peak Day - 05/15/2021



Member Forecasted On Peak Demand Day for June 2021

Morgan County Rural Electric Association

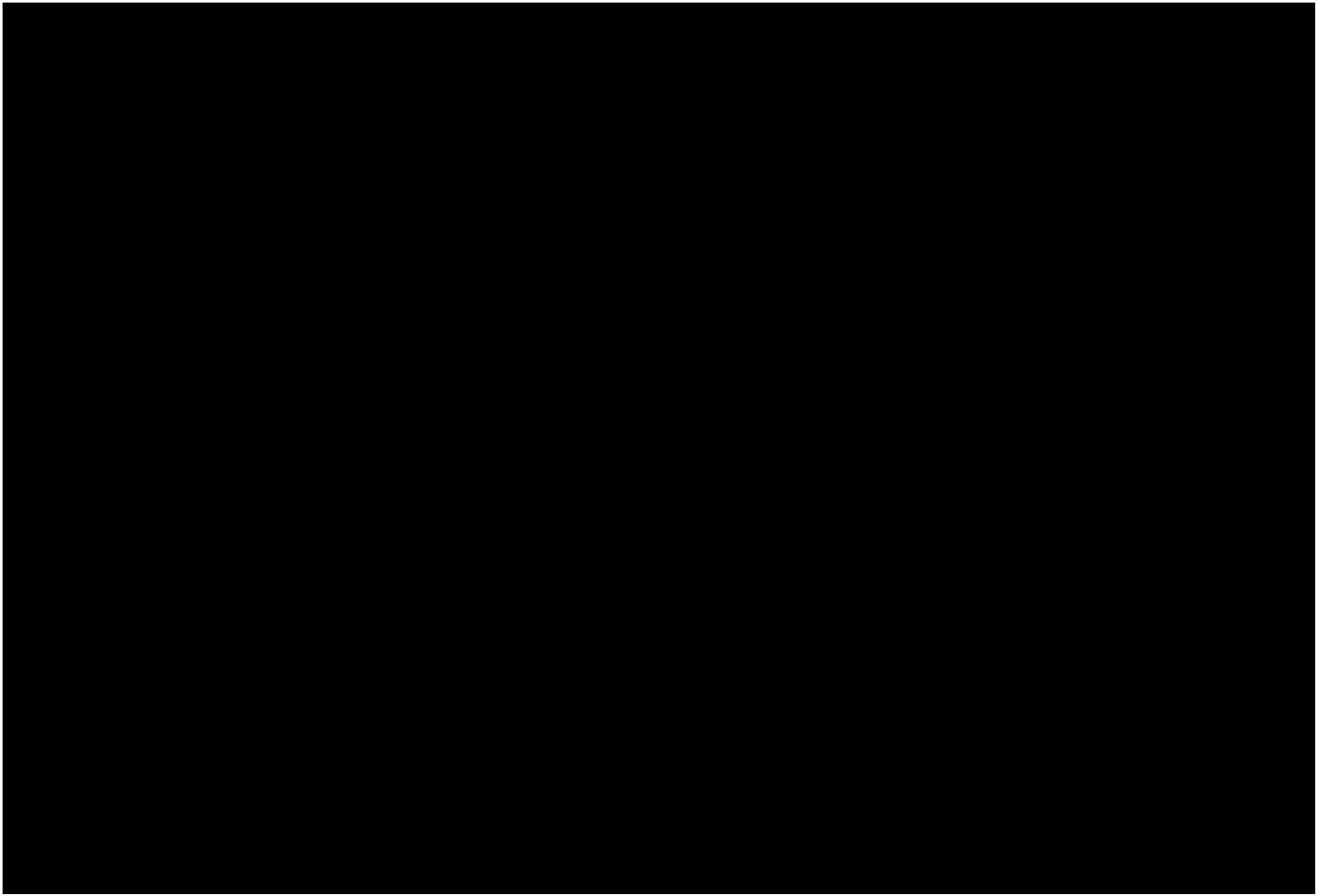
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Morgan County Rural Electric Association

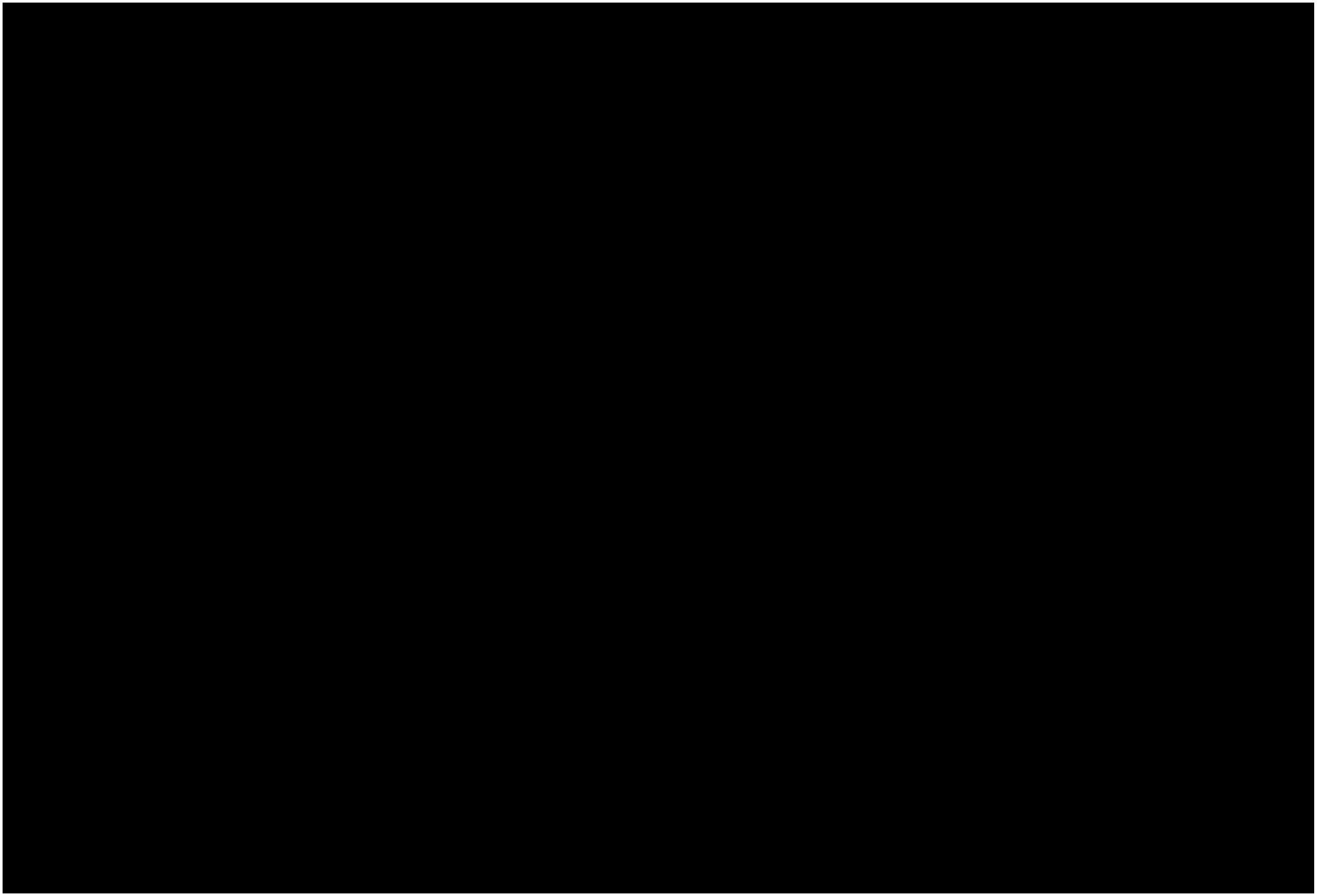
Date of On Peak Day - 07/17/2021



Member Forecasted On Peak Demand Day for August 2021

Morgan County Rural Electric Association

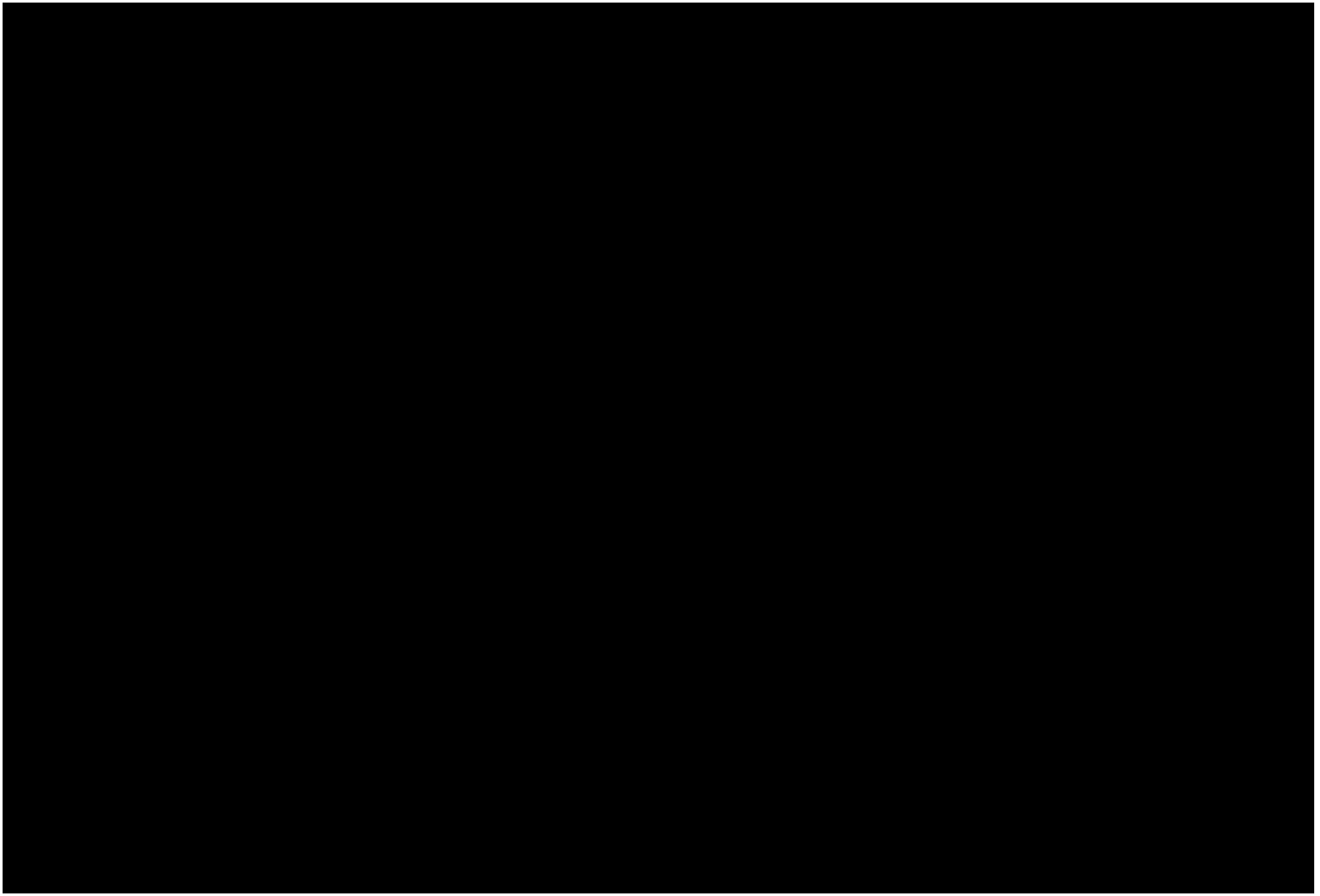
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Morgan County Rural Electric Association

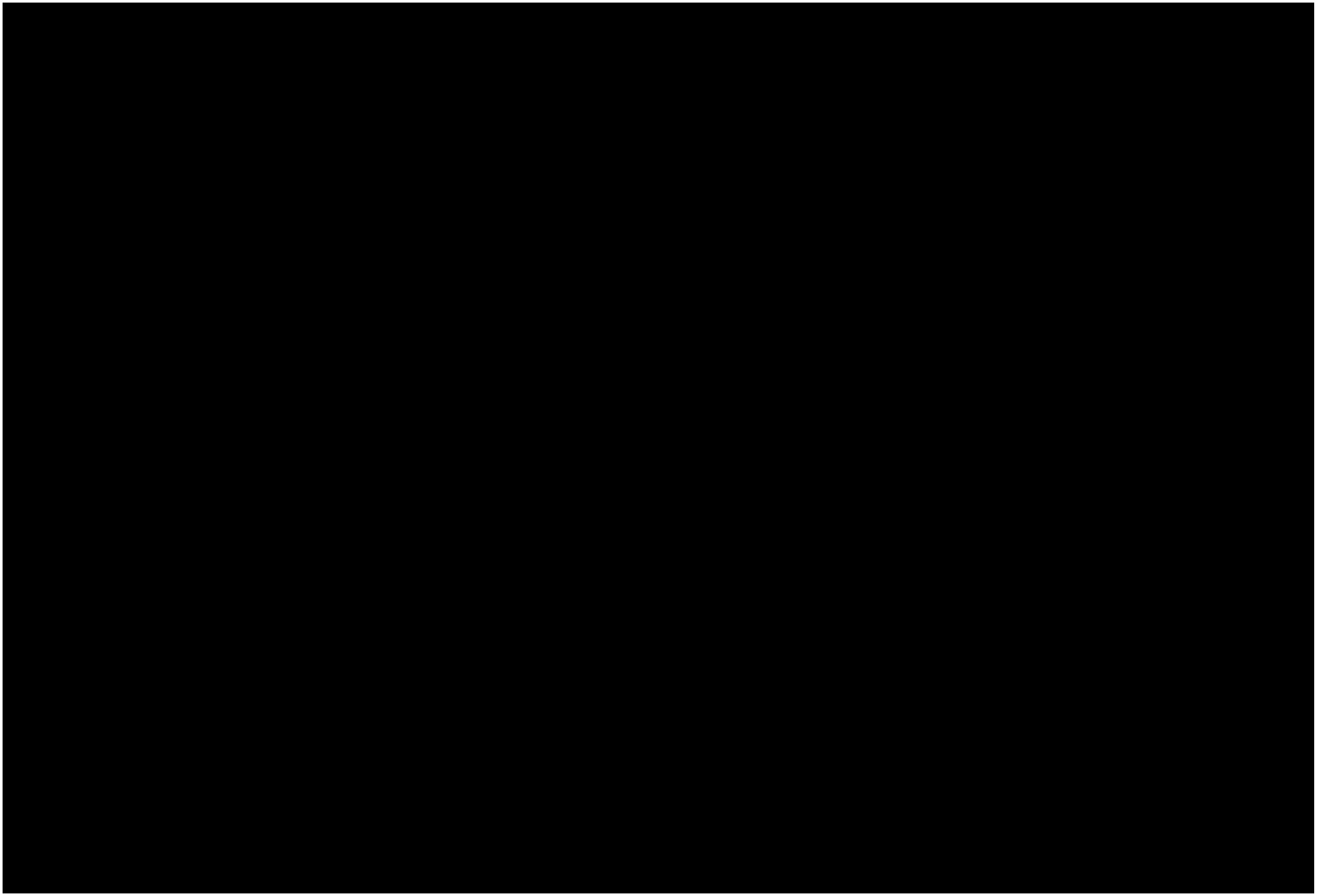
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Morgan County Rural Electric Association

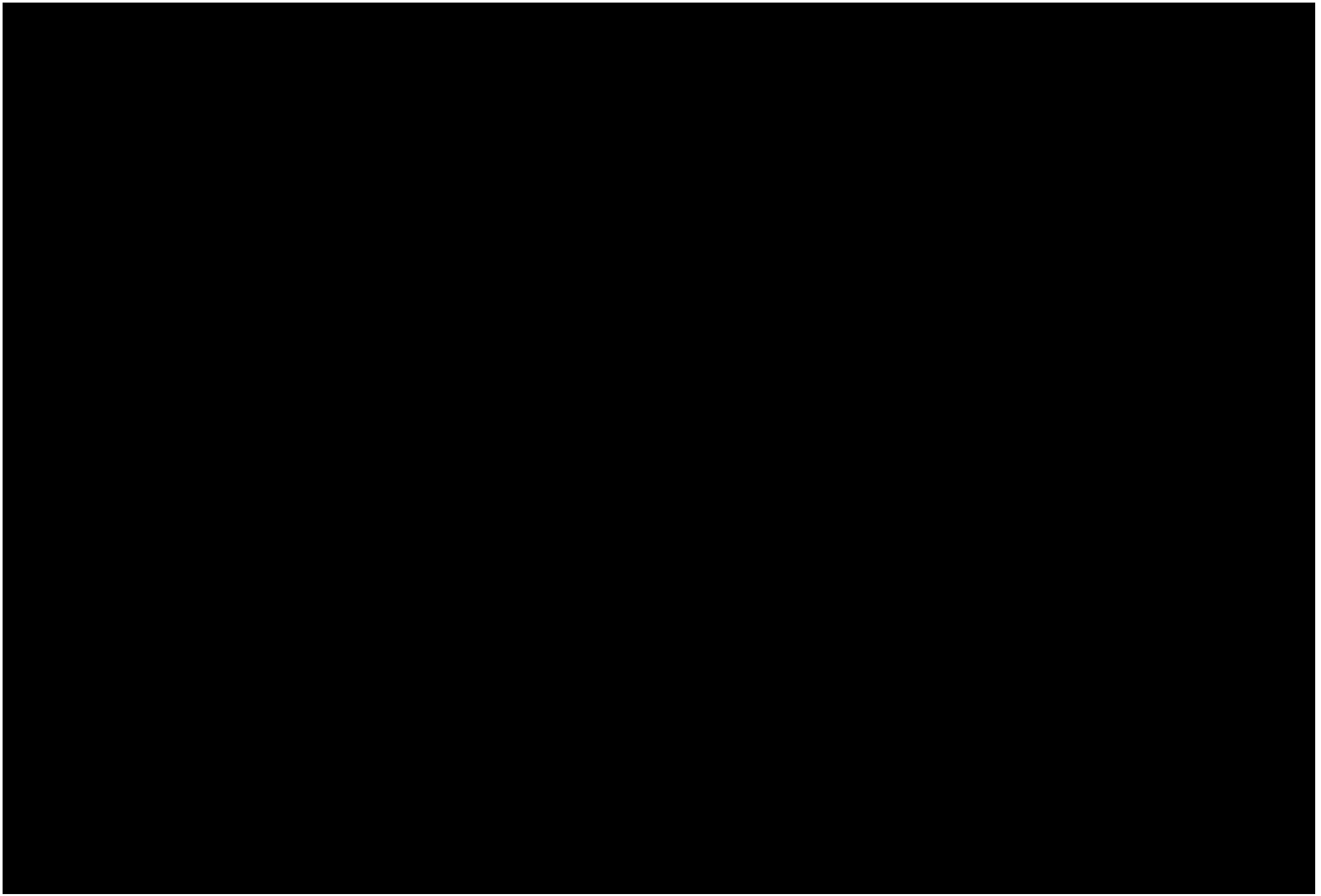
Date of On Peak Day - 10/18/2021



Member Forecasted On Peak Demand Day for November 2021

Morgan County Rural Electric Association

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

Morgan County Rural Electric Association

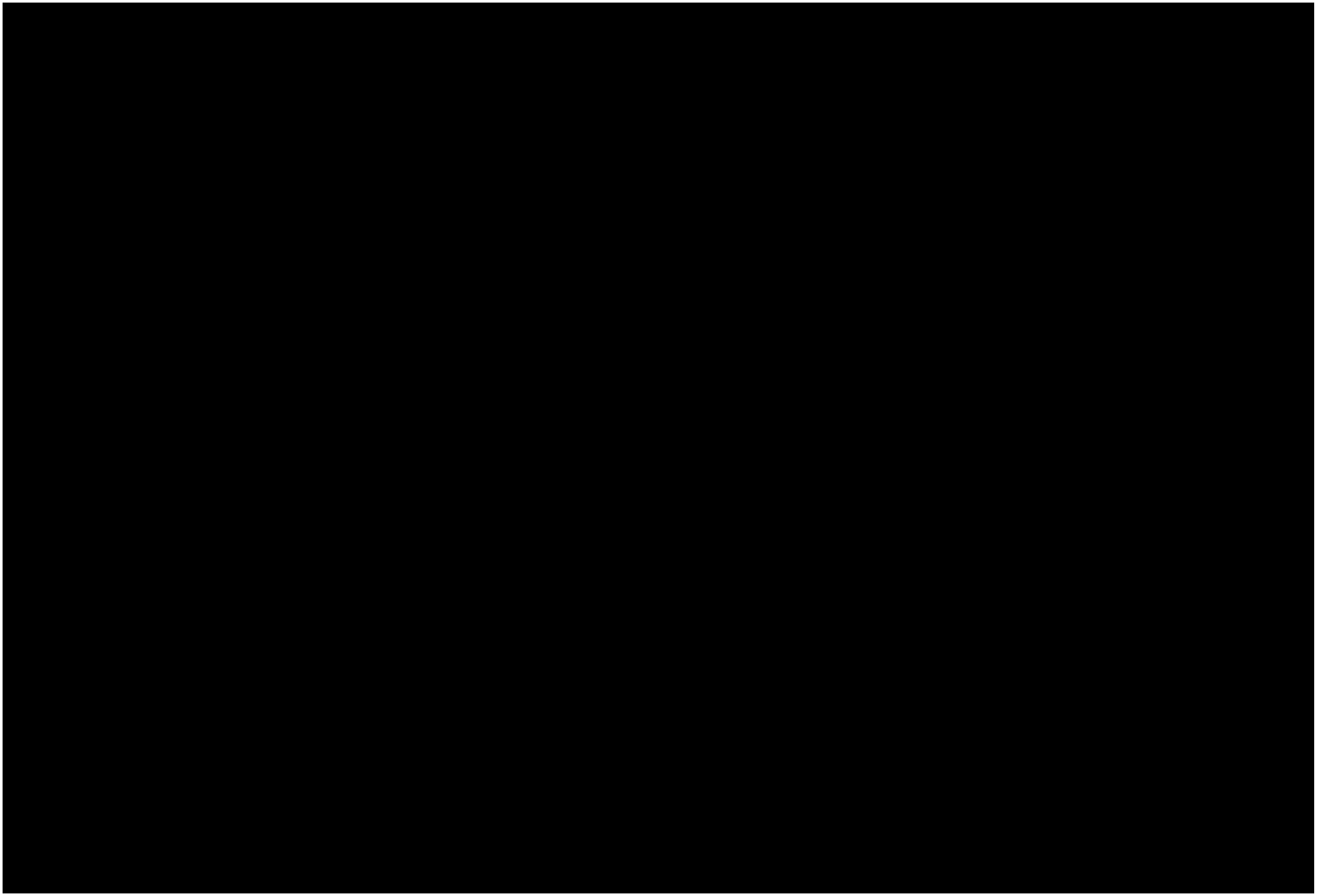
Date of On Peak Day - 12/28/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Mountain Parks Electric, Inc.

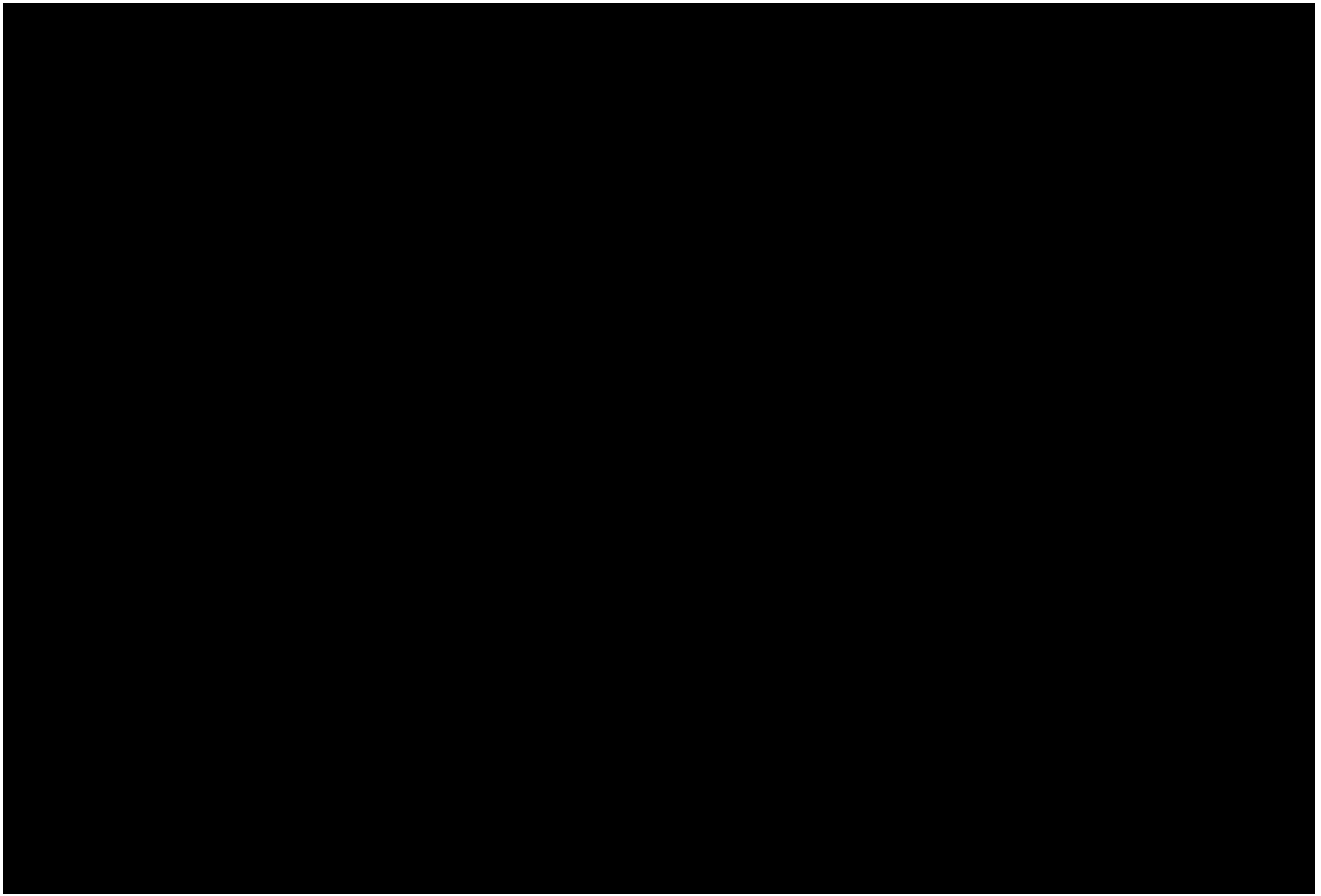
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Mountain Parks Electric, Inc.

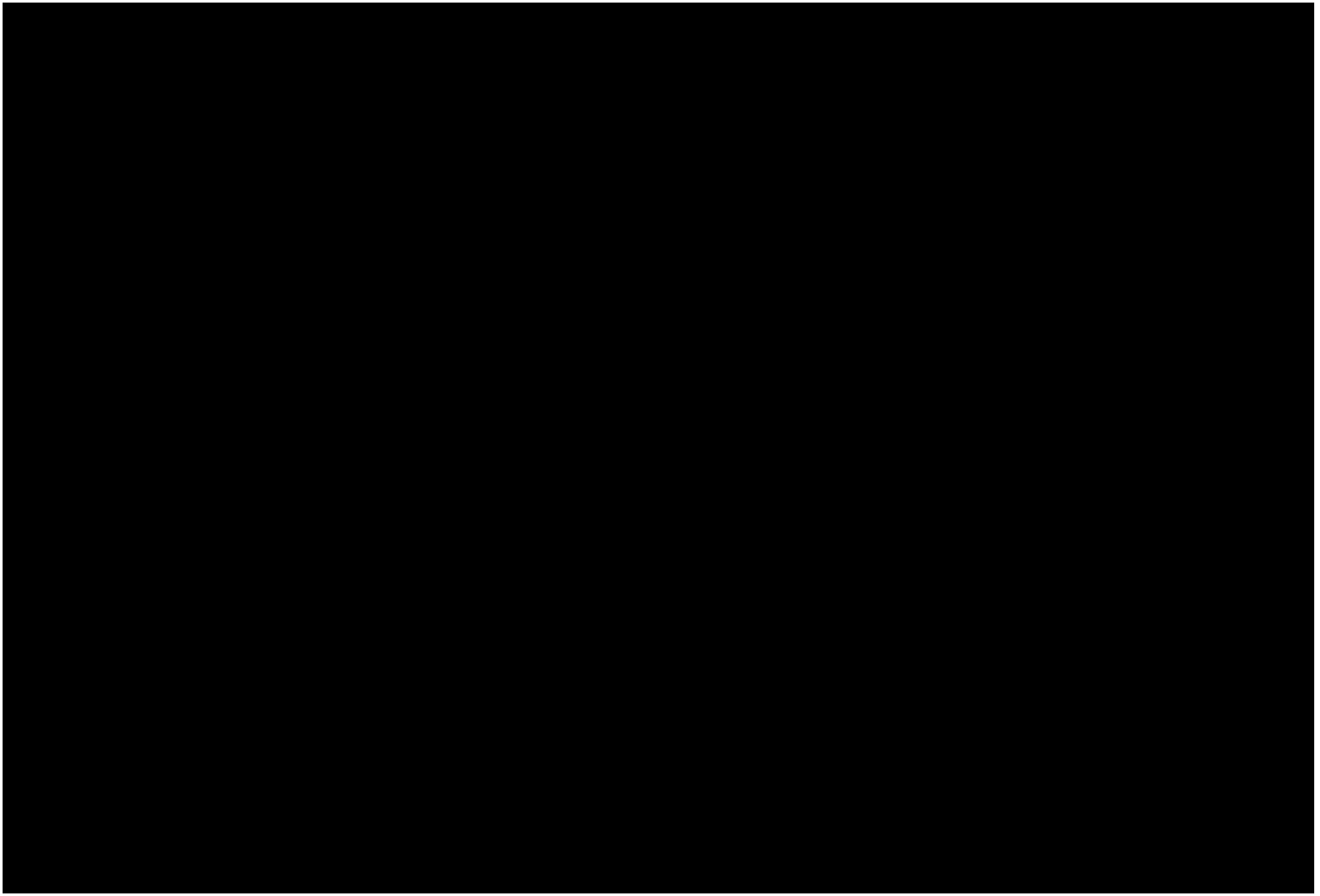
Date of On Peak Day - 02/16/2021



Member Forecasted On Peak Demand Day for March 2021

Mountain Parks Electric, Inc.

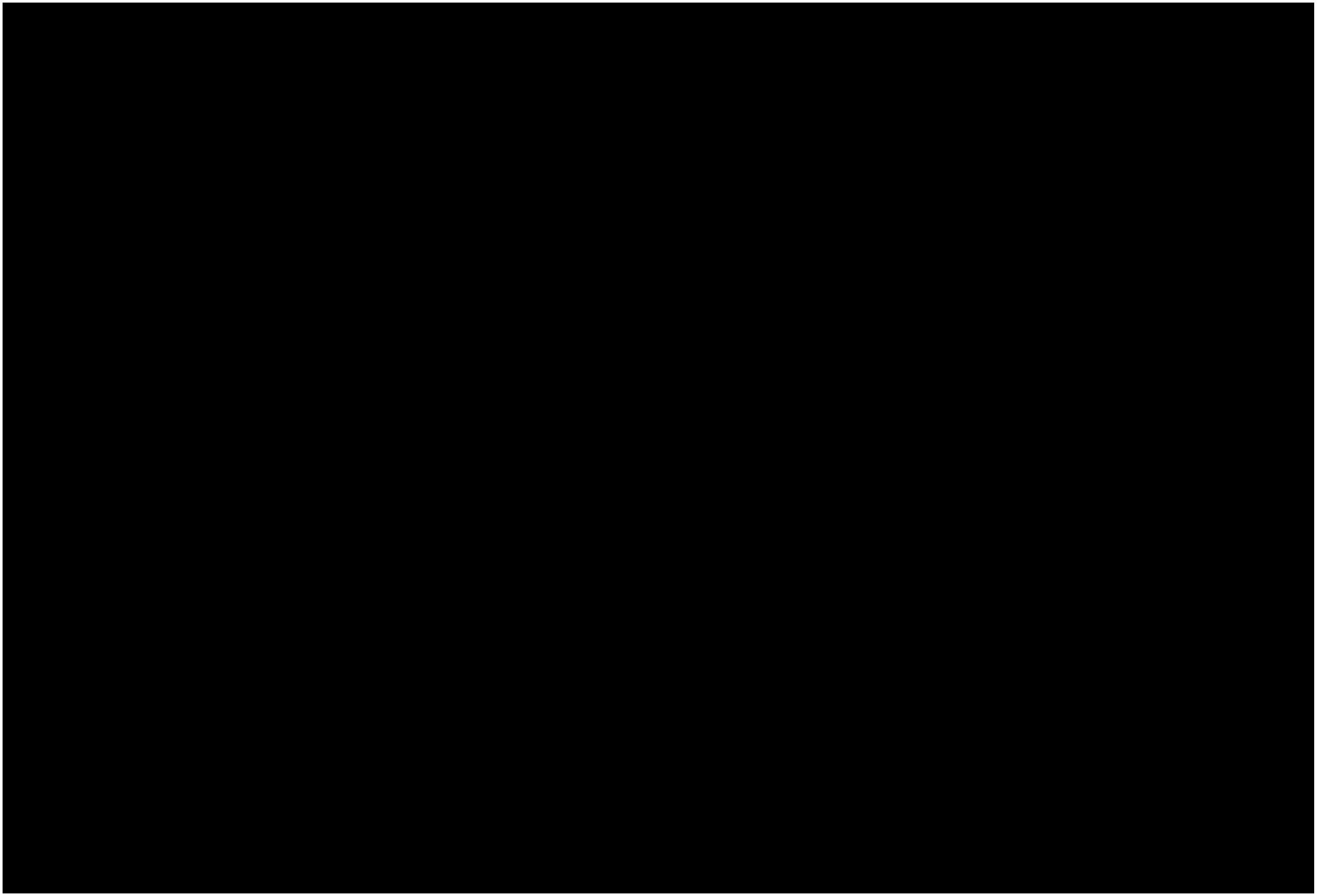
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Mountain Parks Electric, Inc.

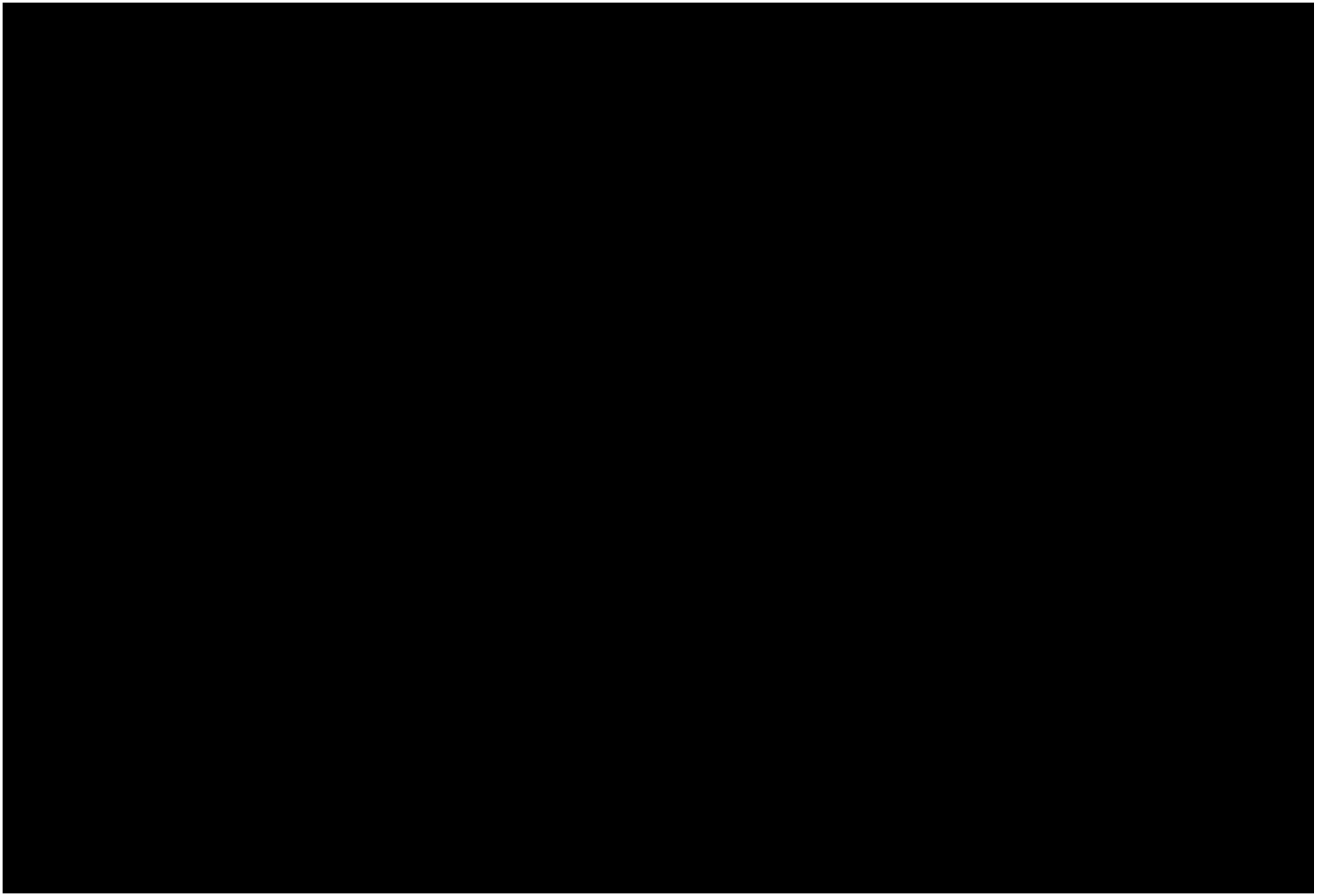
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

Mountain Parks Electric, Inc.

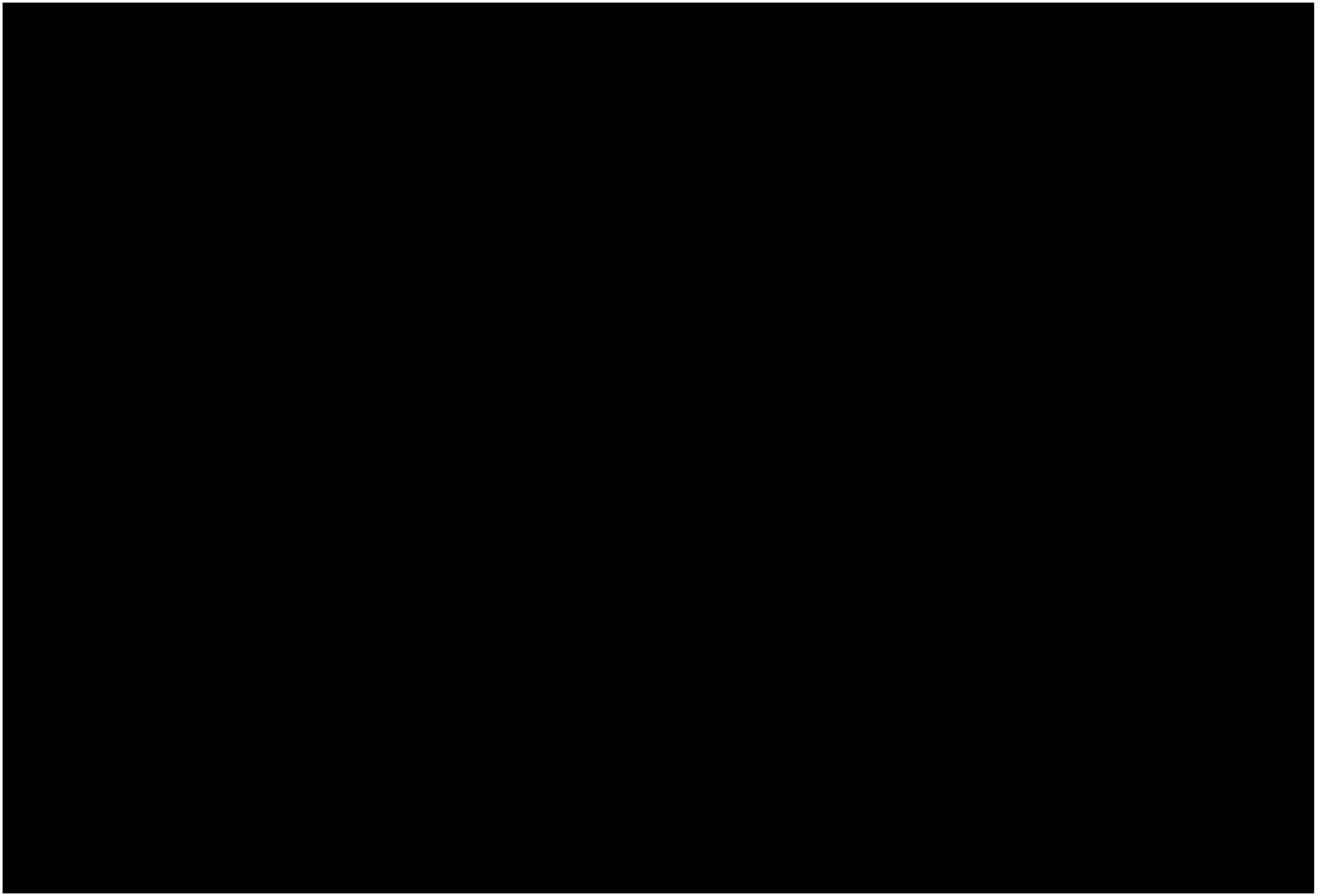
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

Mountain Parks Electric, Inc.

Date of On Peak Day - 06/25/2021



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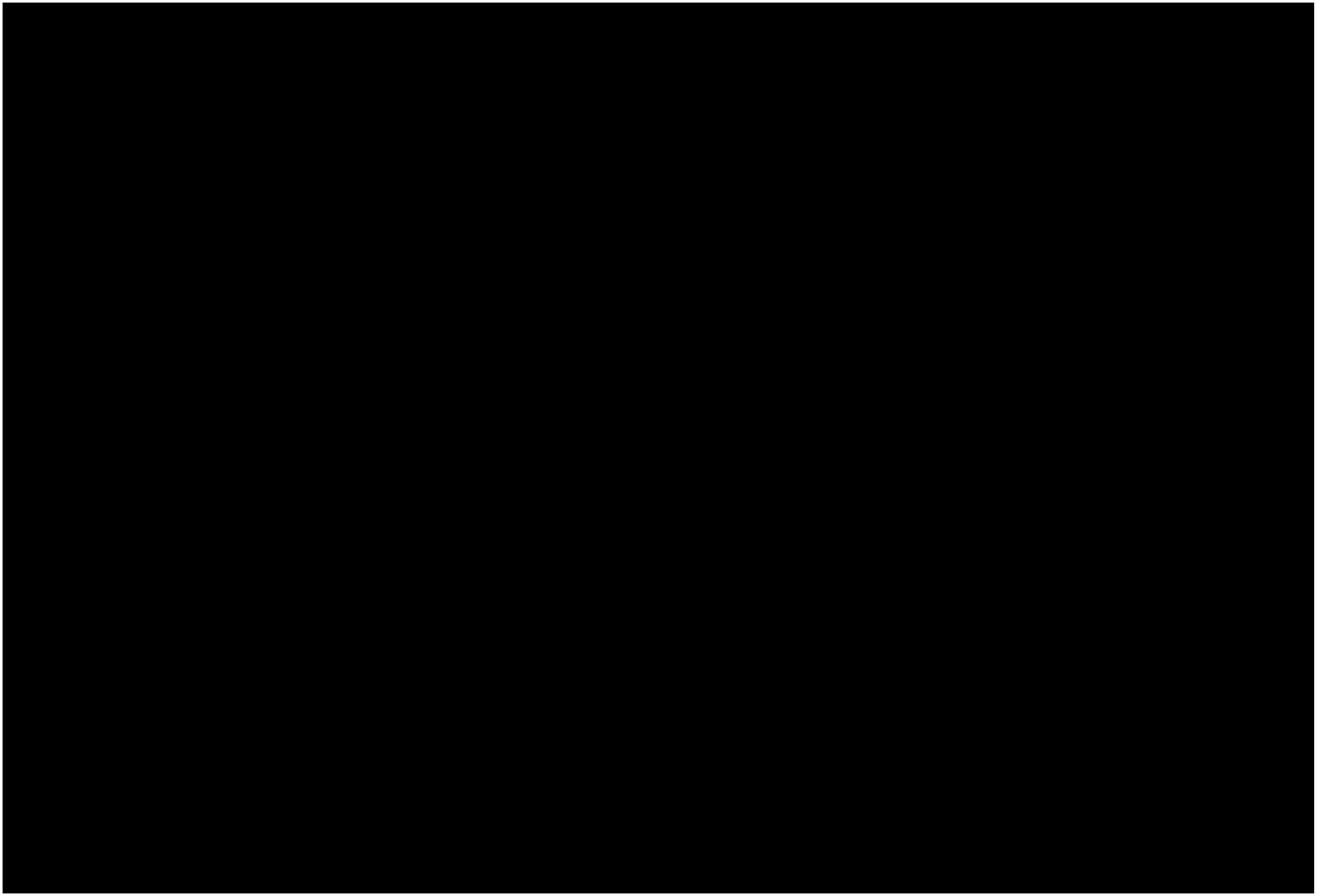
Member Forecasted On Peak Demand Day for July 2021

Mountain Parks Electric, Inc.

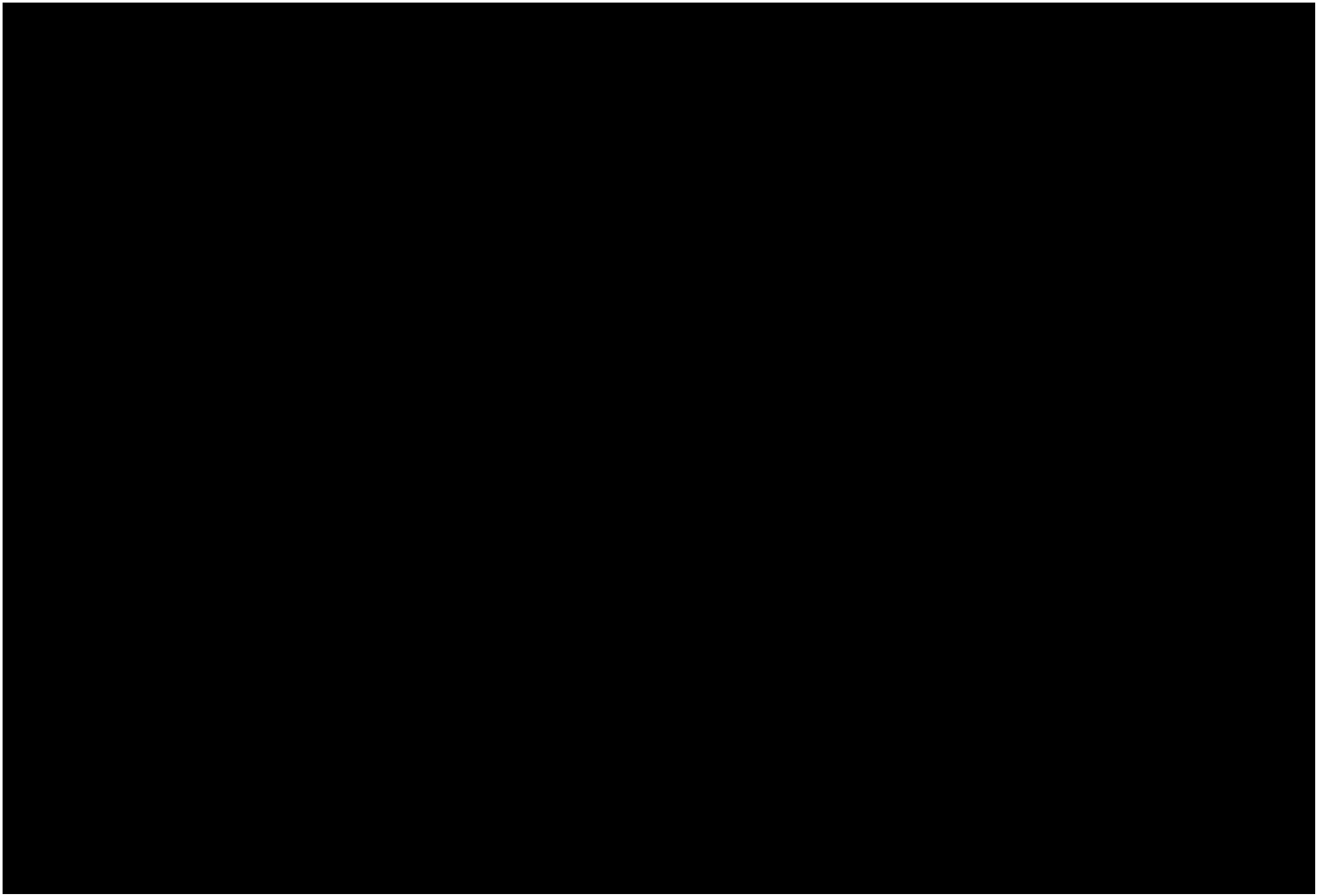
Date of On Peak Day - 07/03/2021



Member Forecasted On Peak Demand Day for August 2021

Mountain Parks Electric, Inc.

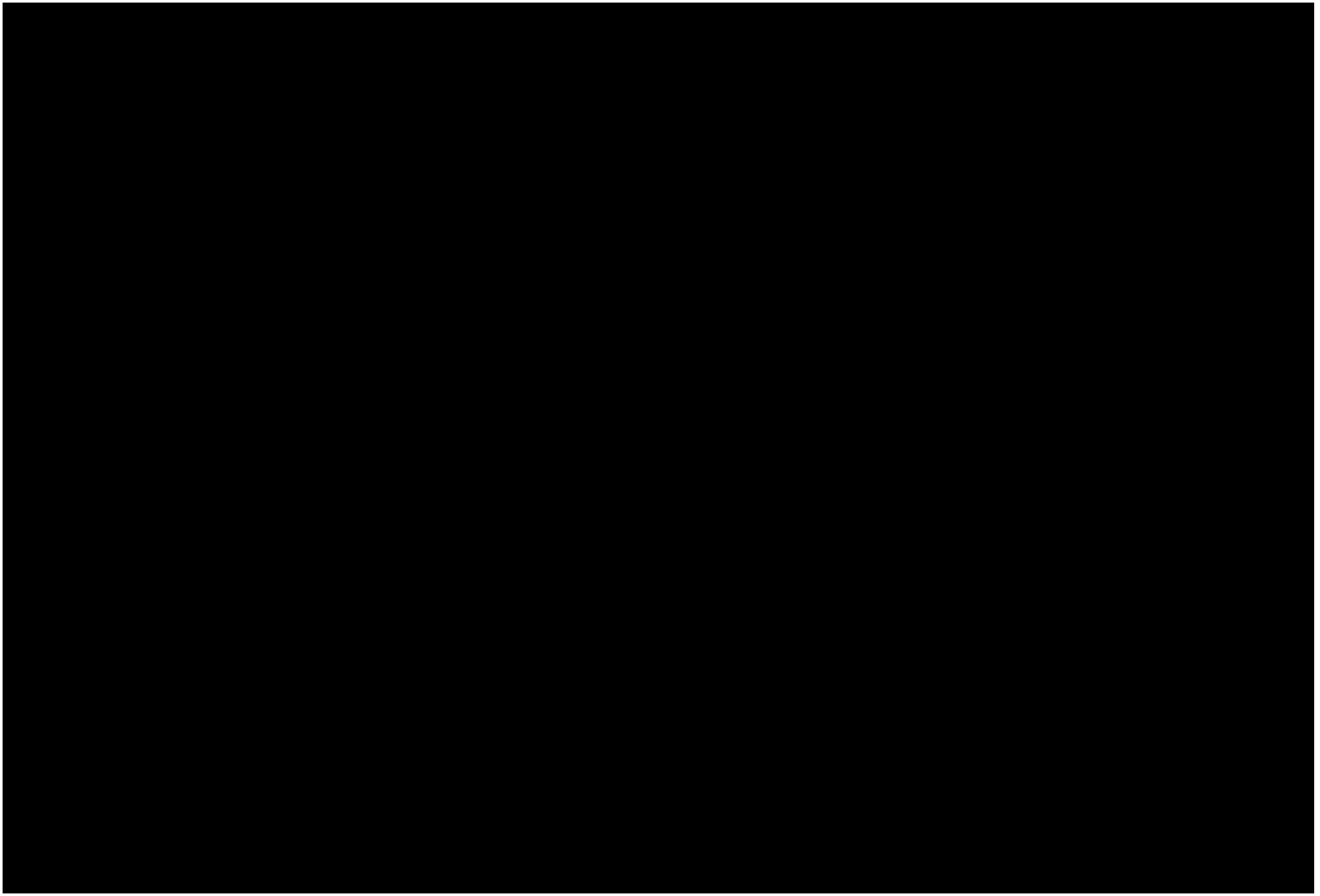
Date of On Peak Day - 08/07/2021



Member Forecasted On Peak Demand Day for September 2021

Mountain Parks Electric, Inc.

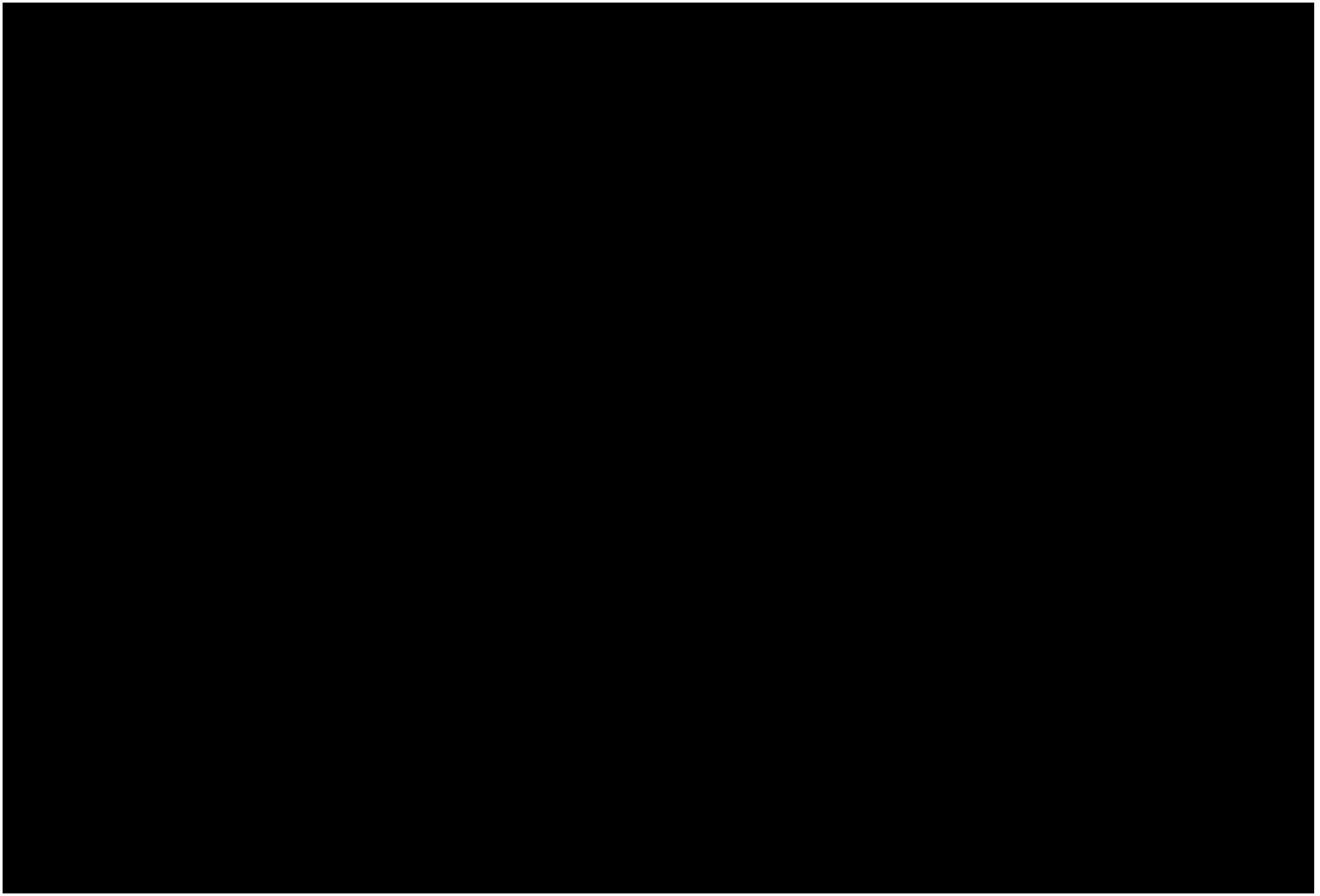
Date of On Peak Day - 09/07/2021



Member Forecasted On Peak Demand Day for October 2021

Mountain Parks Electric, Inc.

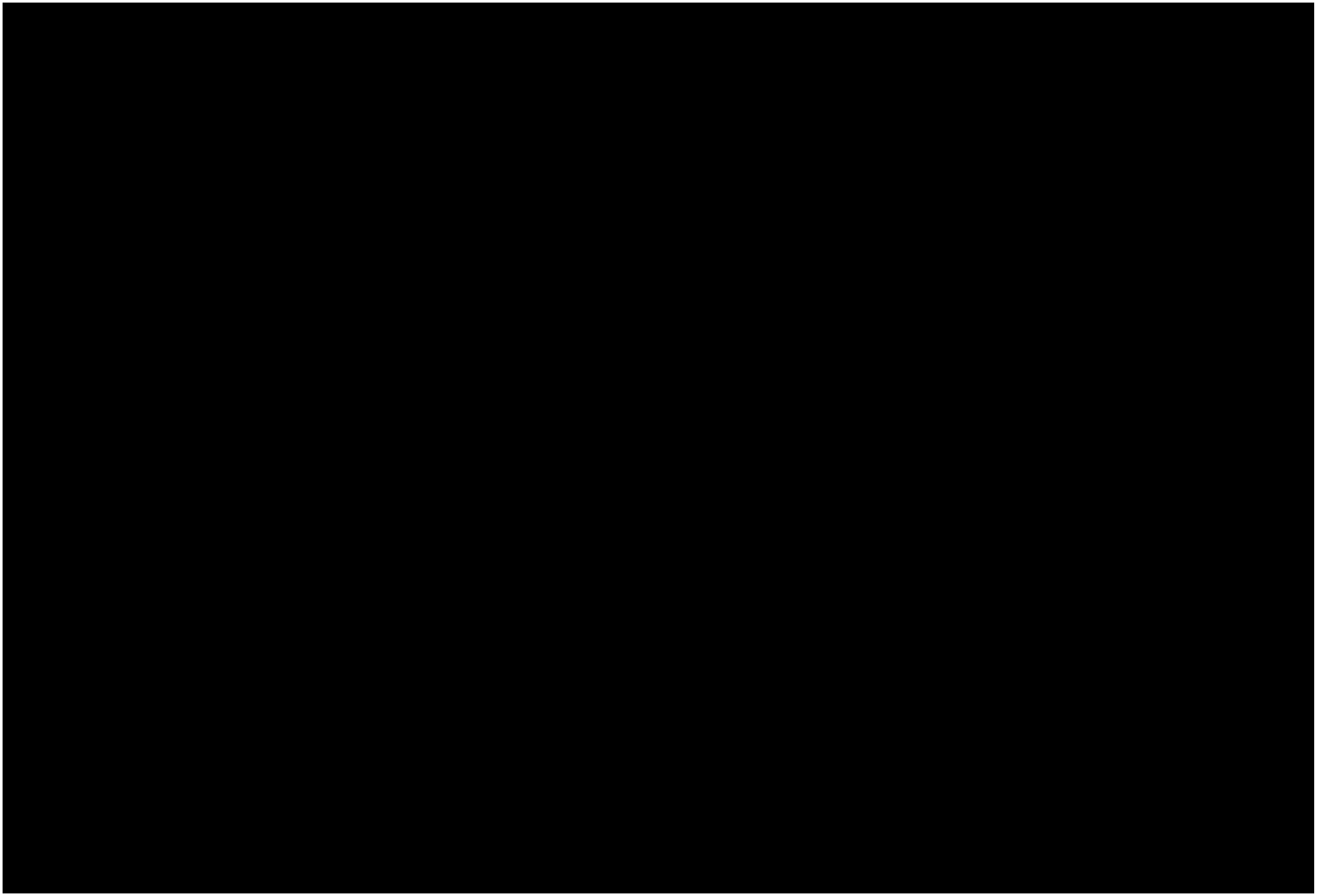
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Mountain Parks Electric, Inc.

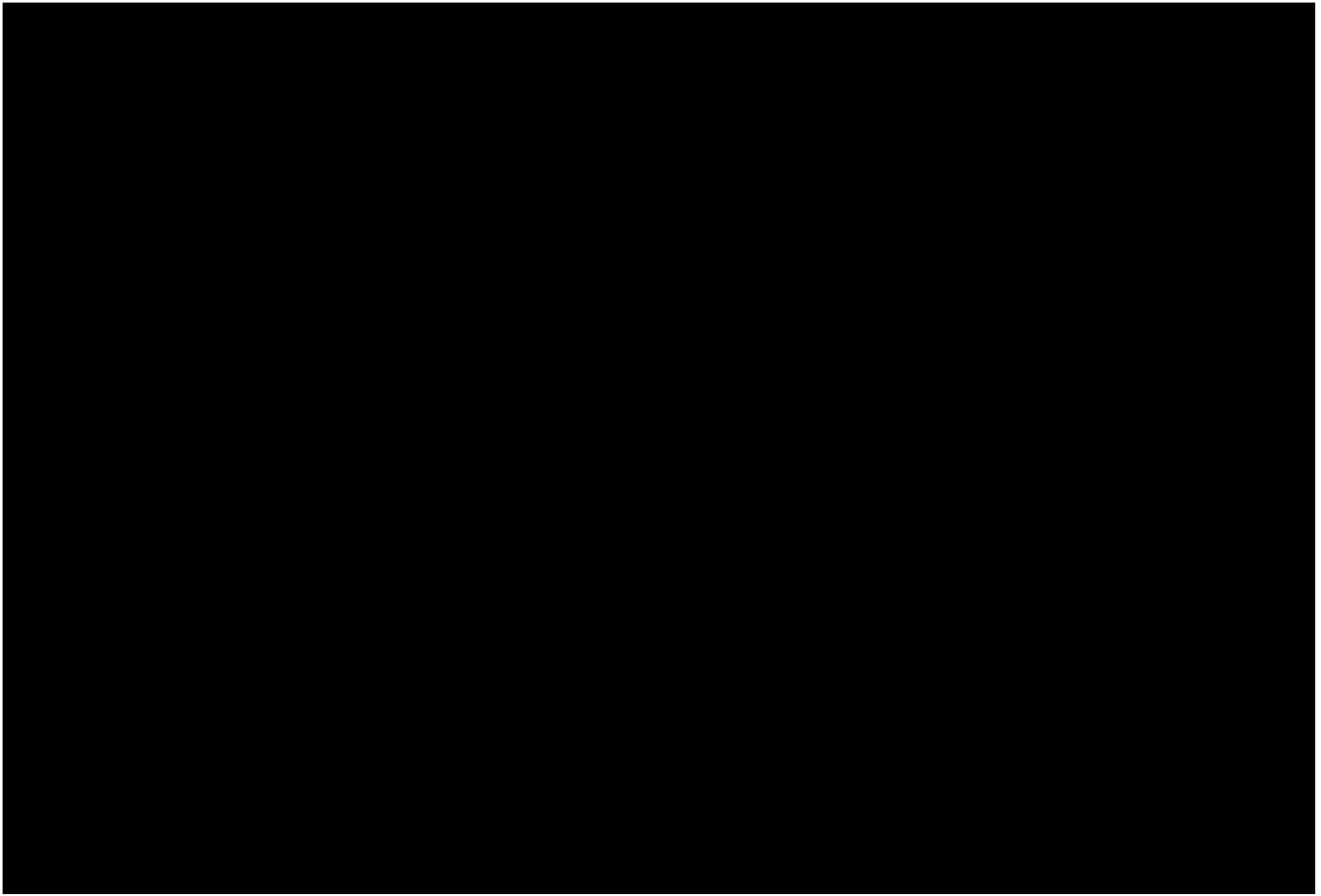
Date of On Peak Day - 11/24/2021



Member Forecasted On Peak Demand Day for December 2021

Mountain Parks Electric, Inc.

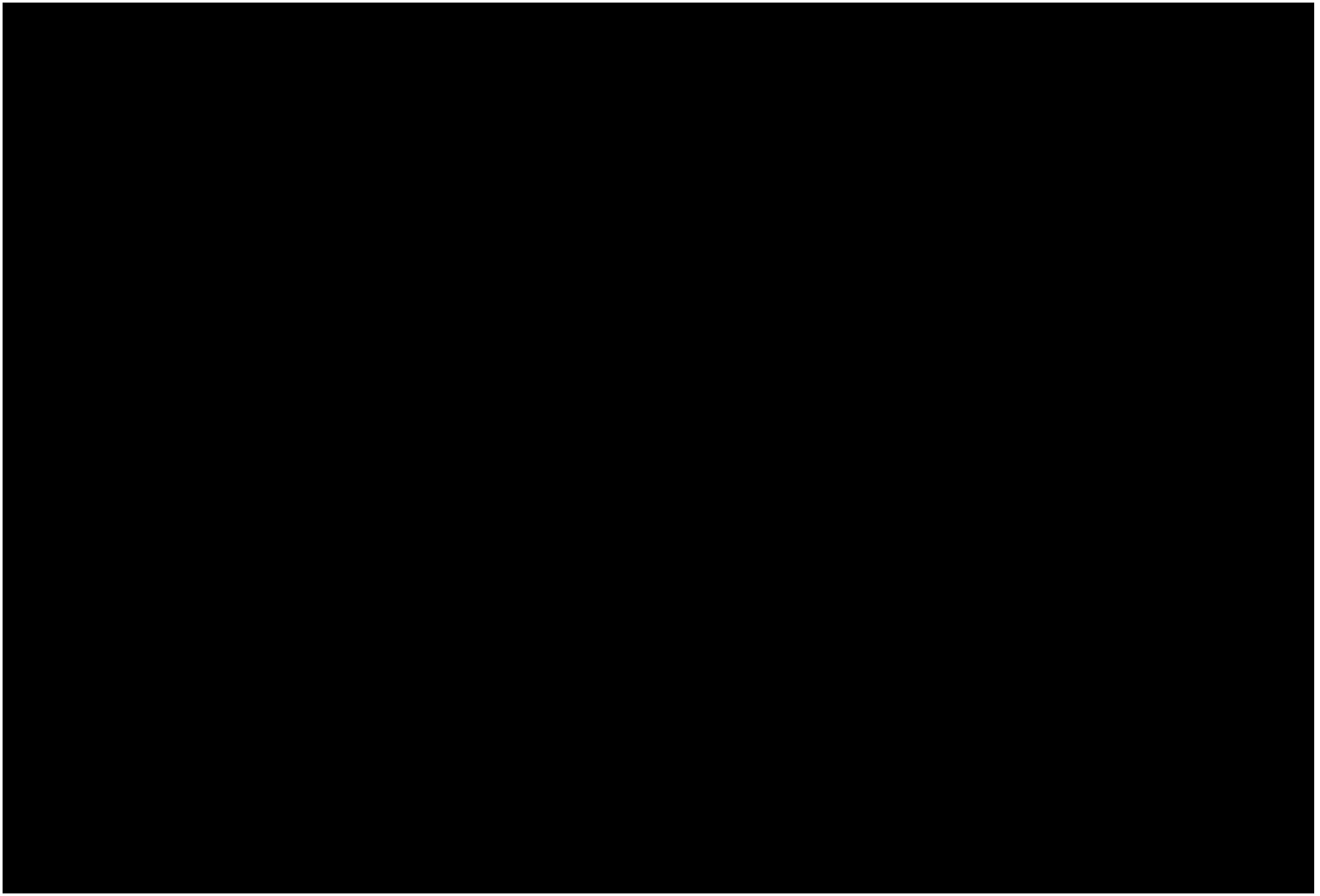
Date of On Peak Day - 12/31/2021



Member Forecasted On Peak Demand Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

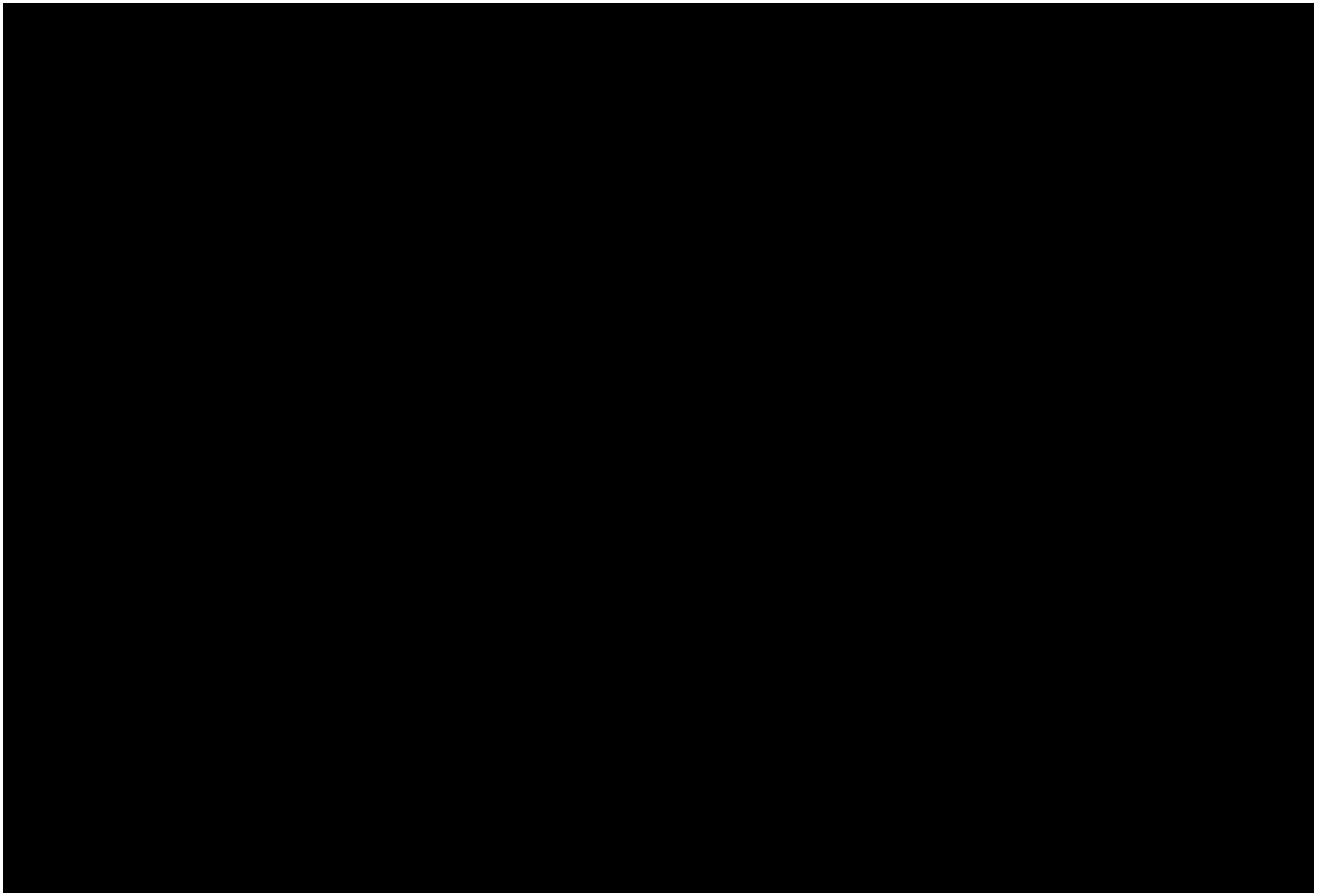
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

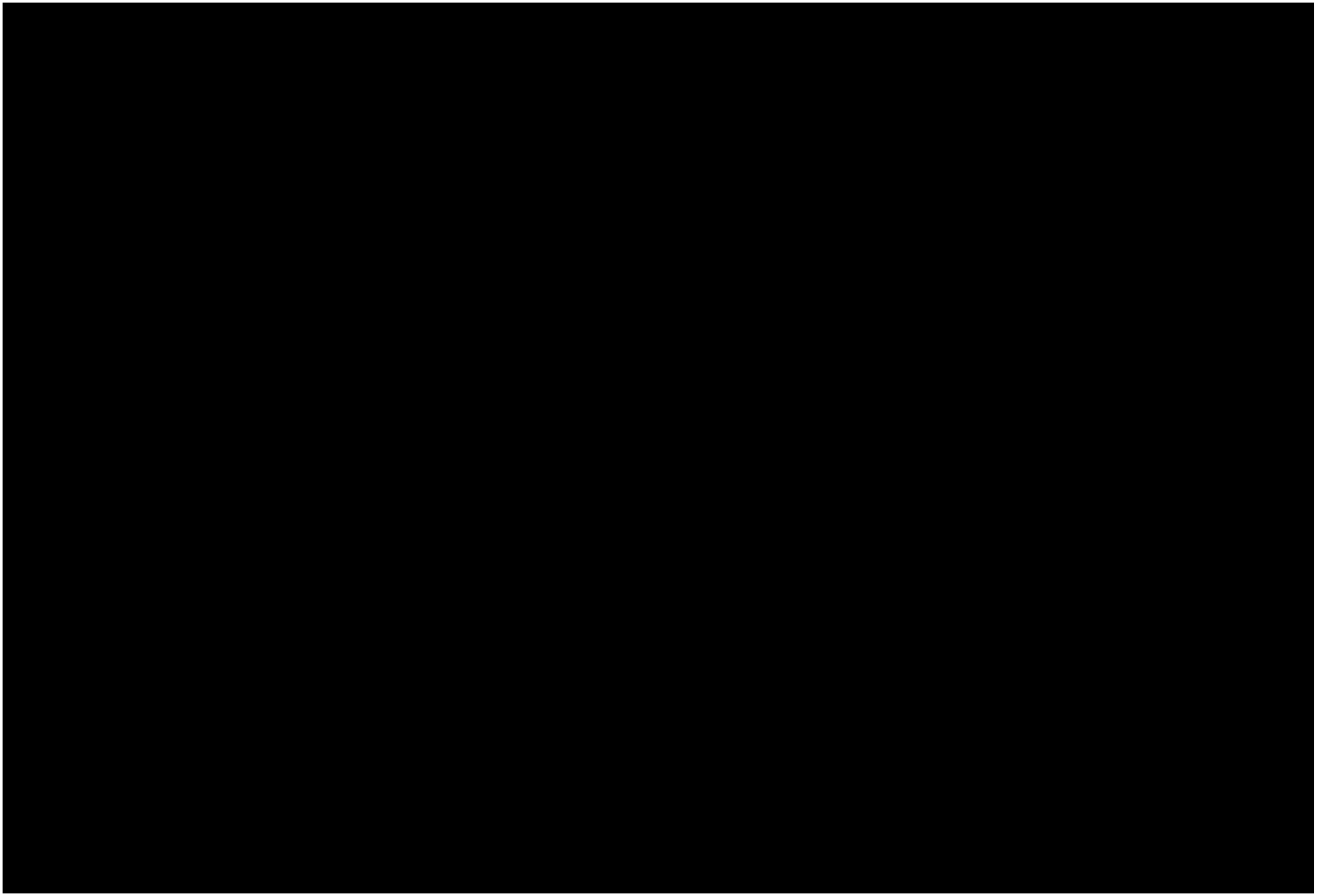
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.

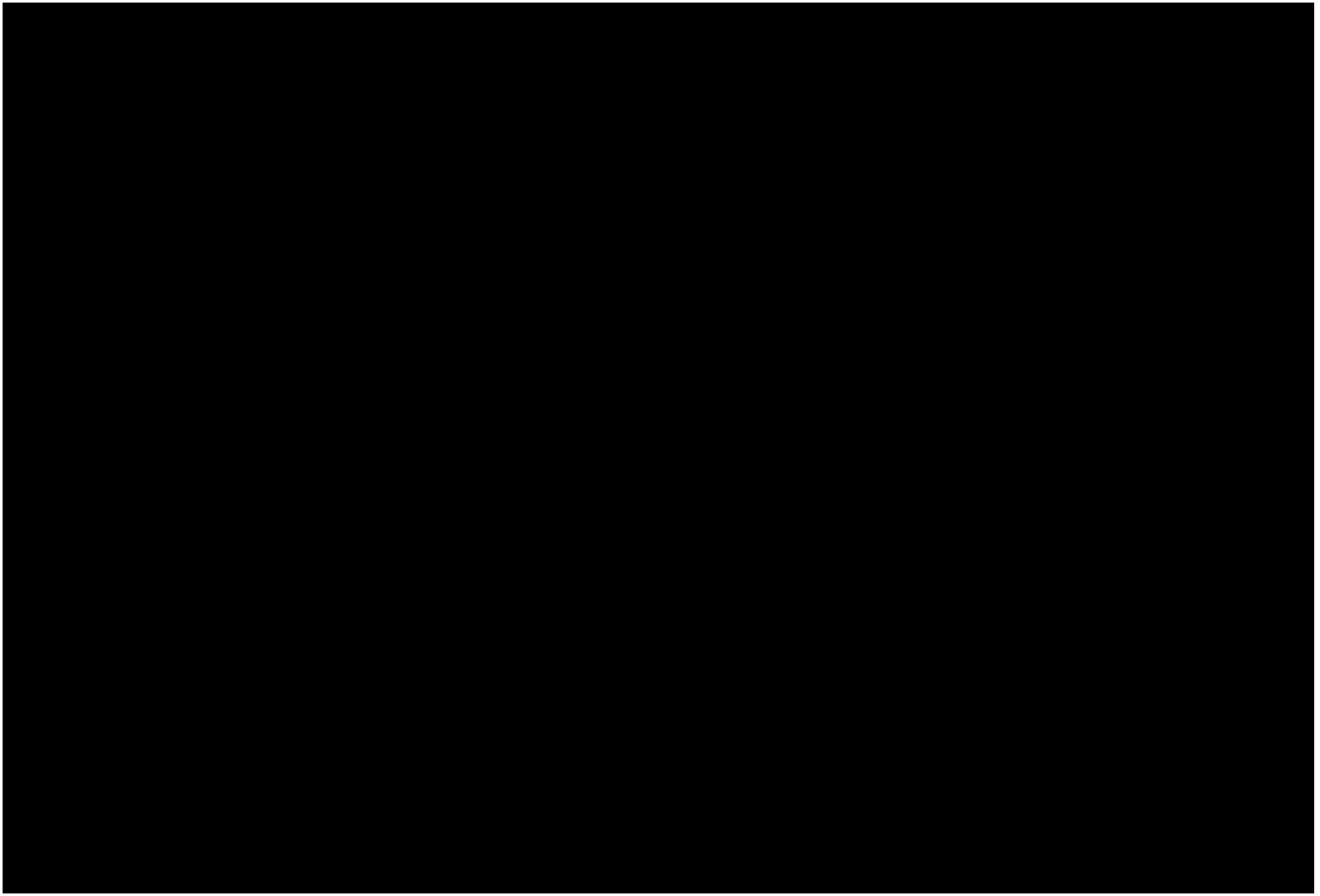
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

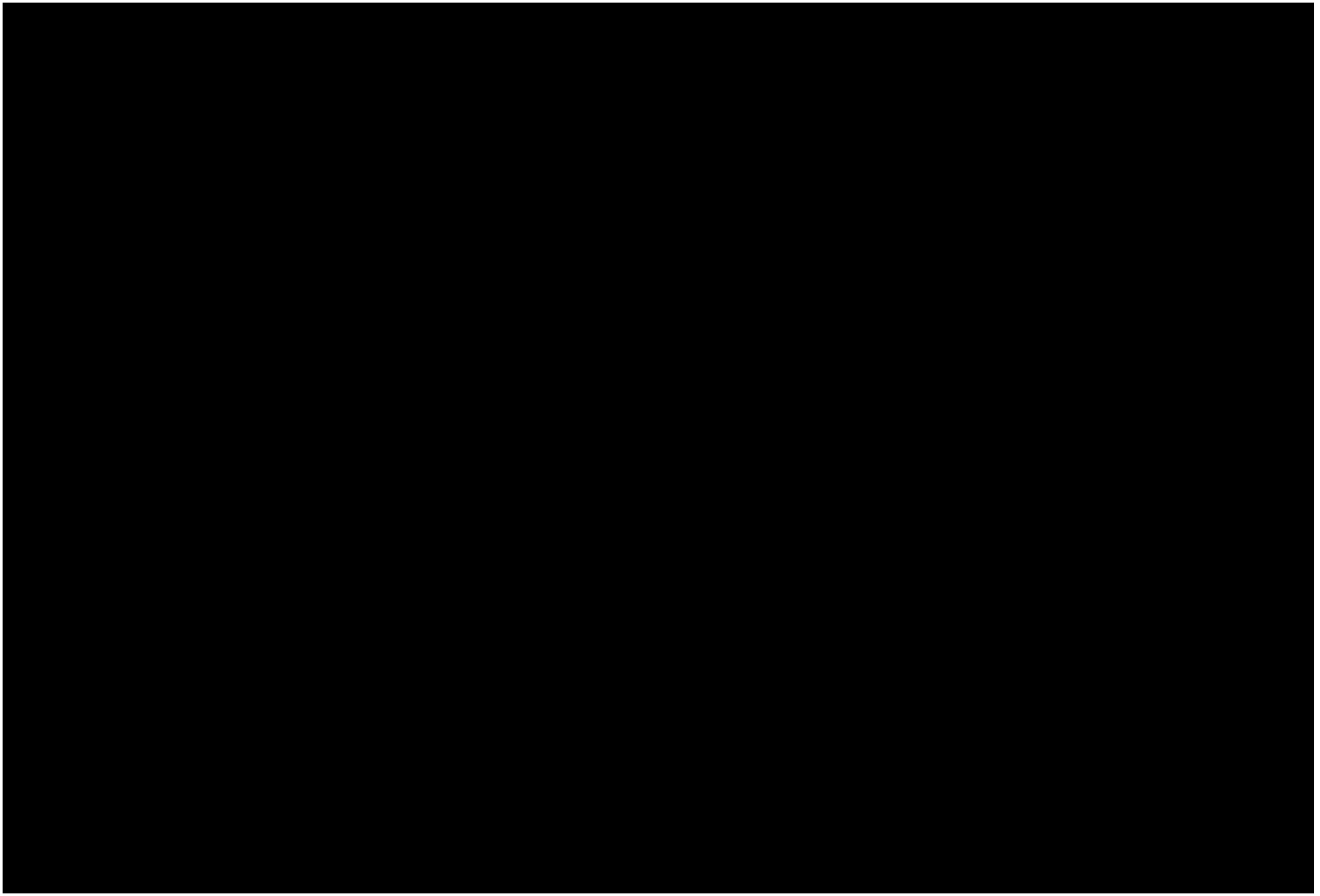
Date of On Peak Day - 04/20/2021



Member Forecasted On Peak Demand Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

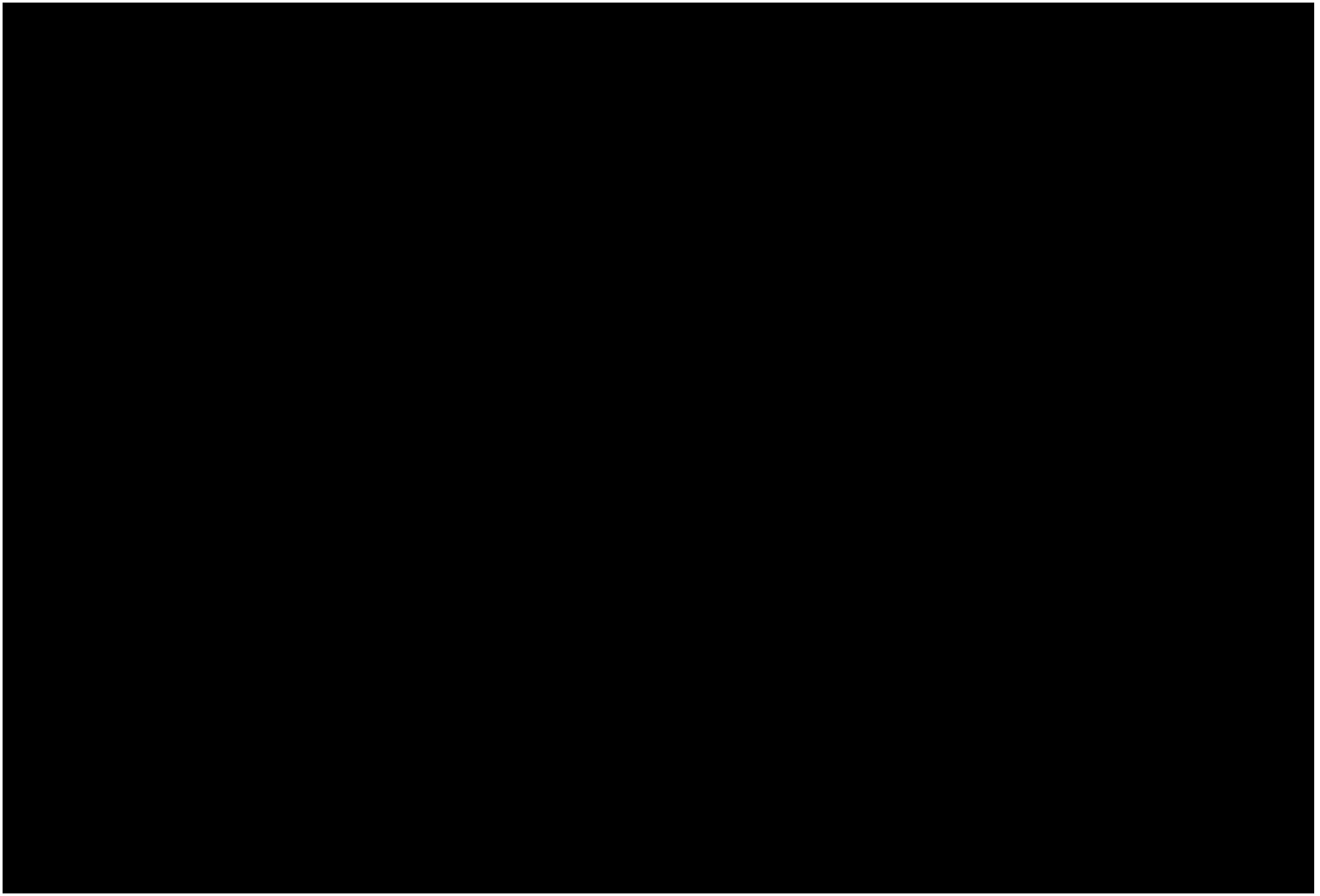
Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

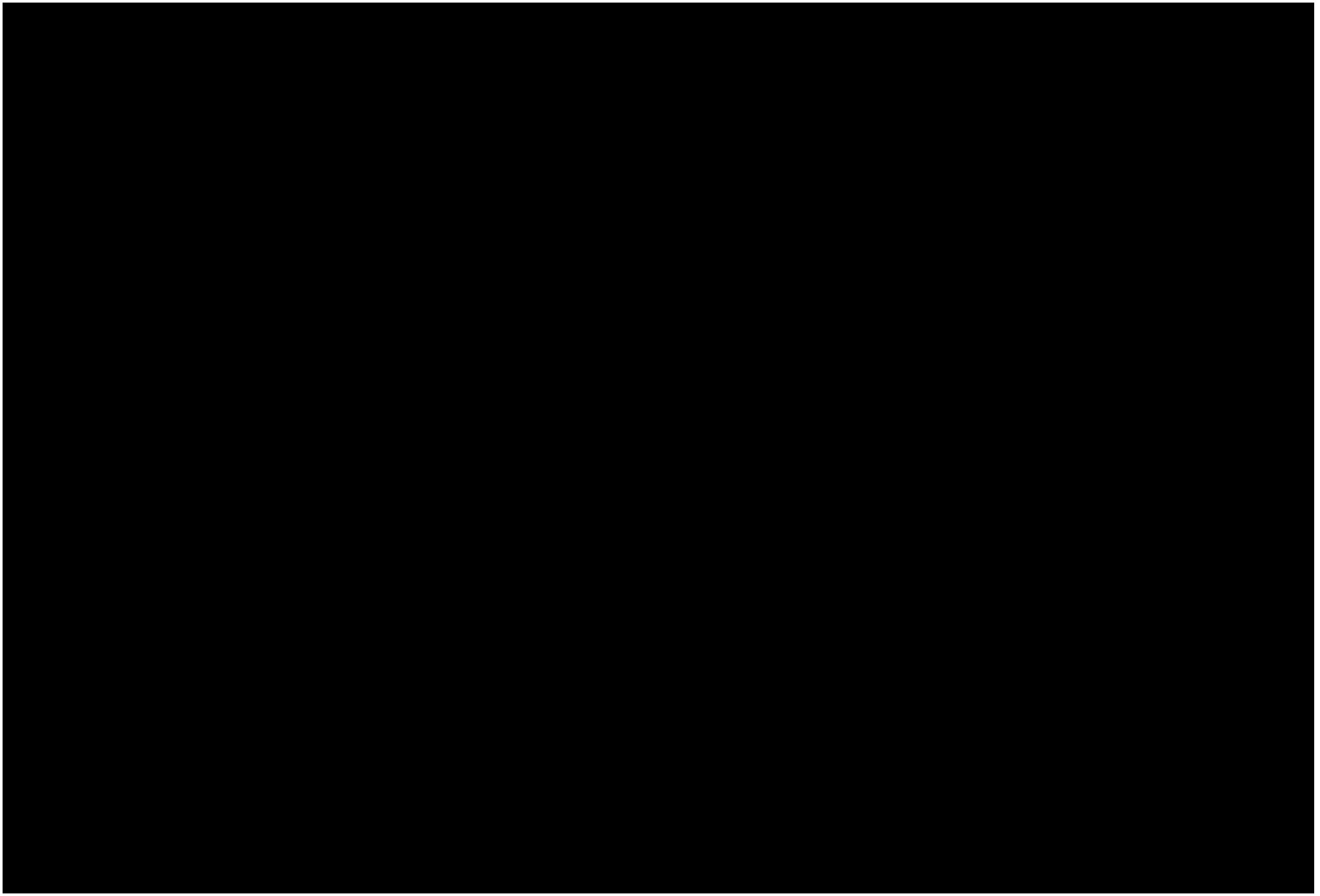
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

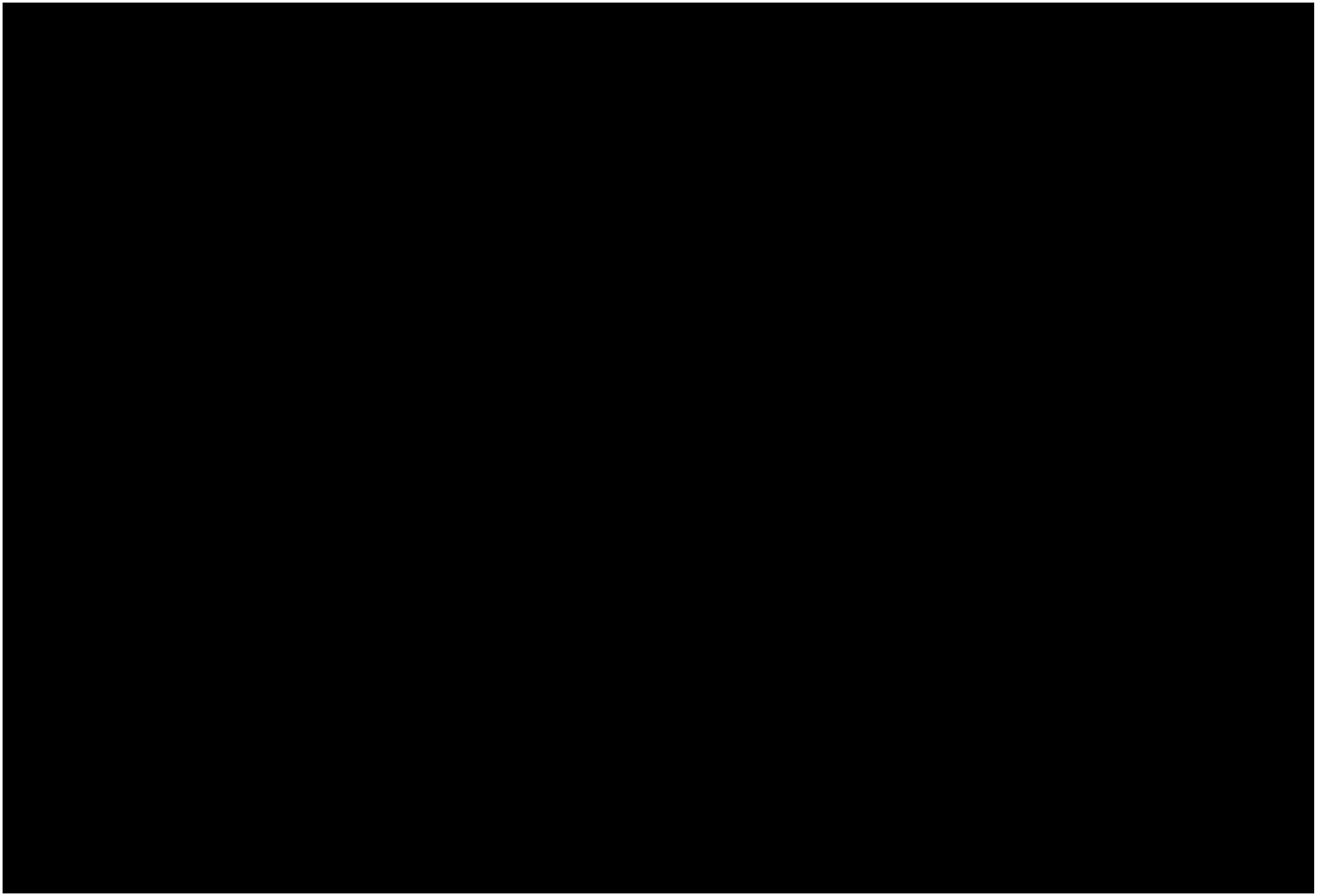
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

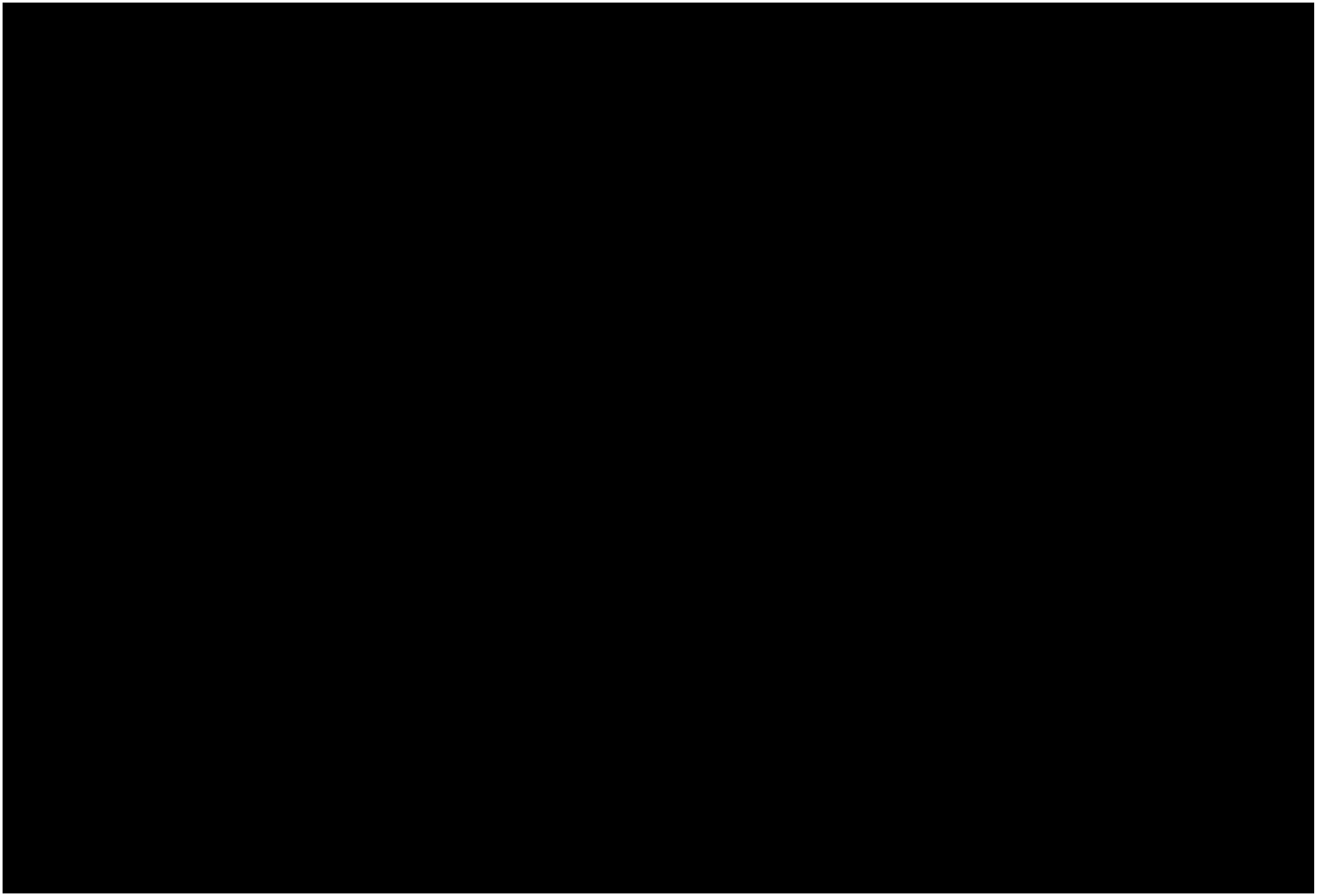
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.

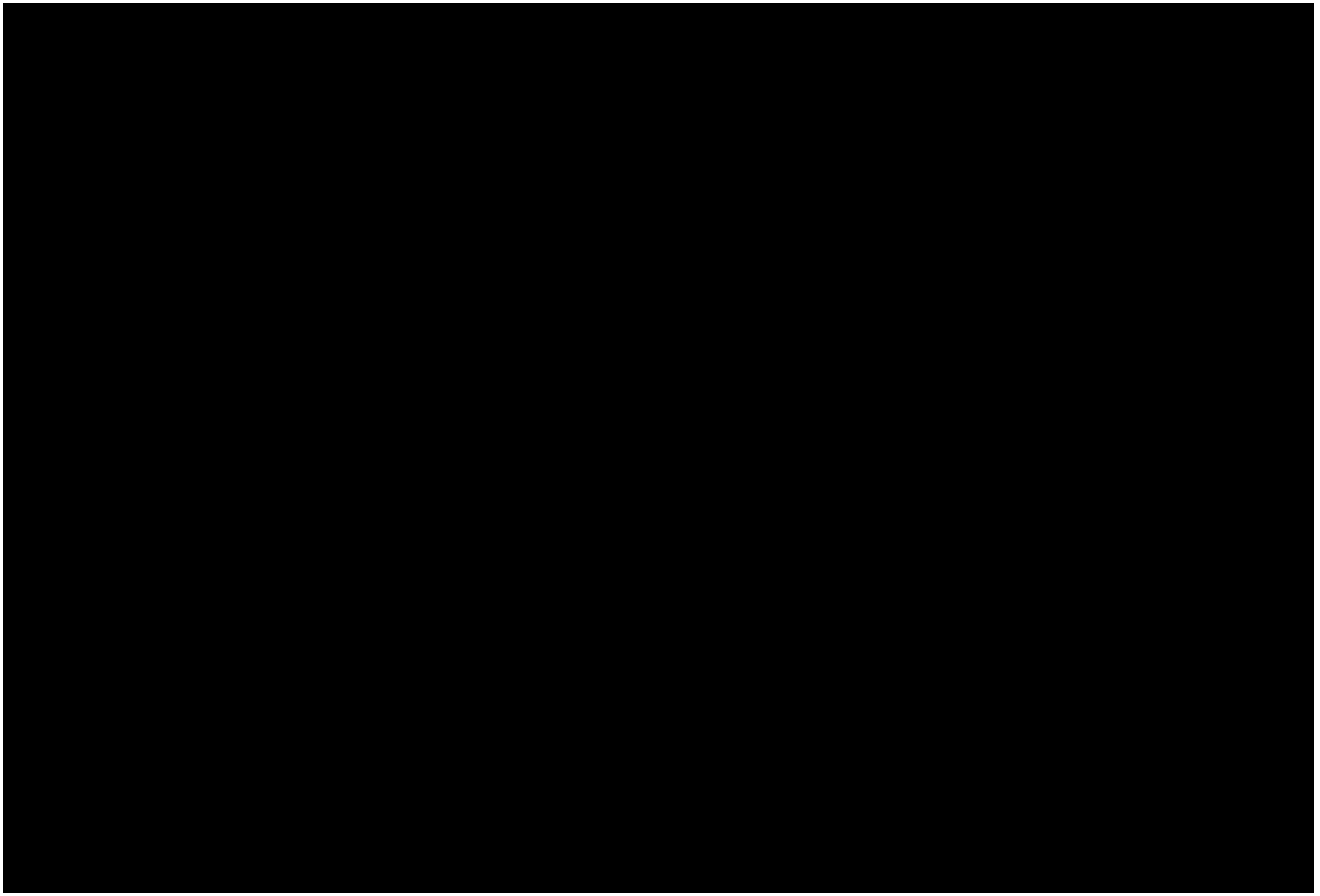
Date of On Peak Day - 09/13/2021



Member Forecasted On Peak Demand Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

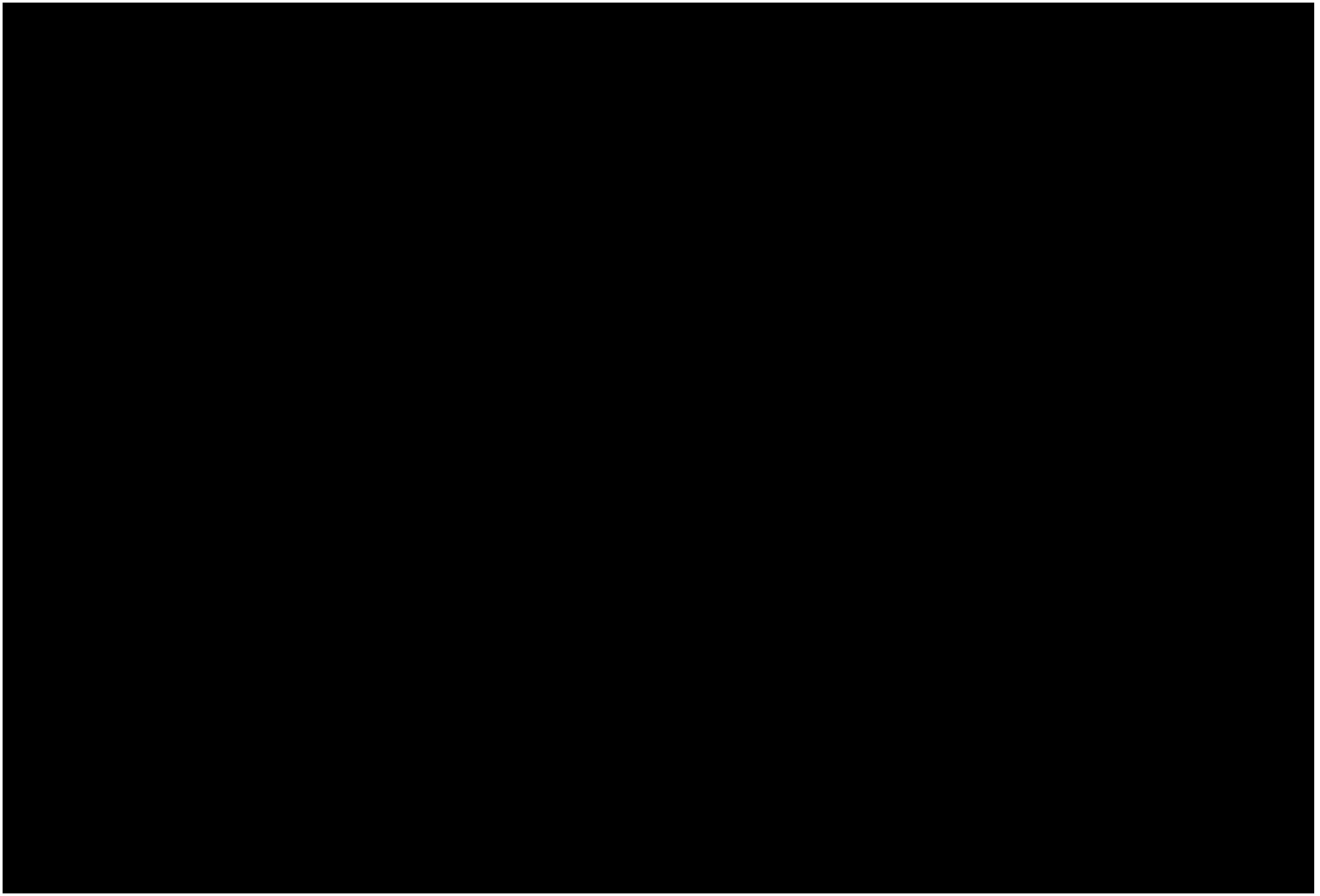
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

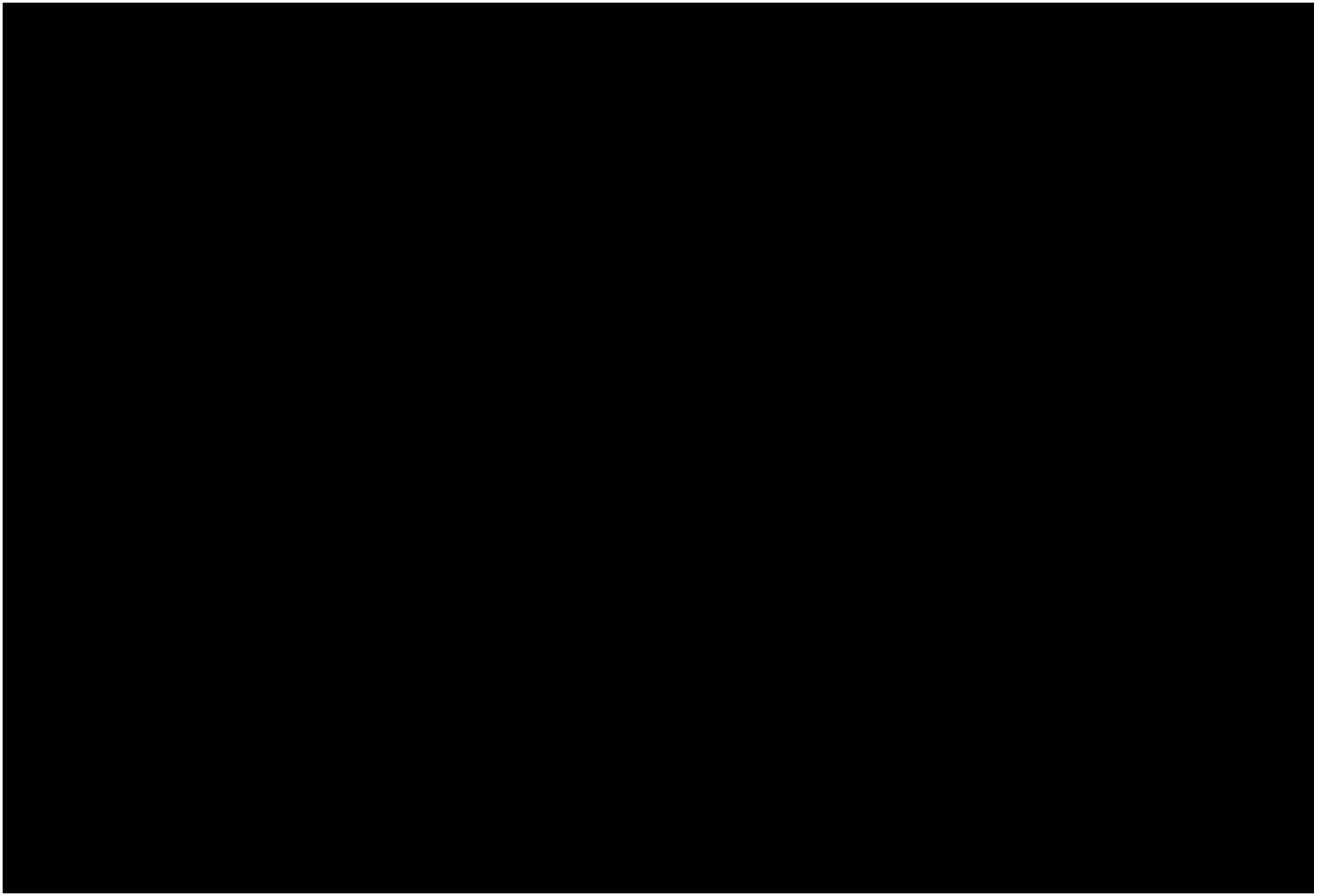
Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

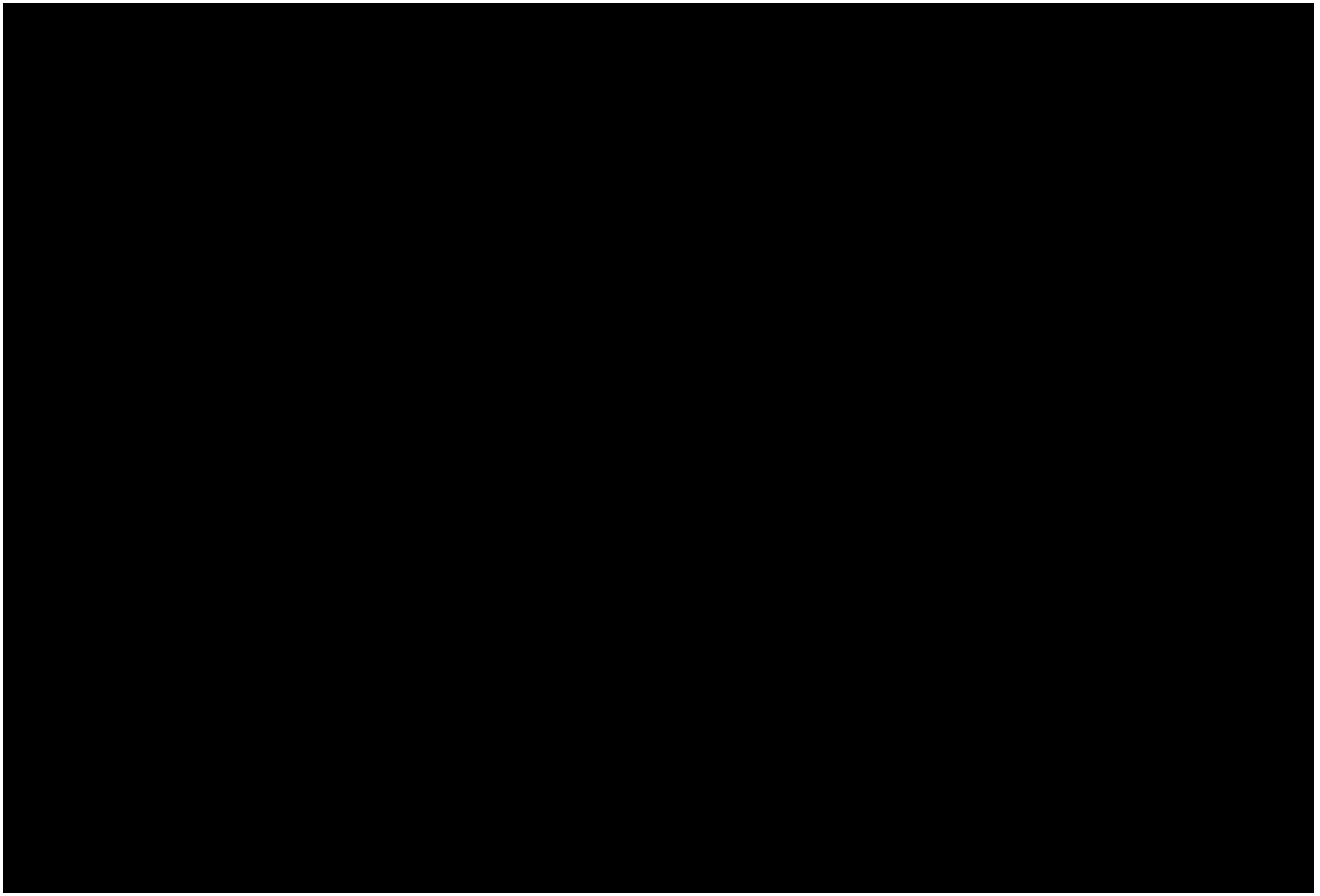
Date of On Peak Day - 12/26/2021



Member Forecasted On Peak Demand Day for January 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Mountain View Electric Association, Inc.

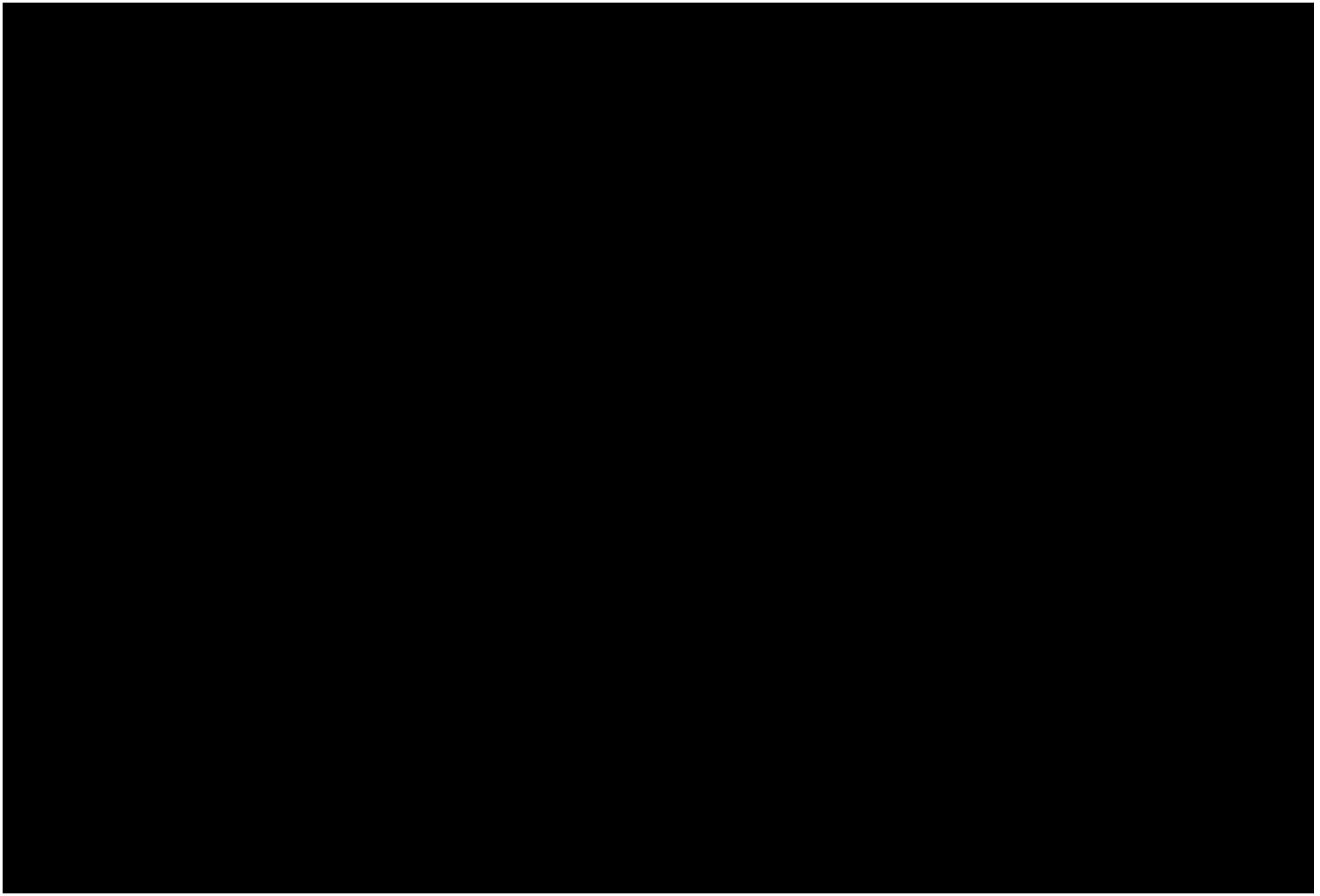
Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Mountain View Electric Association, Inc.

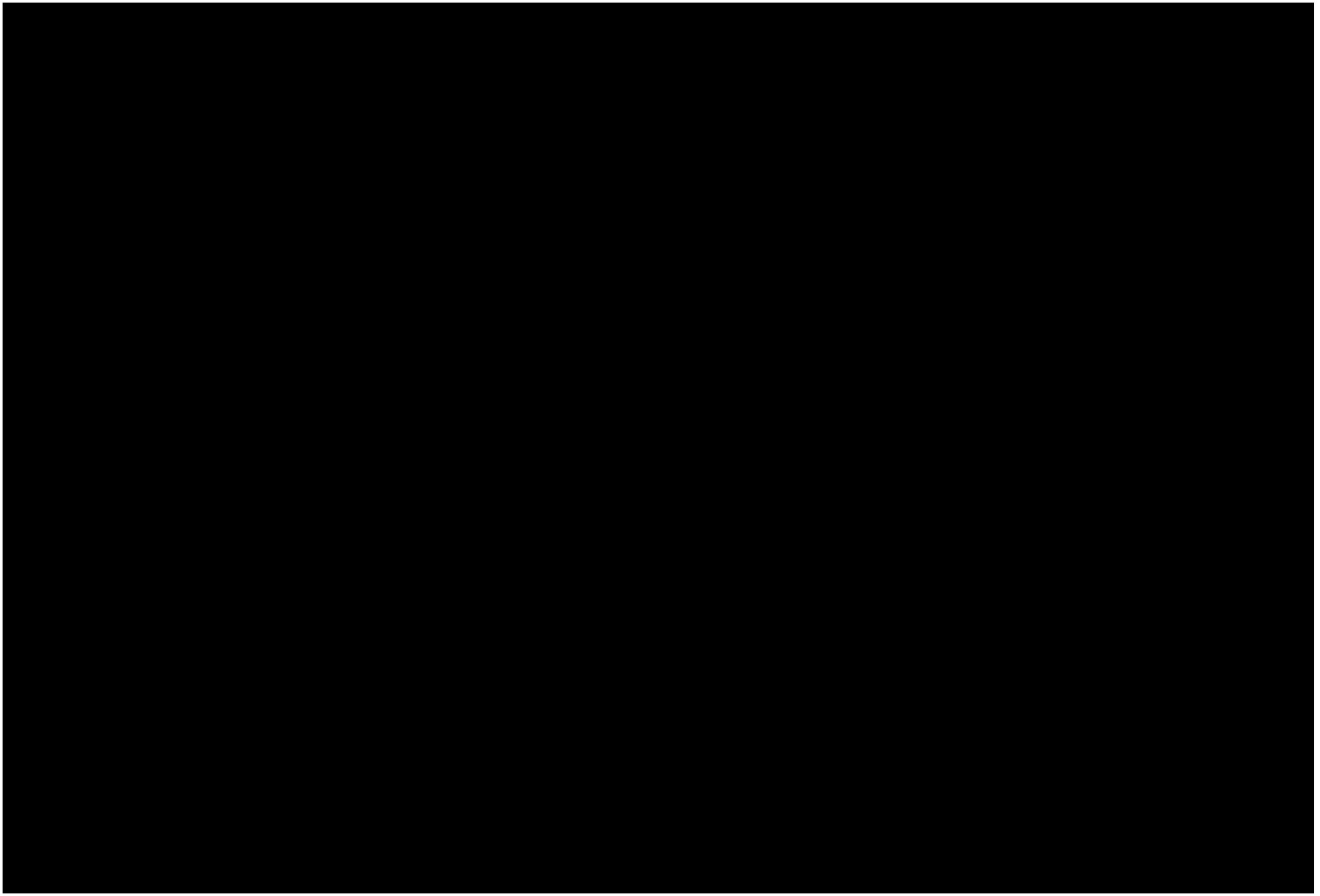
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Mountain View Electric Association, Inc.

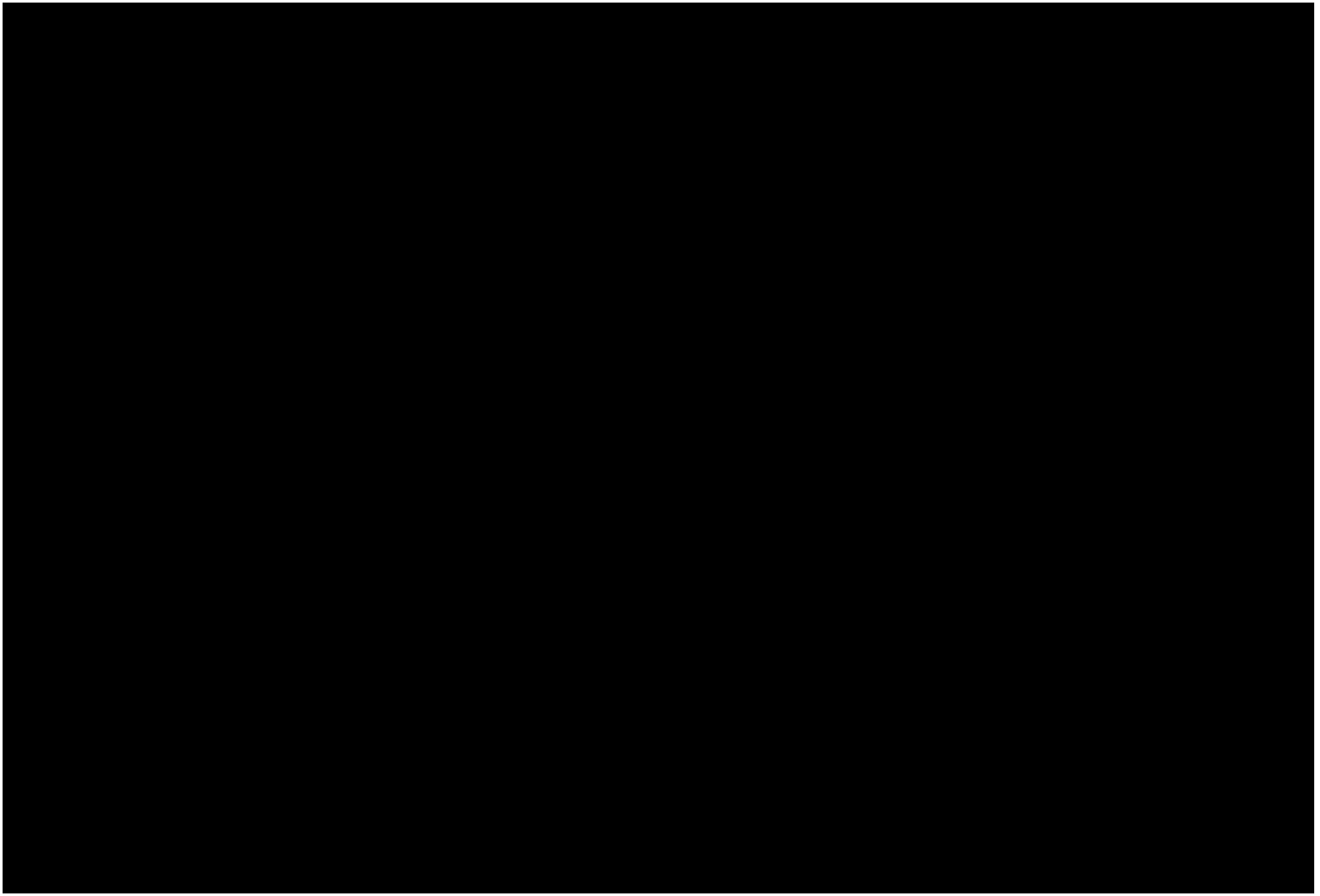
Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Mountain View Electric Association, Inc.

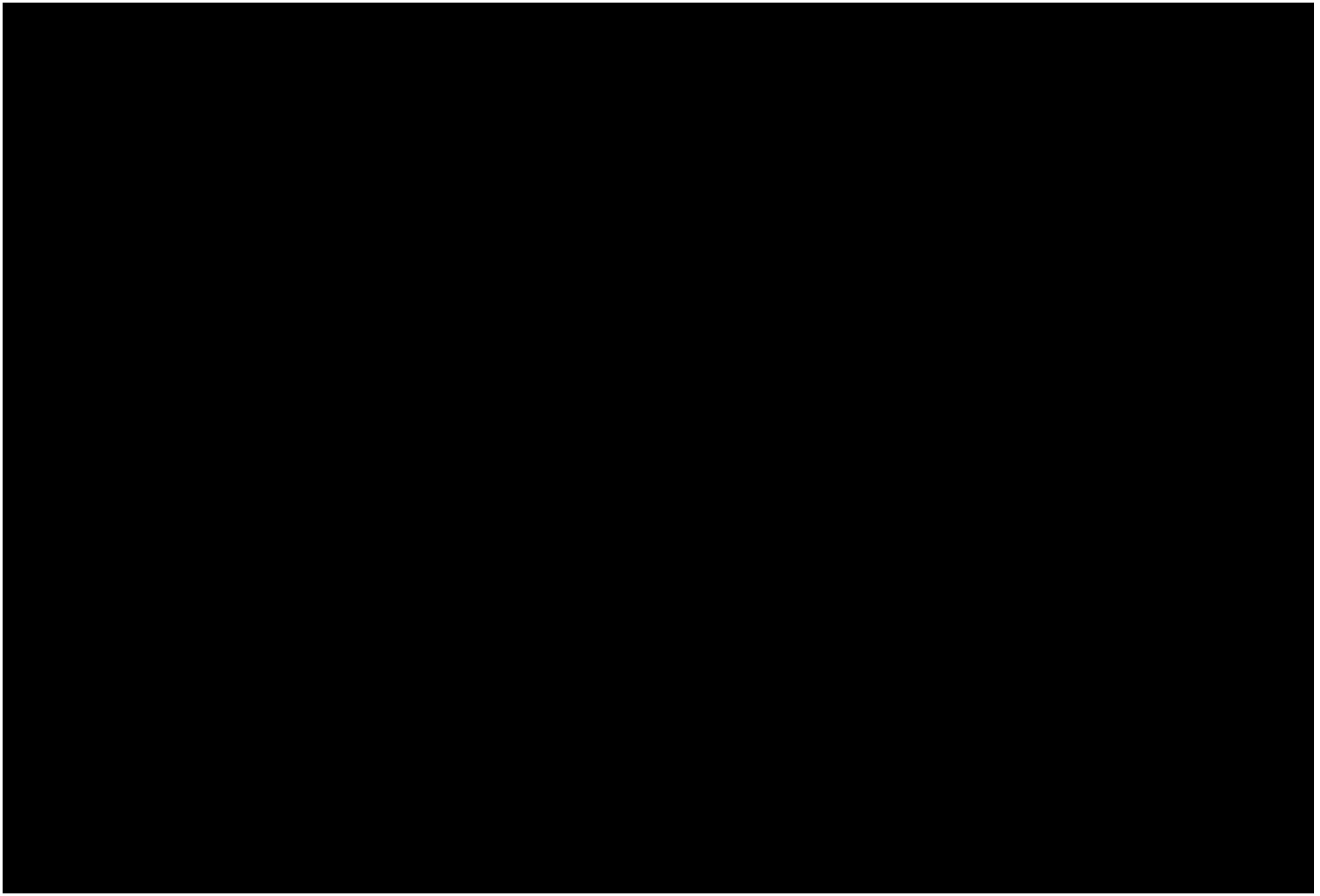
Date of On Peak Day - 05/19/2021



Member Forecasted On Peak Demand Day for June 2021

Mountain View Electric Association, Inc.

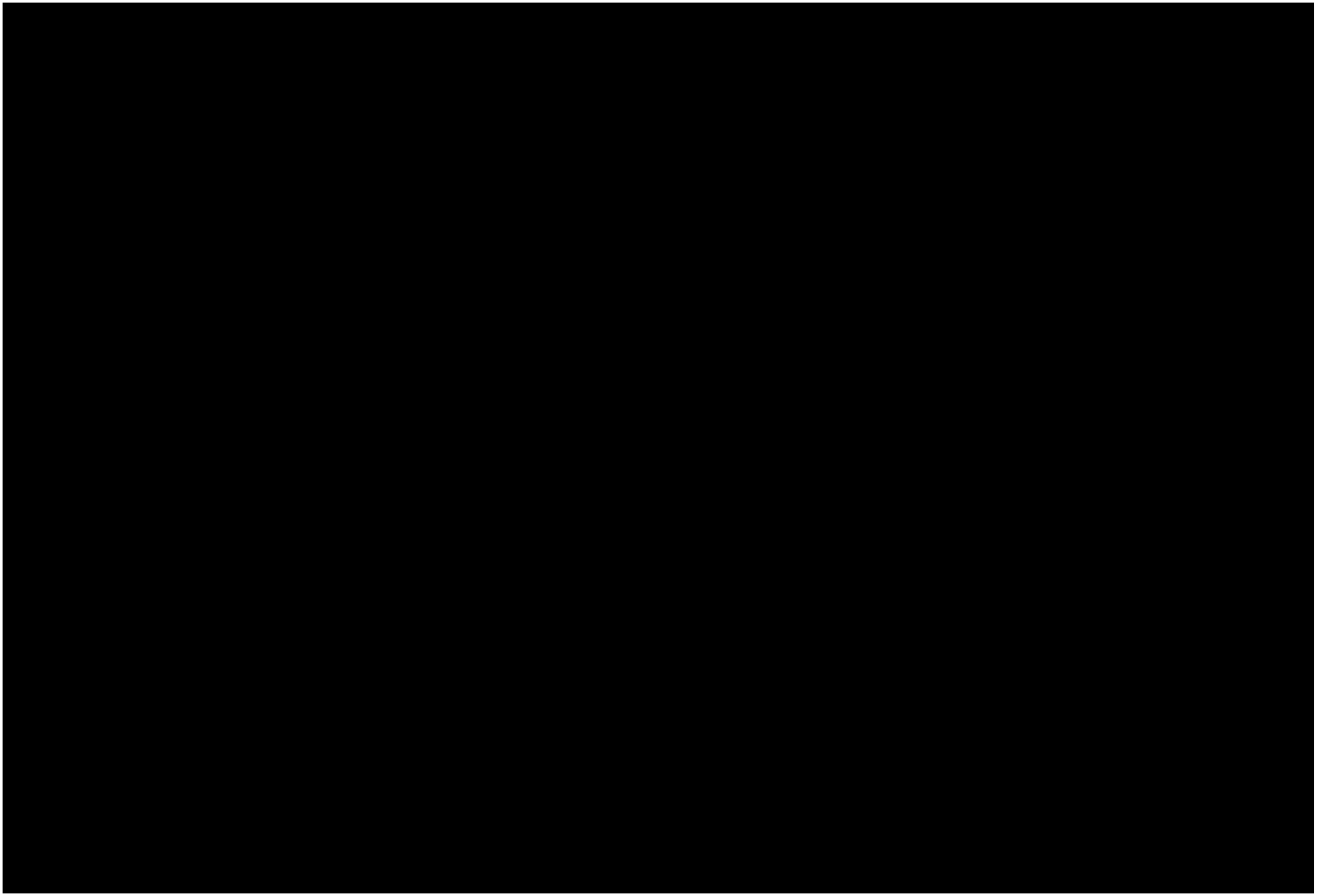
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Mountain View Electric Association, Inc.

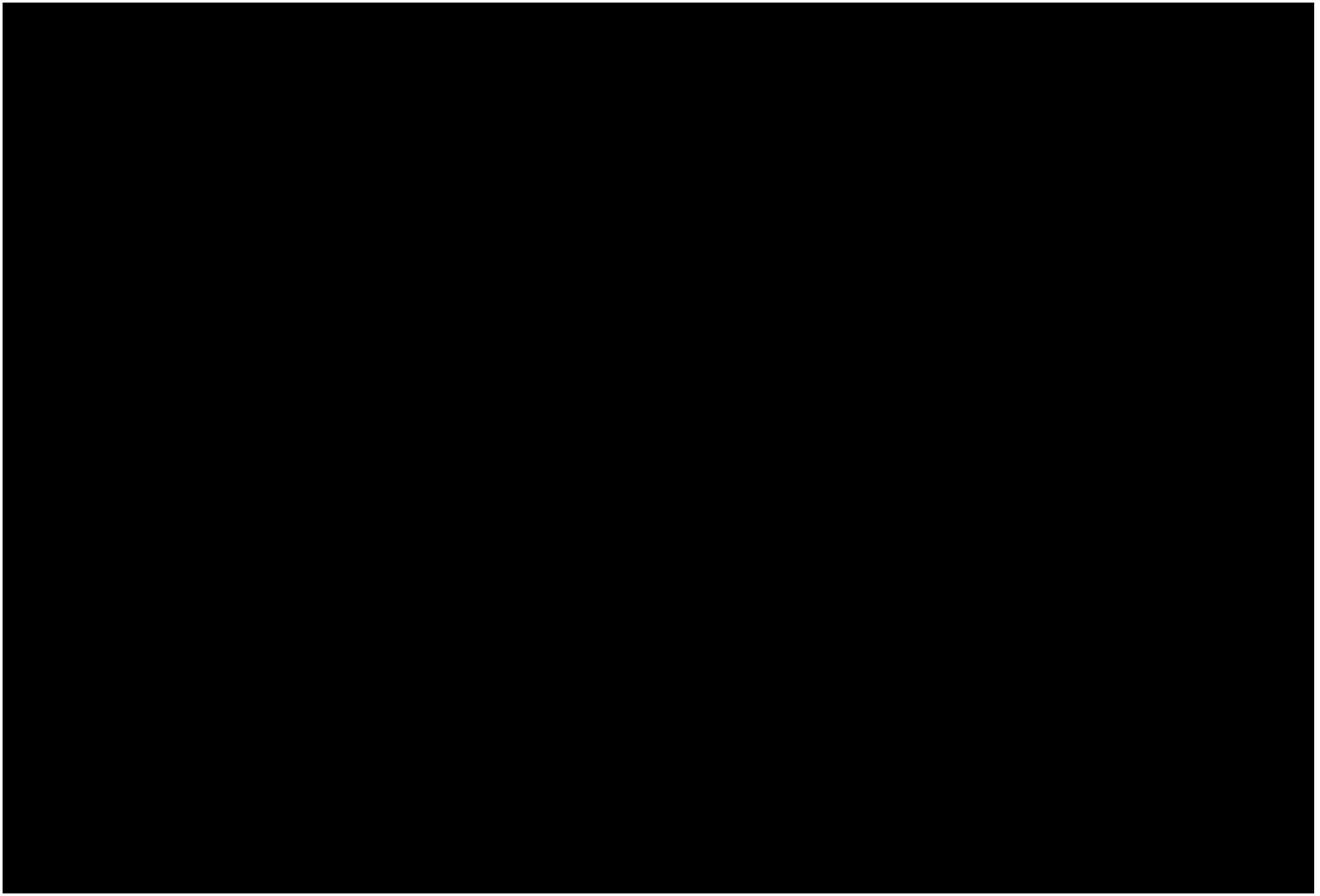
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Mountain View Electric Association, Inc.

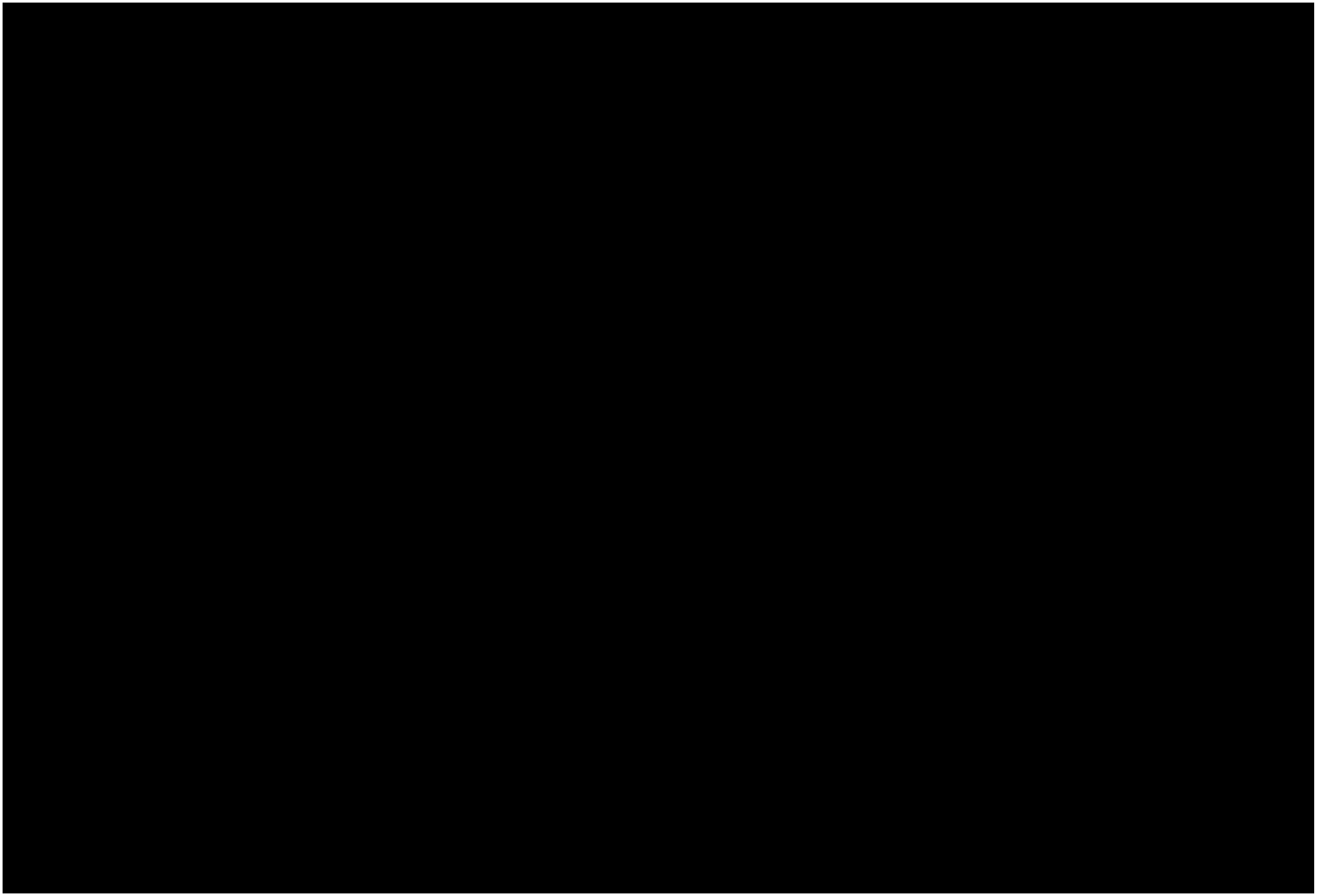
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

Mountain View Electric Association, Inc.

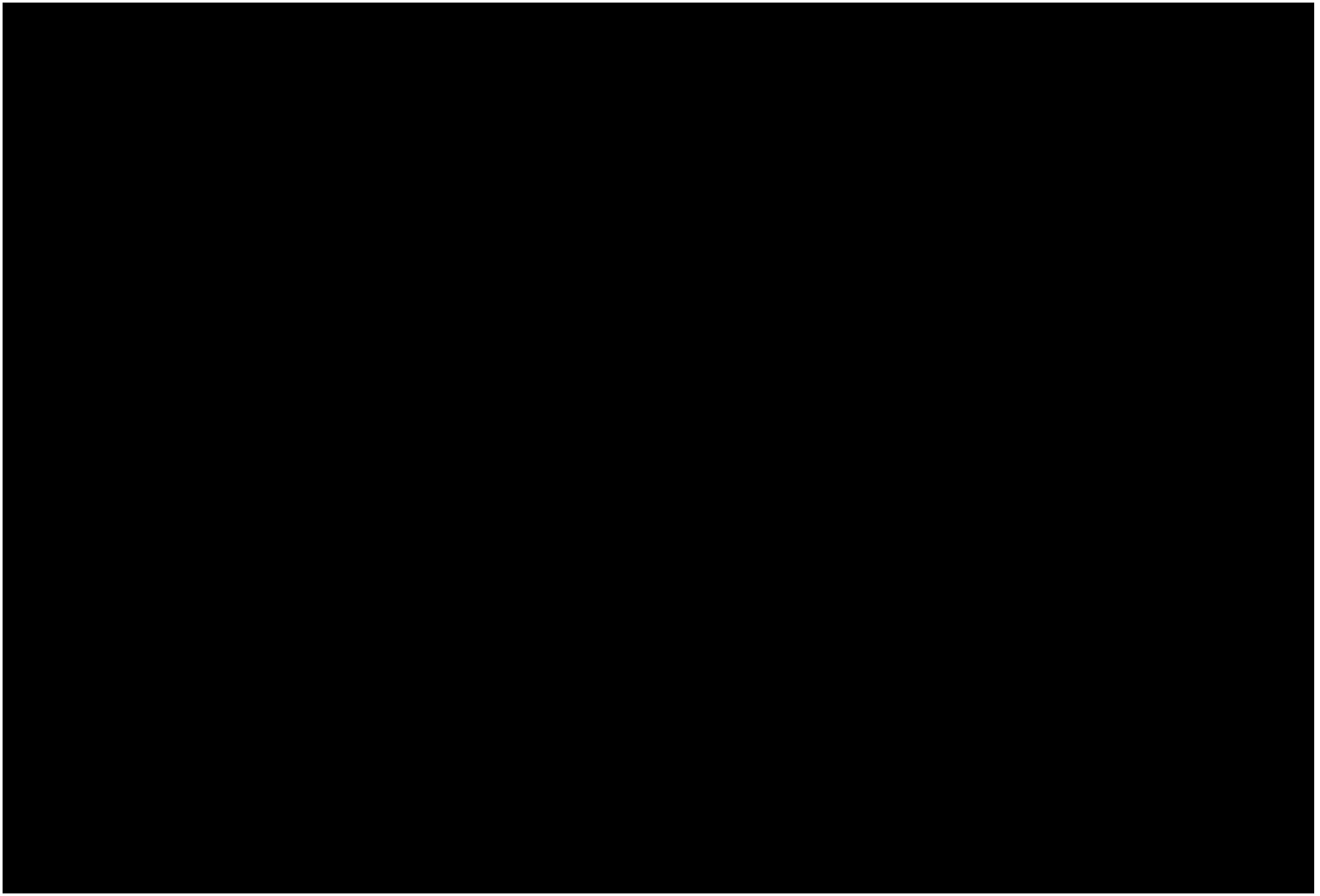
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Mountain View Electric Association, Inc.

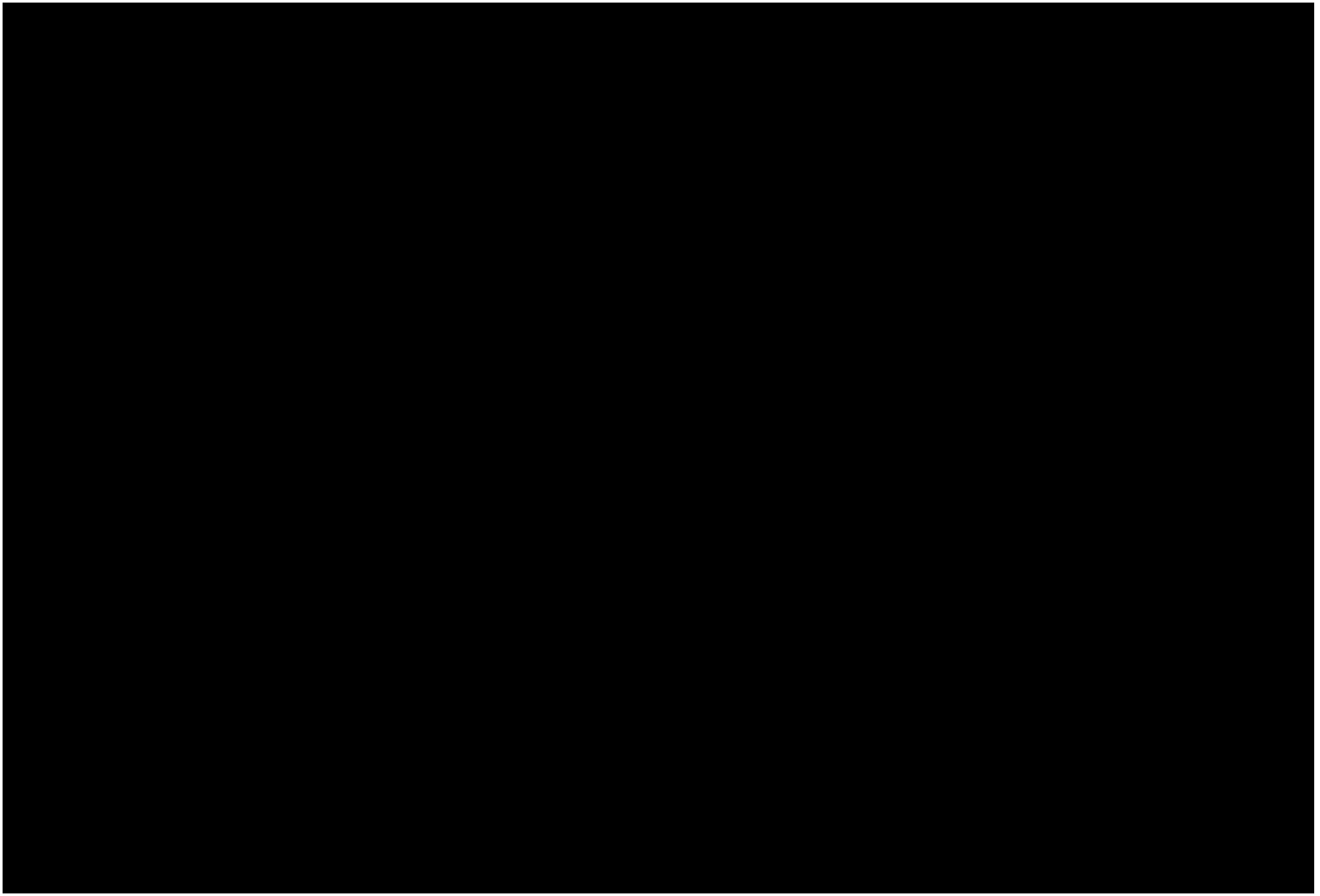
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

Mountain View Electric Association, Inc.

Date of On Peak Day - 12/26/2021

[redacted]

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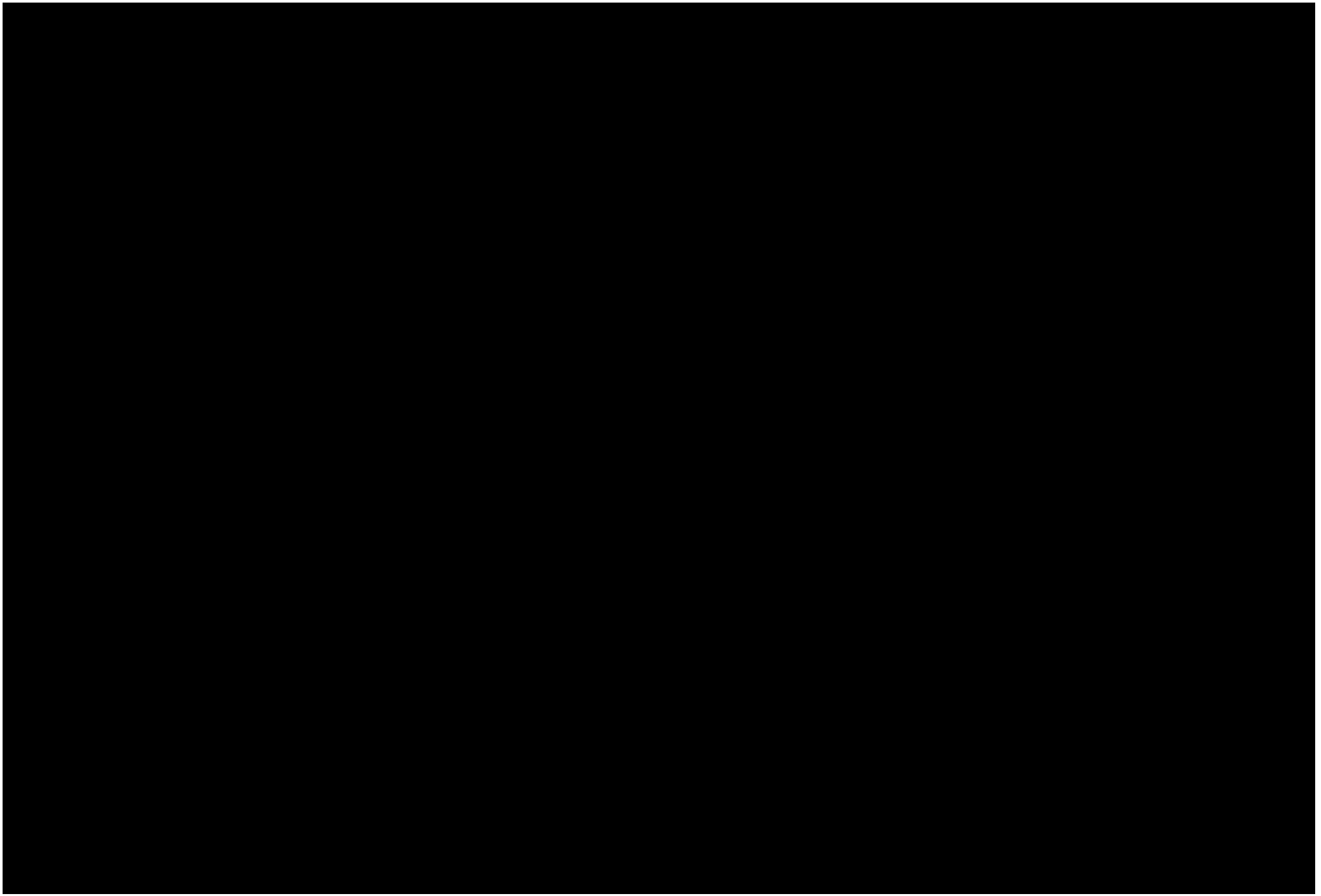
Member Forecasted On Peak Demand Day for January 2021

Midwest Electric Cooperative Corporation

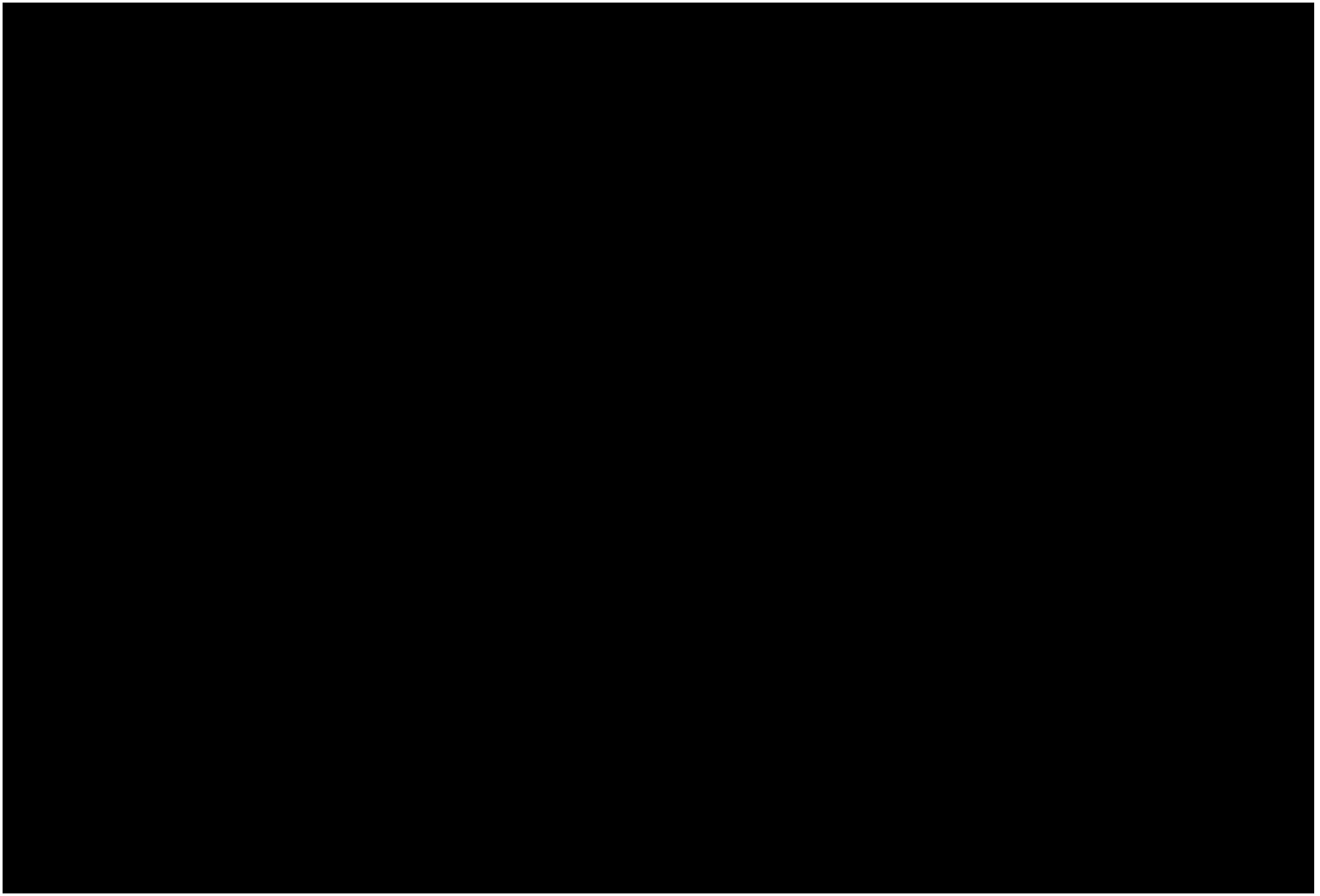
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Midwest Electric Cooperative Corporation

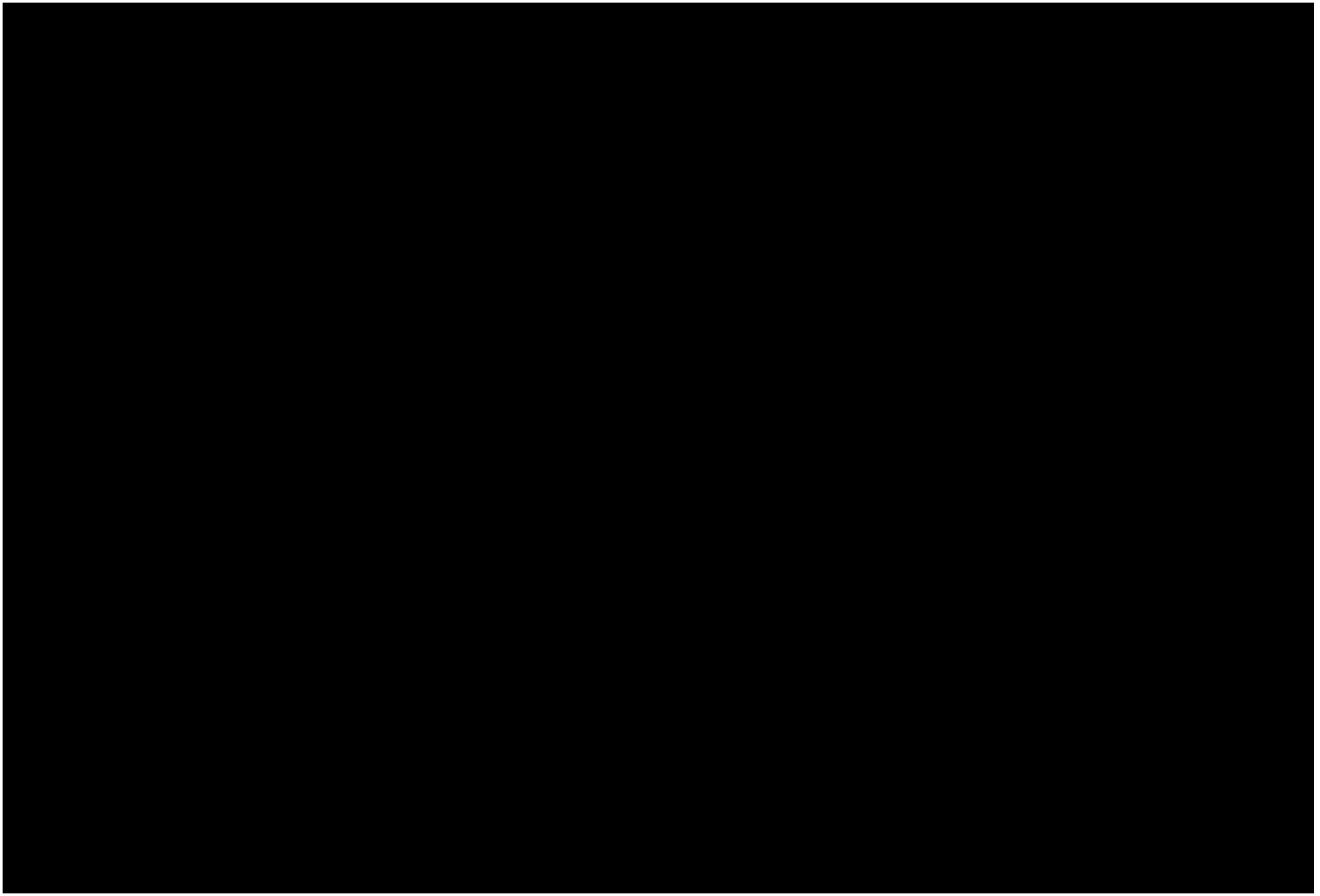
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Midwest Electric Cooperative Corporation

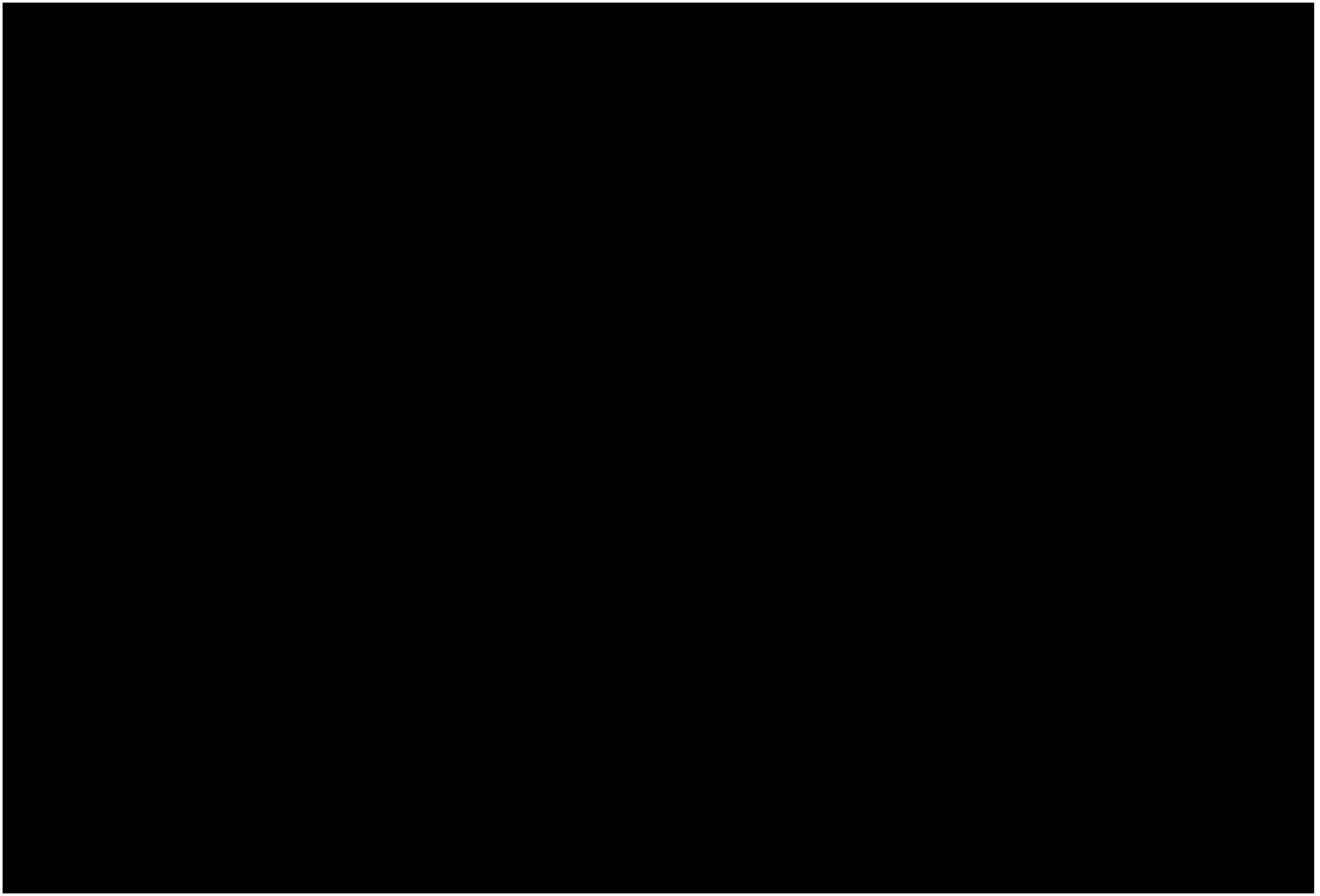
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Midwest Electric Cooperative Corporation

Date of On Peak Day - 04/01/2021

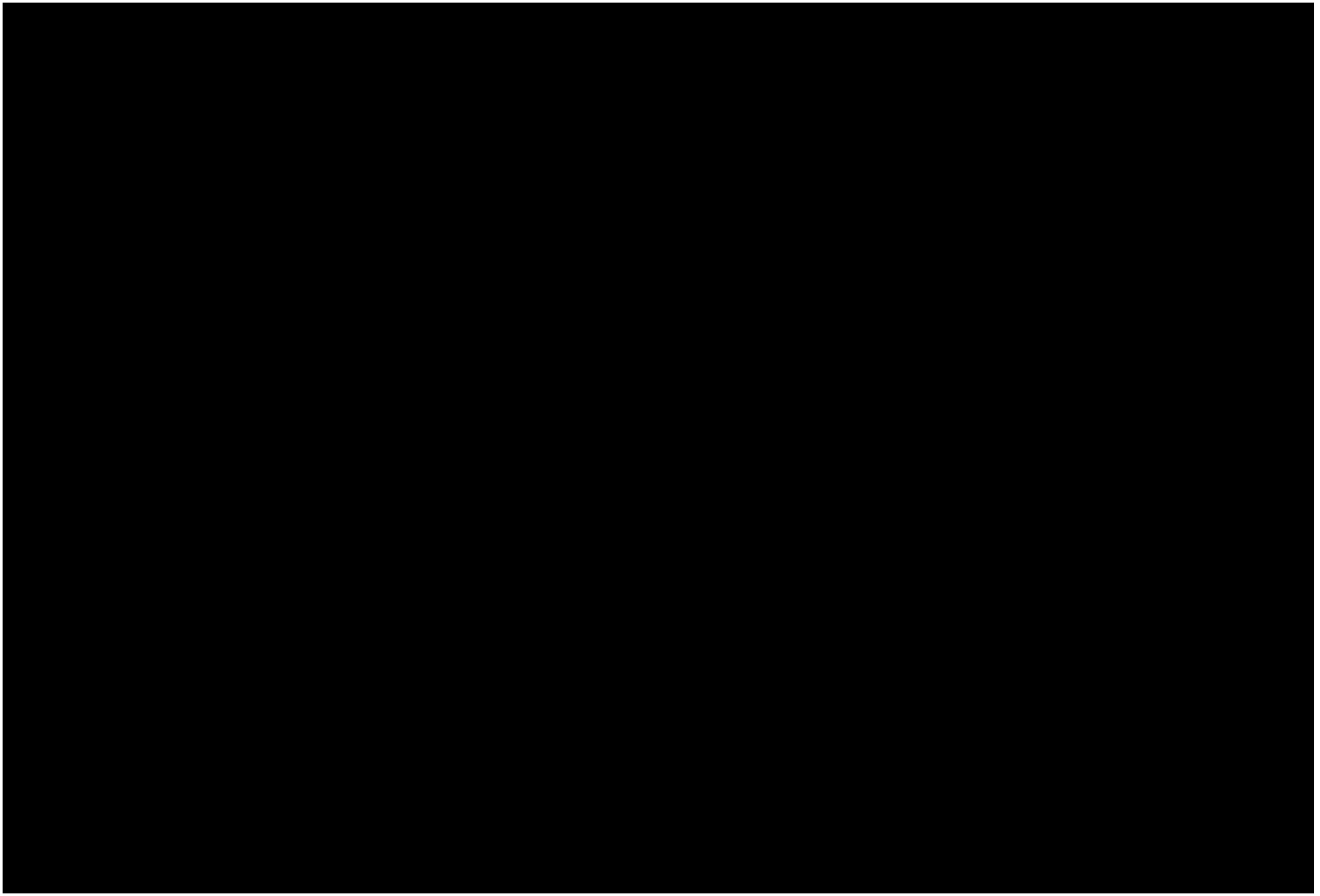


Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
Page 688 of 2886

Member Forecasted On Peak Demand Day for May 2021

Midwest Electric Cooperative Corporation

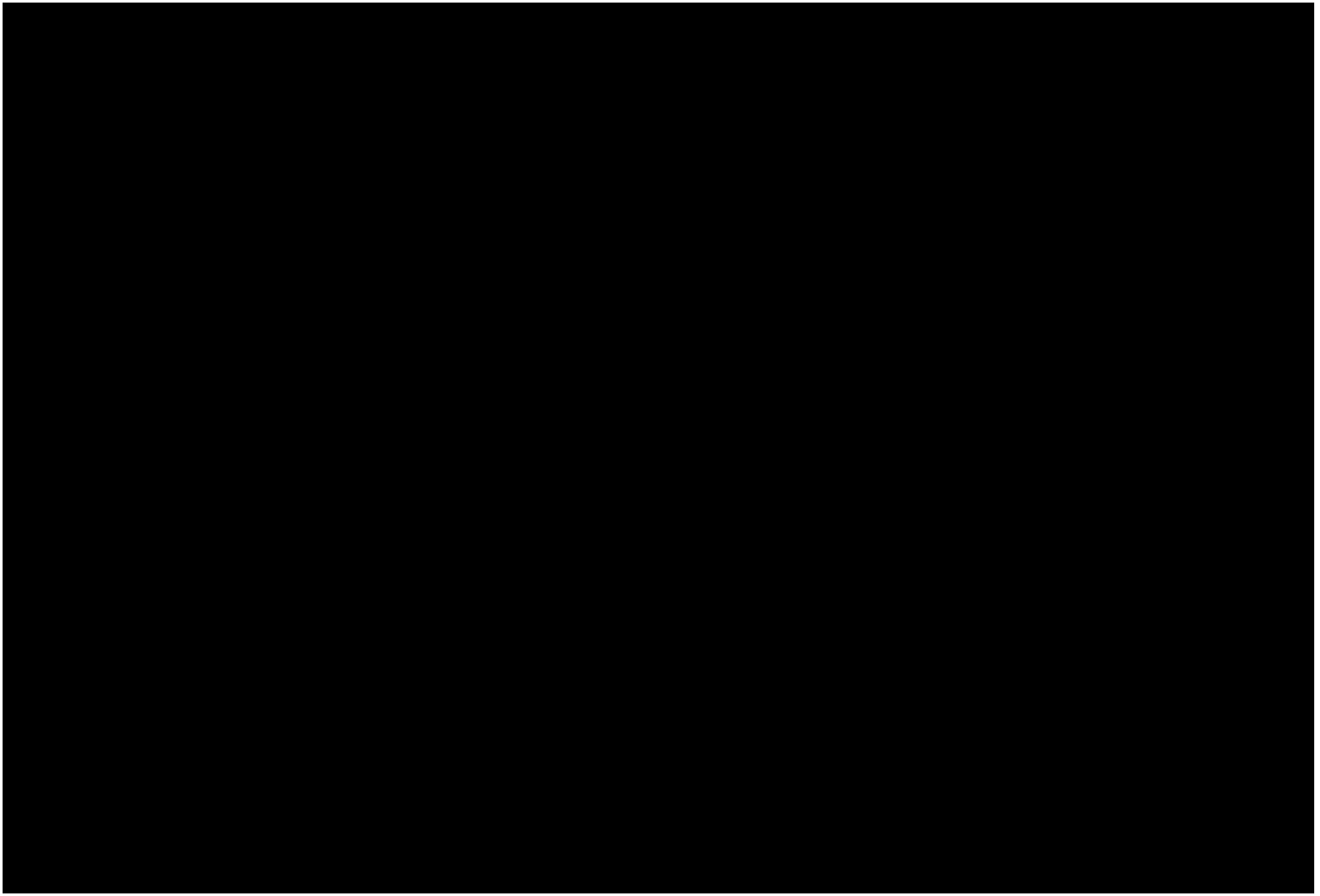
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Midwest Electric Cooperative Corporation

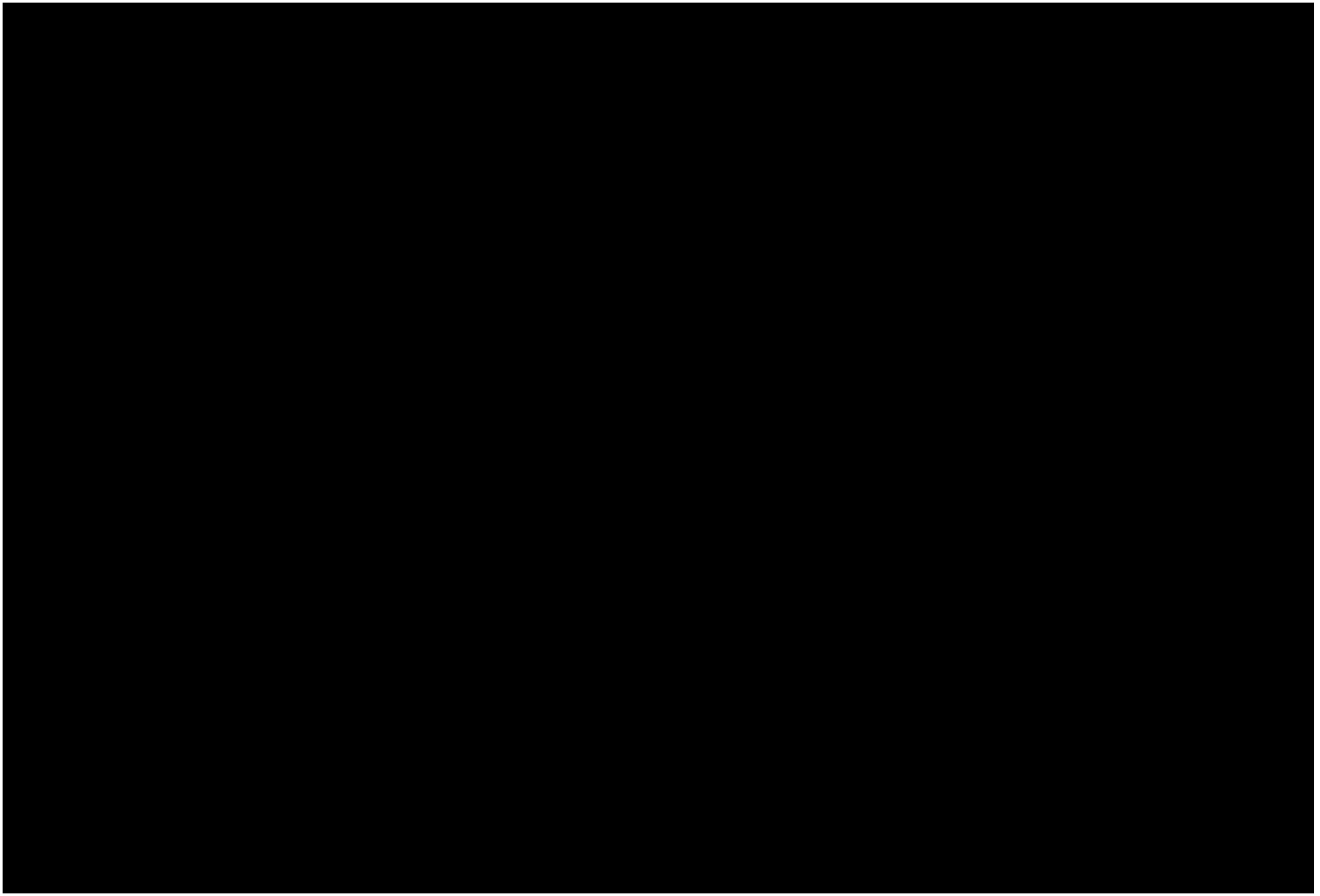
Date of On Peak Day - 06/12/2021



Member Forecasted On Peak Demand Day for July 2021

Midwest Electric Cooperative Corporation

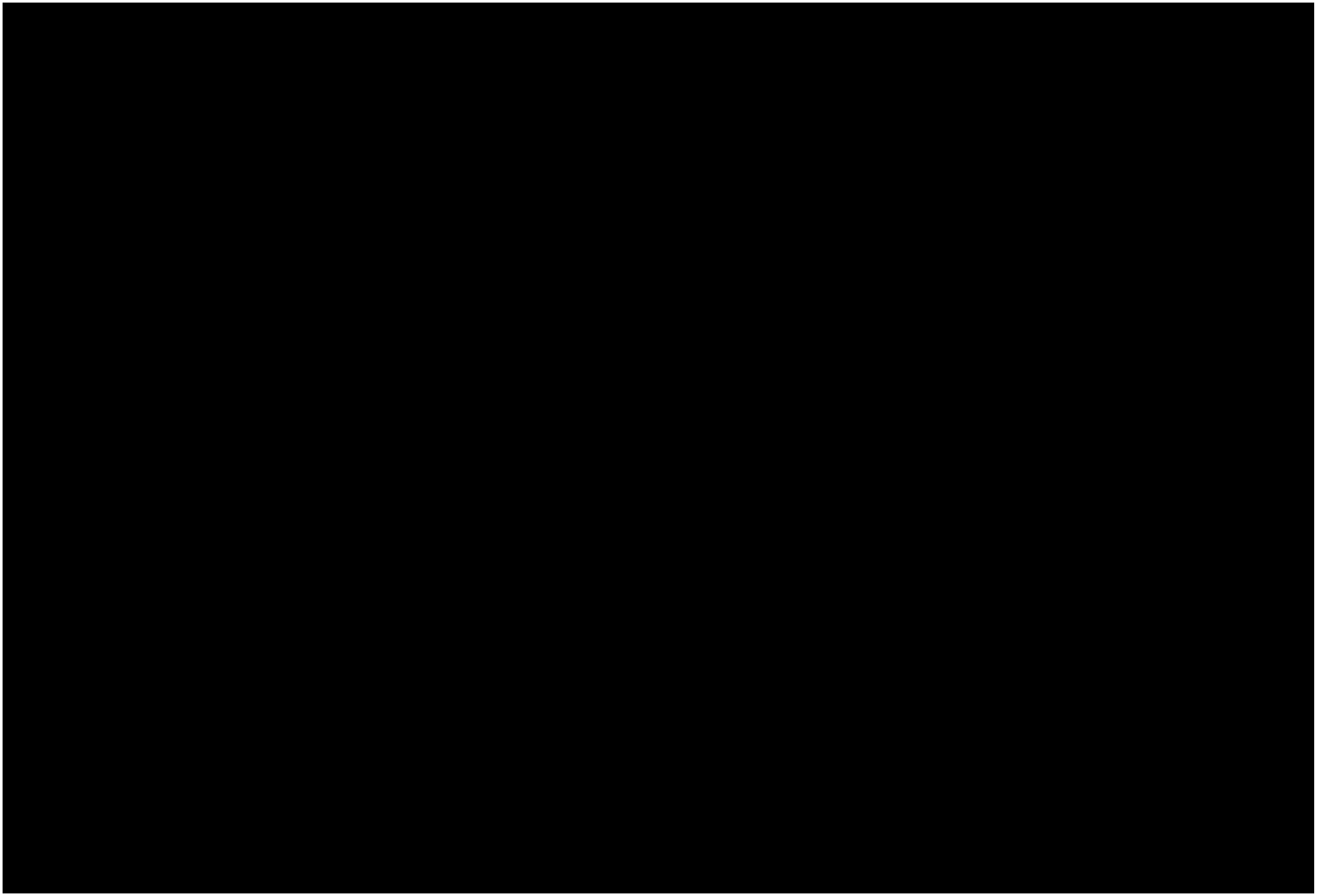
Date of On Peak Day - 07/12/2021



Member Forecasted On Peak Demand Day for August 2021

Midwest Electric Cooperative Corporation

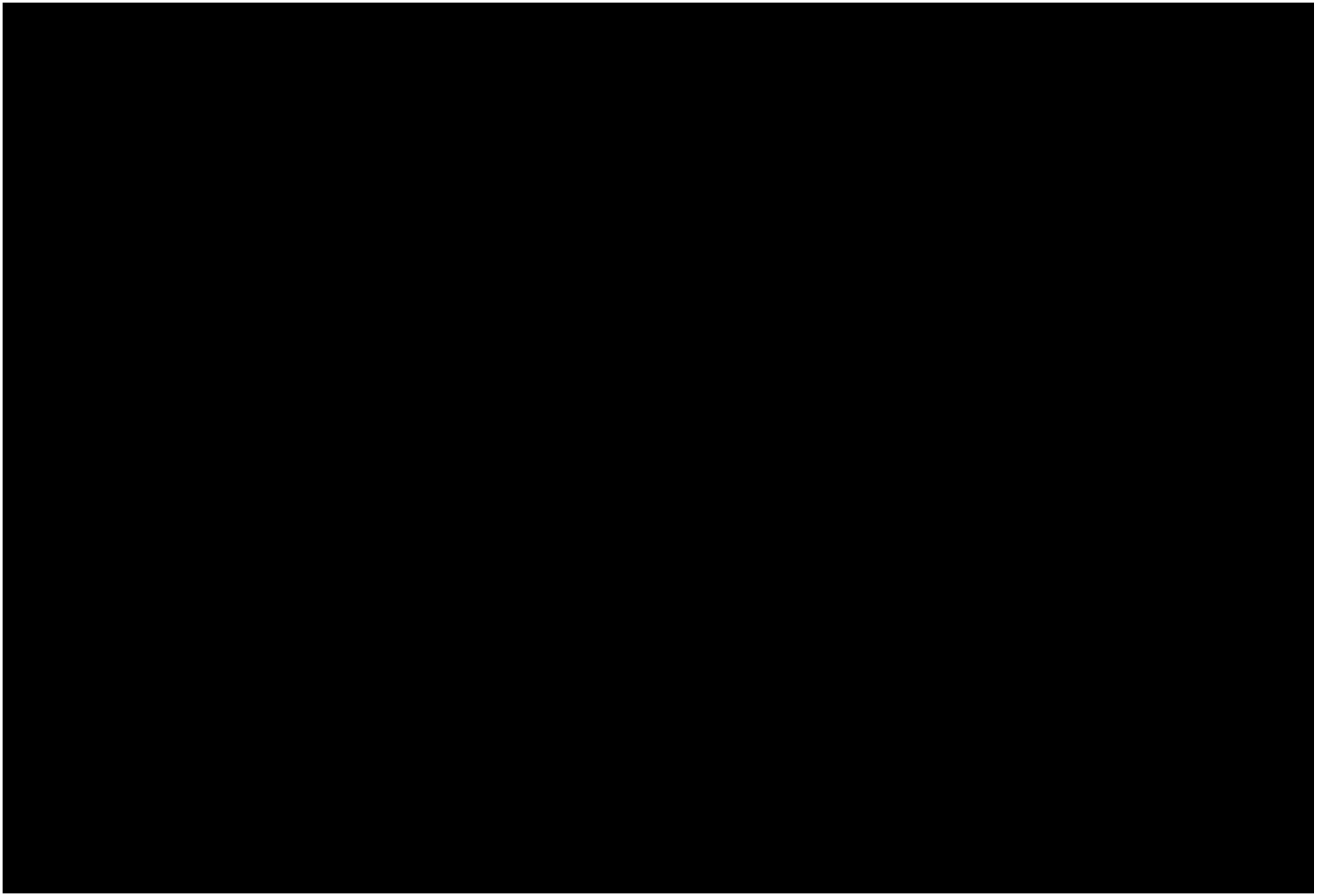
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Midwest Electric Cooperative Corporation

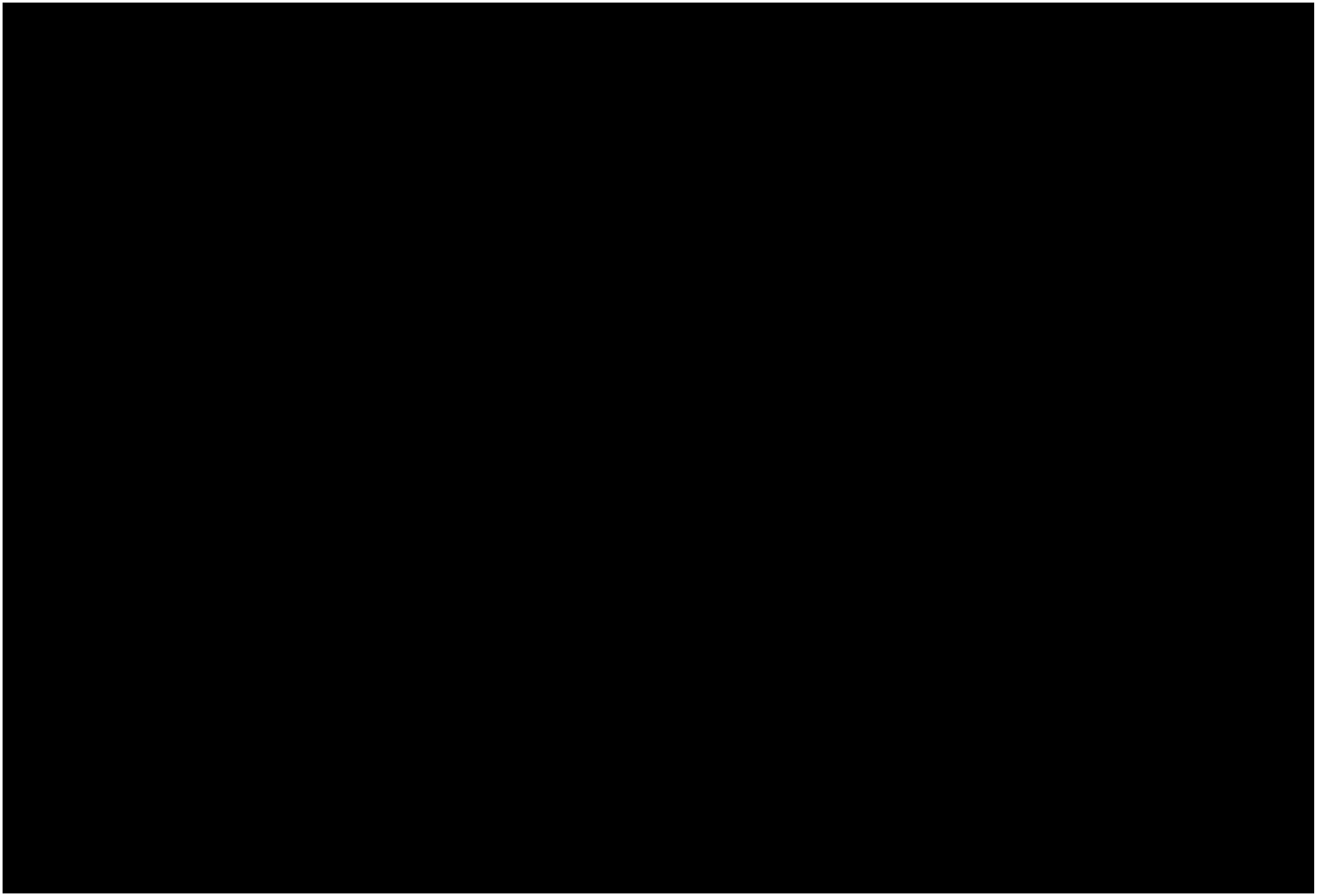
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Midwest Electric Cooperative Corporation

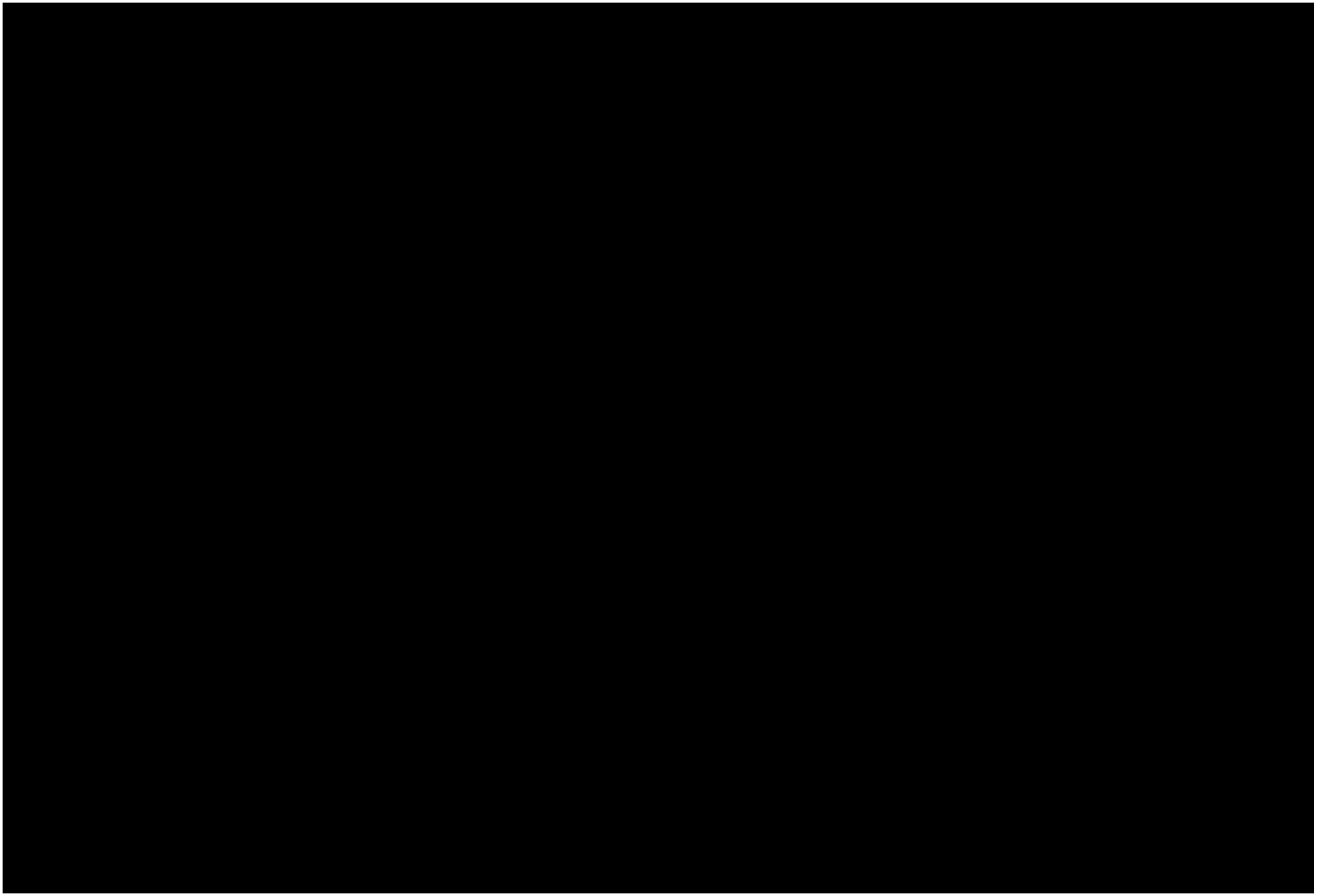
Date of On Peak Day - 10/20/2021



Member Forecasted On Peak Demand Day for November 2021

Midwest Electric Cooperative Corporation

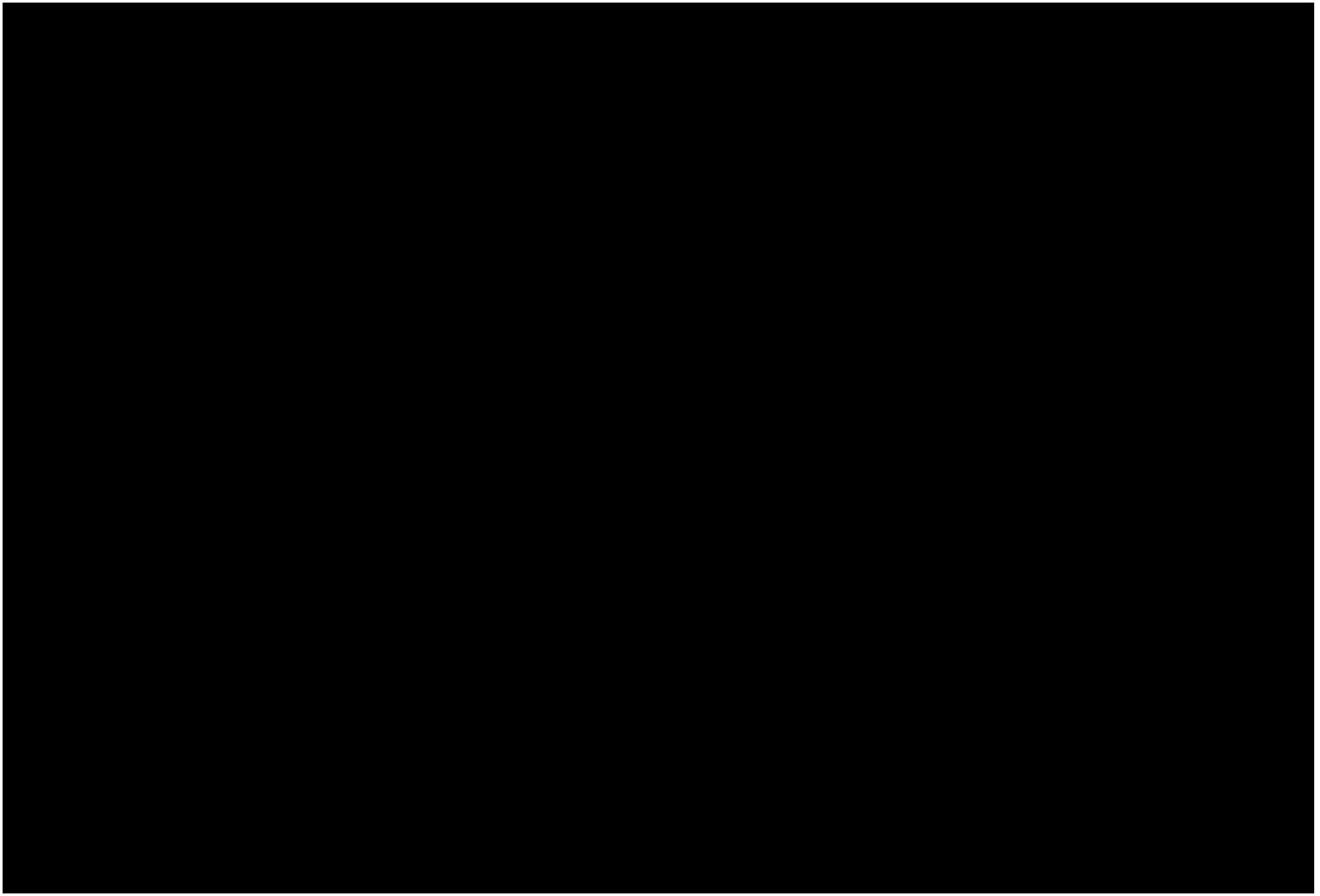
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Midwest Electric Cooperative Corporation

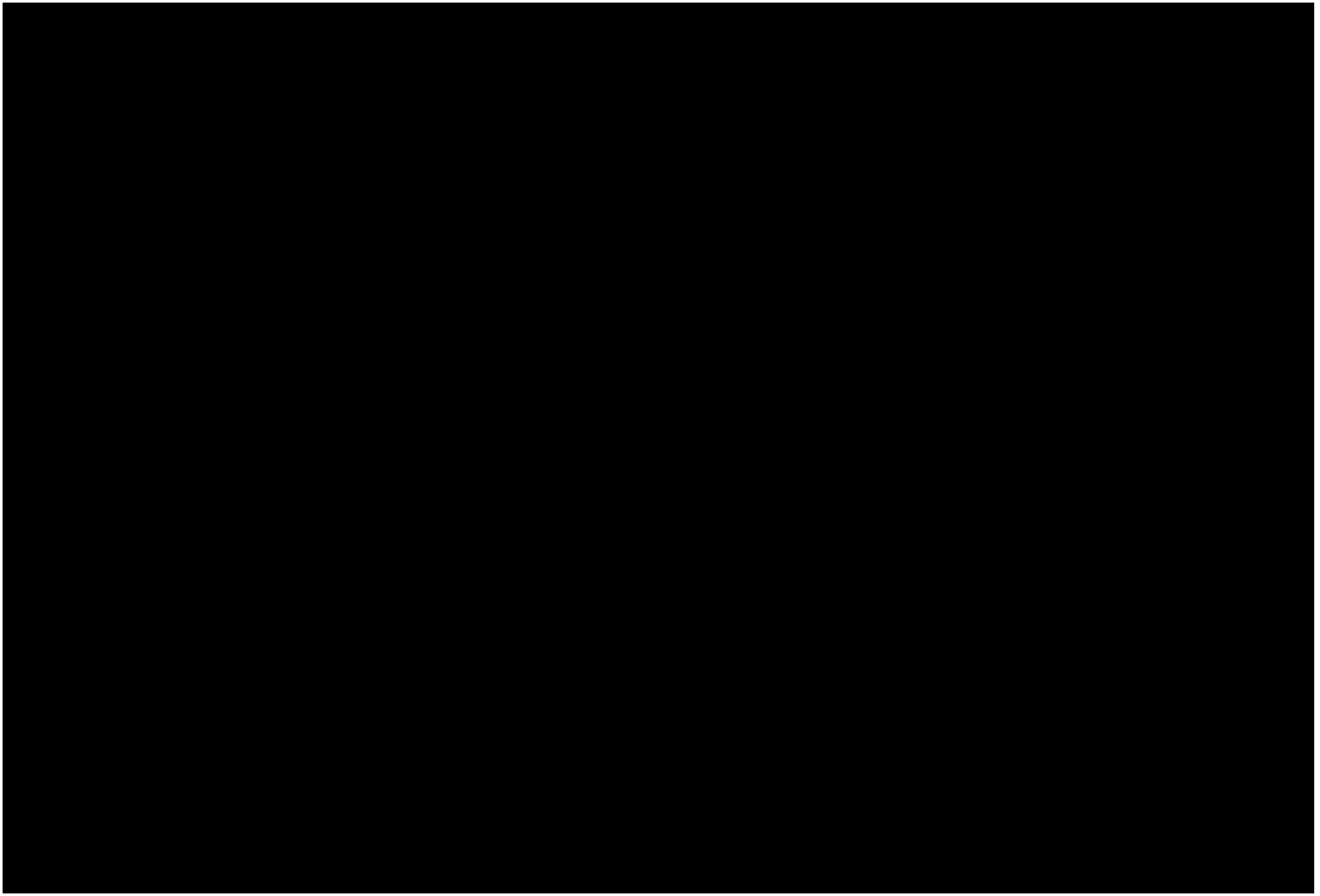
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 01/29/2021



Member Forecasted On Peak Demand Day for February 2021

Niobrara Electric Association, Inc.

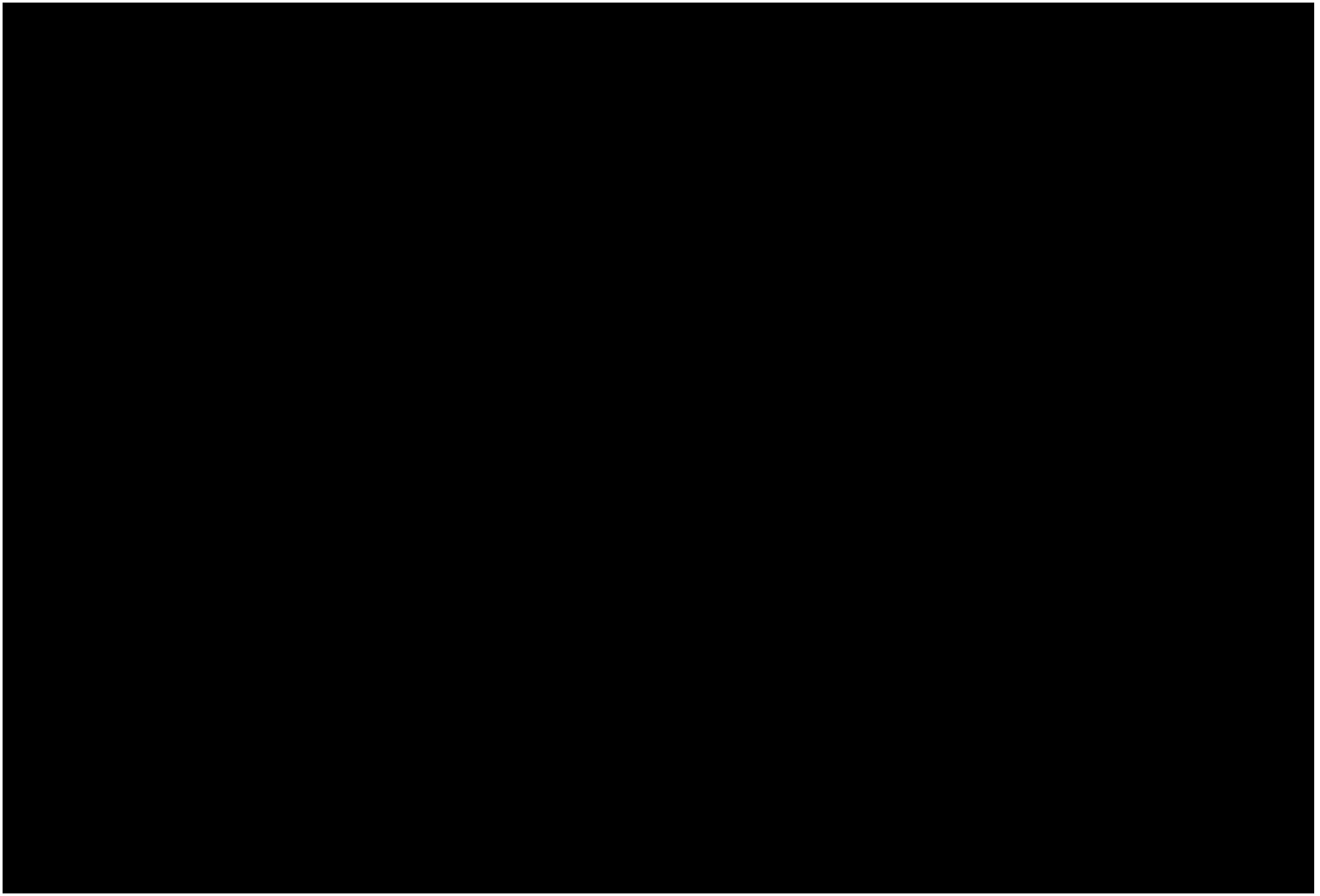
Date of On Peak Day - 02/15/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Niobrara Electric Association, Inc.

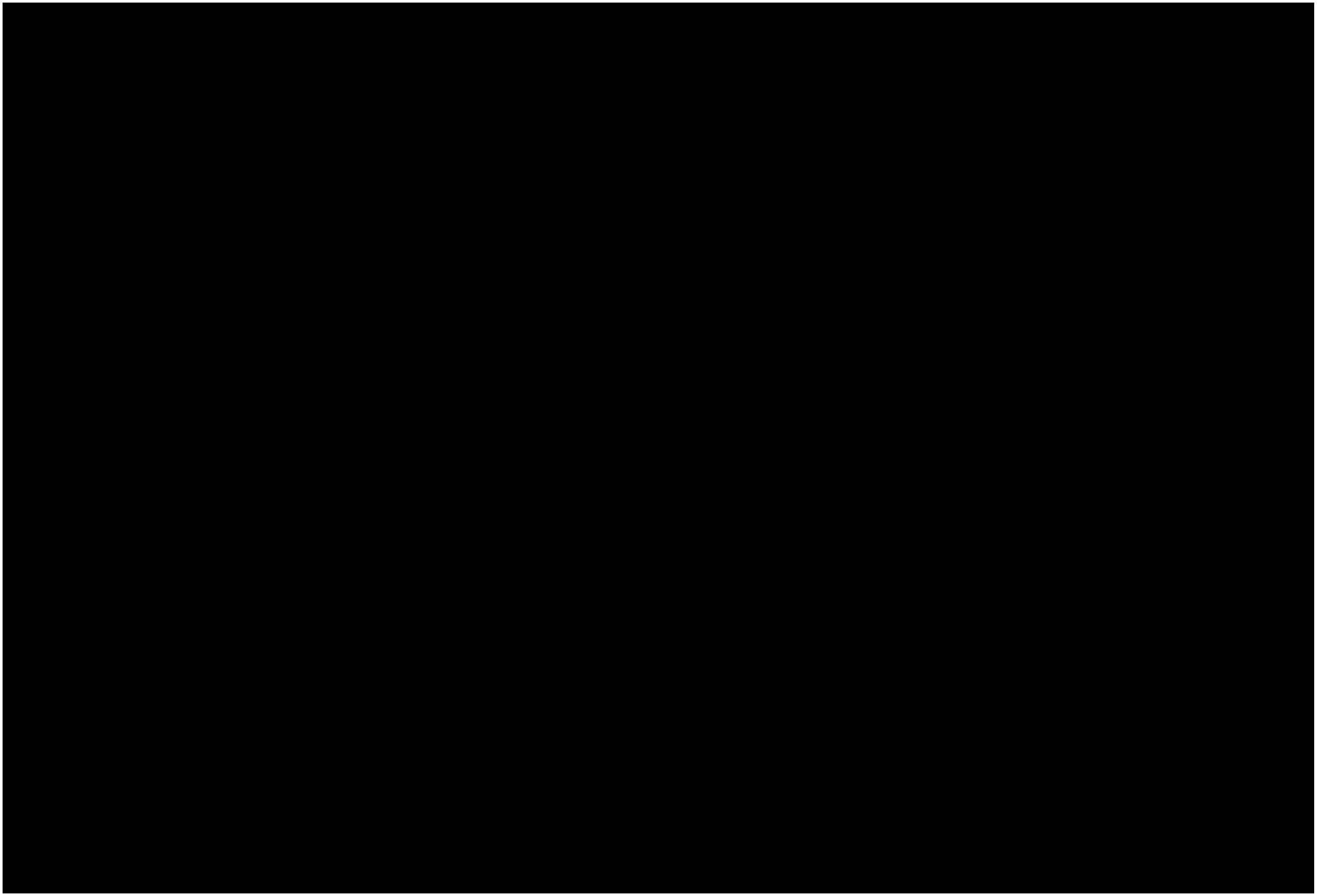
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 05/31/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Niobrara Electric Association, Inc.

Date of On Peak Day - 06/05/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

Niobrara Electric Association, Inc.

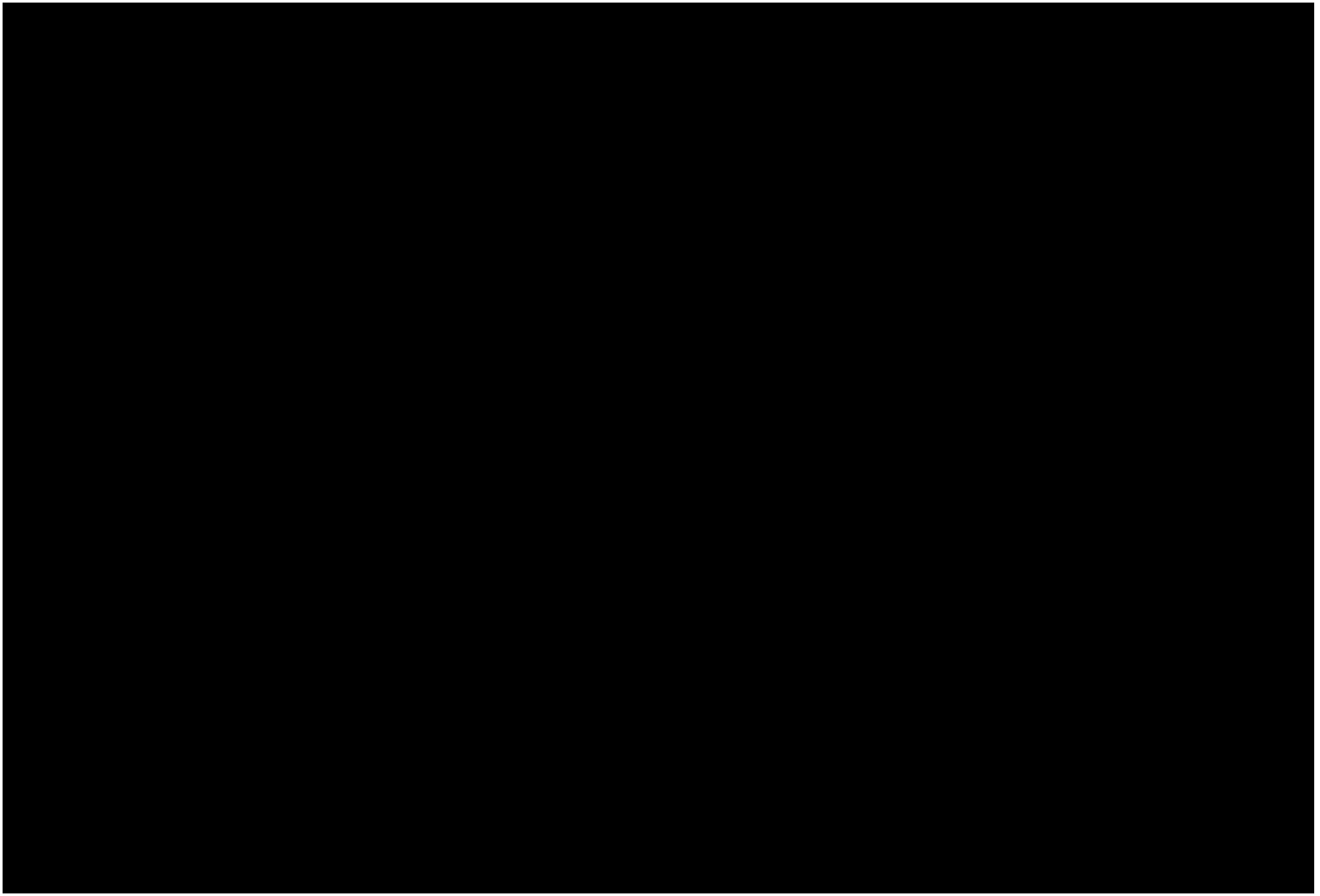
Date of On Peak Day - 07/10/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Niobrara Electric Association, Inc.

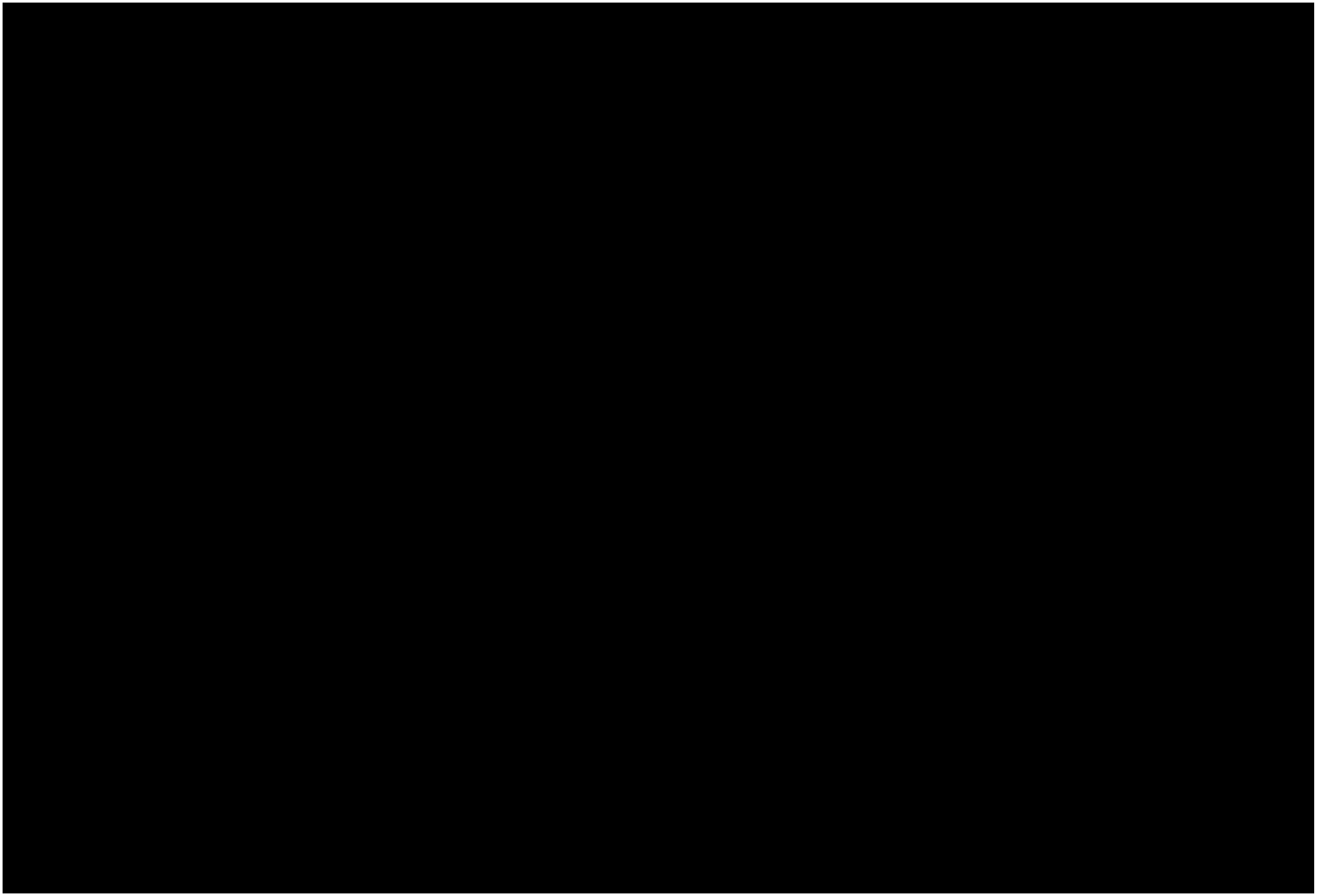
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Niobrara Electric Association, Inc.

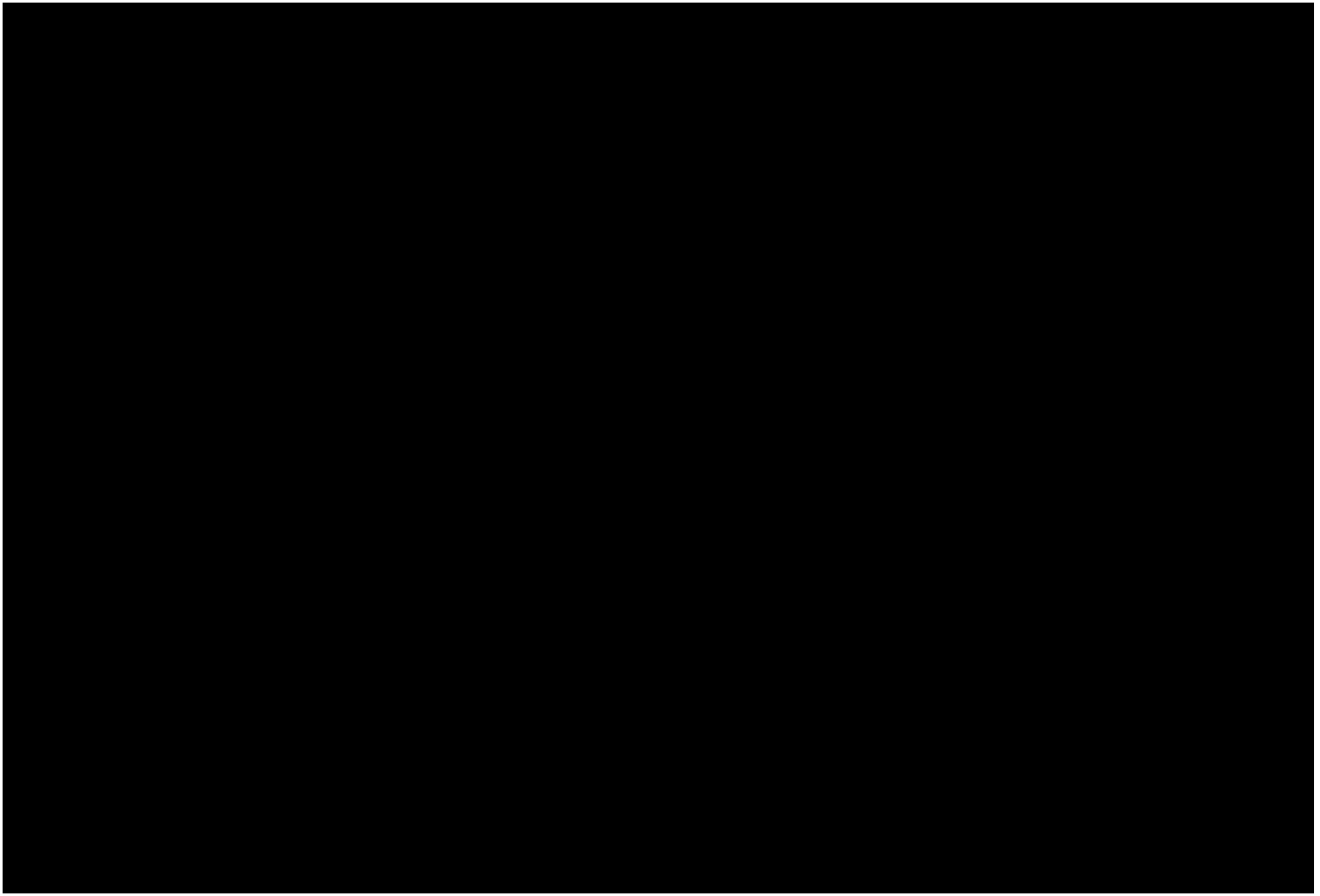
Date of On Peak Day - 09/07/2021



Member Forecasted On Peak Demand Day for October 2021

Niobrara Electric Association, Inc.

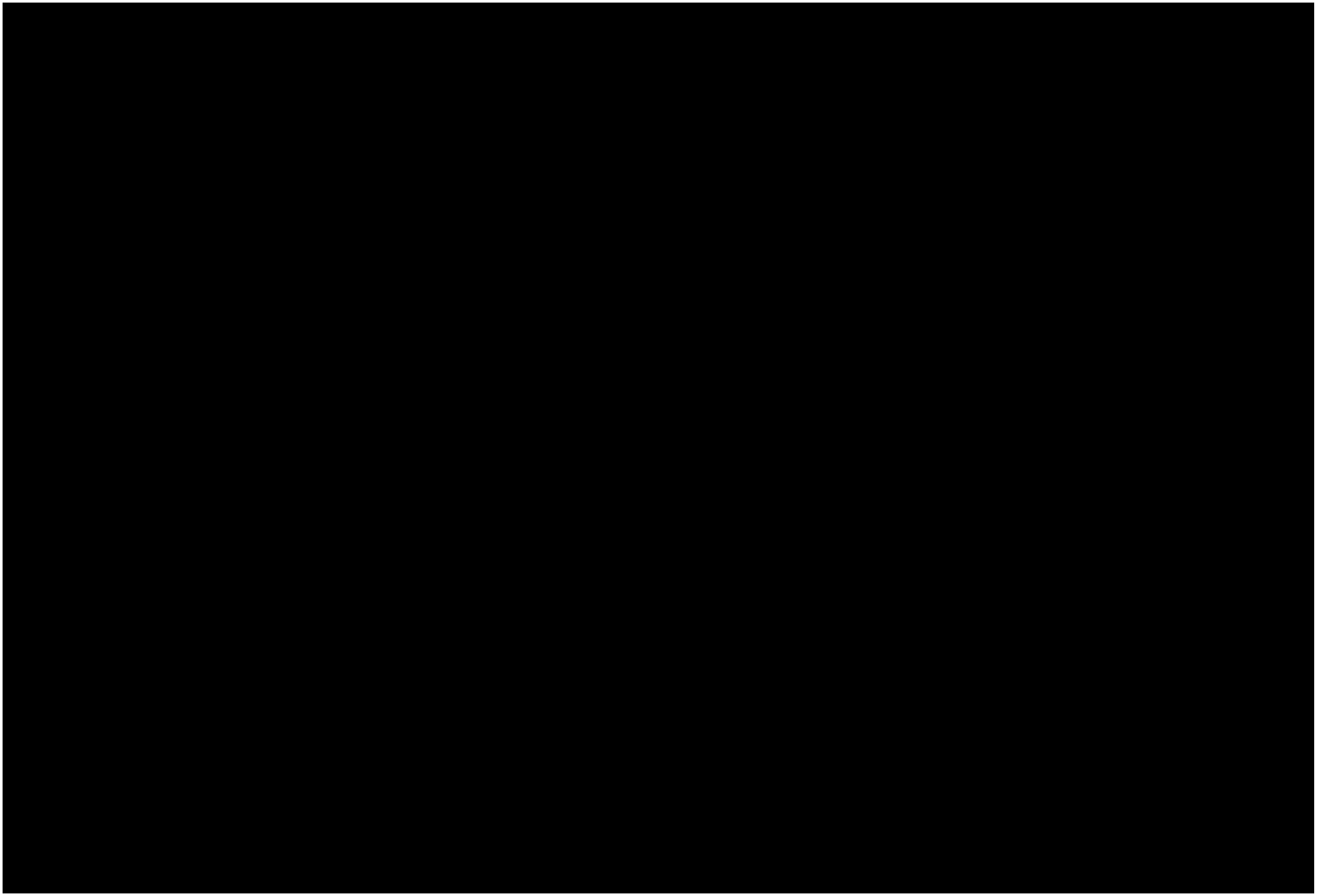
Date of On Peak Day - 10/03/2021



Member Forecasted On Peak Demand Day for November 2021

Niobrara Electric Association, Inc.

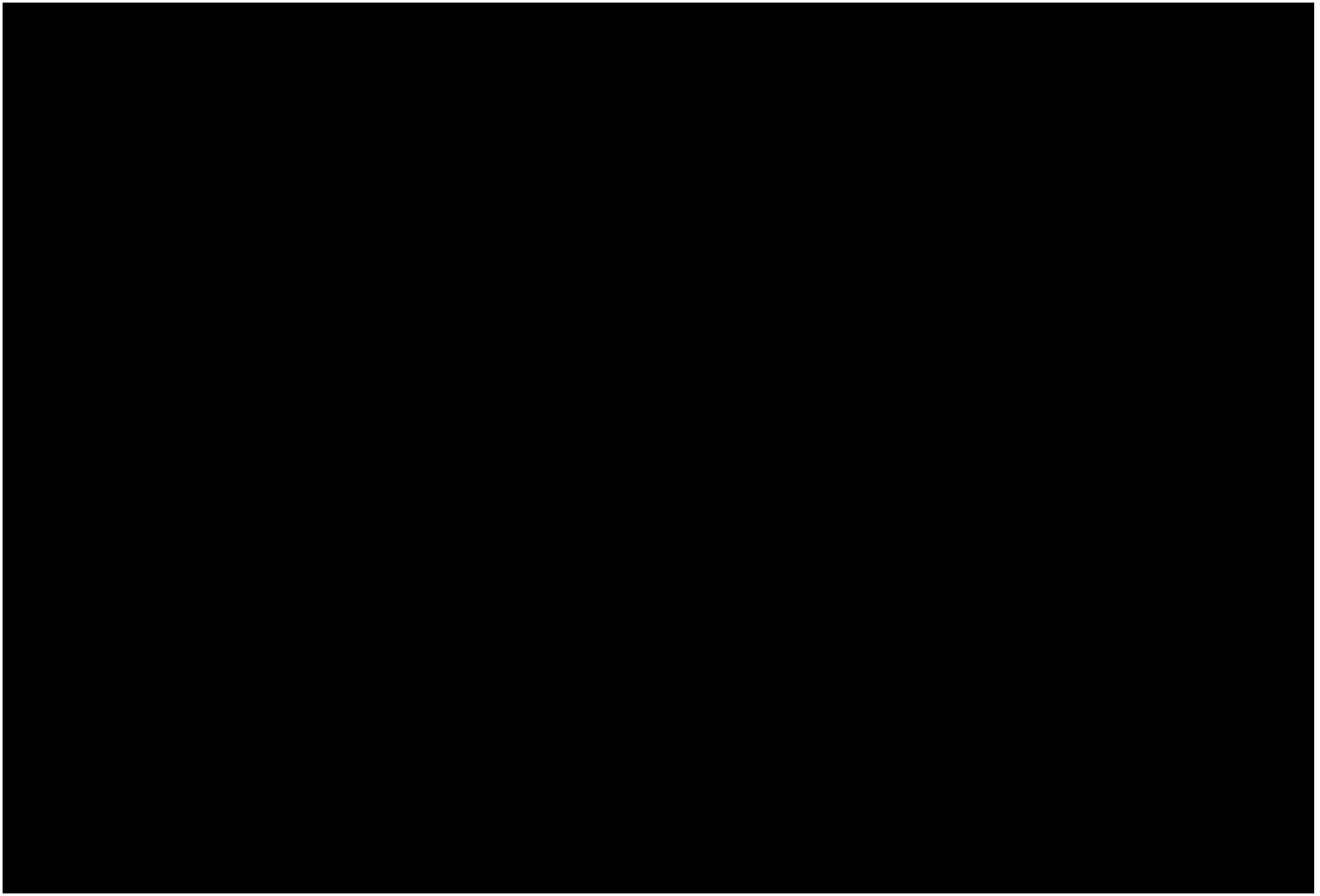
Date of On Peak Day - 11/21/2021



Member Forecasted On Peak Demand Day for December 2021

Niobrara Electric Association, Inc.

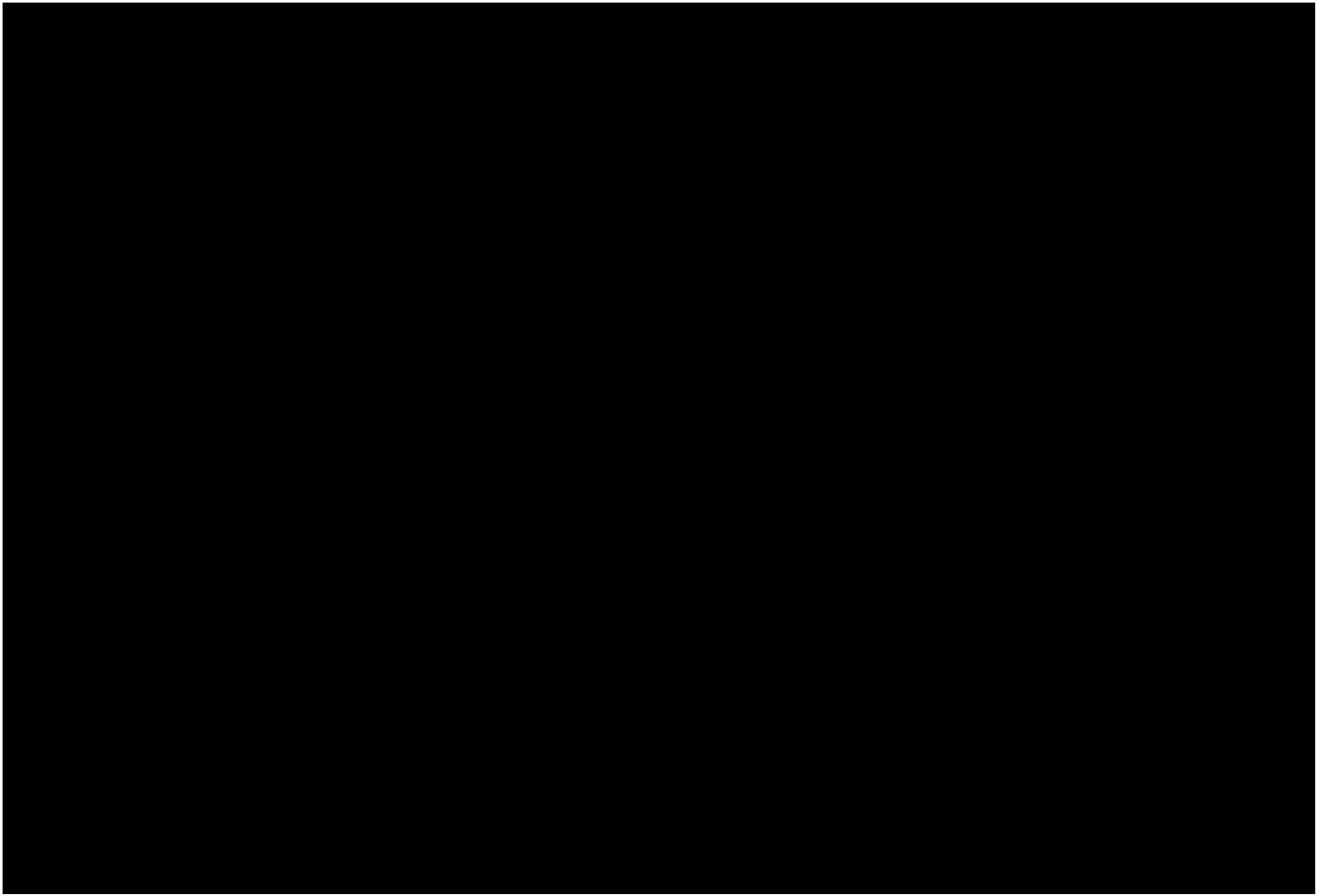
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Northwest Rural Public Power District

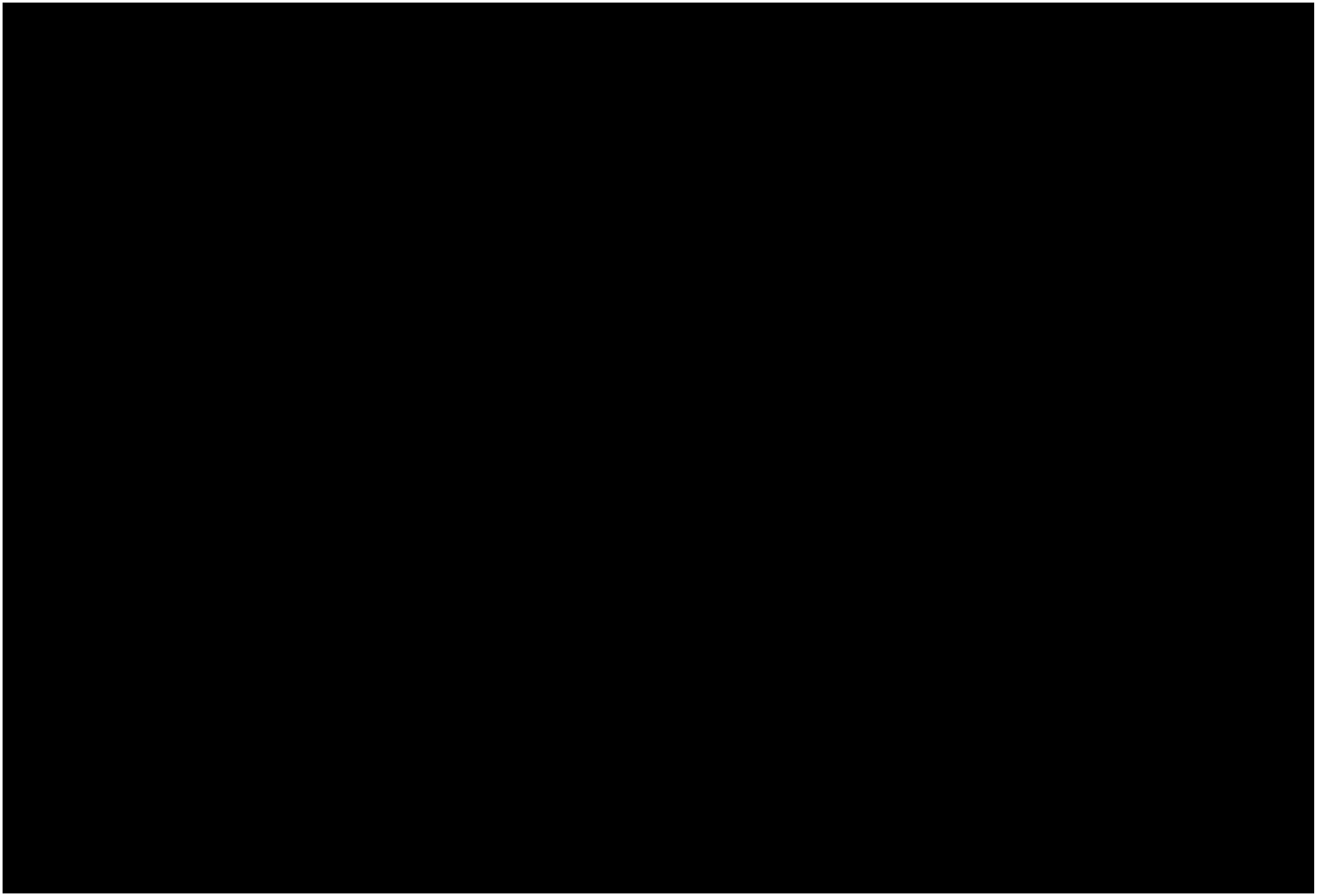
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Northwest Rural Public Power District

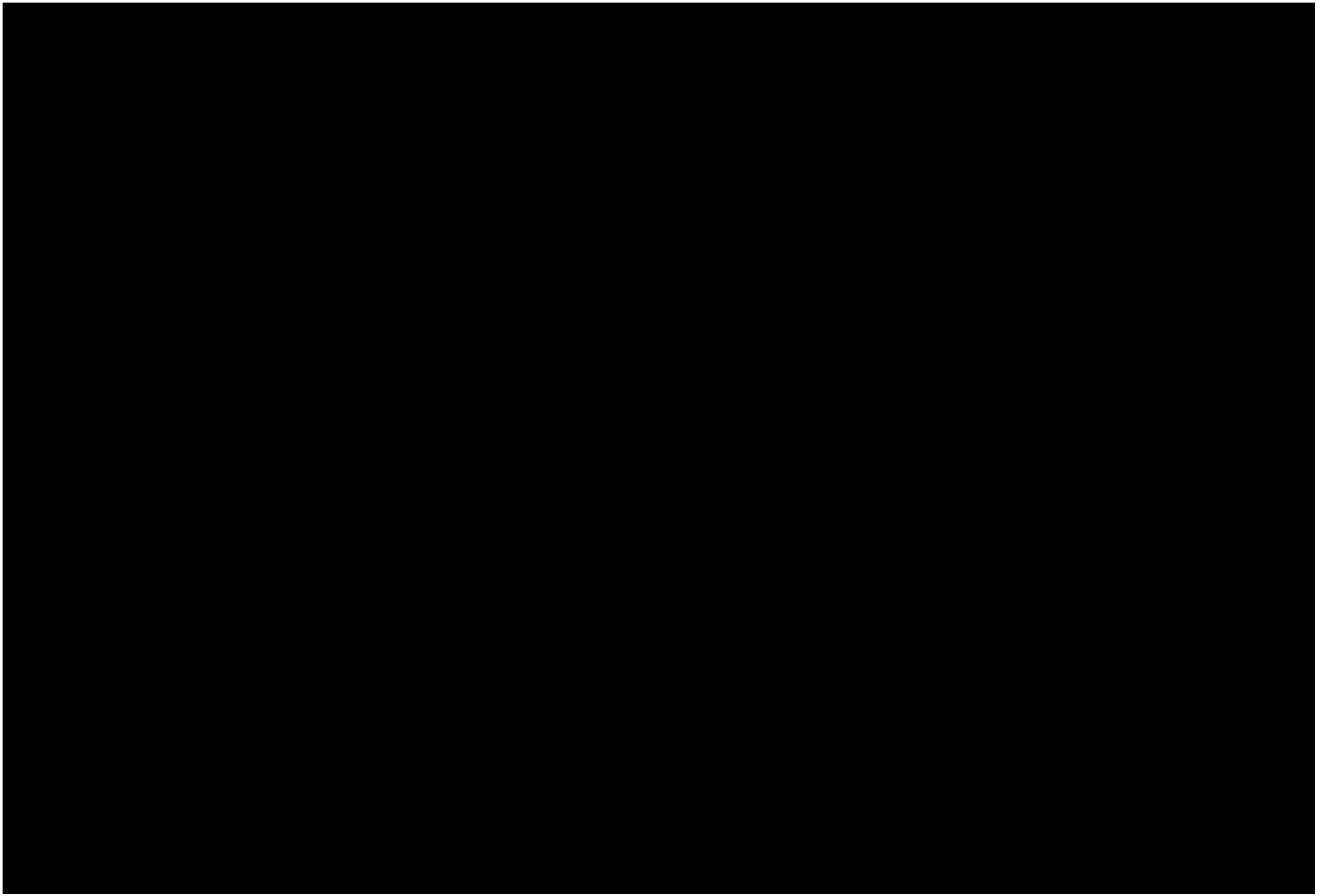
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Northwest Rural Public Power District

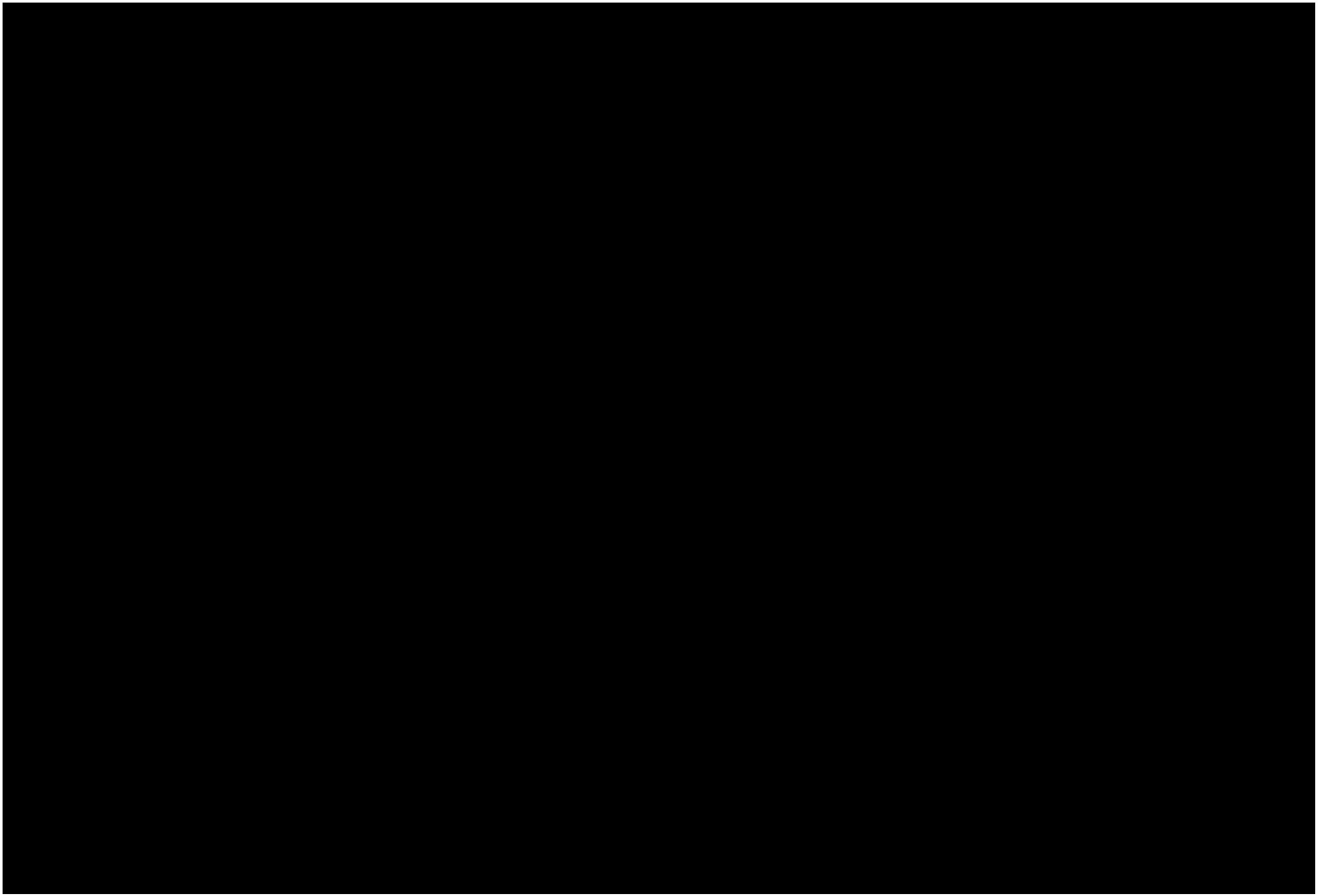
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Northwest Rural Public Power District

Date of On Peak Day - 04/13/2021



Member Forecasted On Peak Demand Day for May 2021

Northwest Rural Public Power District

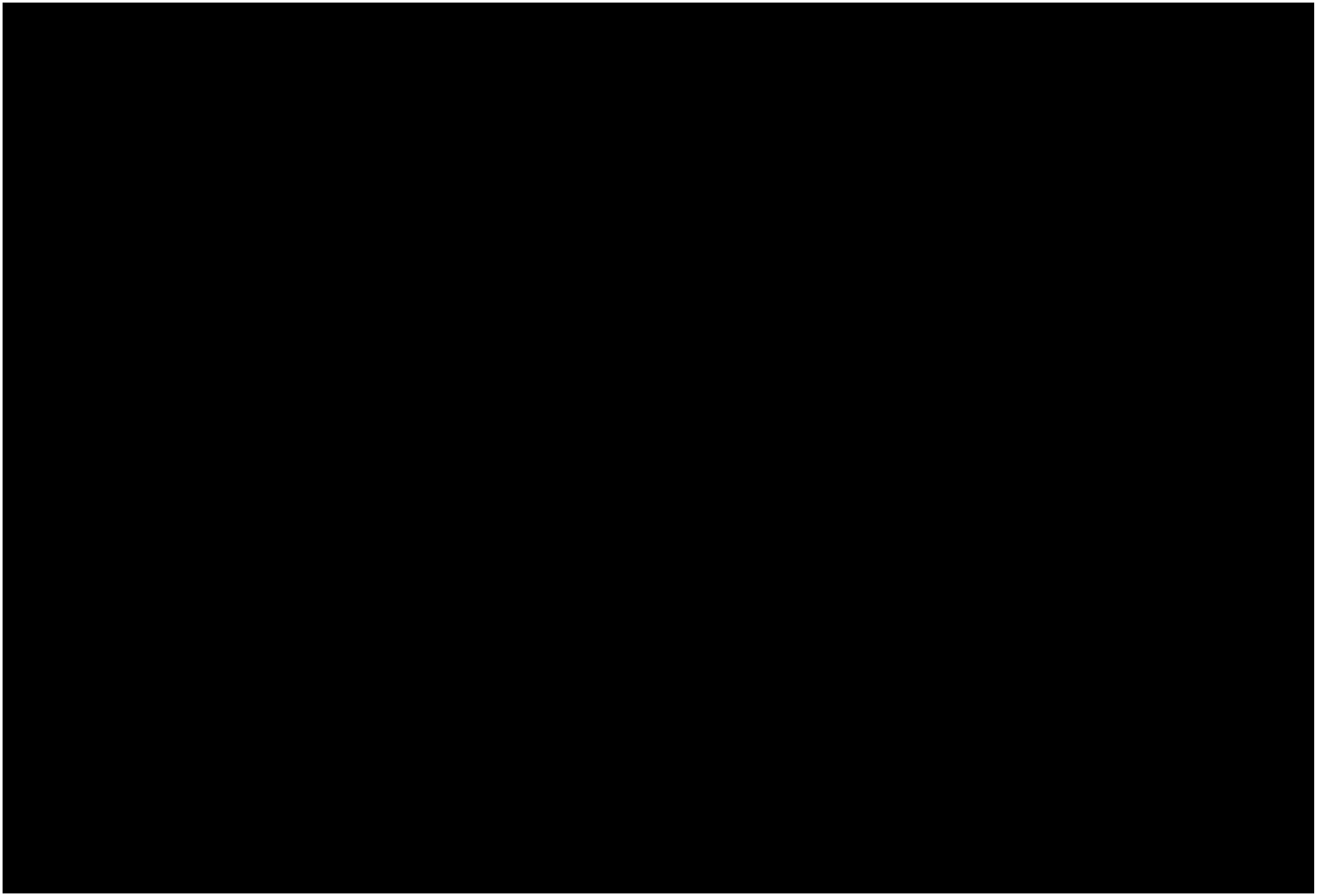
Date of On Peak Day - 05/09/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Northwest Rural Public Power District

Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Northwest Rural Public Power District

Date of On Peak Day - 07/20/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Northwest Rural Public Power District

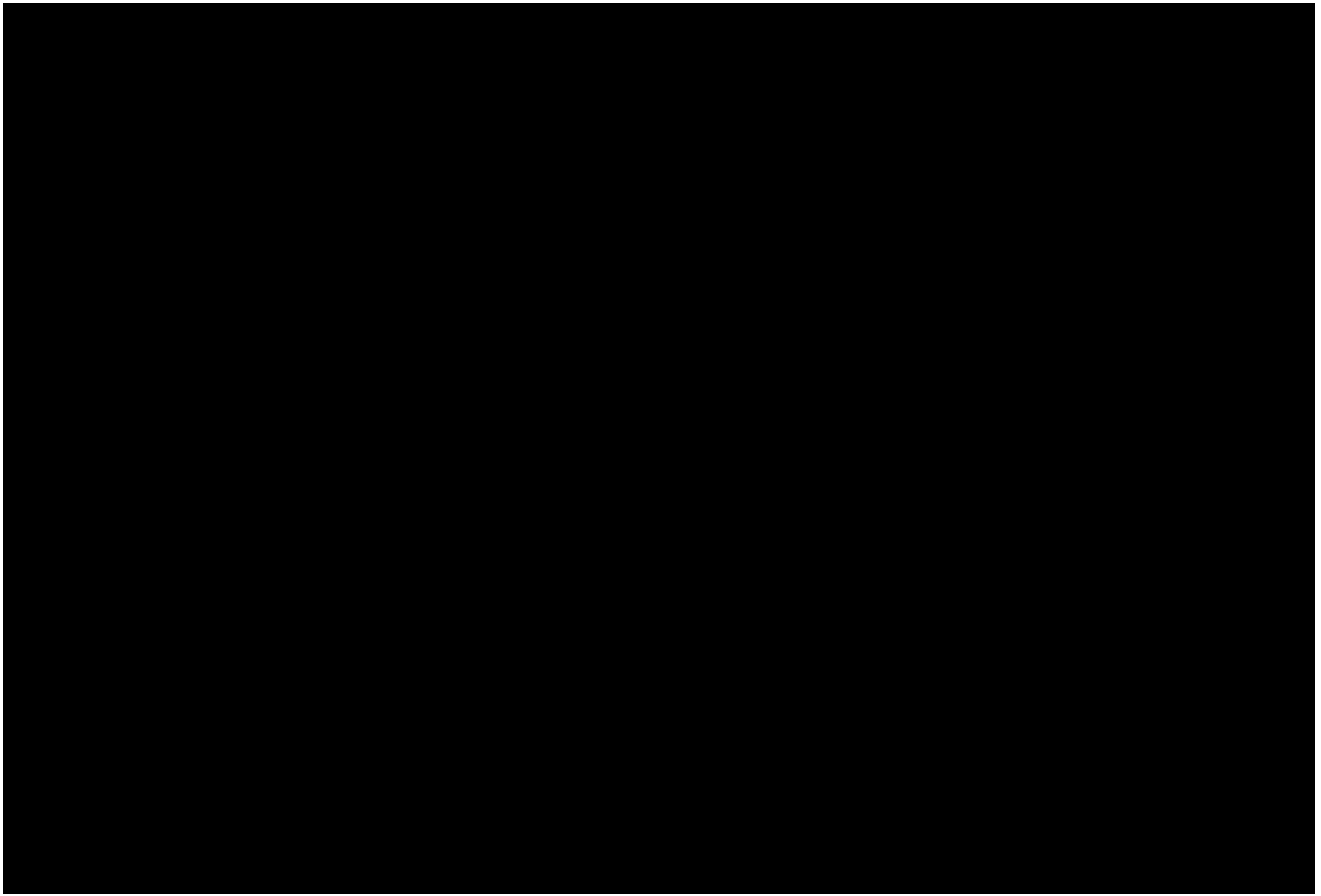
Date of On Peak Day - 08/23/2021

[redacted]

Member Forecasted On Peak Demand Day for September 2021

Northwest Rural Public Power District

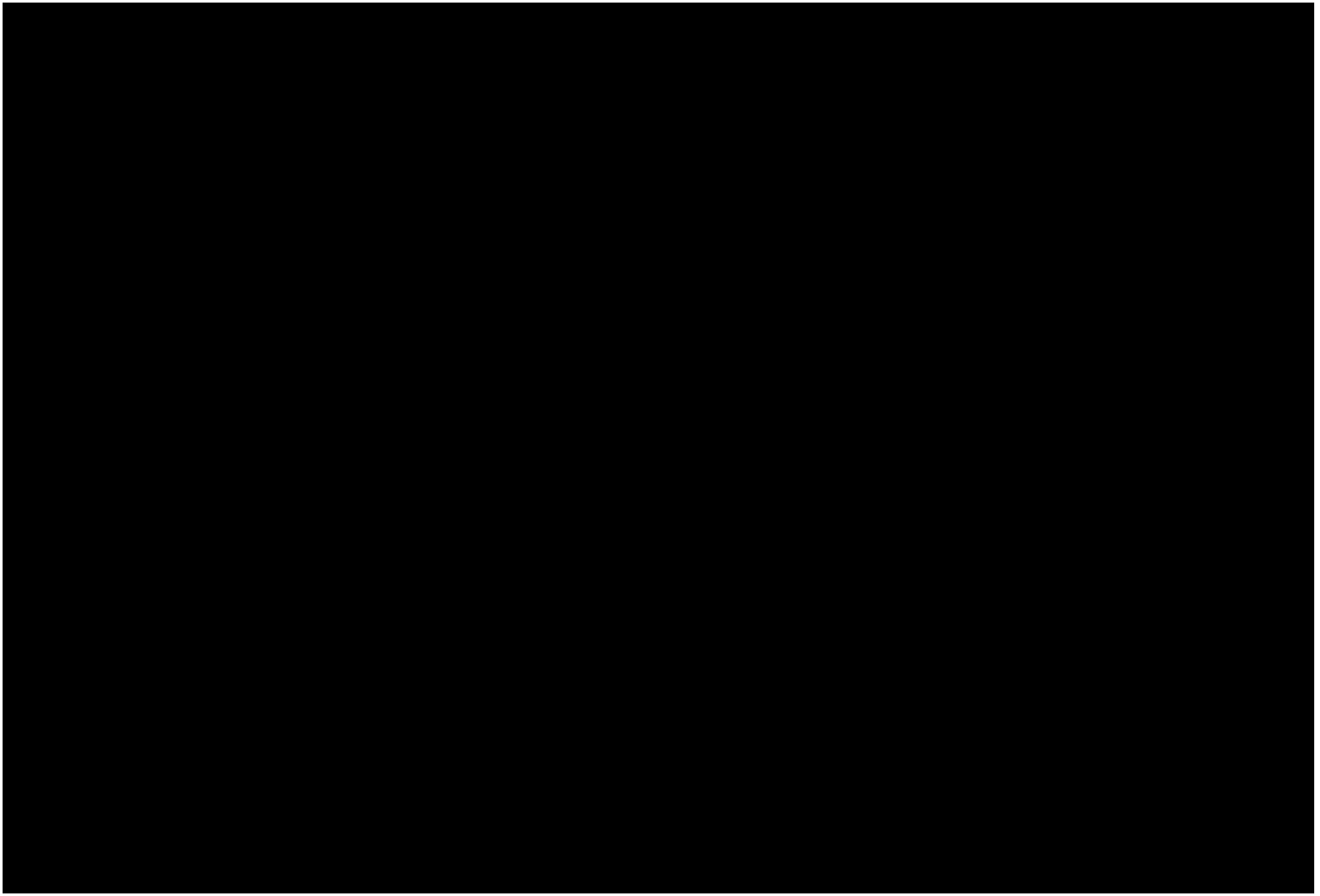
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Northwest Rural Public Power District

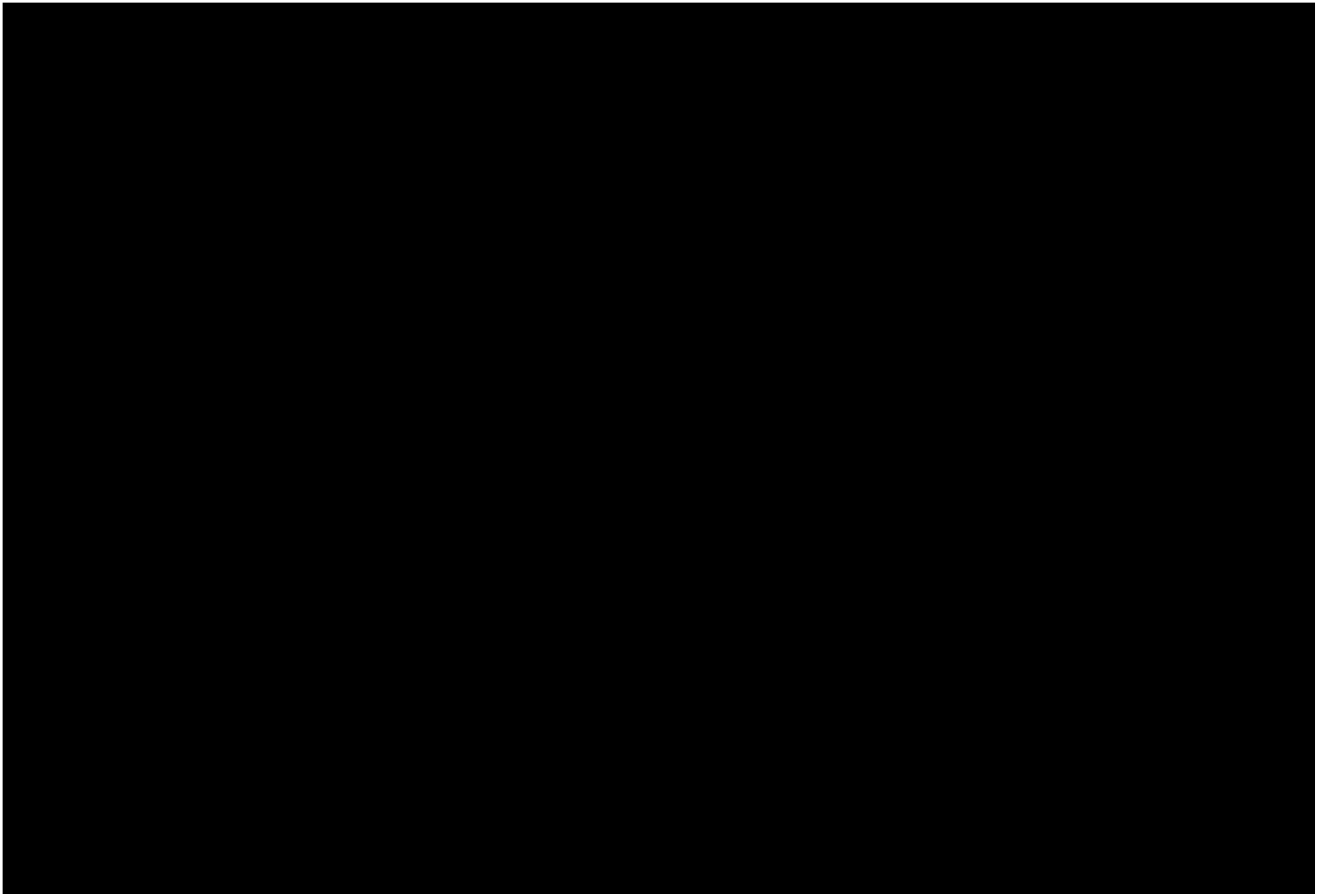
Date of On Peak Day - 10/10/2021



Member Forecasted On Peak Demand Day for November 2021

Northwest Rural Public Power District

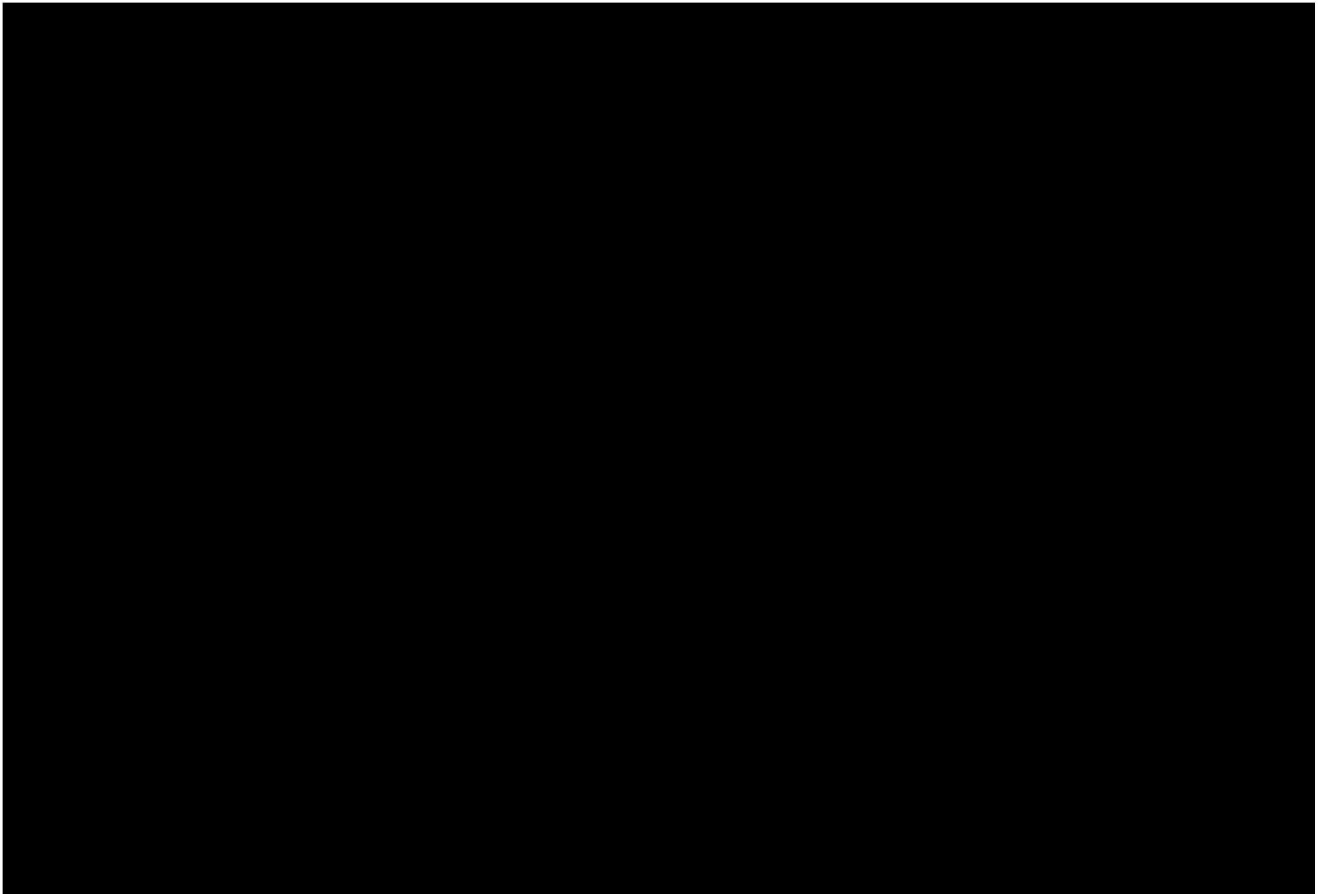
Date of On Peak Day - 11/27/2021



Member Forecasted On Peak Demand Day for December 2021

Northwest Rural Public Power District

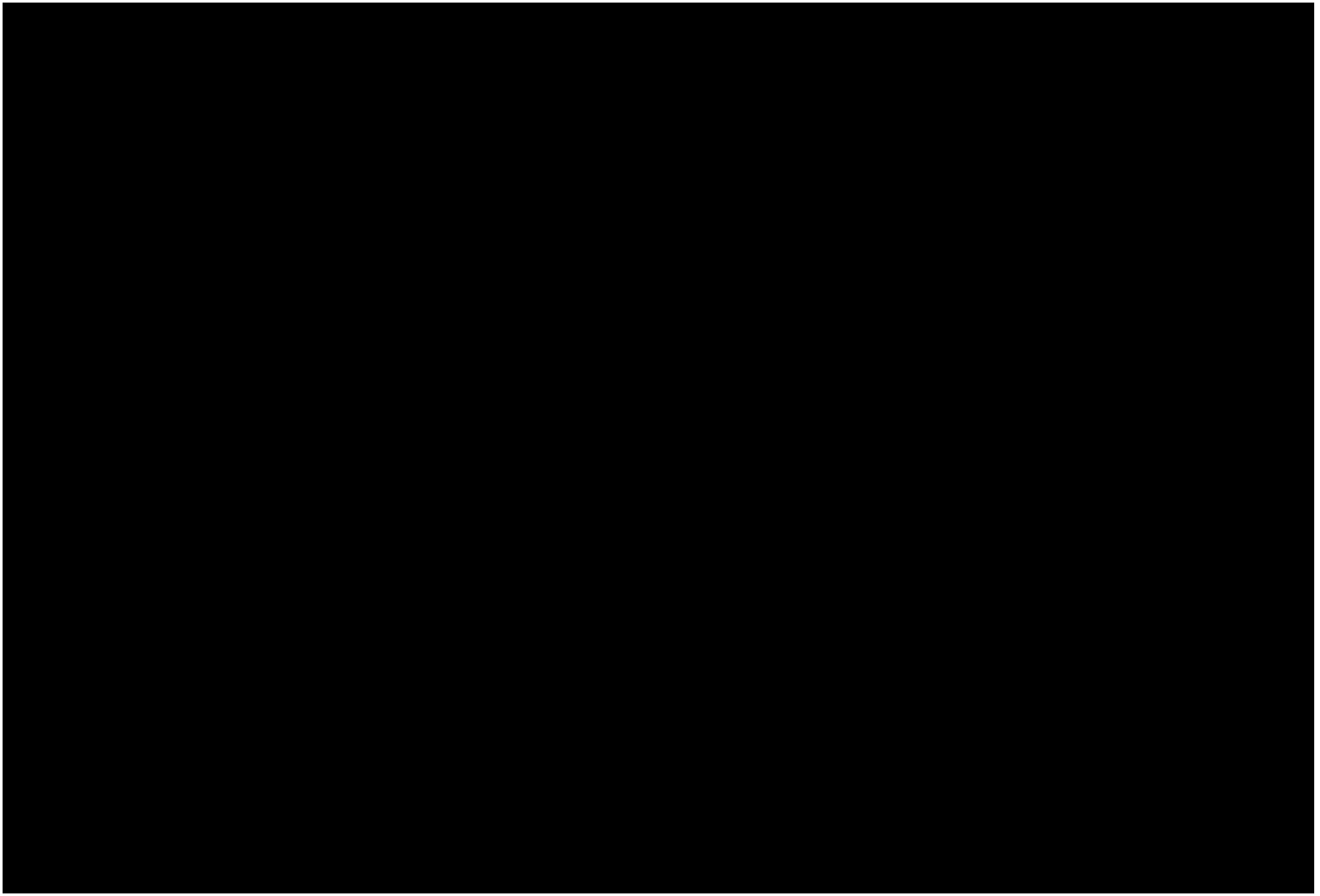
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

Otero County Electric Cooperative, Inc.

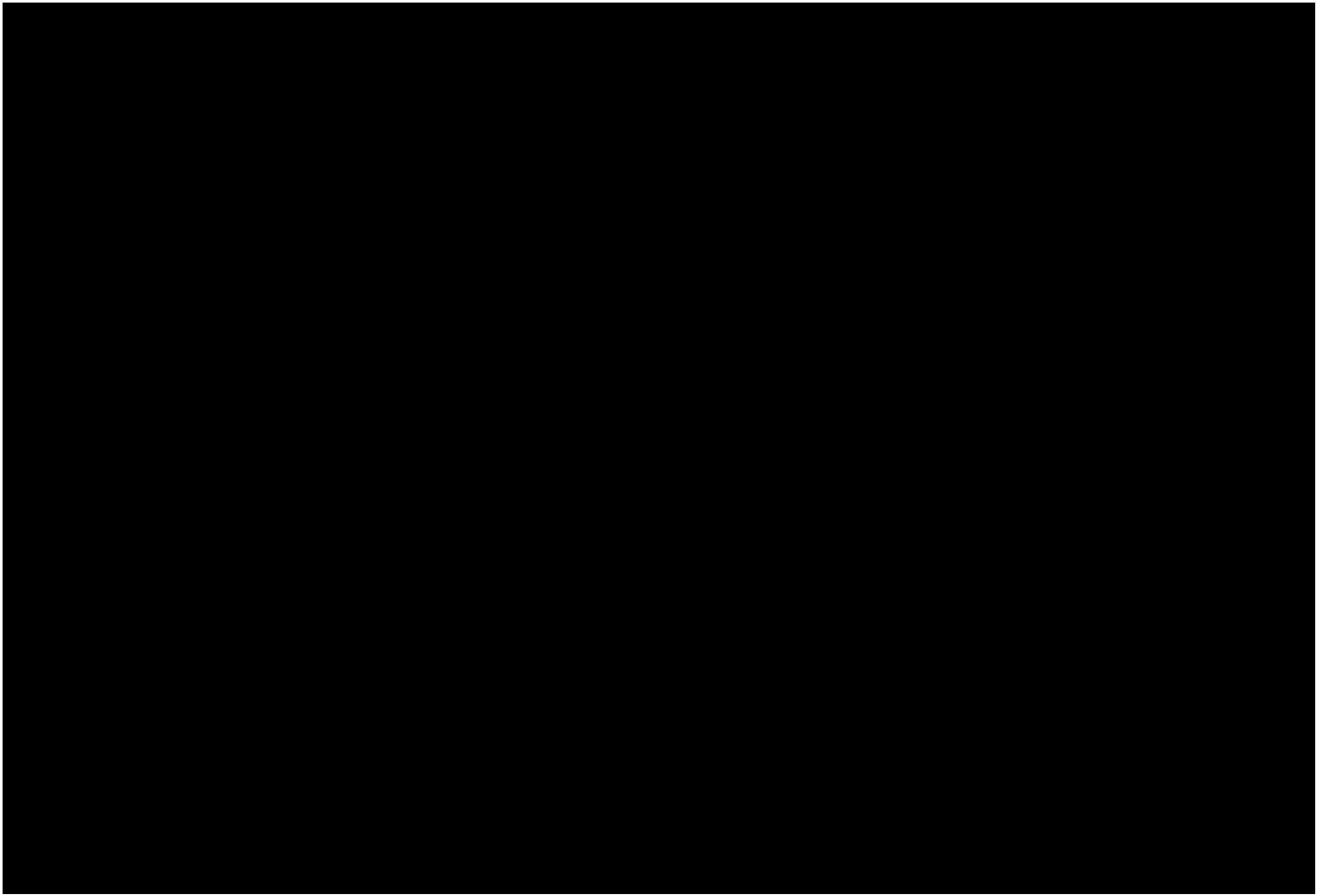
Date of On Peak Day - 01/02/2021



Member Forecasted On Peak Demand Day for February 2021

Otero County Electric Cooperative, Inc.

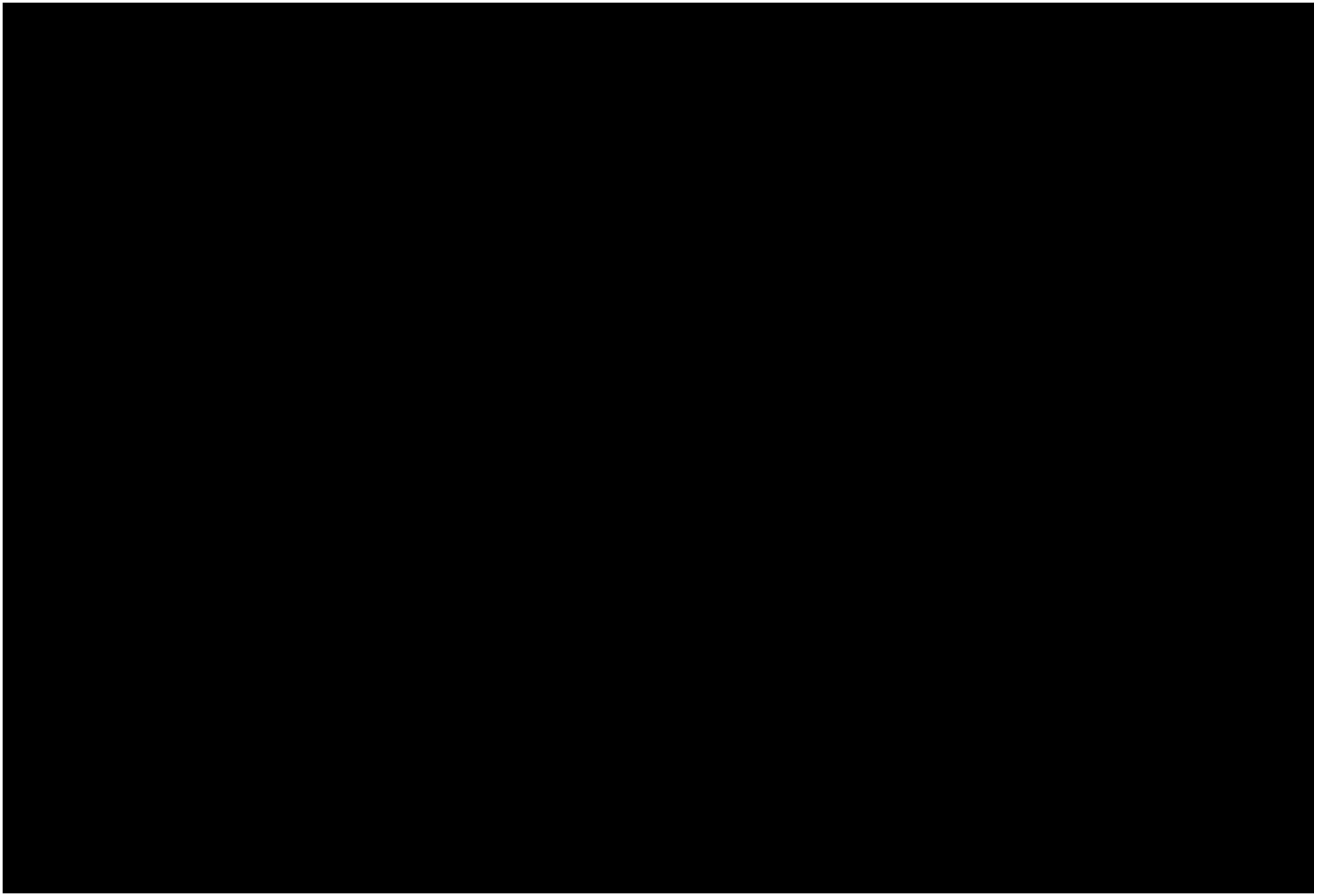
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Otero County Electric Cooperative, Inc.

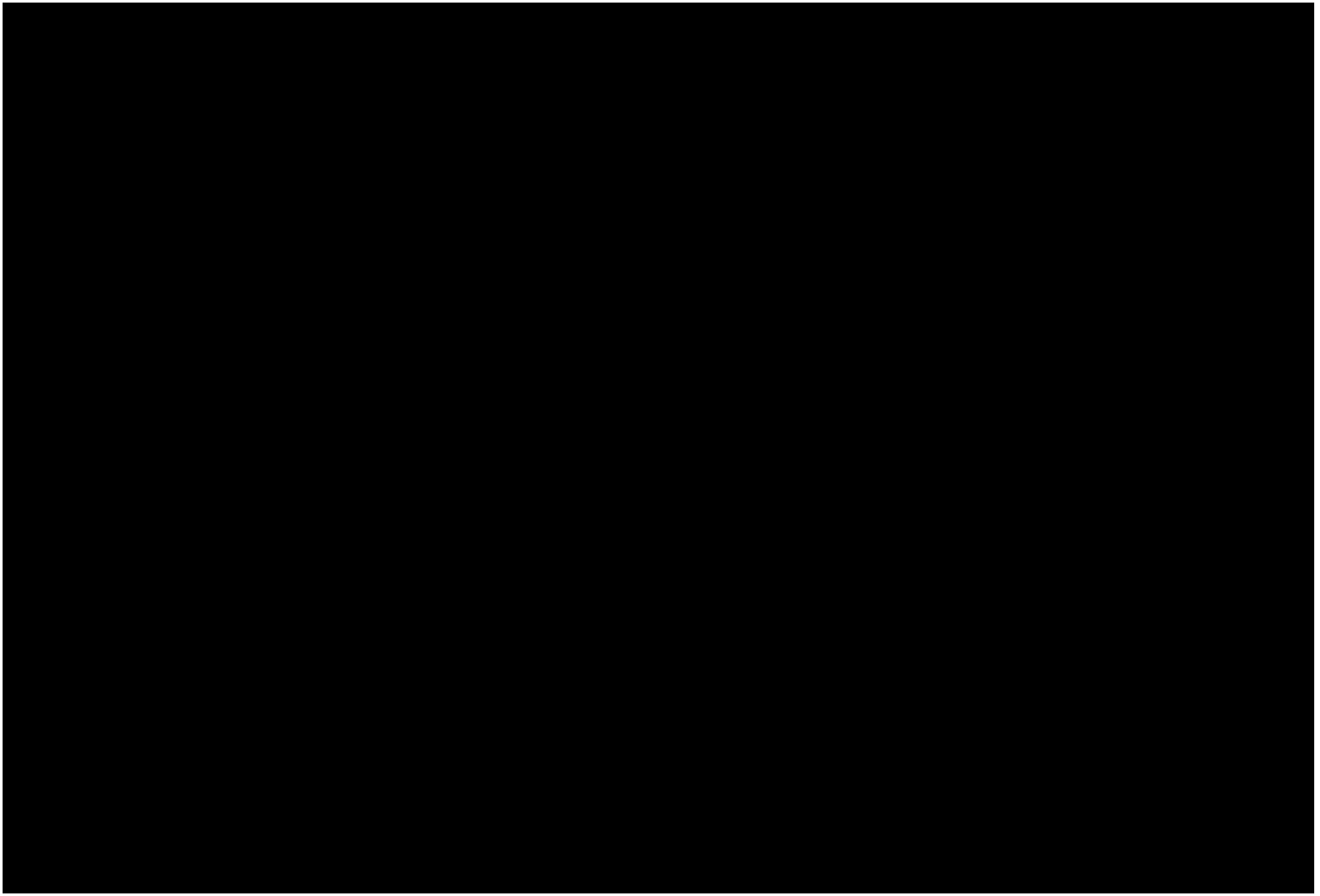
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Otero County Electric Cooperative, Inc.

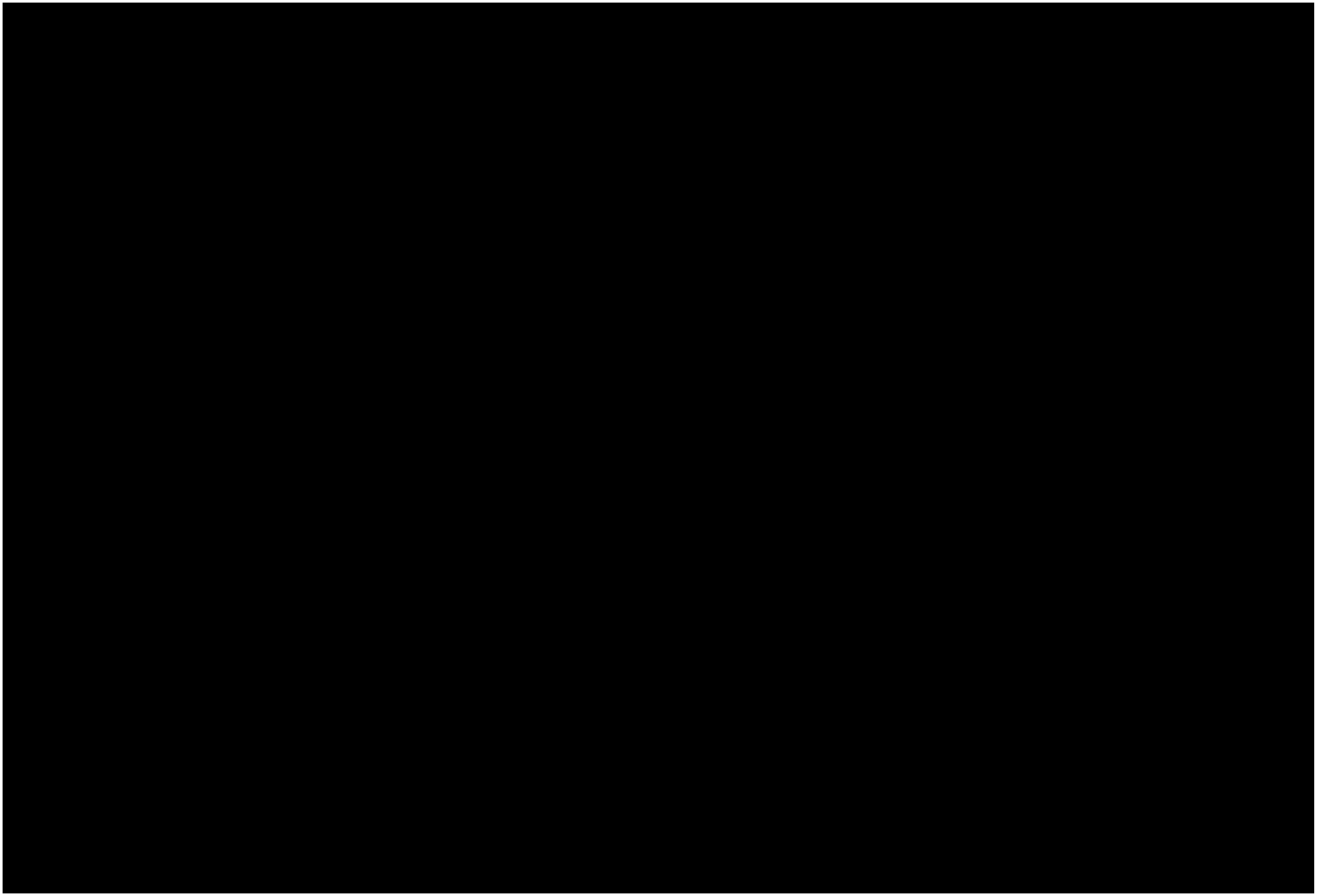
Date of On Peak Day - 04/27/2021



Member Forecasted On Peak Demand Day for May 2021

Otero County Electric Cooperative, Inc.

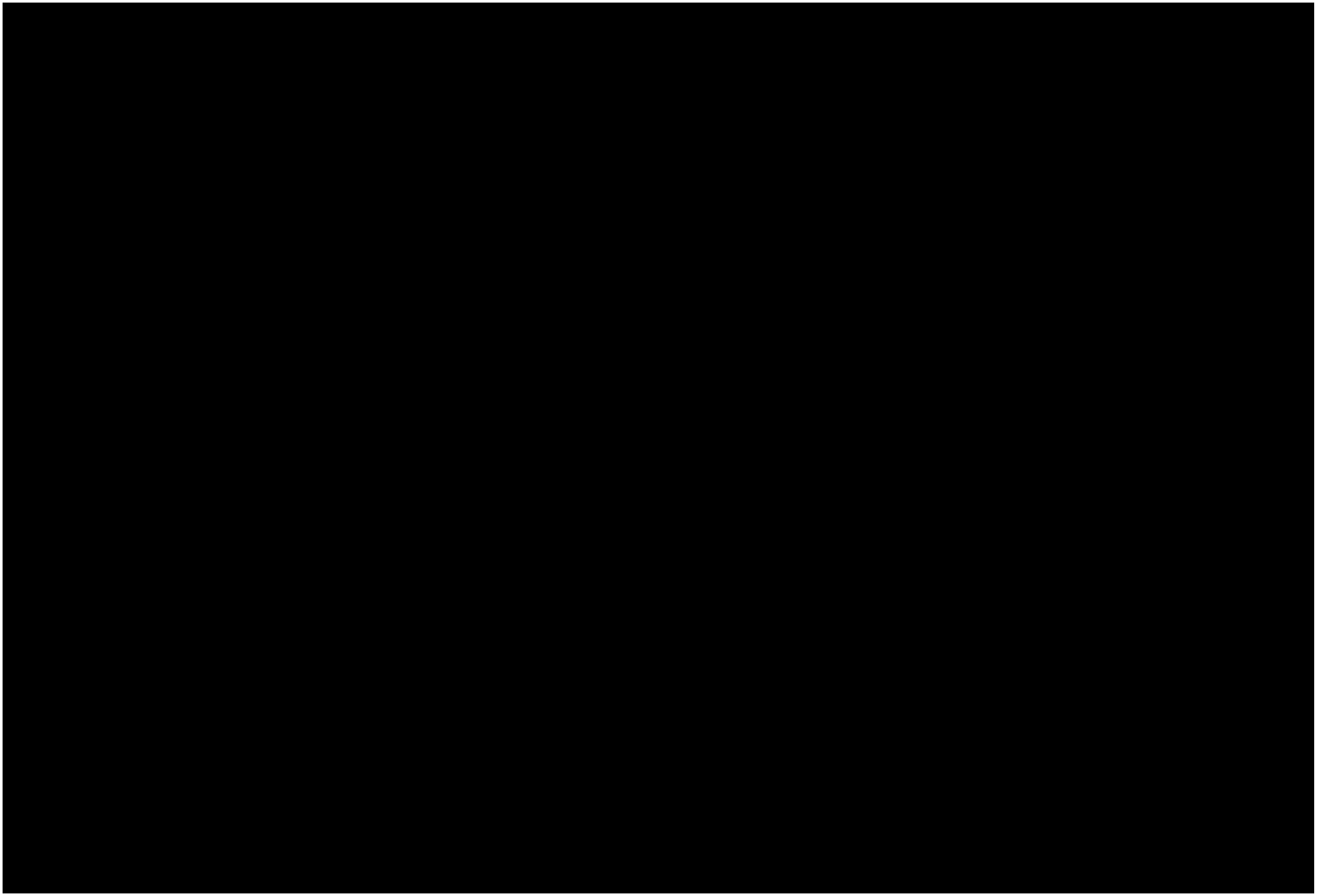
Date of On Peak Day - 05/30/2021



Member Forecasted On Peak Demand Day for June 2021

Otero County Electric Cooperative, Inc.

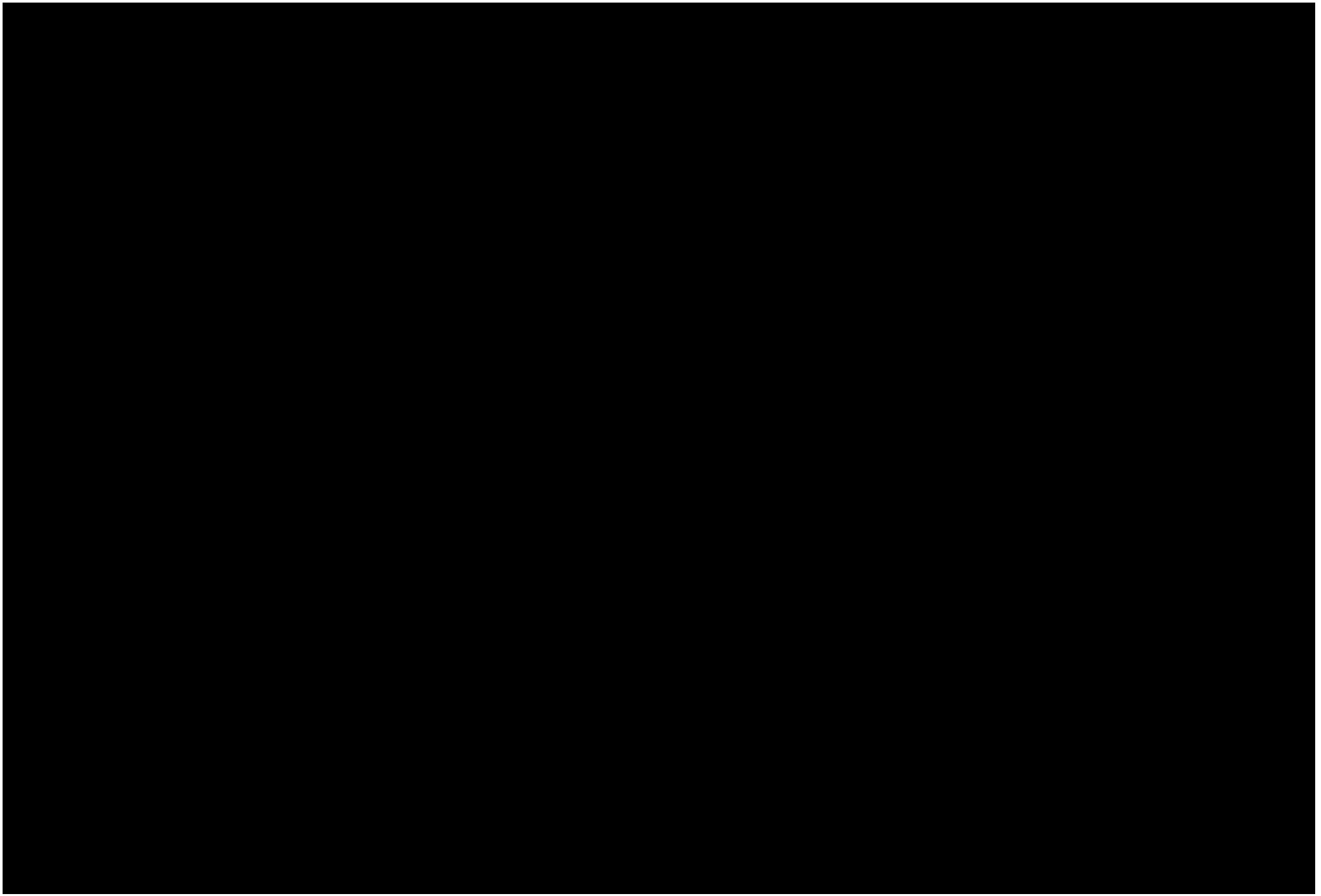
Date of On Peak Day - 06/23/2021



Member Forecasted On Peak Demand Day for July 2021

Otero County Electric Cooperative, Inc.

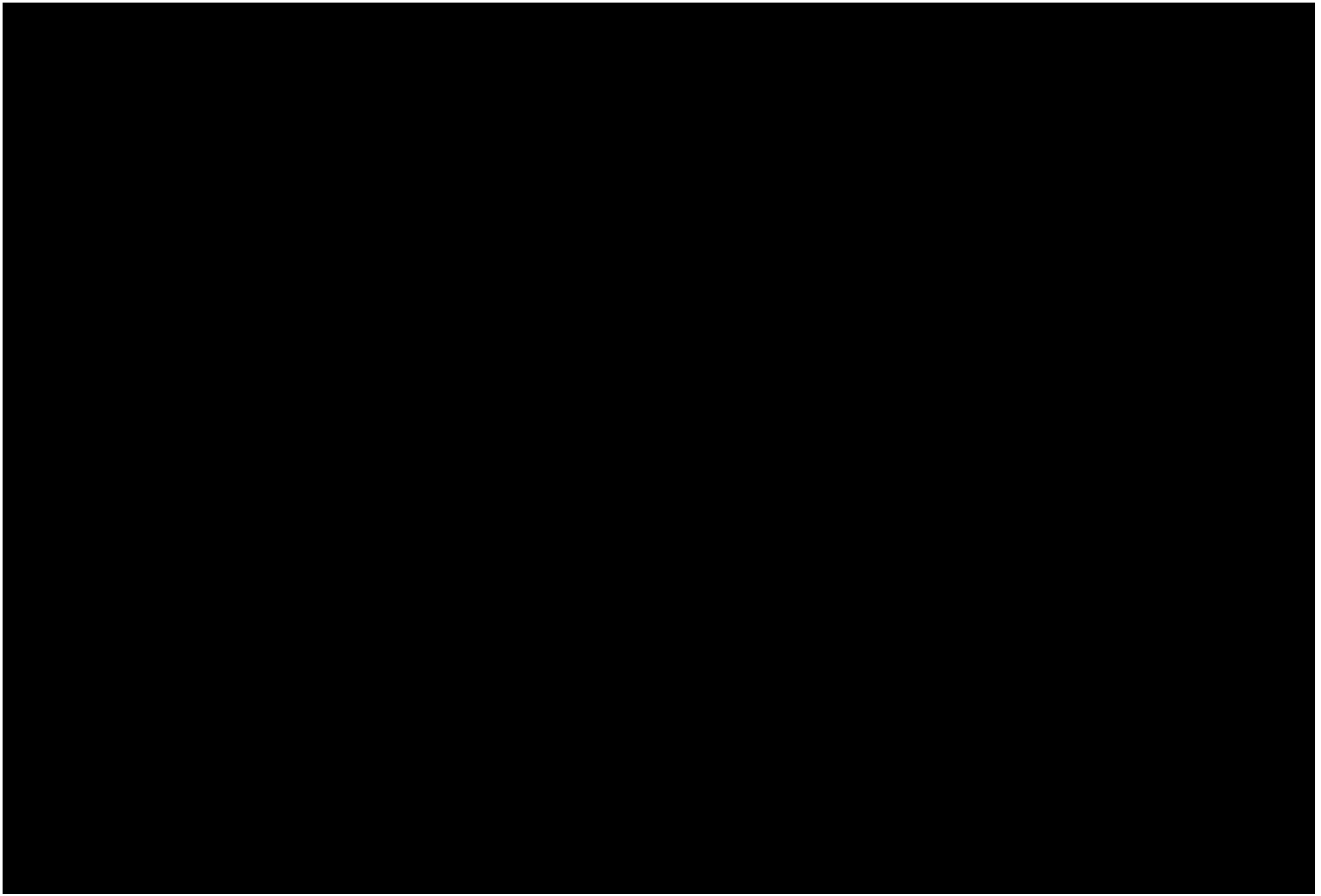
Date of On Peak Day - 07/14/2021



Member Forecasted On Peak Demand Day for August 2021

Otero County Electric Cooperative, Inc.

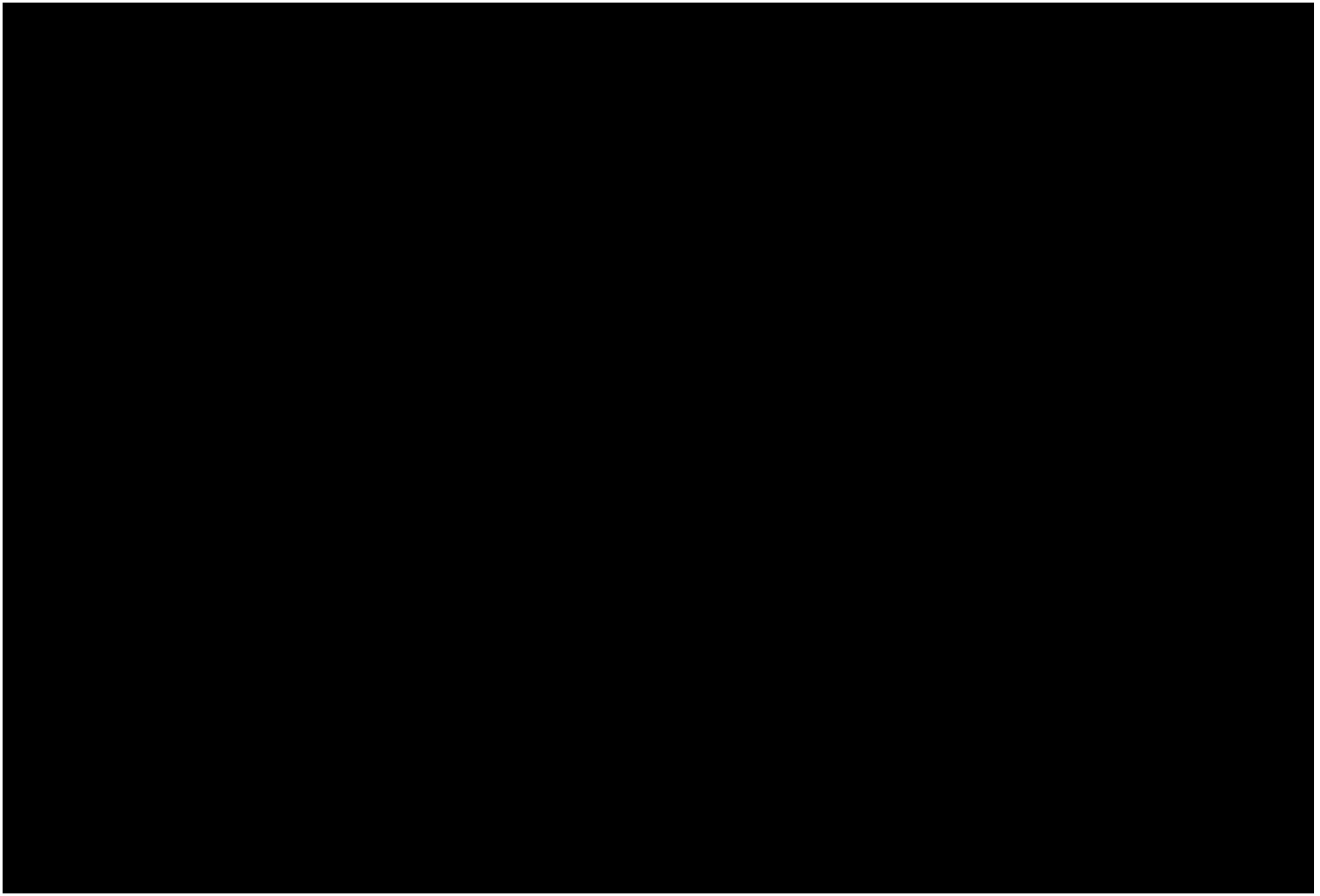
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Otero County Electric Cooperative, Inc.

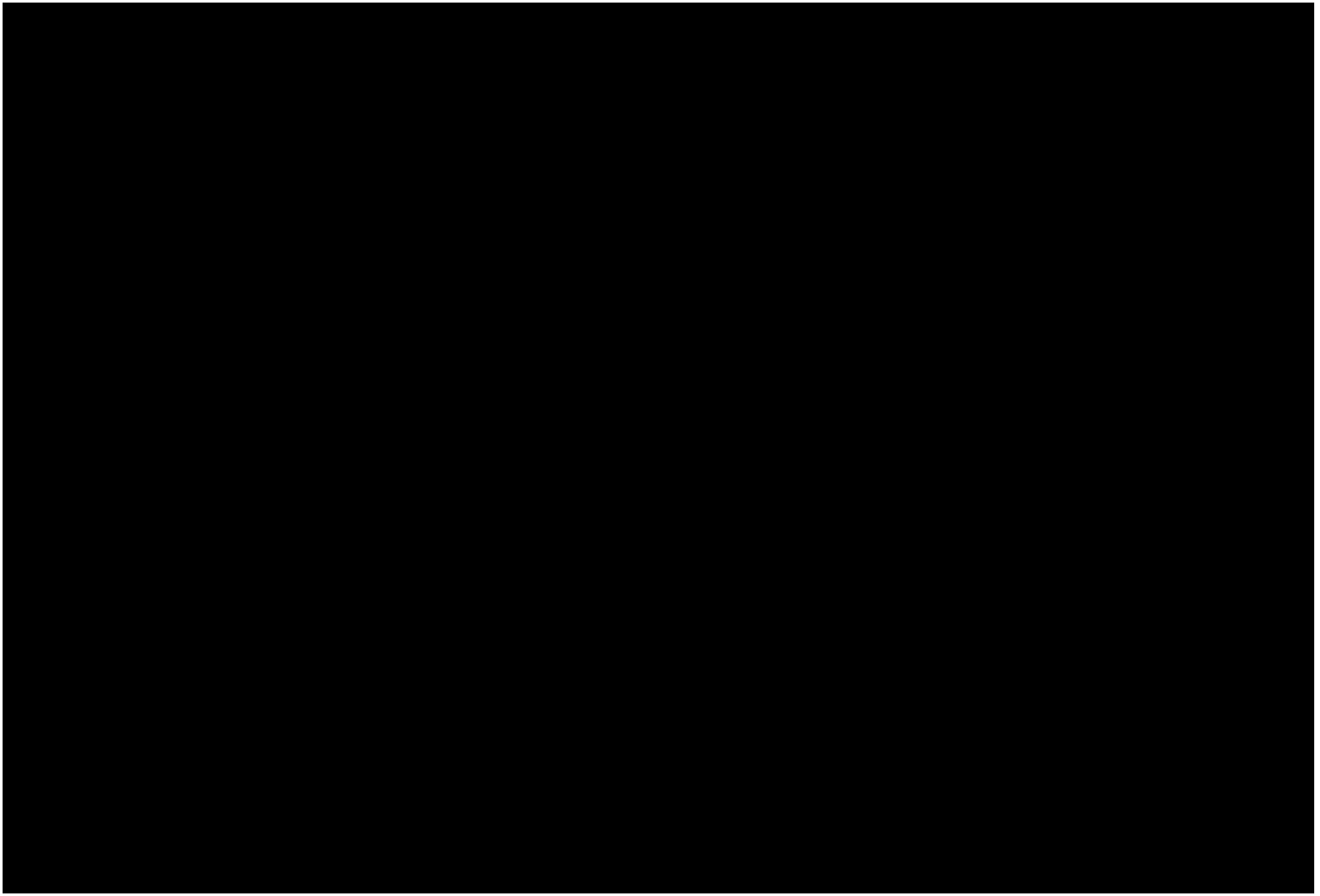
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Otero County Electric Cooperative, Inc.

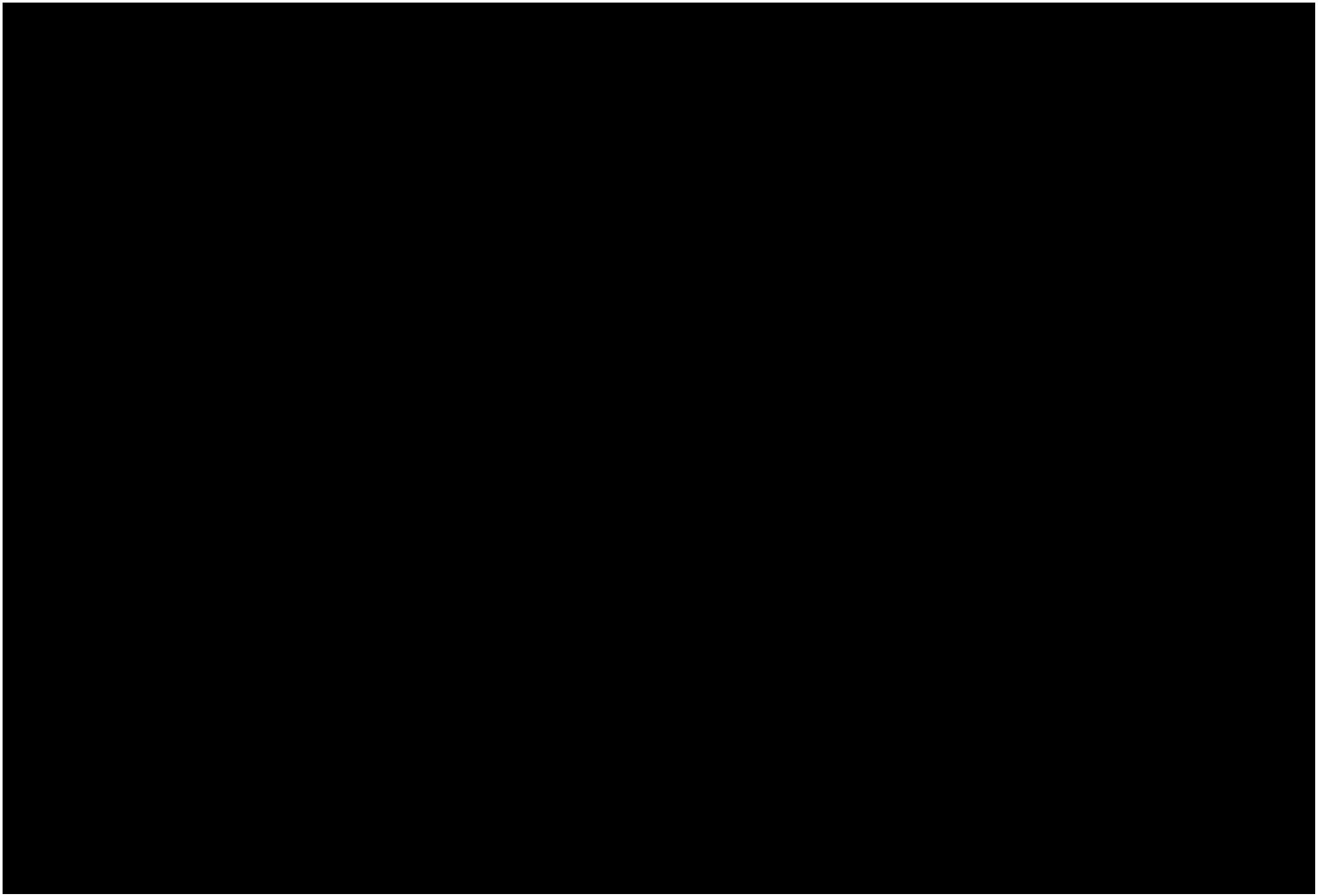
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Otero County Electric Cooperative, Inc.

Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Otero County Electric Cooperative, Inc.

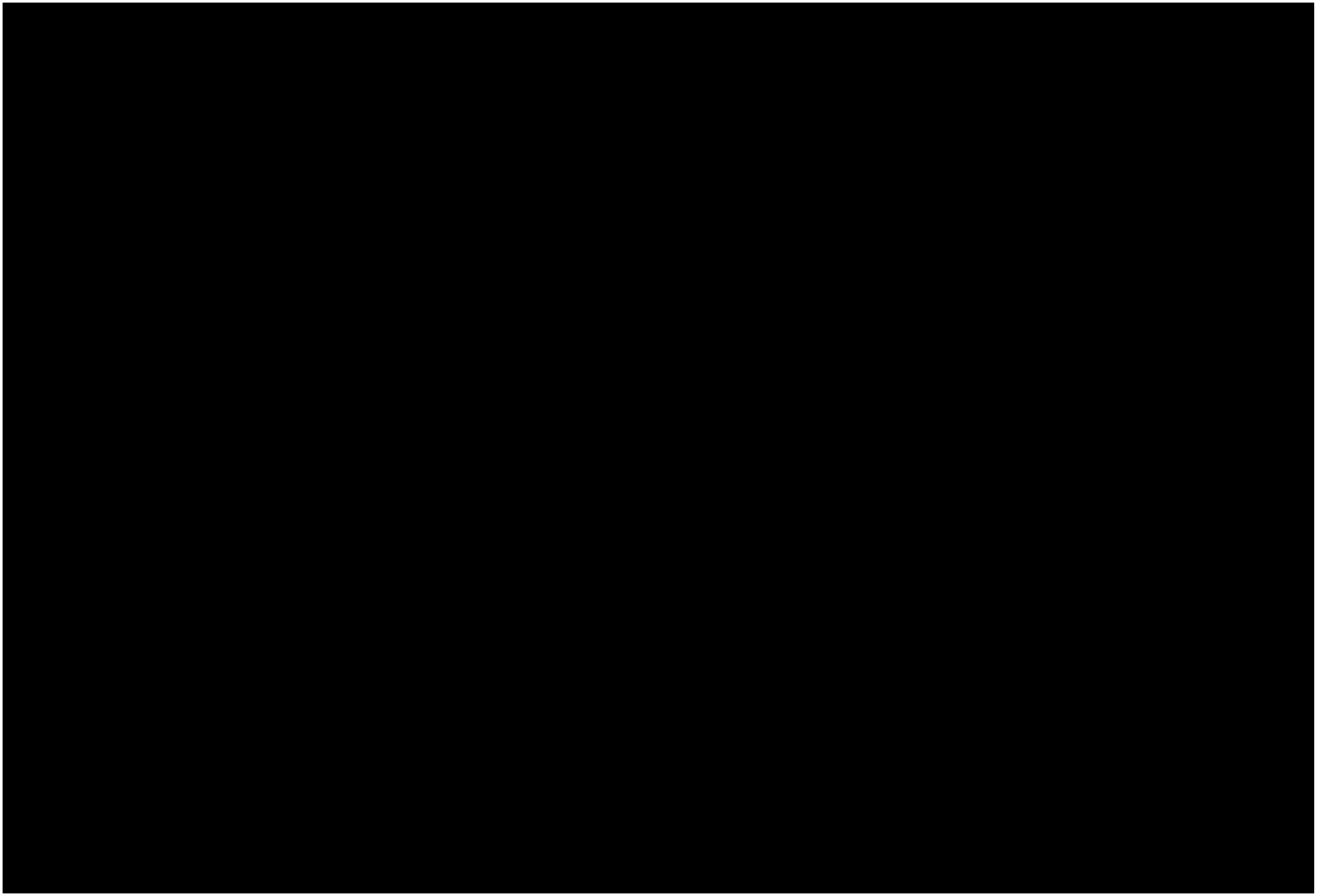
Date of On Peak Day - 12/26/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Panhandle Rural Electric Membership Association

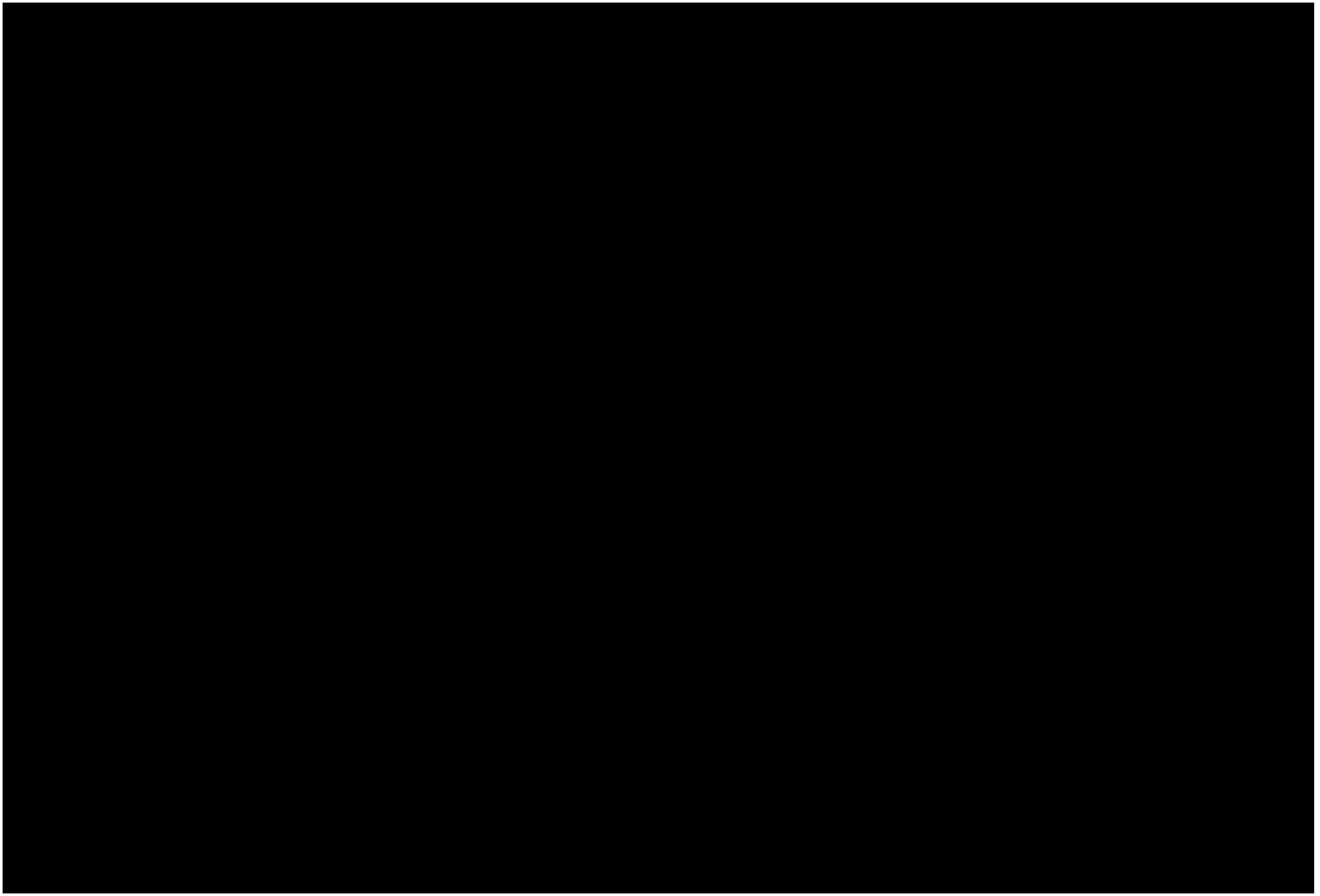
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Panhandle Rural Electric Membership Association

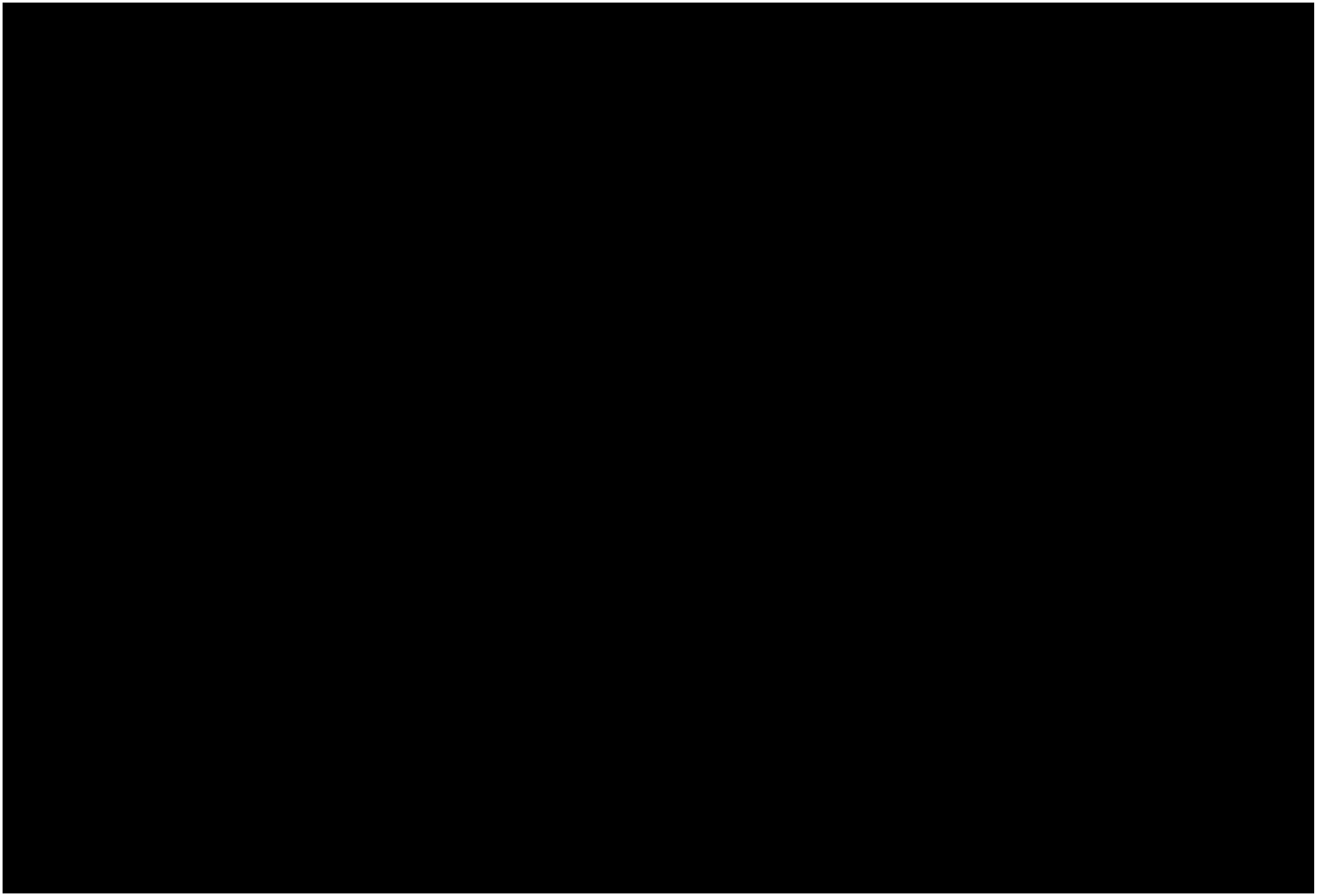
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Panhandle Rural Electric Membership Association

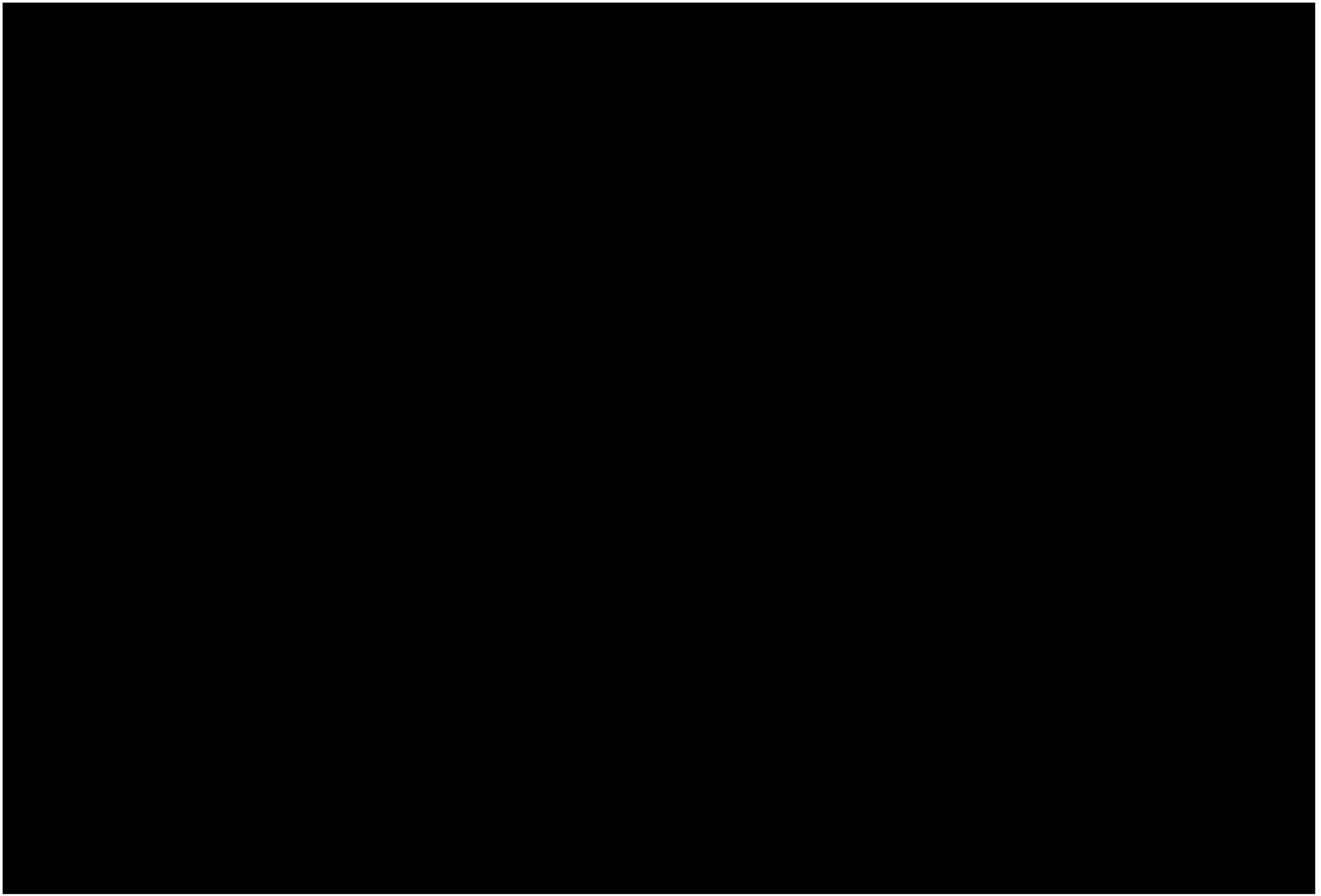
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Panhandle Rural Electric Membership Association

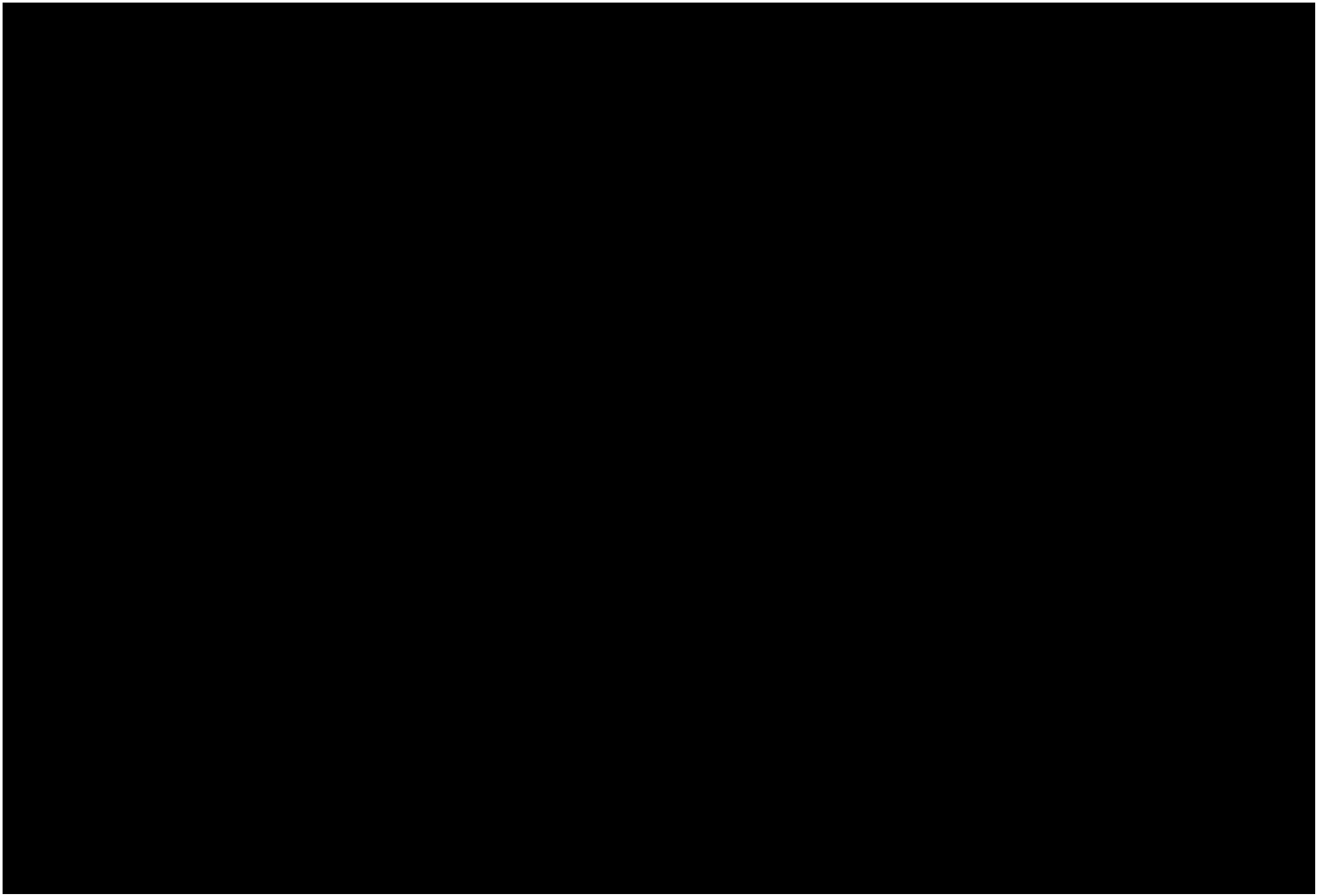
Date of On Peak Day - 04/05/2021



Member Forecasted On Peak Demand Day for May 2021

Panhandle Rural Electric Membership Association

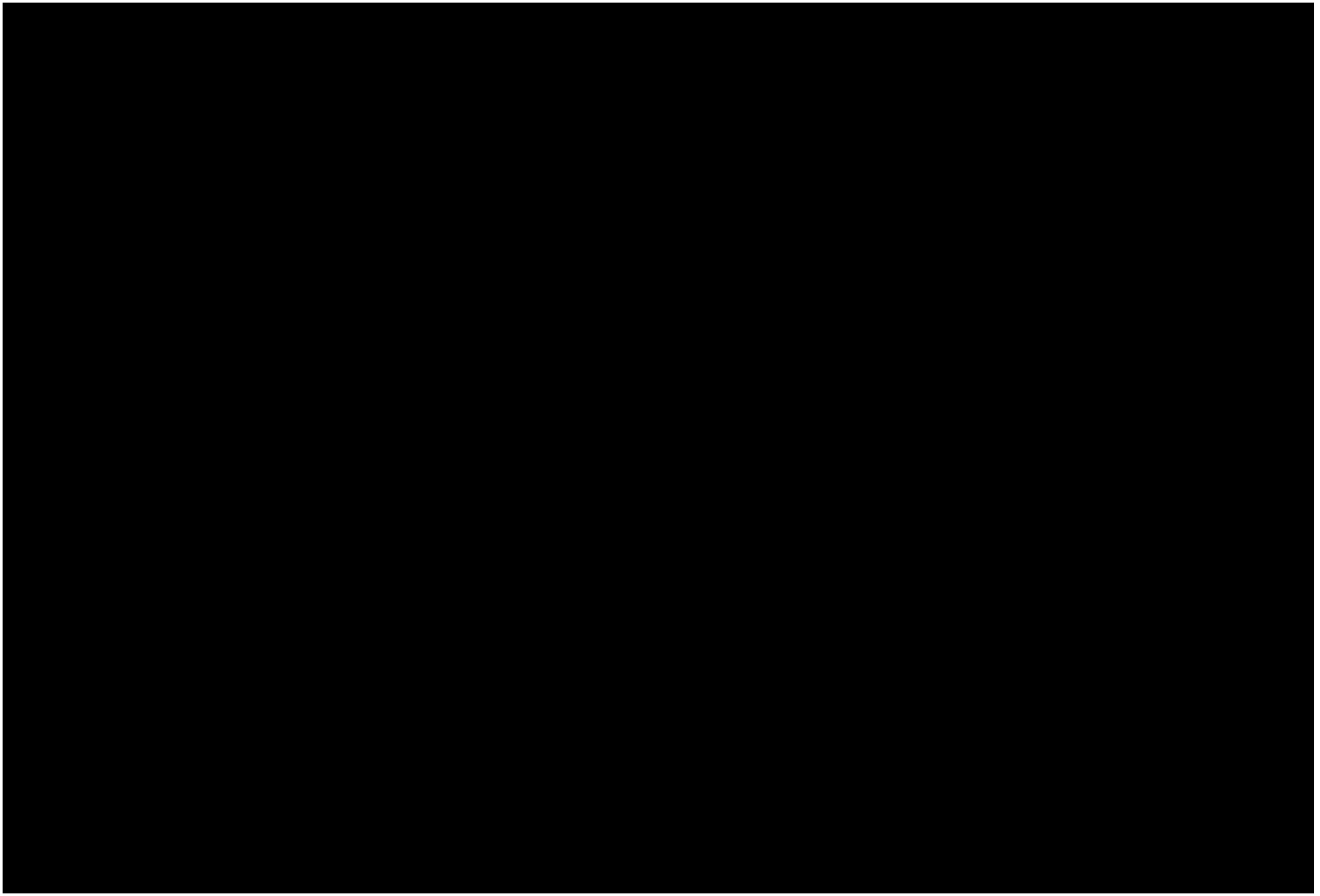
Date of On Peak Day - 05/15/2021



Member Forecasted On Peak Demand Day for June 2021

Panhandle Rural Electric Membership Association

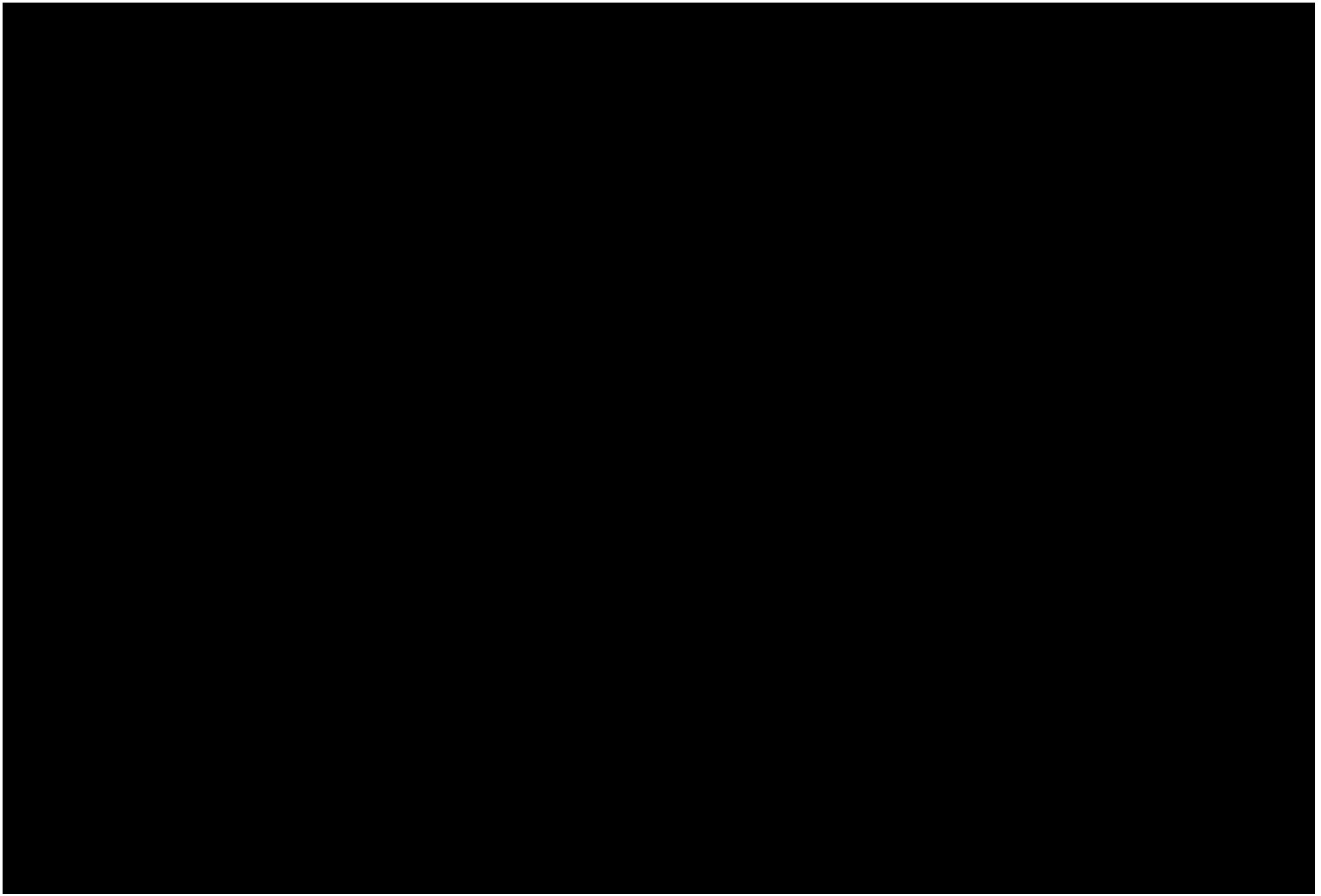
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Panhandle Rural Electric Membership Association

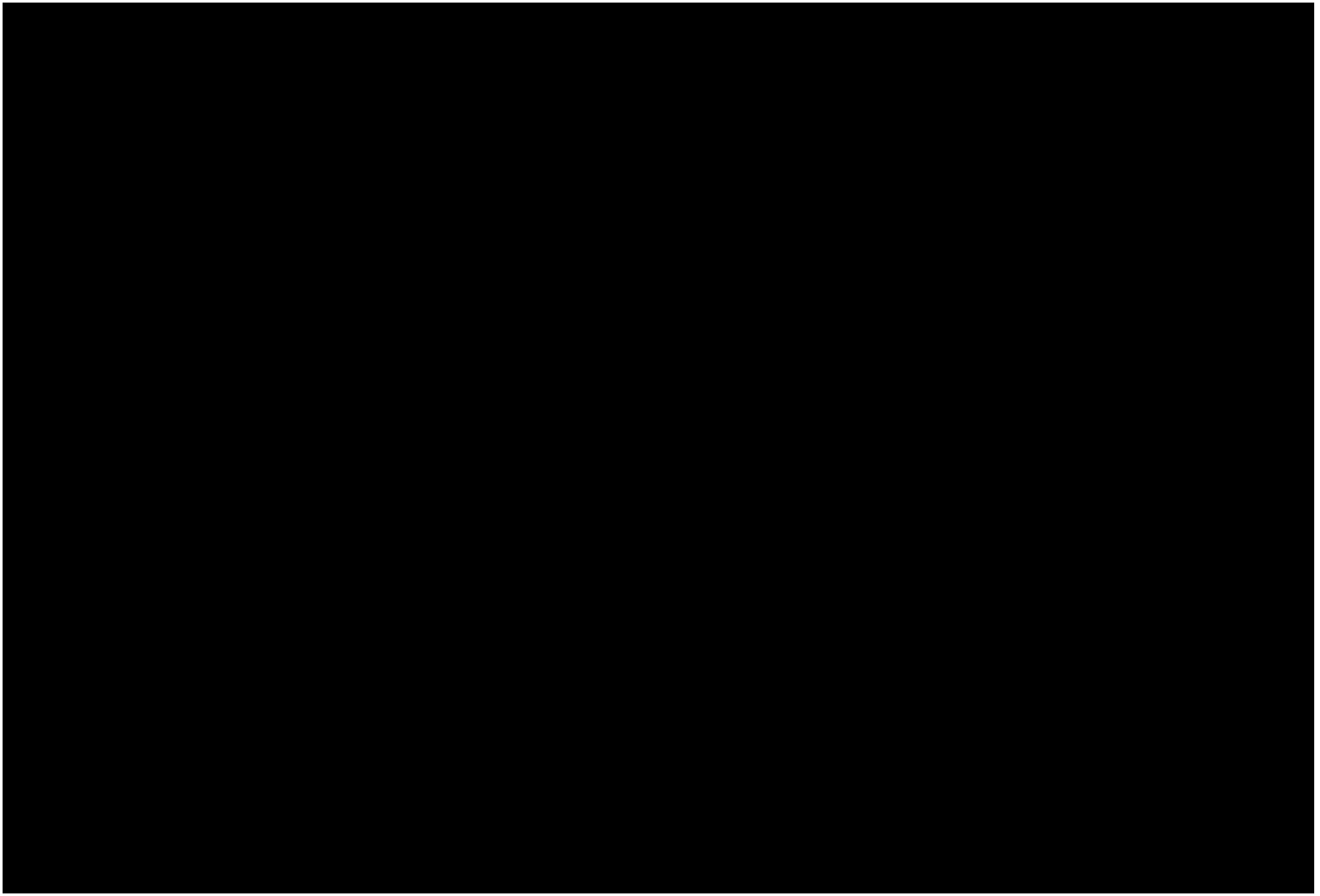
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Panhandle Rural Electric Membership Association

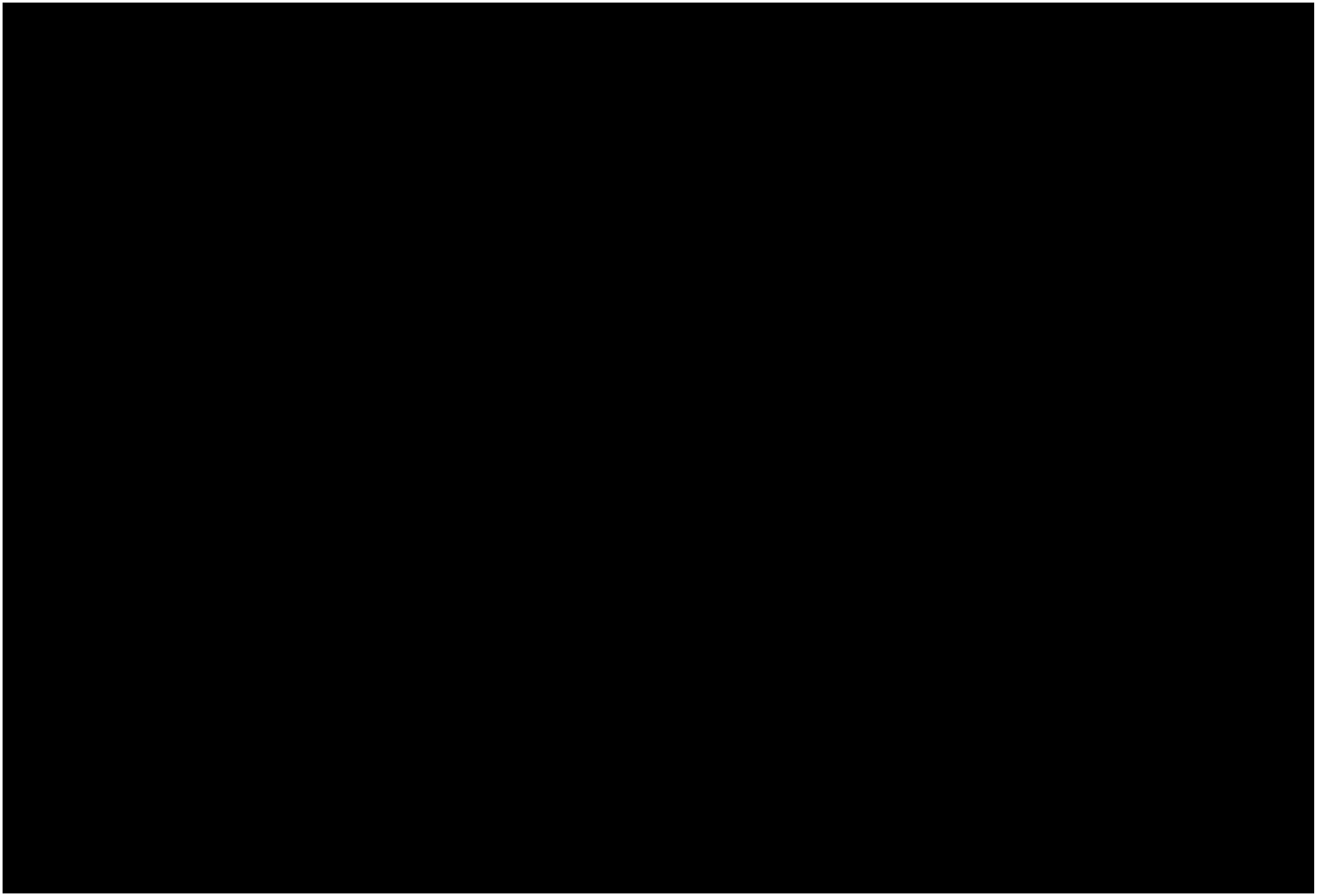
Date of On Peak Day - 08/24/2021



Member Forecasted On Peak Demand Day for September 2021

Panhandle Rural Electric Membership Association

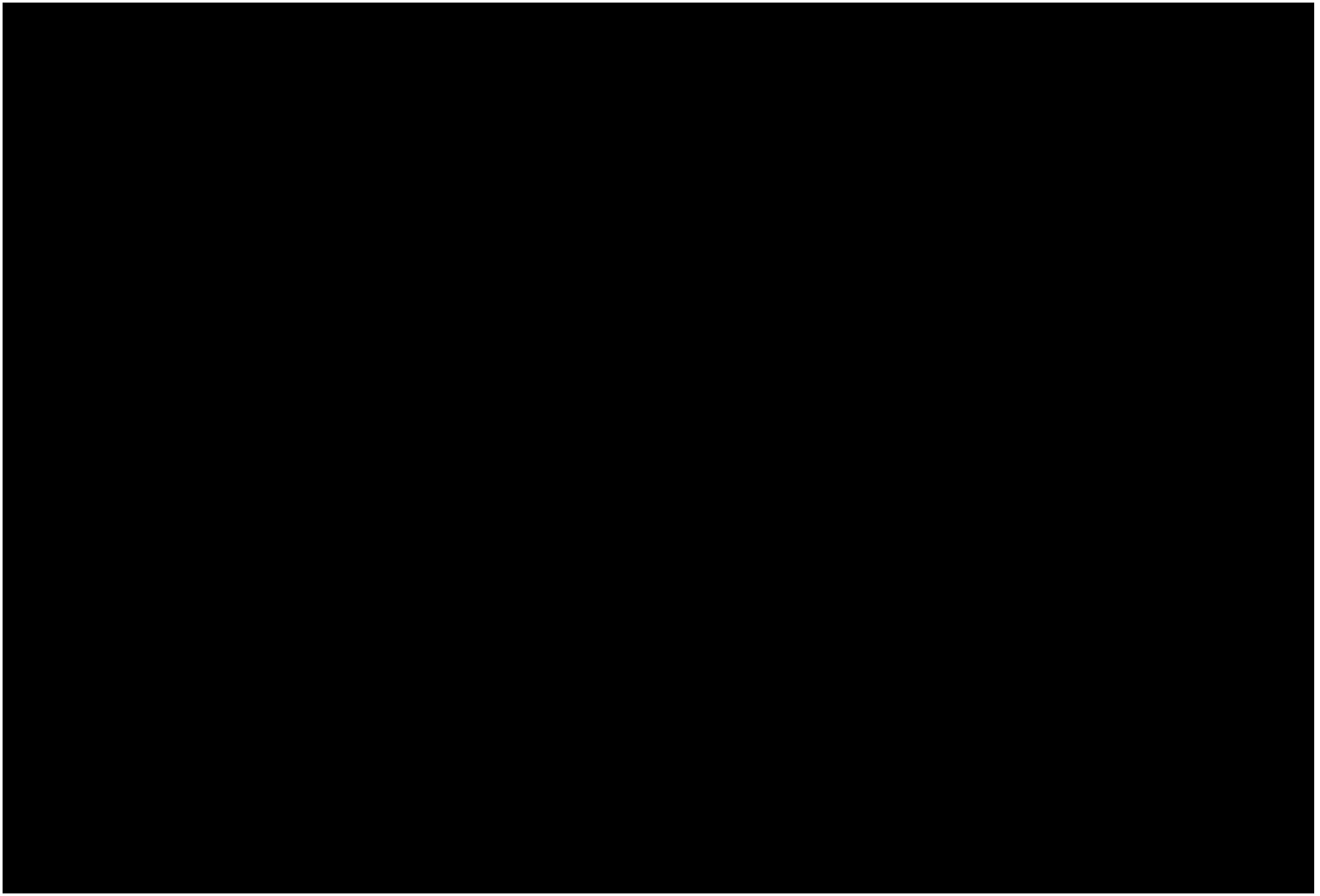
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Panhandle Rural Electric Membership Association

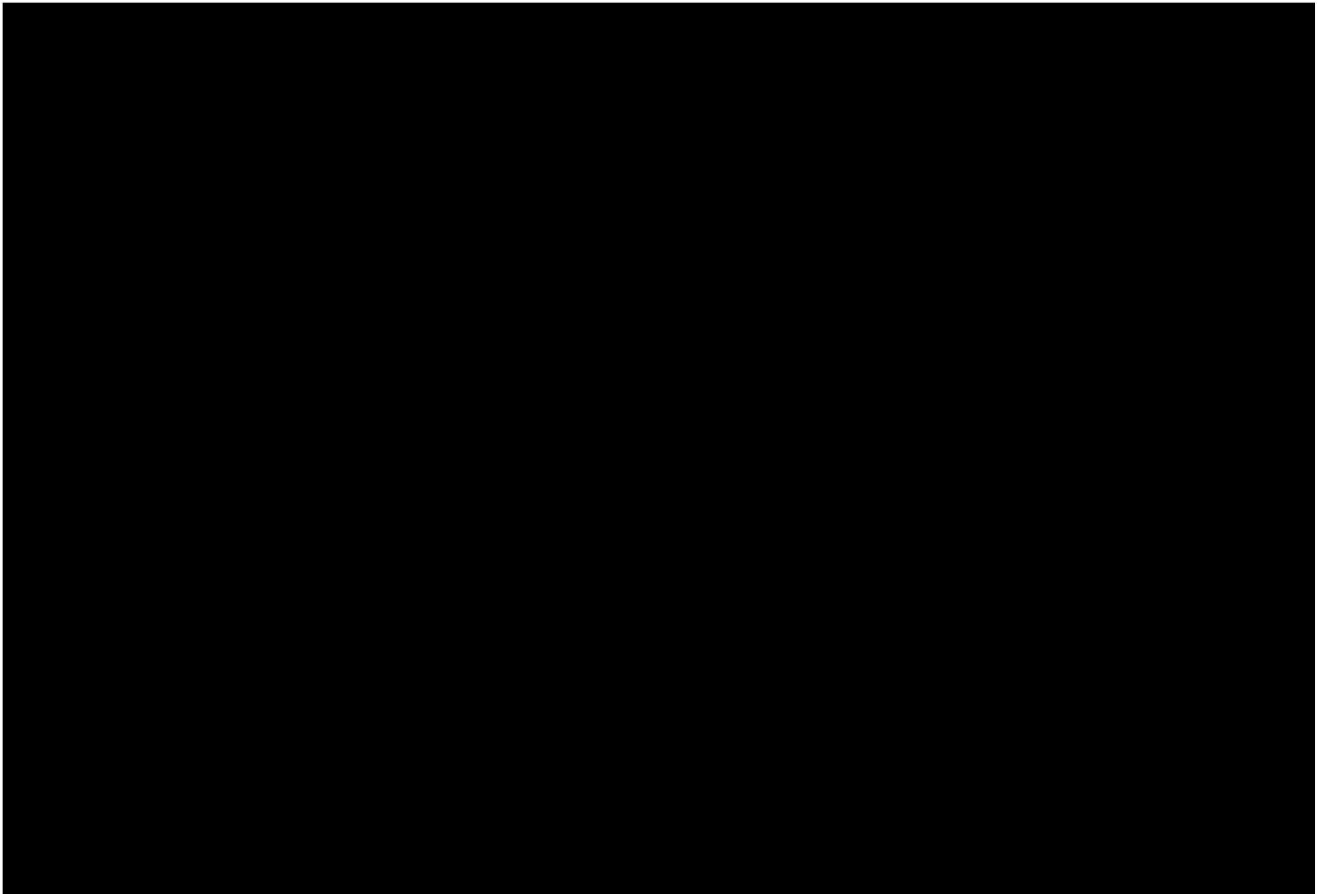
Date of On Peak Day - 10/17/2021



Member Forecasted On Peak Demand Day for November 2021

Panhandle Rural Electric Membership Association

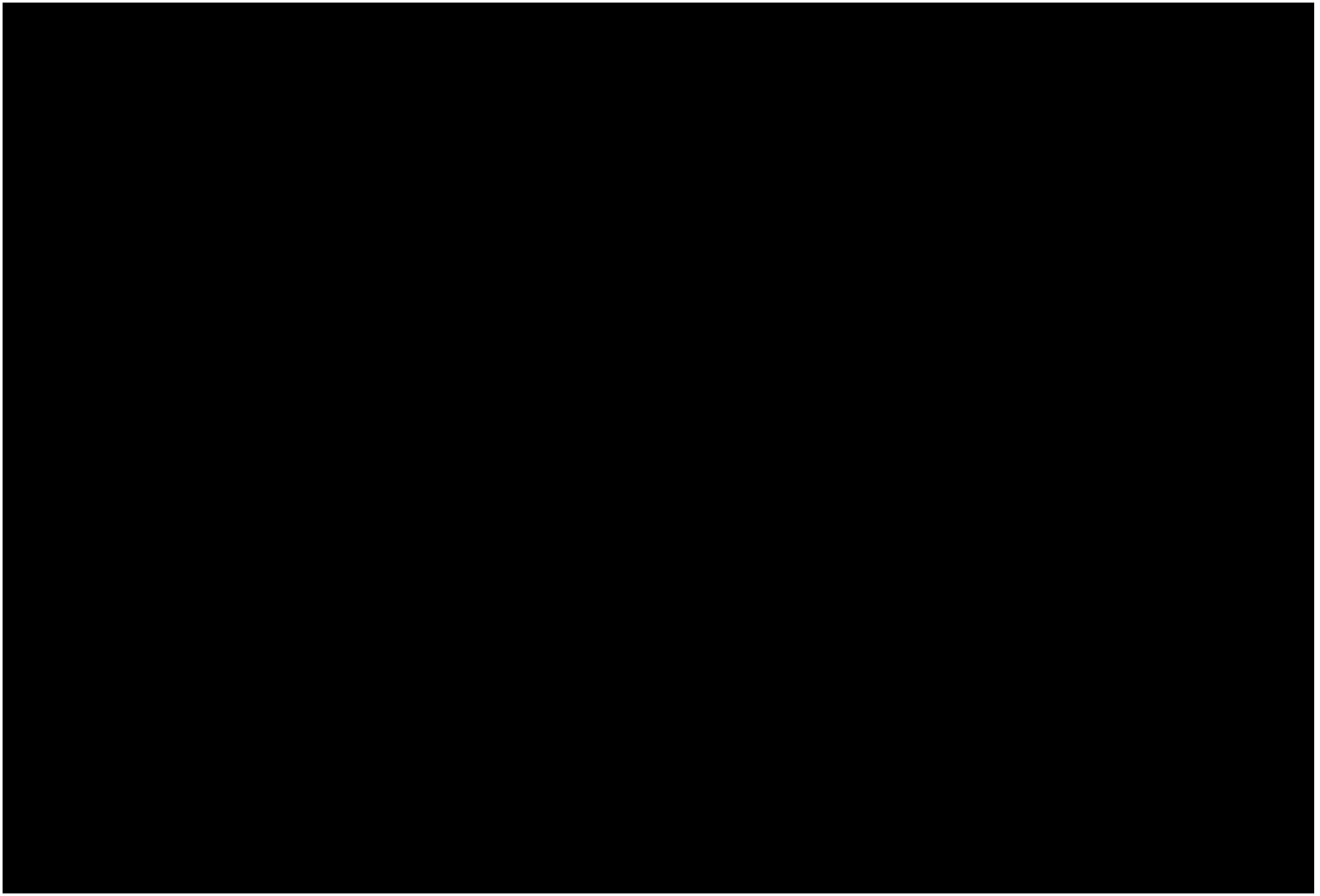
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Panhandle Rural Electric Membership Association

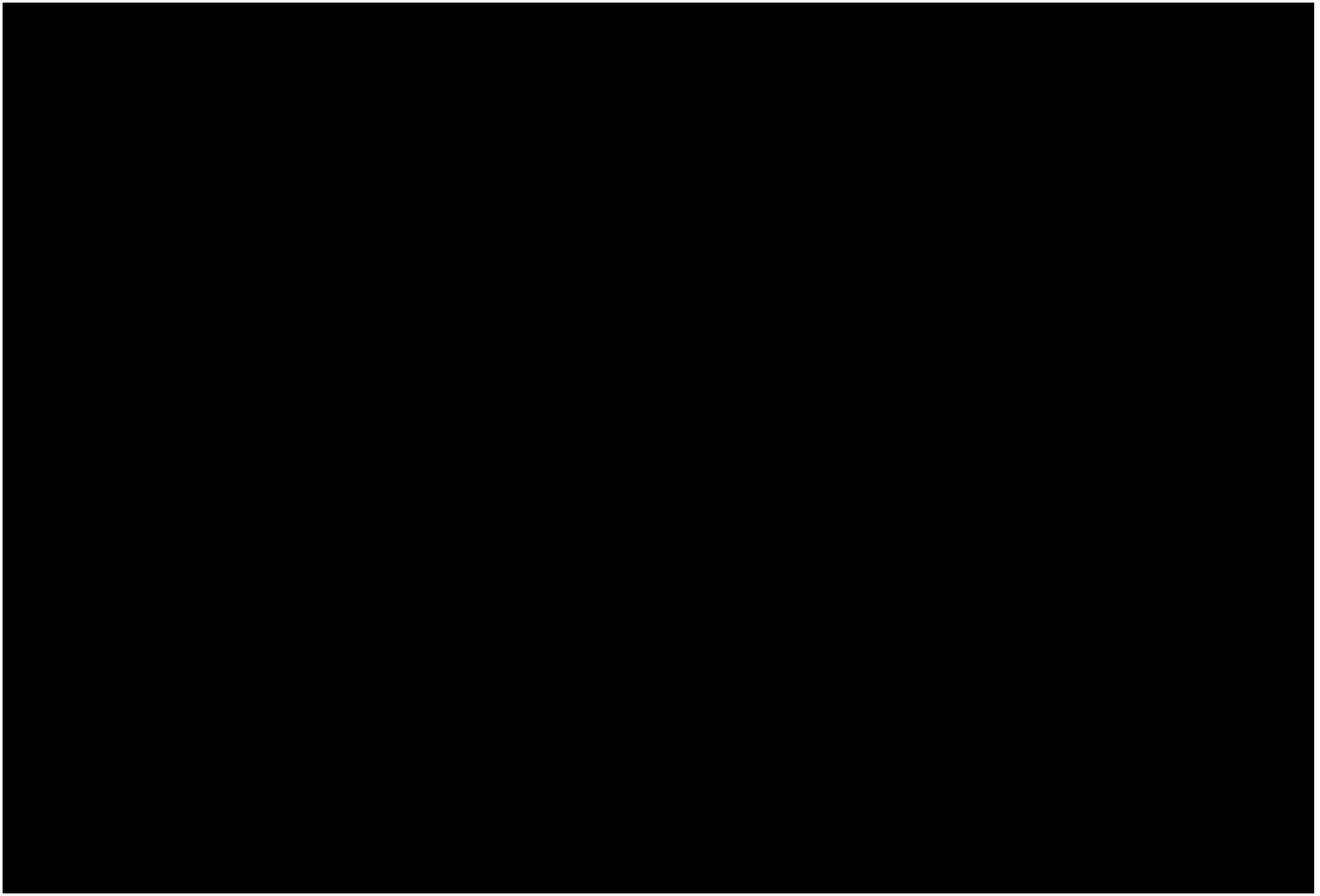
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

Poudre Valley Electric Association, Inc.

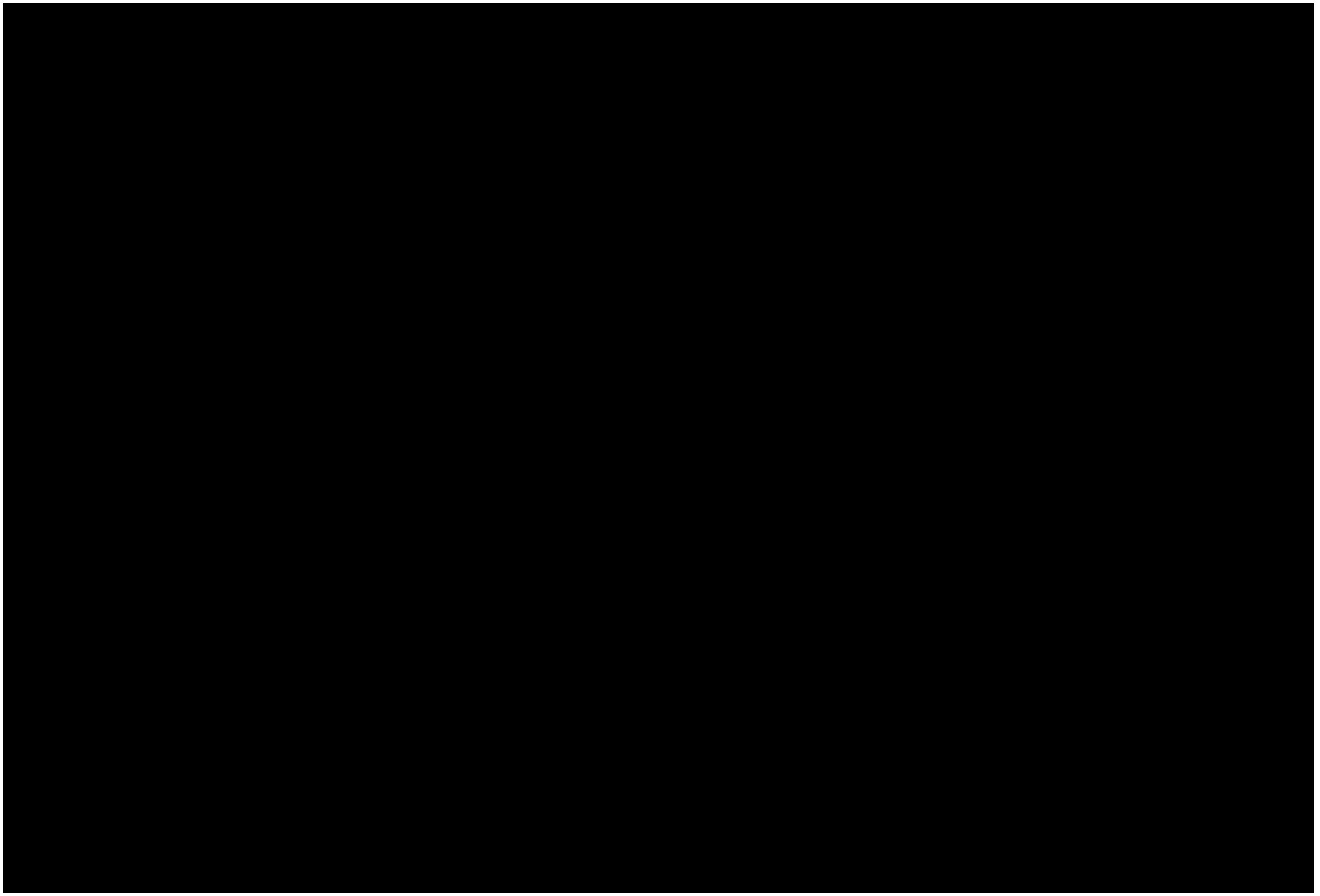
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Poudre Valley Electric Association, Inc.

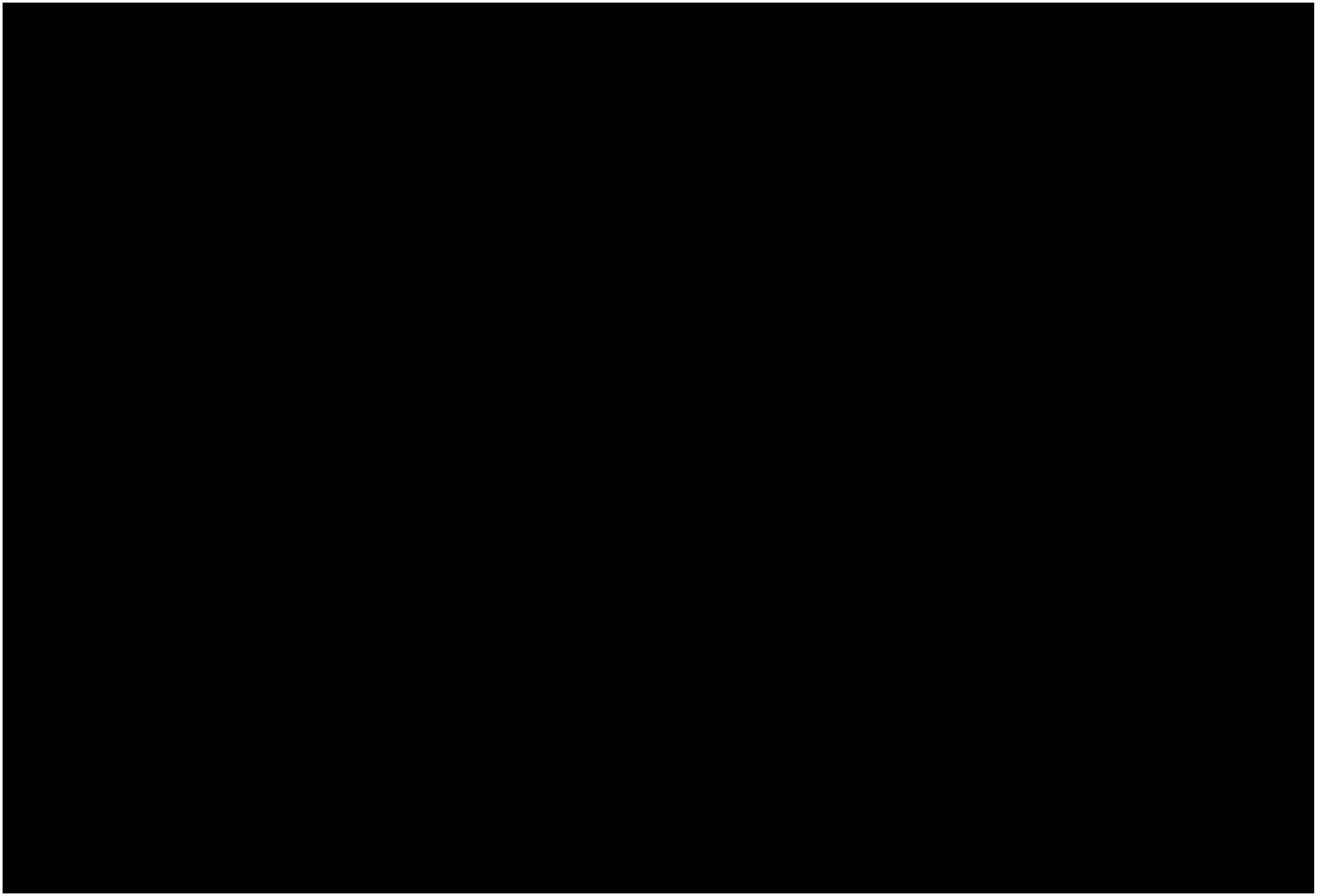
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Poudre Valley Electric Association, Inc.

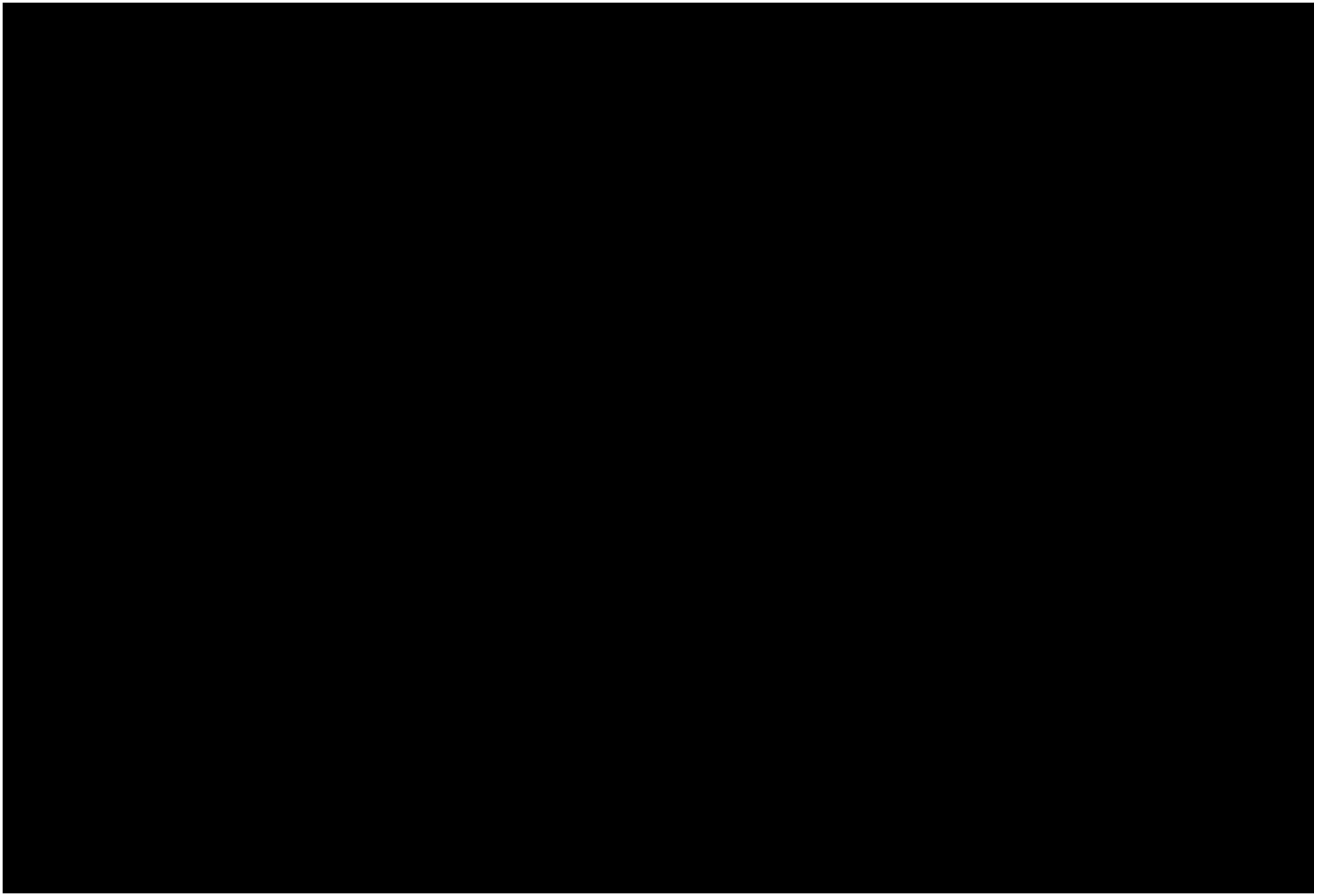
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Poudre Valley Electric Association, Inc.

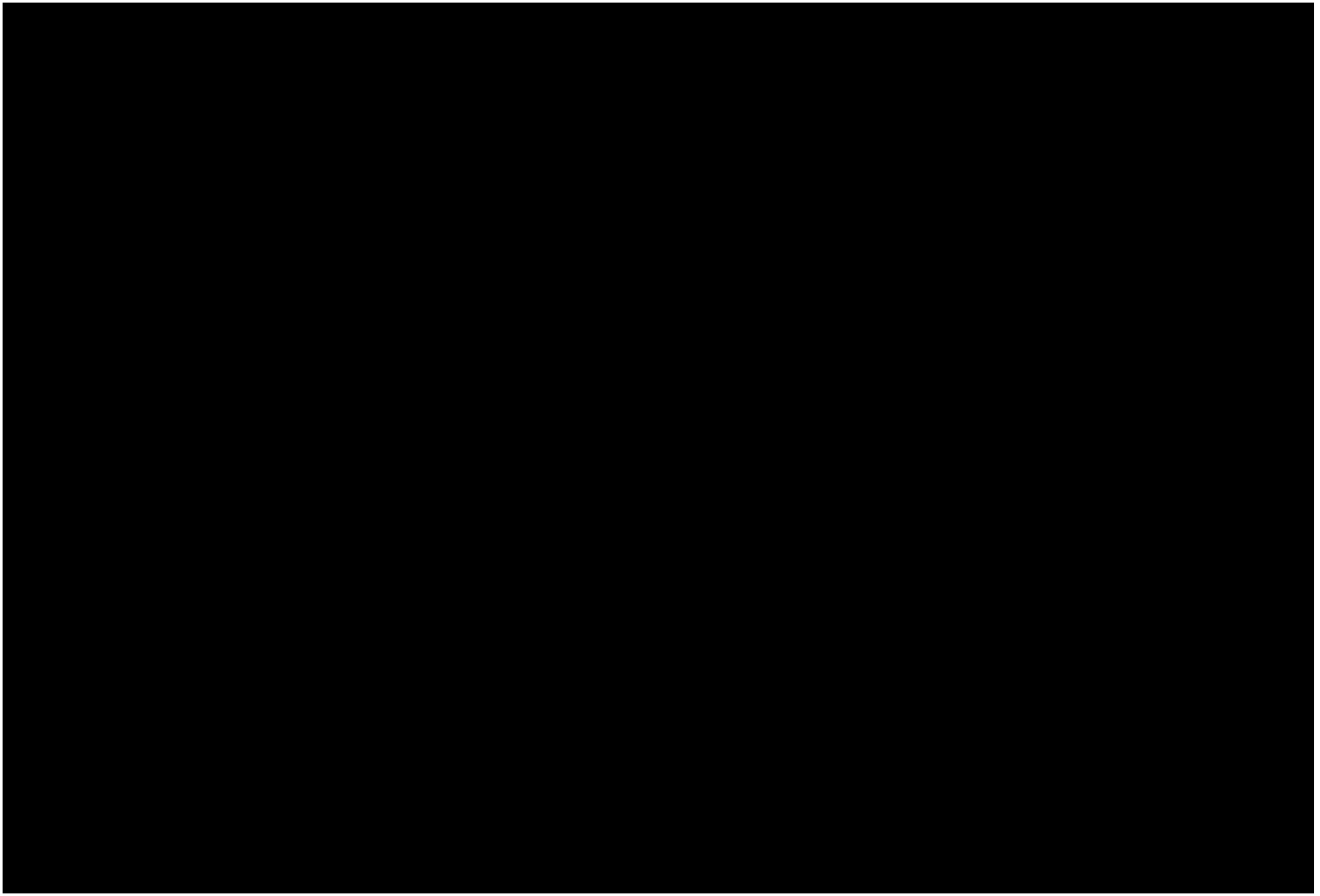
Date of On Peak Day - 04/02/2021



Member Forecasted On Peak Demand Day for May 2021

Poudre Valley Electric Association, Inc.

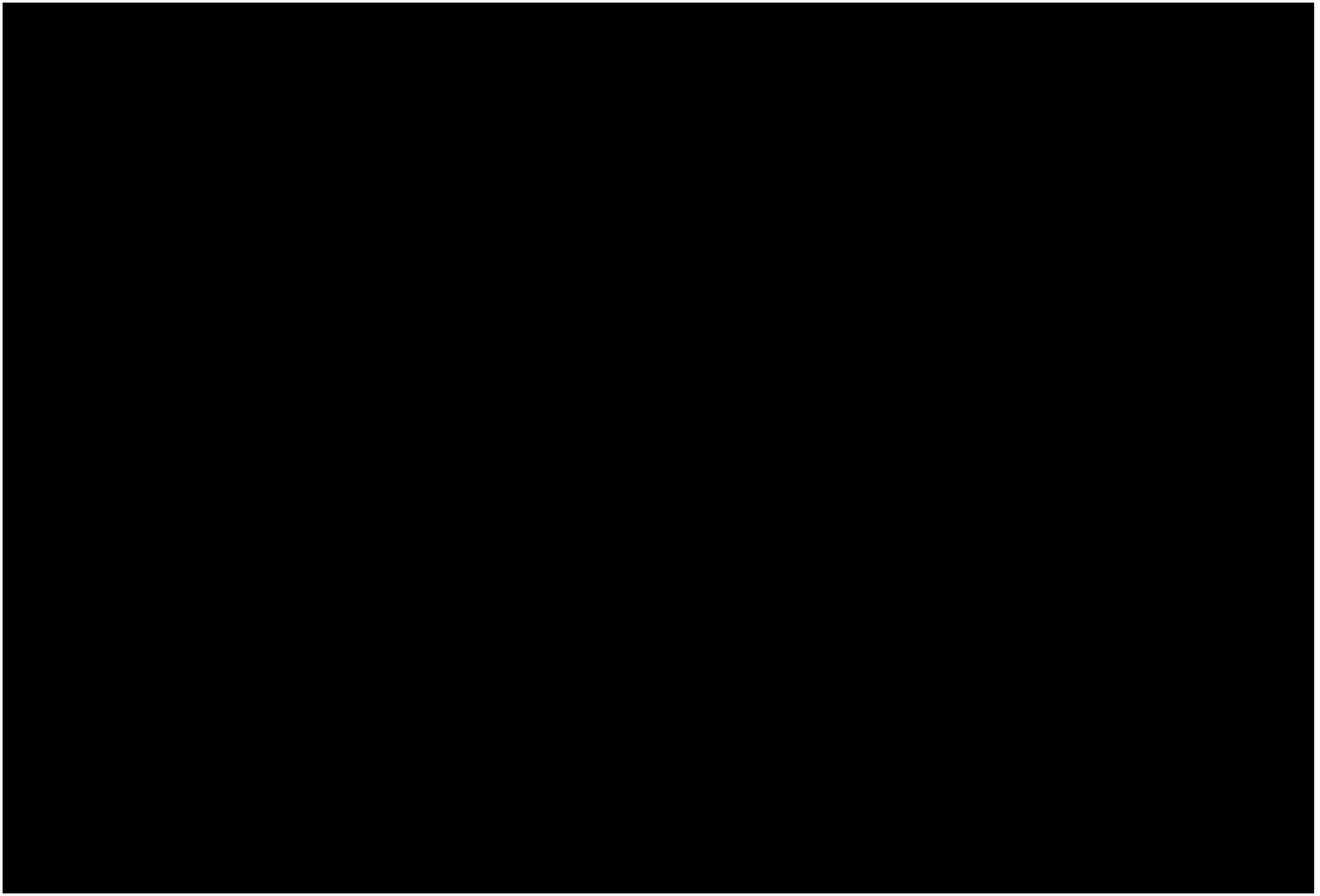
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Poudre Valley Electric Association, Inc.

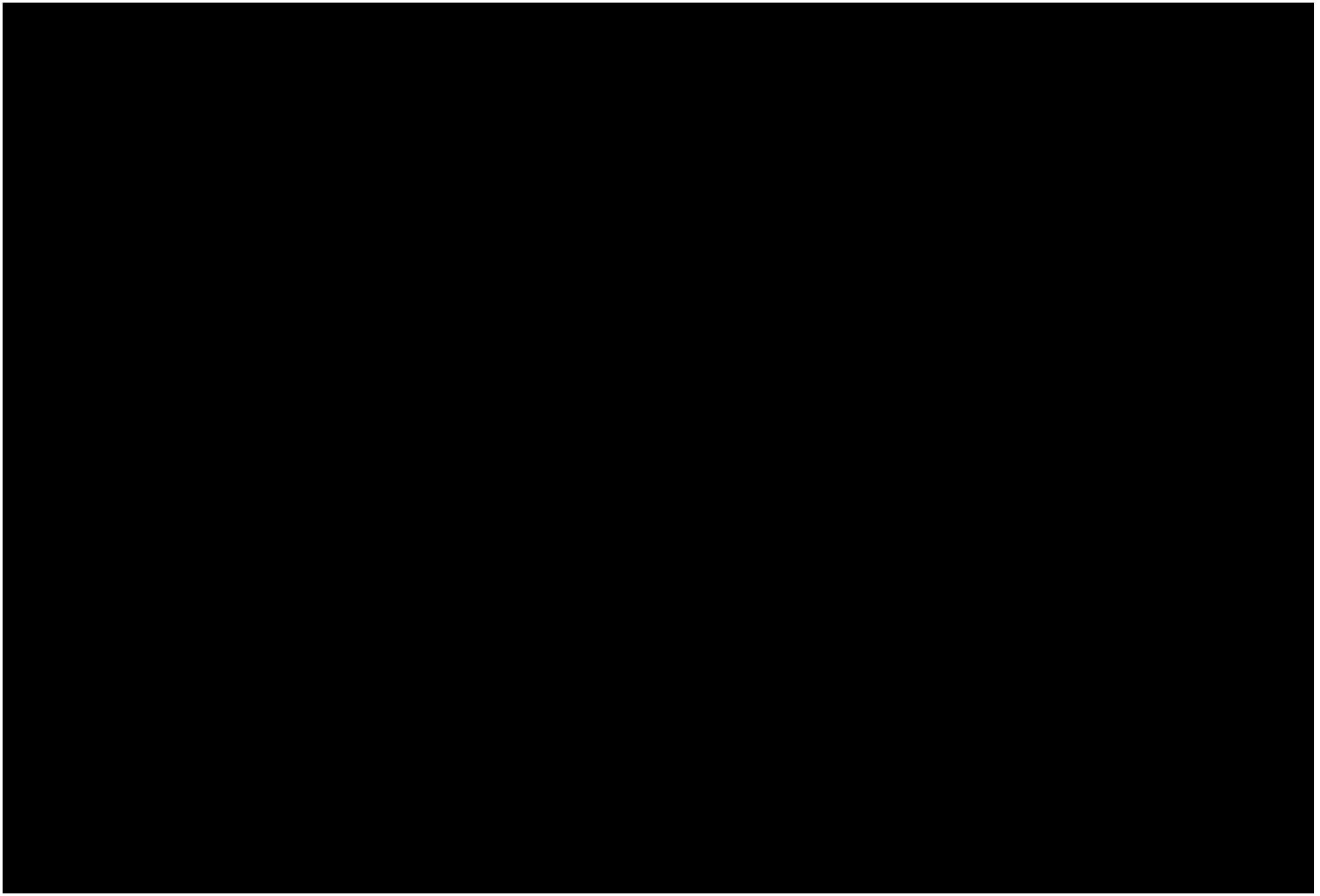
Date of On Peak Day - 06/10/2021



Member Forecasted On Peak Demand Day for July 2021

Poudre Valley Electric Association, Inc.

Date of On Peak Day - 07/19/2021



Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
Page 751 of 2886

Member Forecasted On Peak Demand Day for August 2021

Poudre Valley Electric Association, Inc.

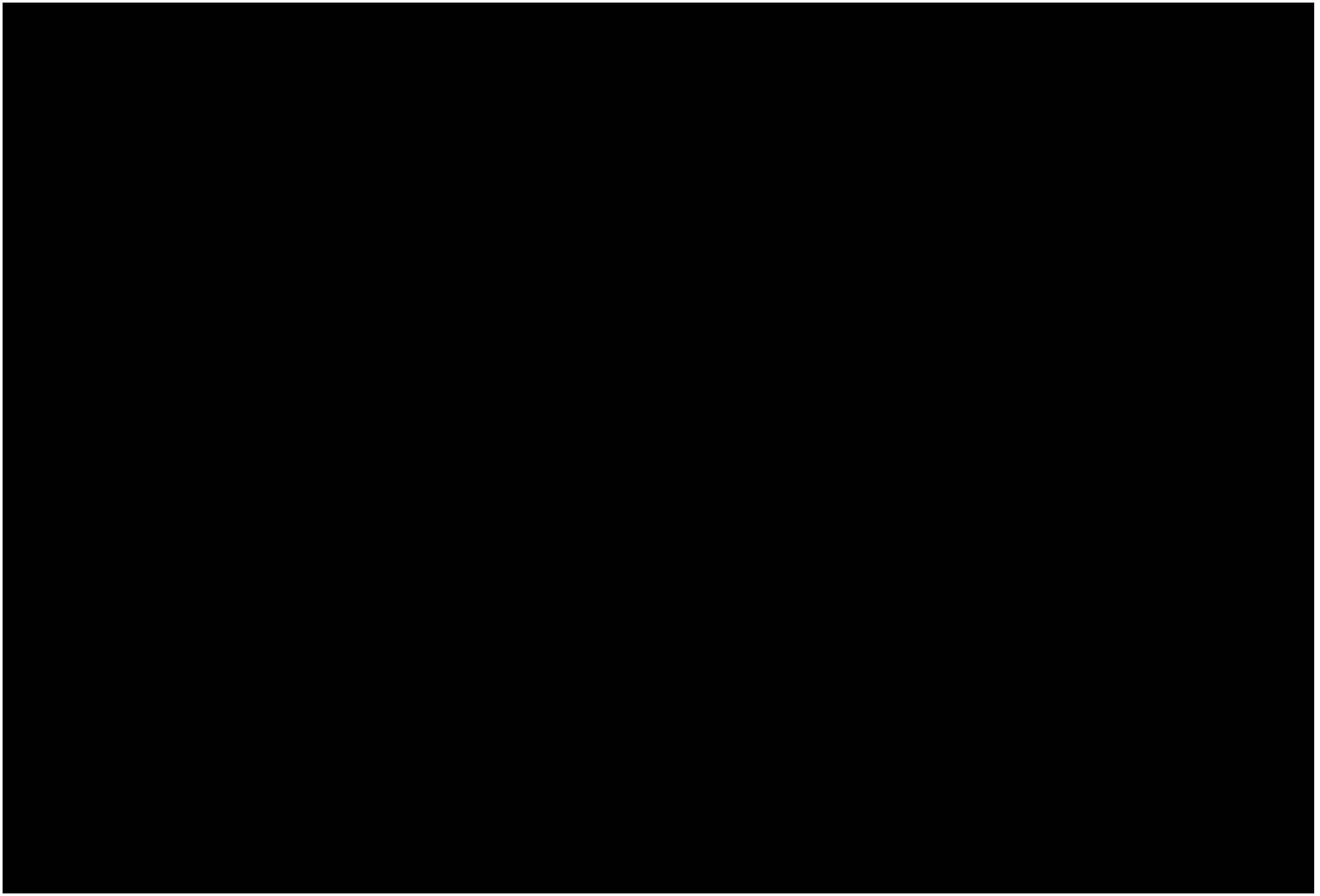
Date of On Peak Day - 08/28/2021

[redacted]

Member Forecasted On Peak Demand Day for September 2021

Poudre Valley Electric Association, Inc.

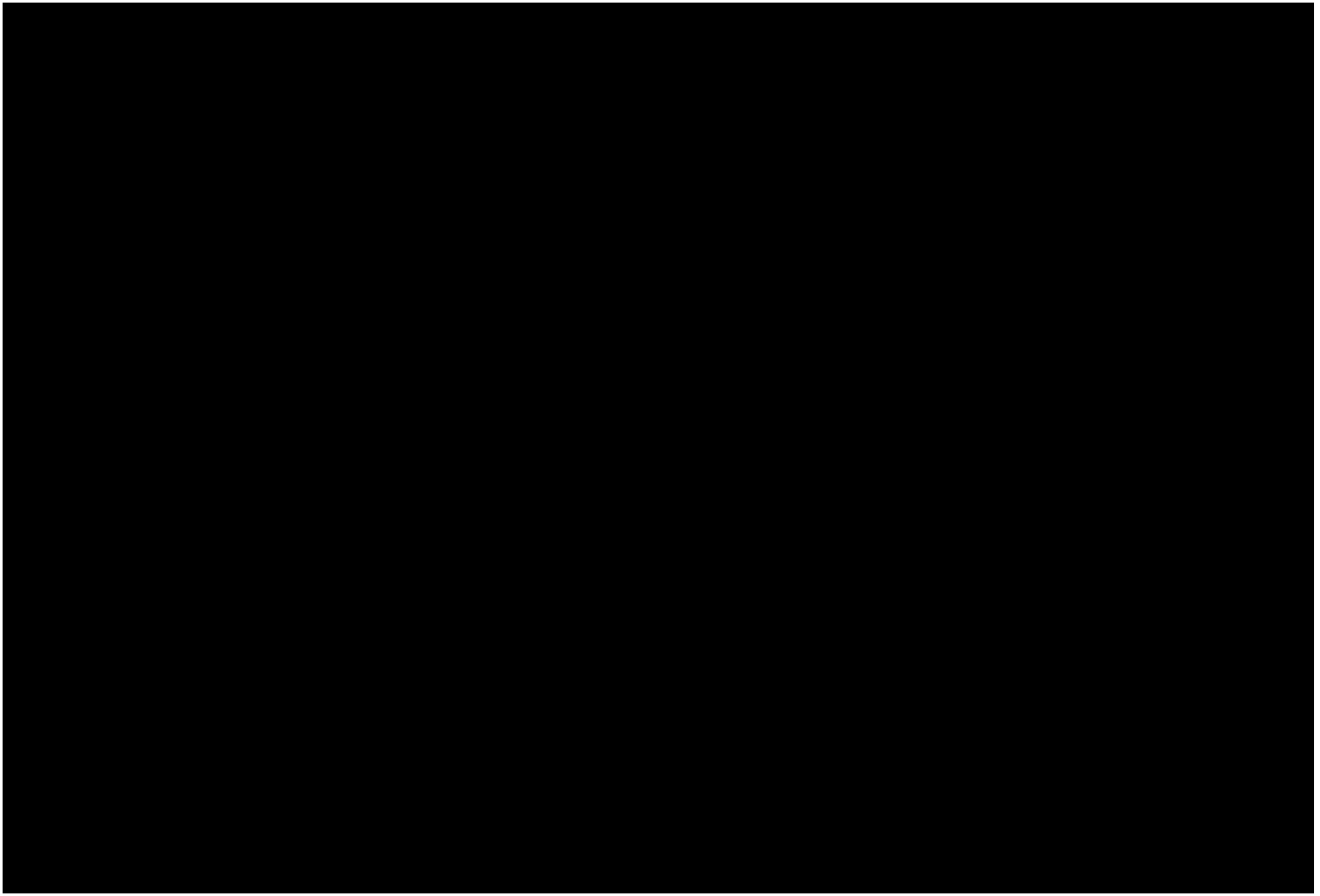
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Poudre Valley Electric Association, Inc.

Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

Poudre Valley Electric Association, Inc.

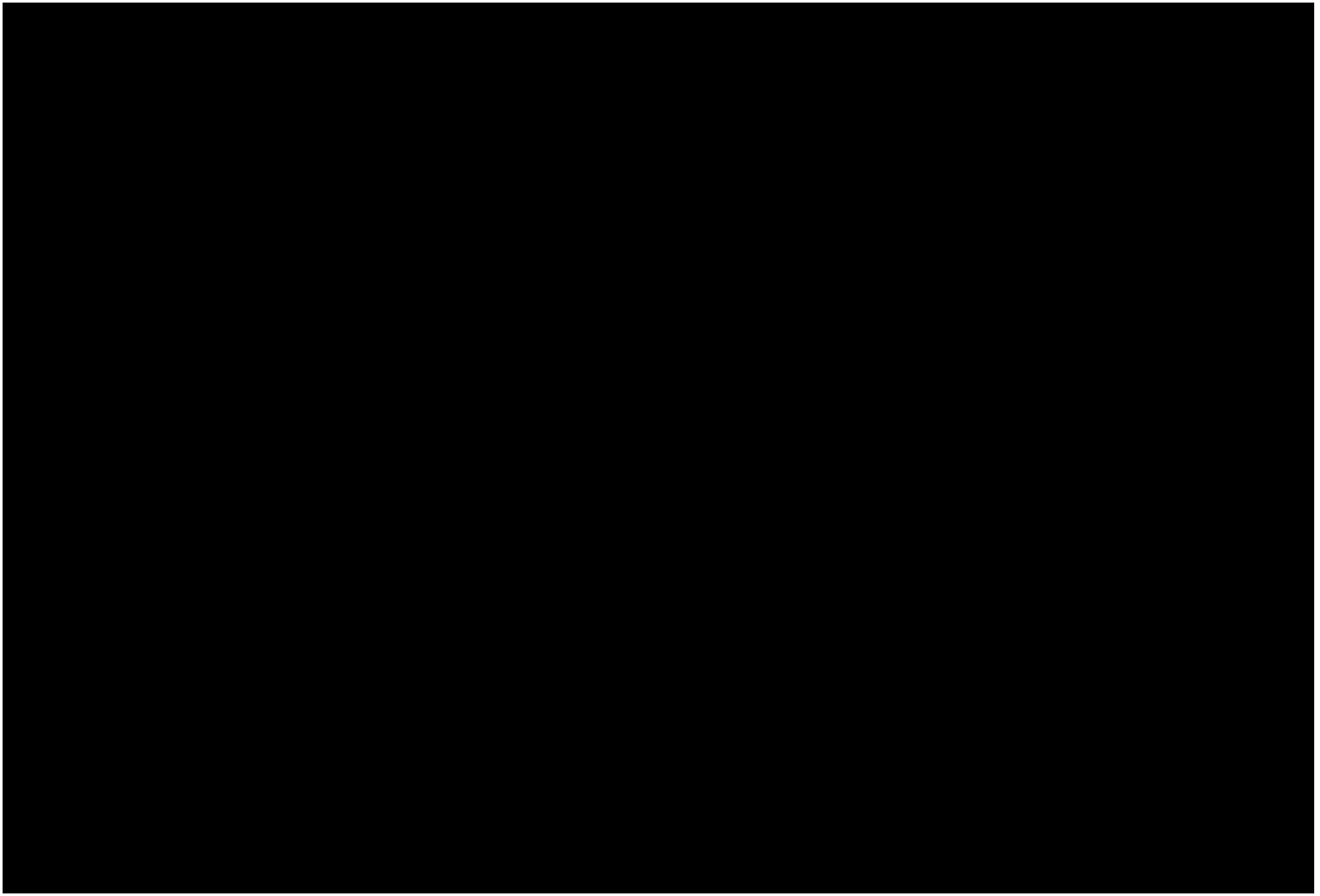
Date of On Peak Day - 11/08/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

Poudre Valley Electric Association, Inc.

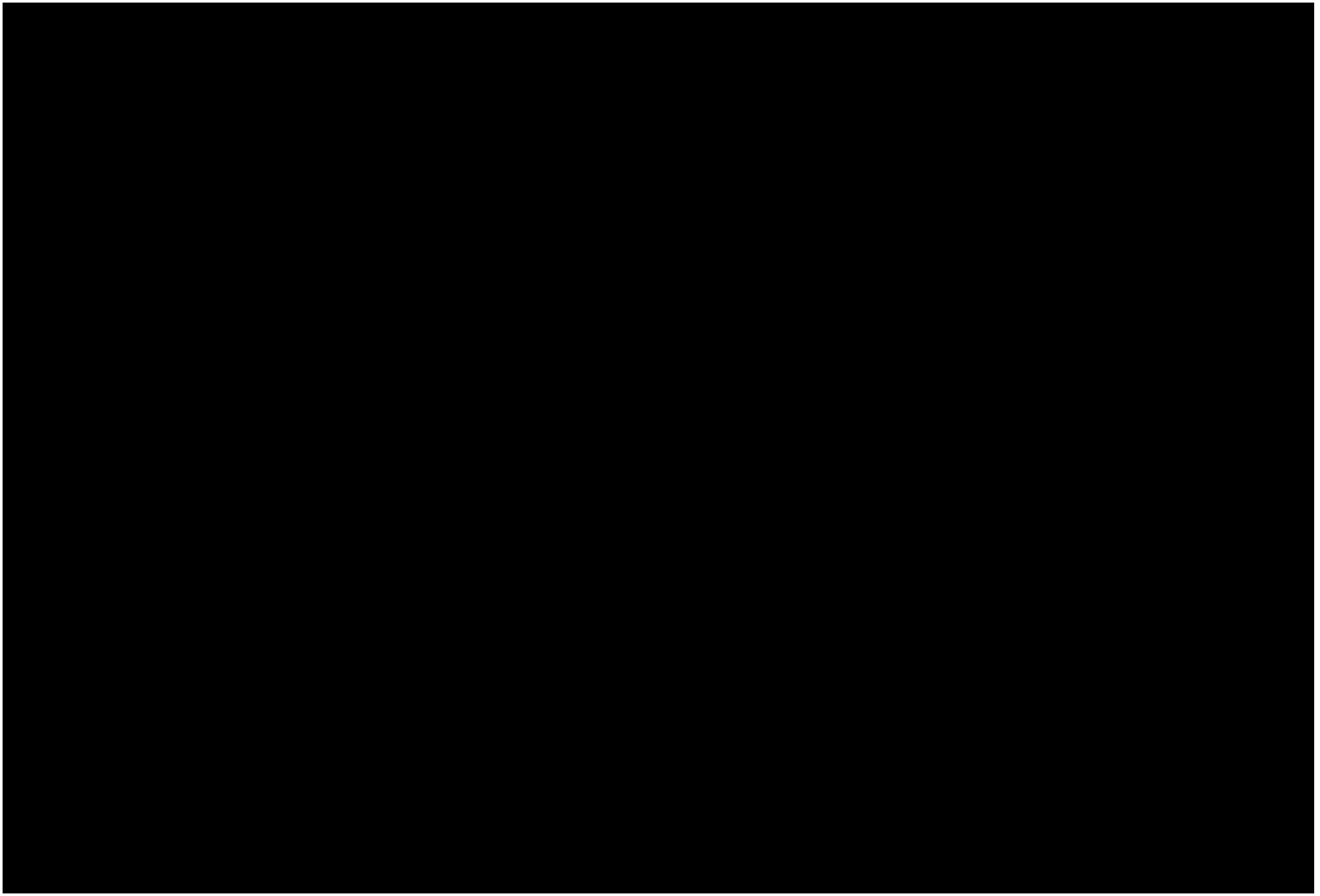
Date of On Peak Day - 12/15/2021



Member Forecasted On Peak Demand Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.

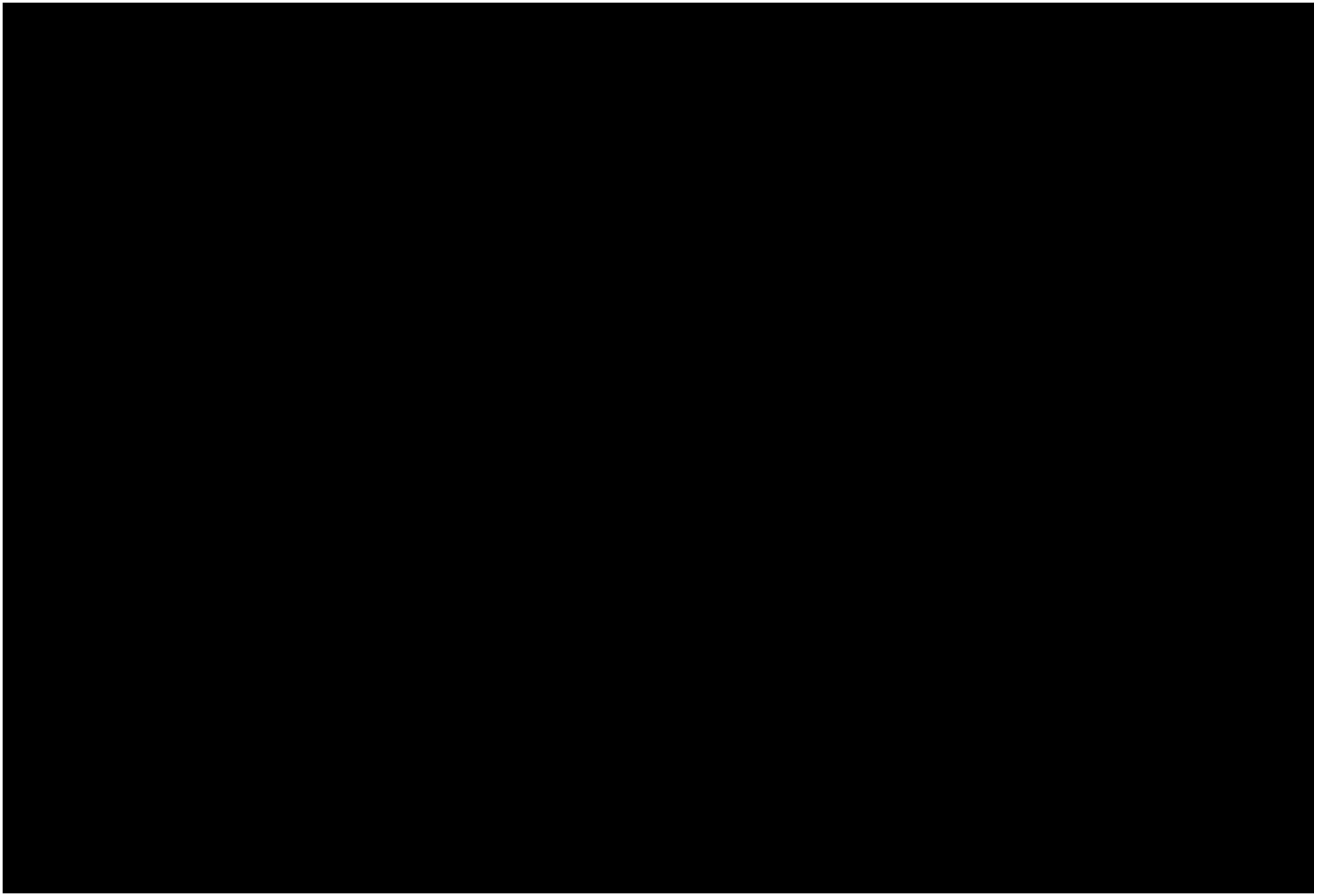
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.

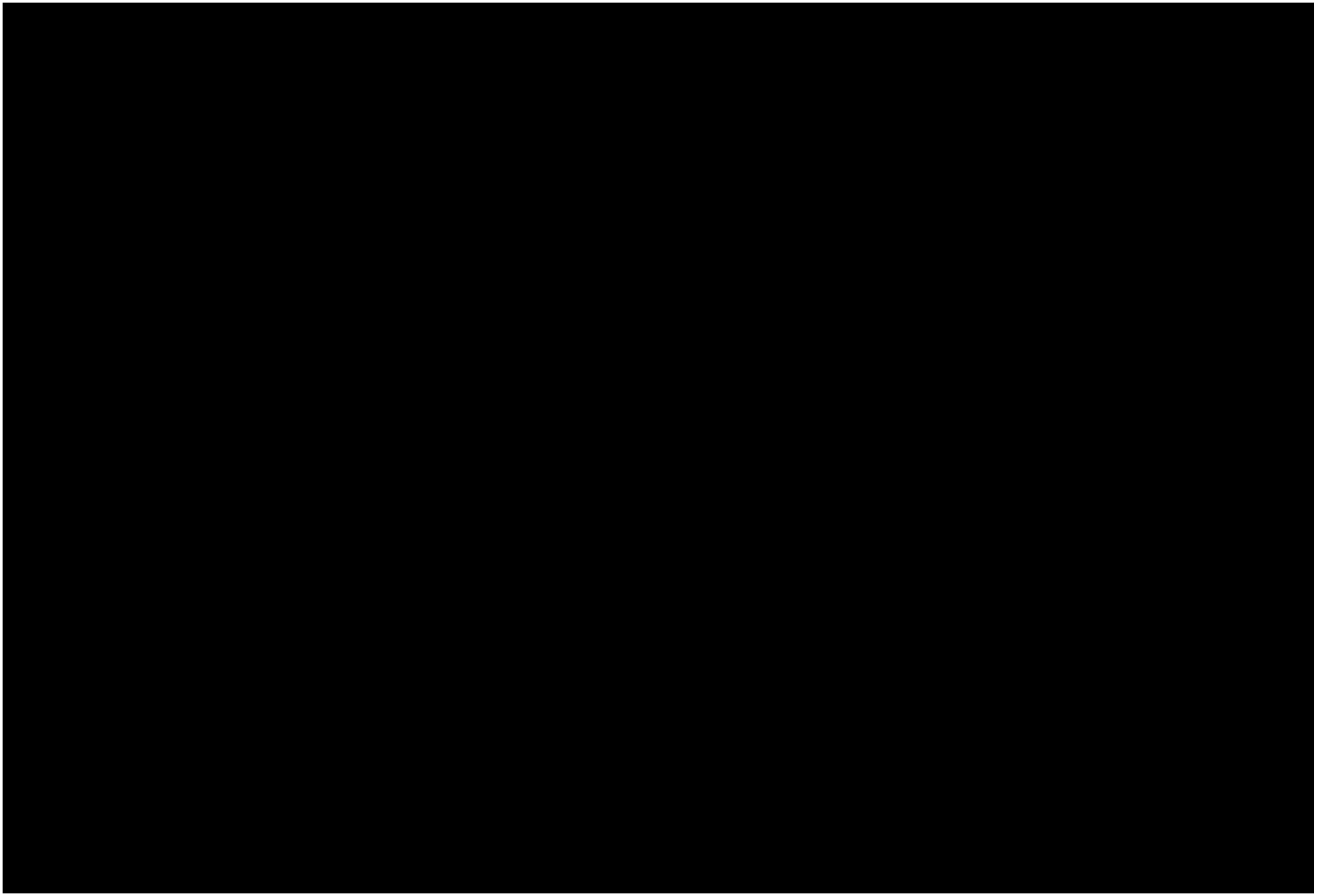
Date of On Peak Day - 02/01/2021



Member Forecasted On Peak Demand Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

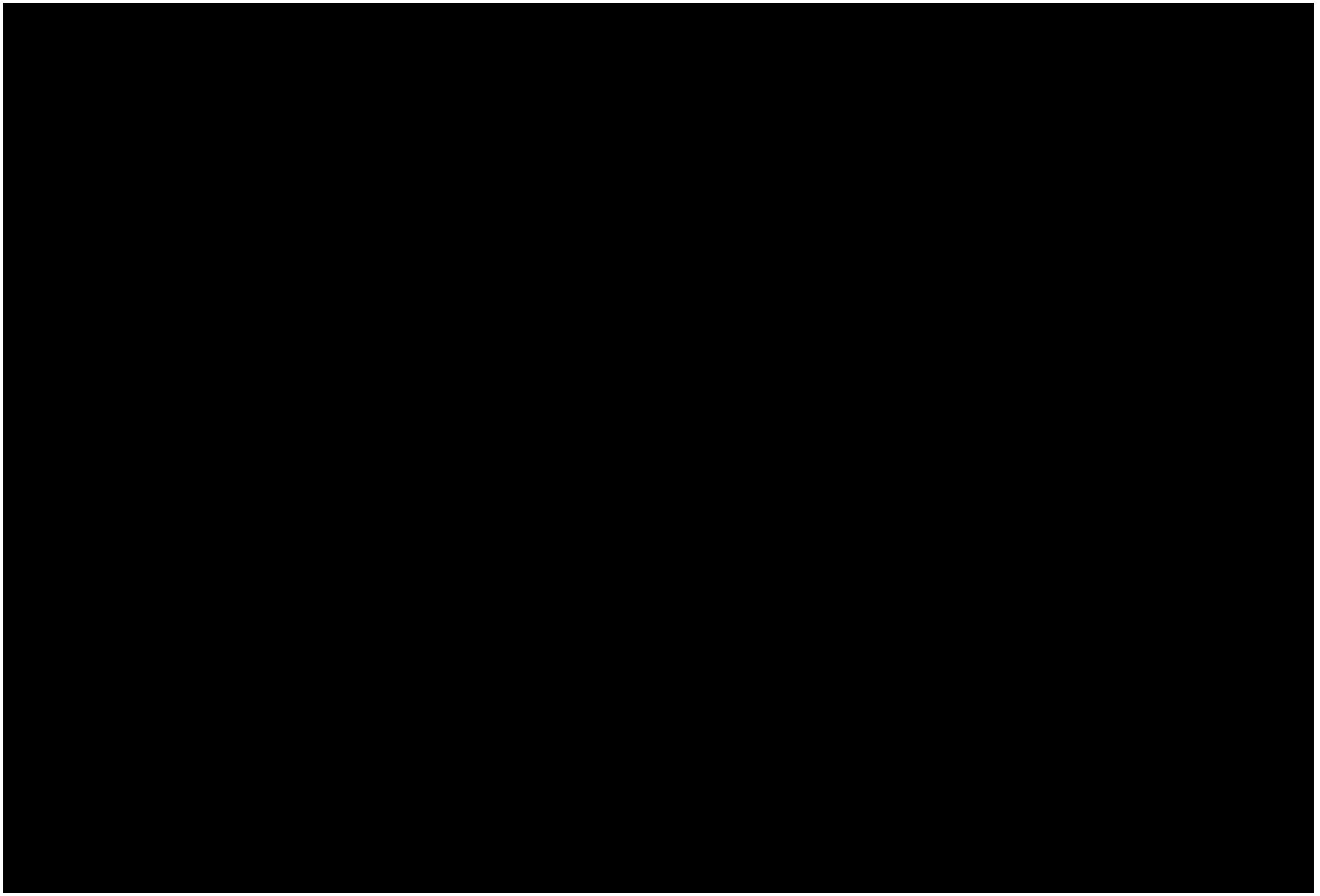
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

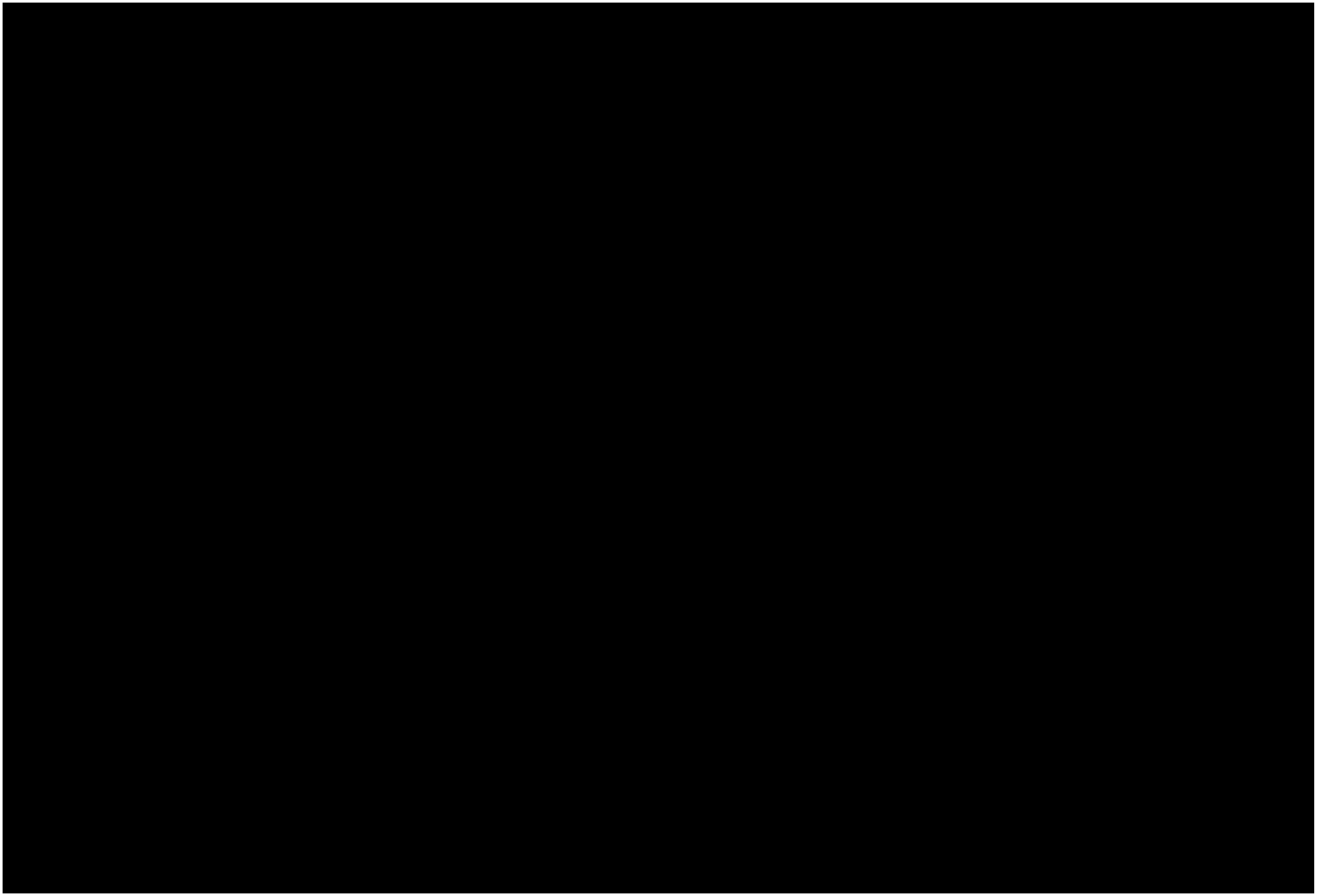
Date of On Peak Day - 05/19/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.

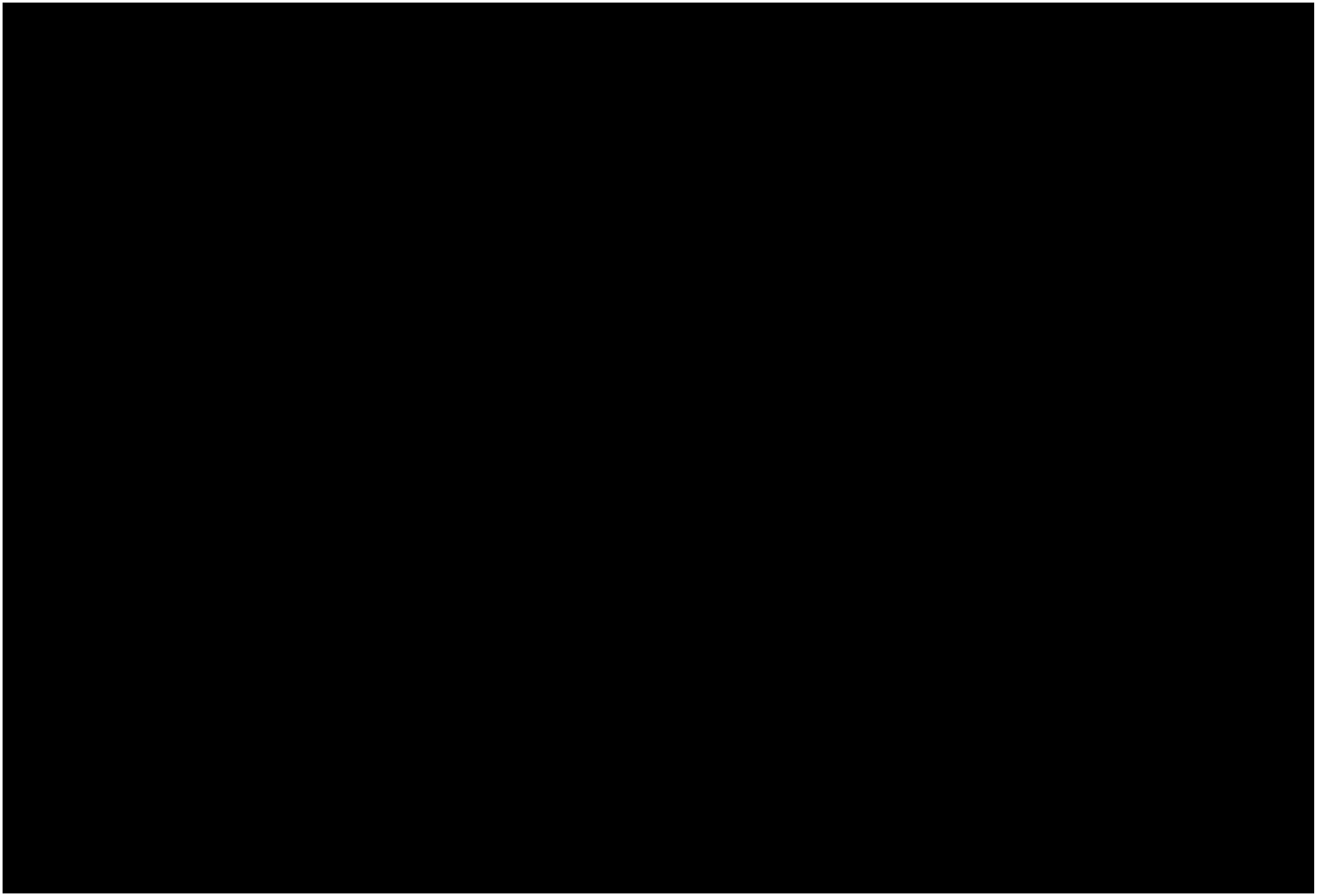
Date of On Peak Day - 06/24/2021



Member Forecasted On Peak Demand Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

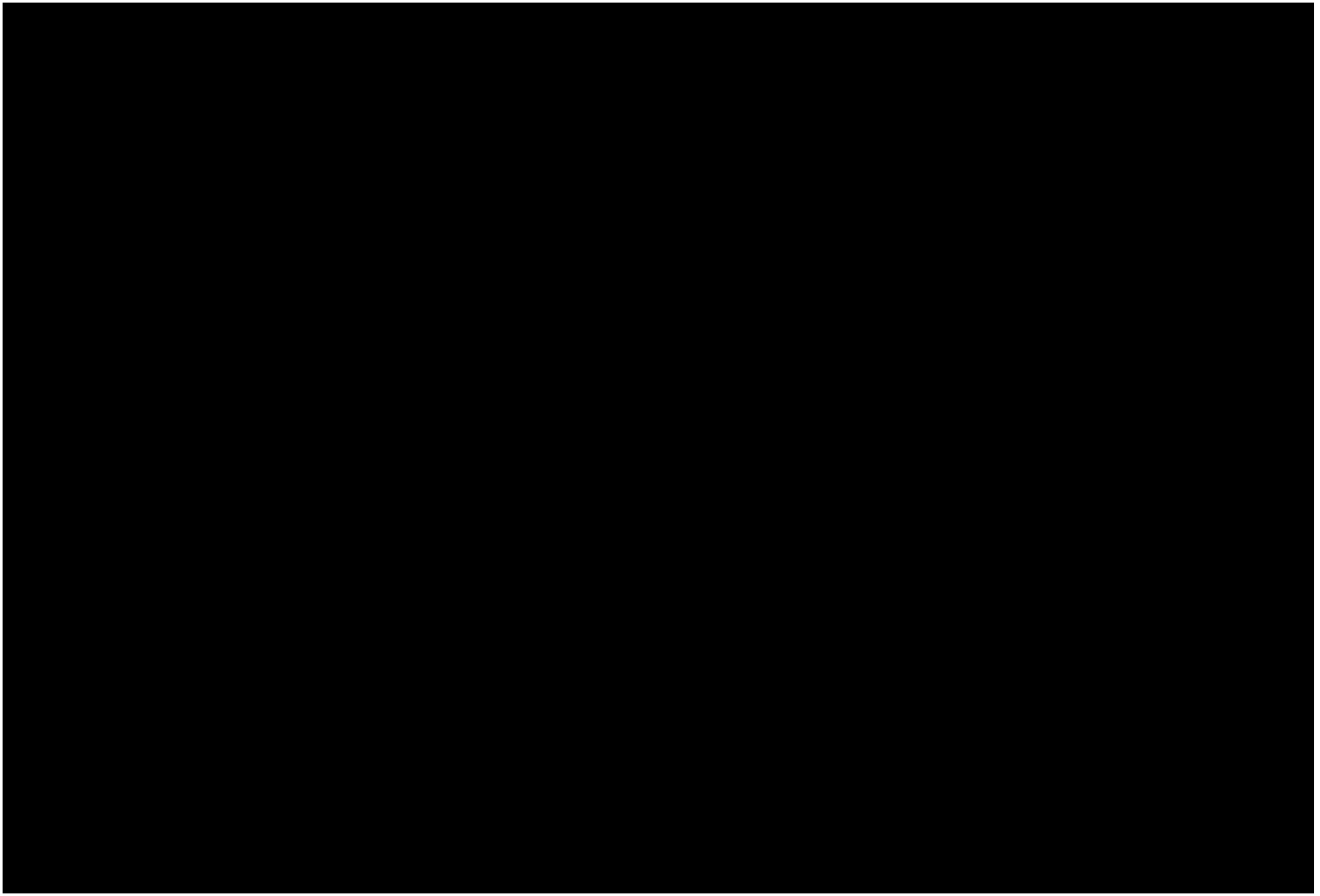
Date of On Peak Day - 07/17/2021



Member Forecasted On Peak Demand Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

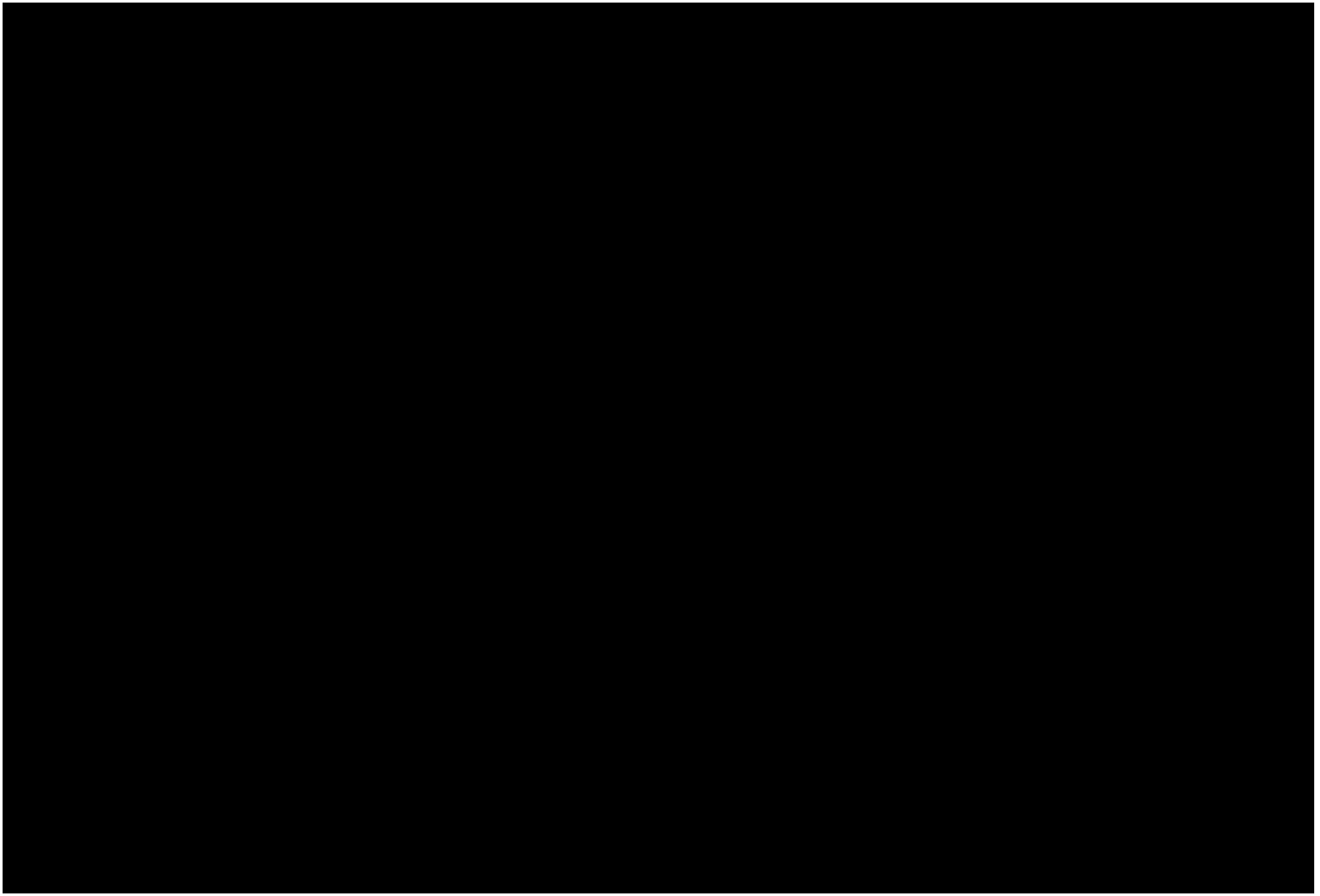
Date of On Peak Day - 08/10/2021



Member Forecasted On Peak Demand Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

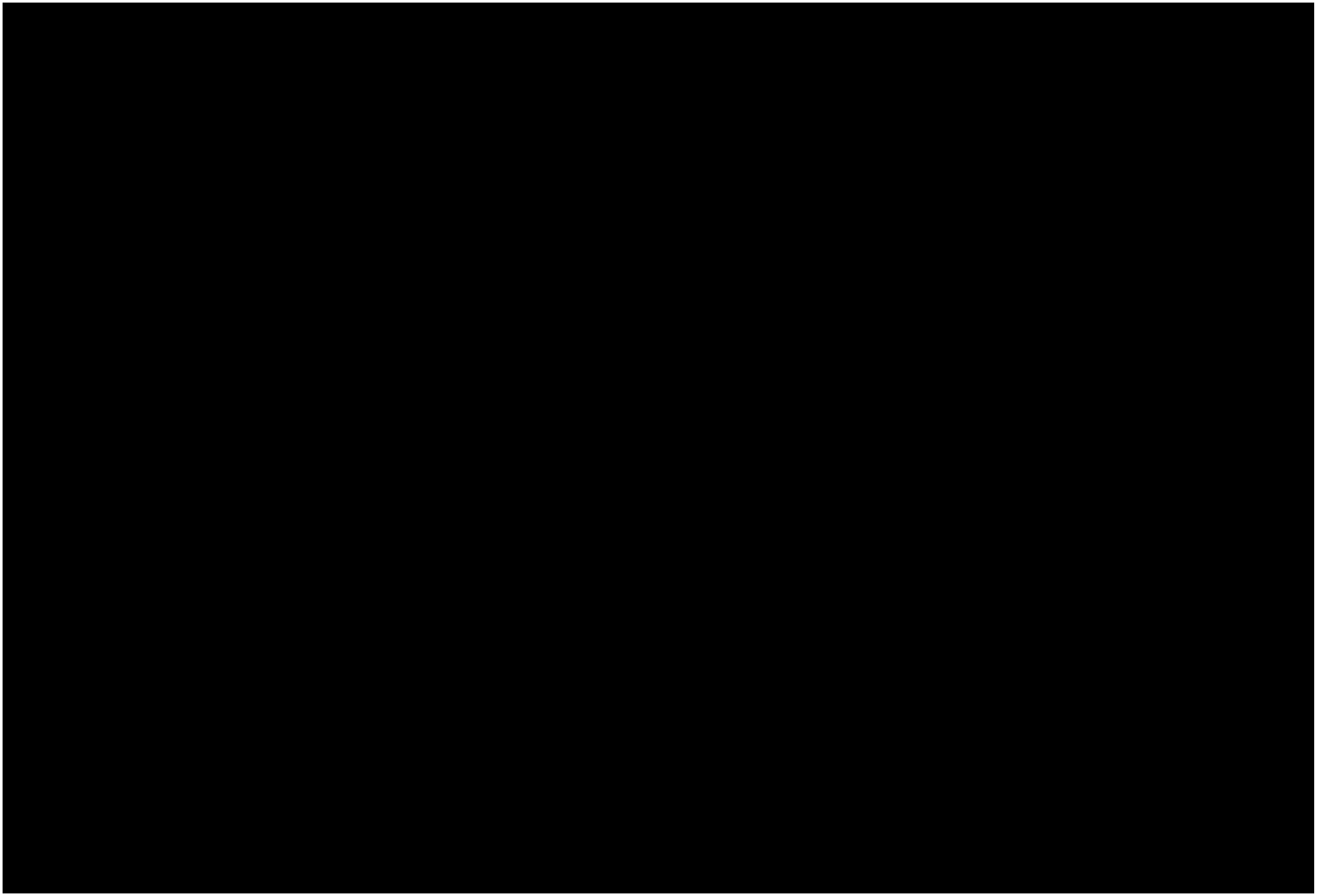
Date of On Peak Day - 09/04/2021



Member Forecasted On Peak Demand Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

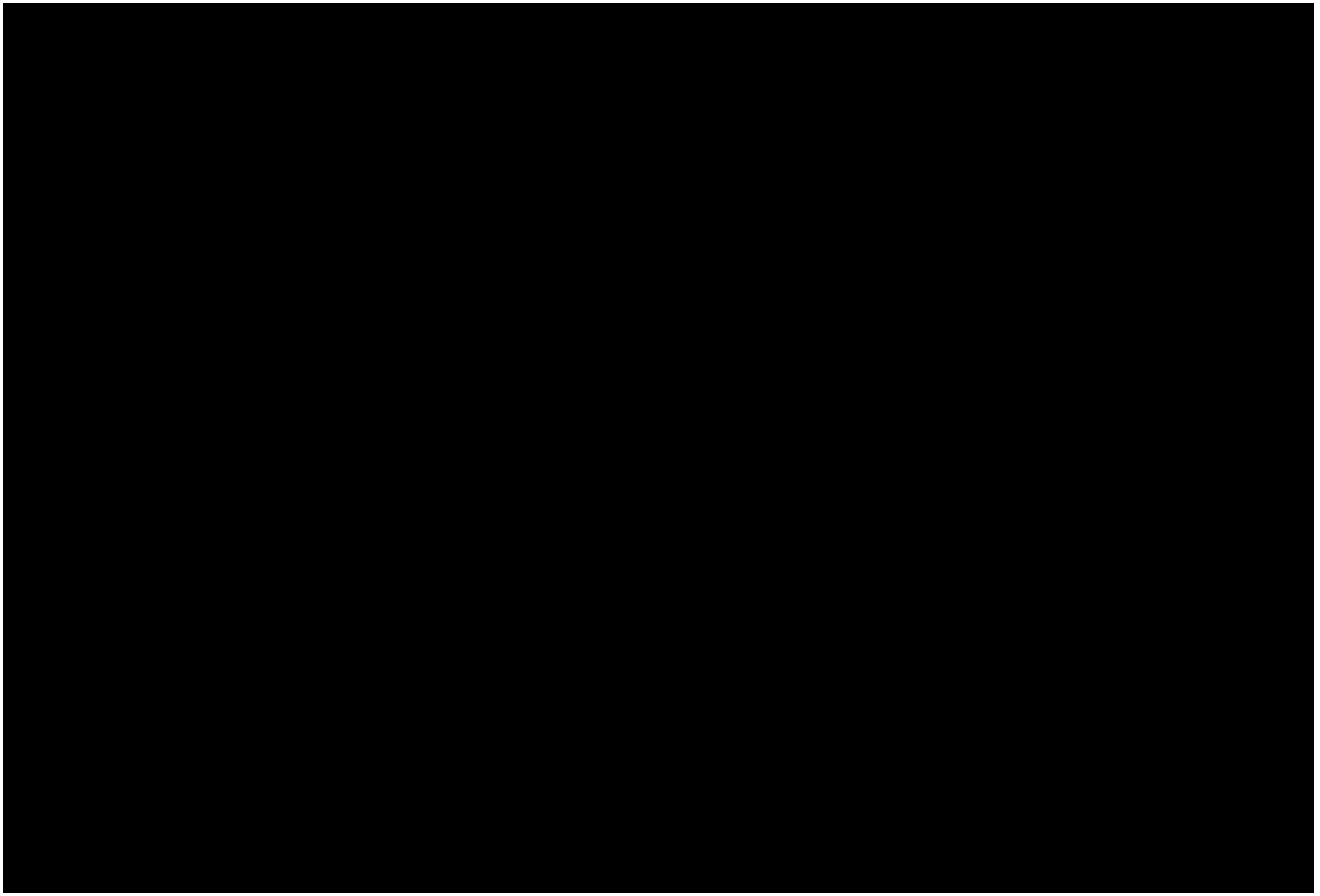
Date of On Peak Day - 10/21/2021



Member Forecasted On Peak Demand Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

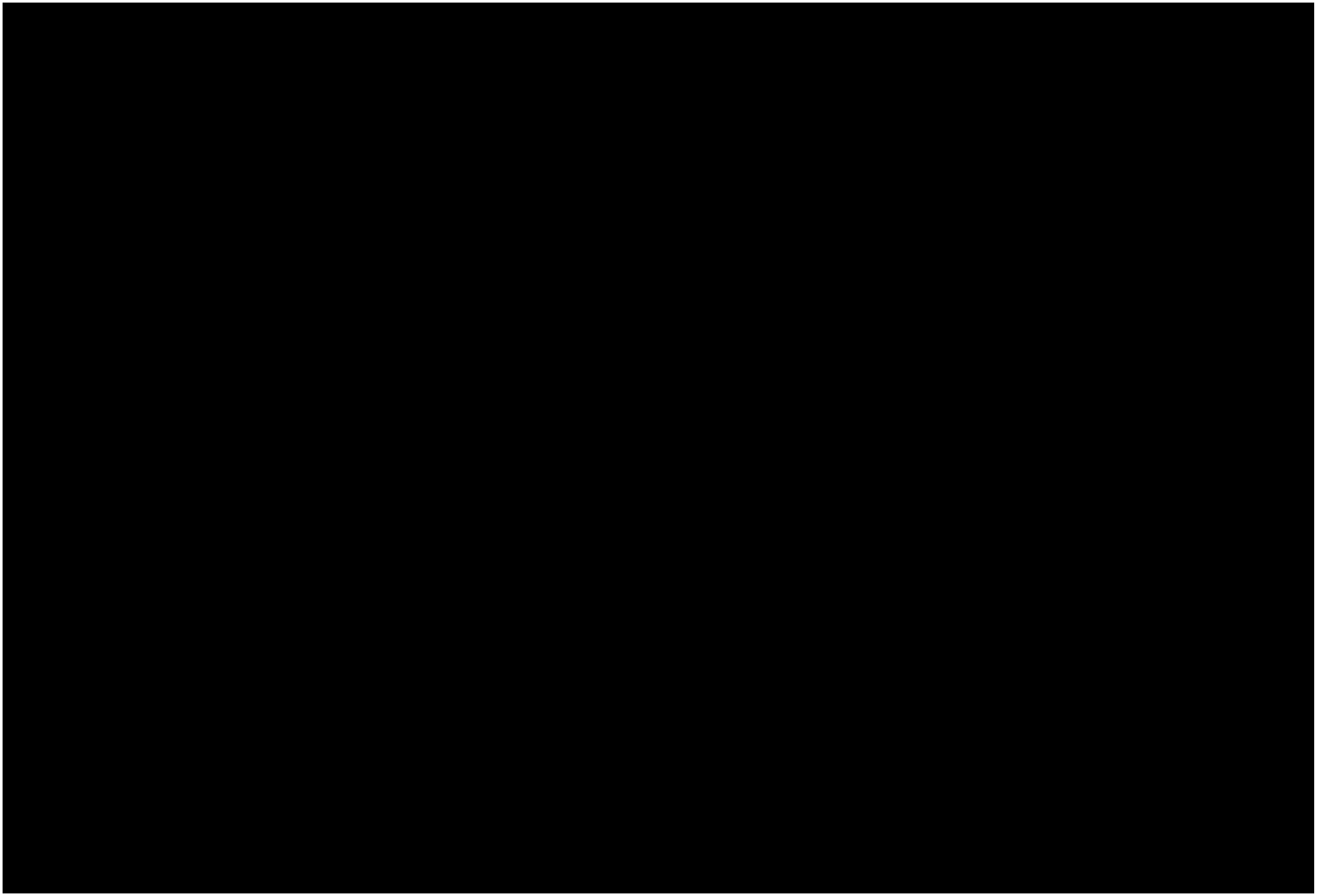
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

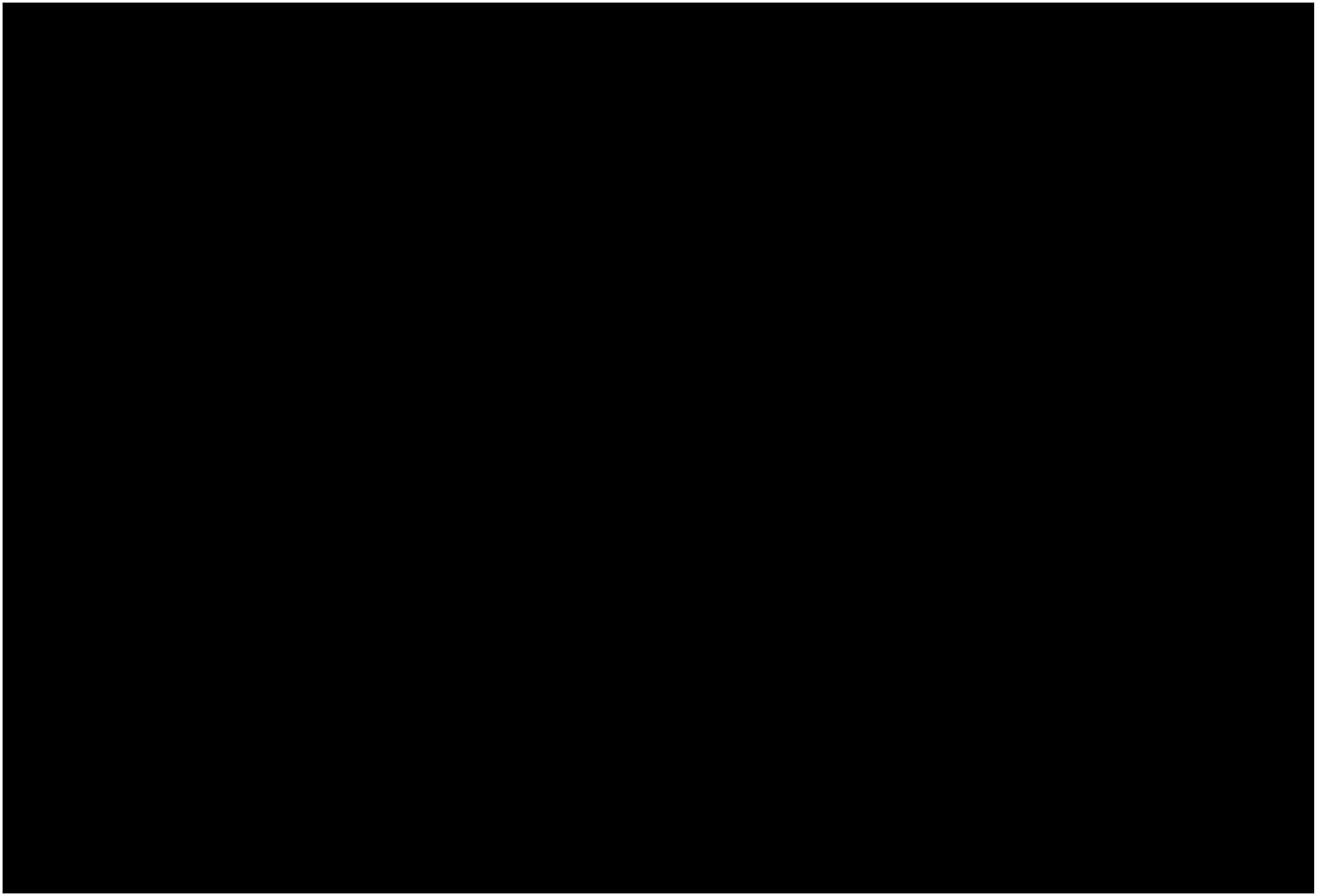
Date of On Peak Day - 12/24/2021



Member Forecasted On Peak Demand Day for January 2021

Roosevelt Public Power District

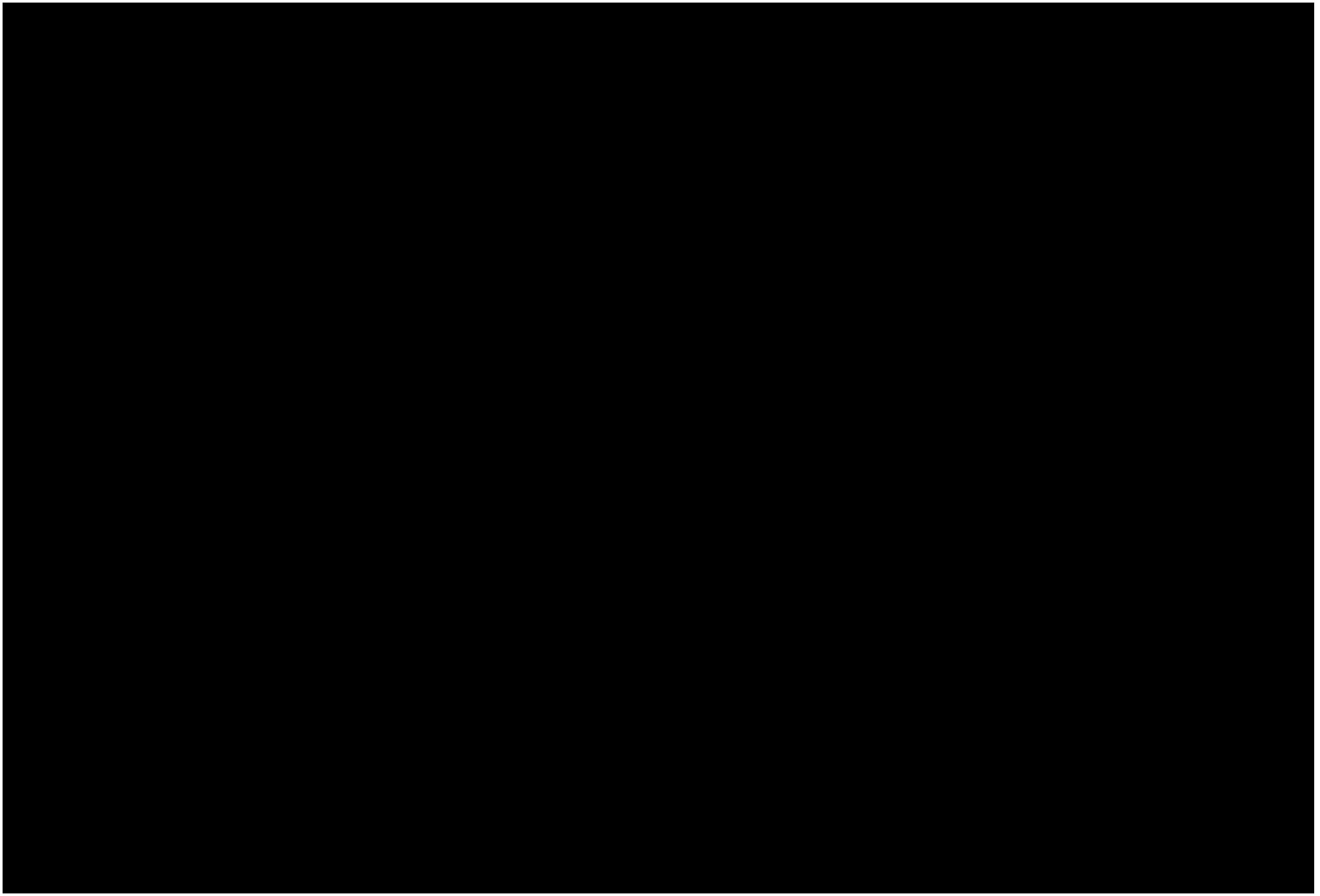
Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Roosevelt Public Power District

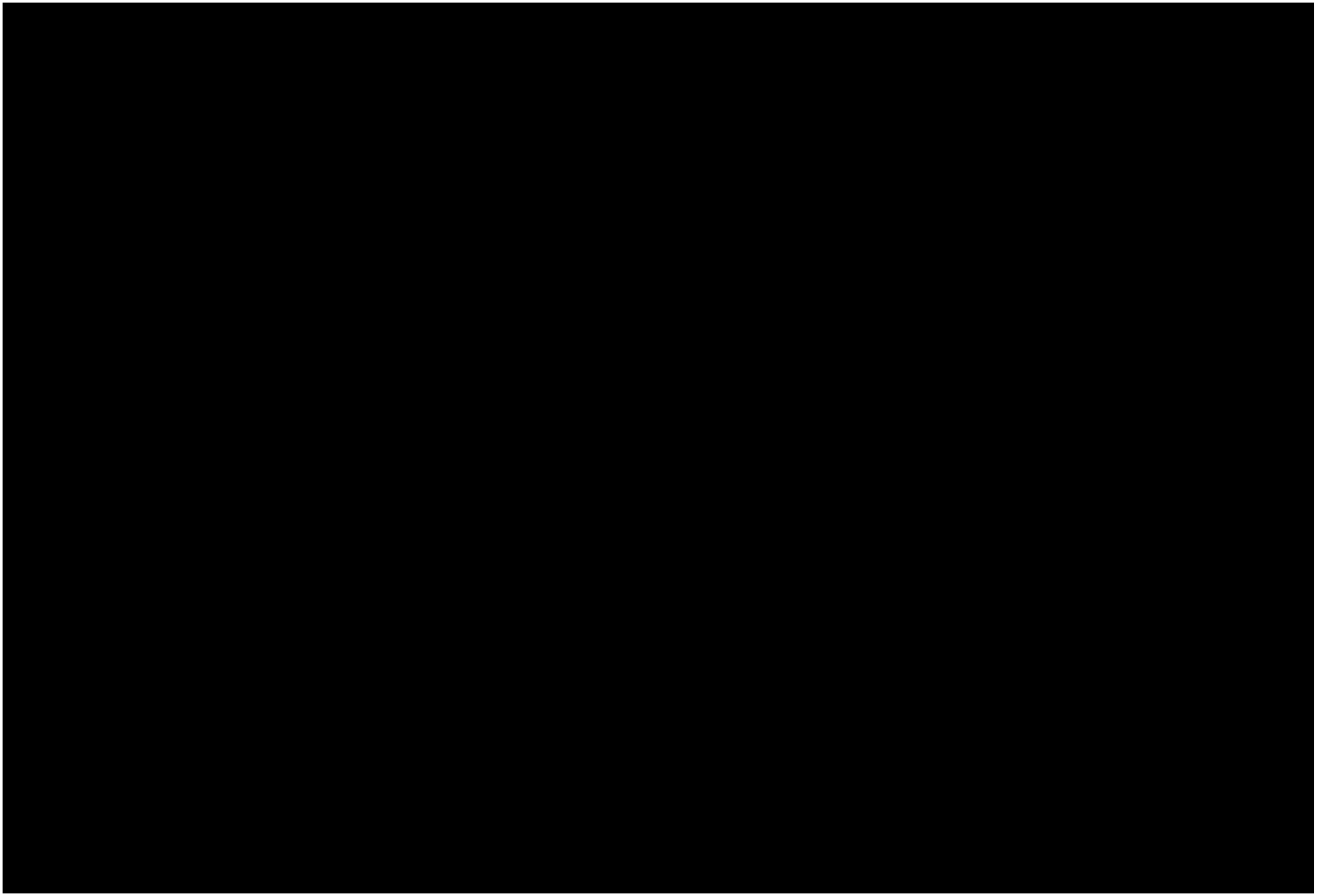
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Roosevelt Public Power District

Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Roosevelt Public Power District

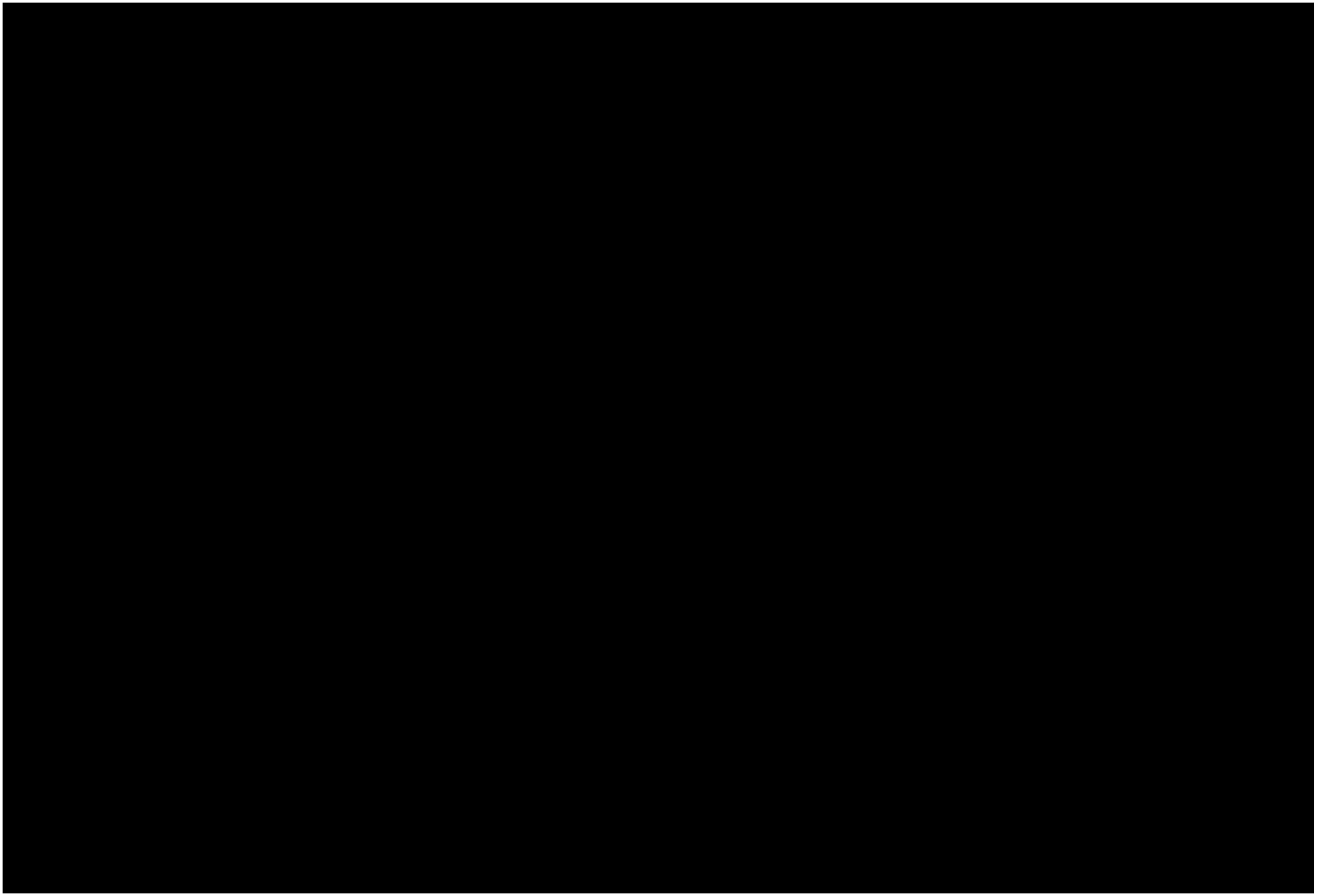
Date of On Peak Day - 04/05/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Roosevelt Public Power District

Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Roosevelt Public Power District

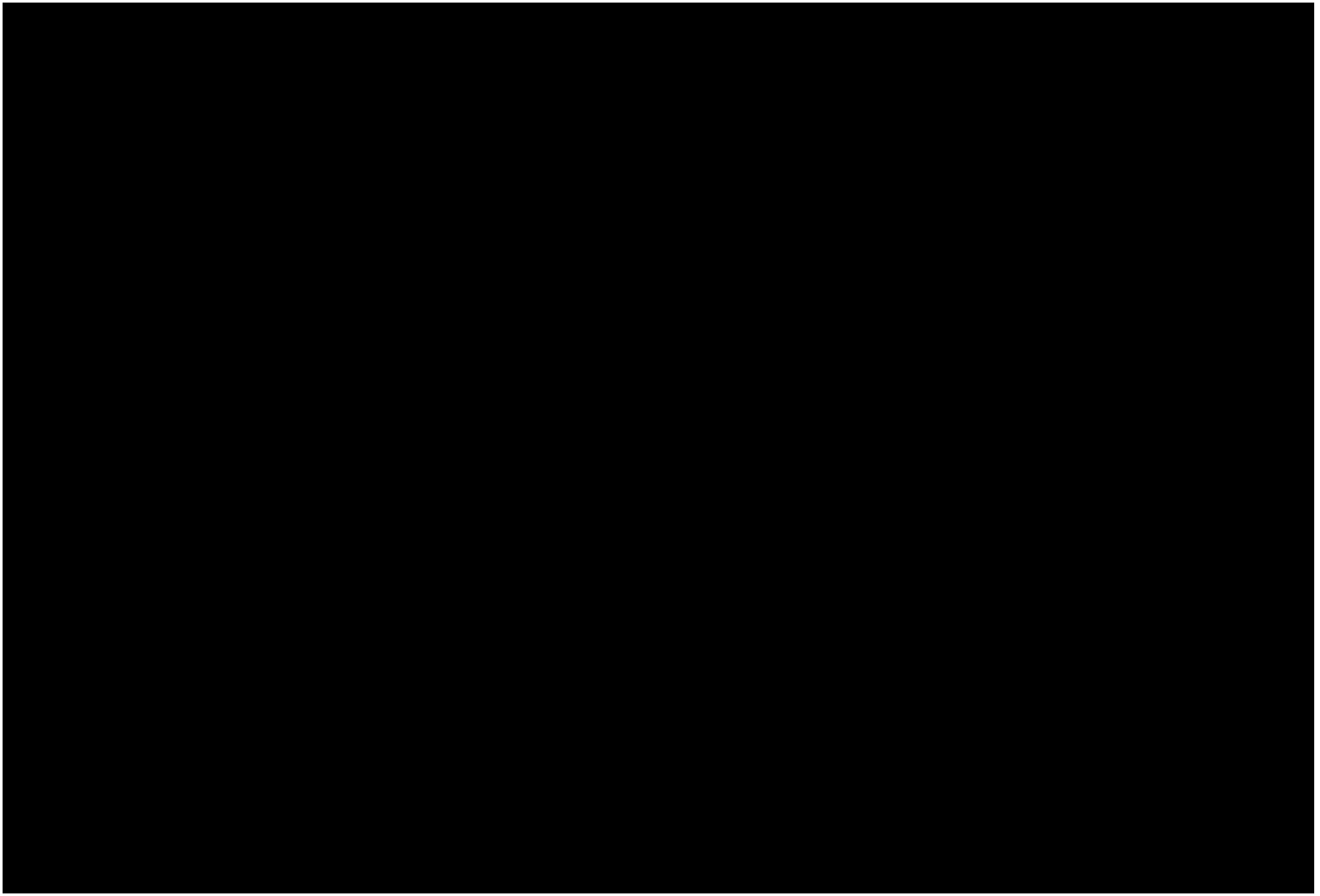
Date of On Peak Day - 06/28/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

Roosevelt Public Power District

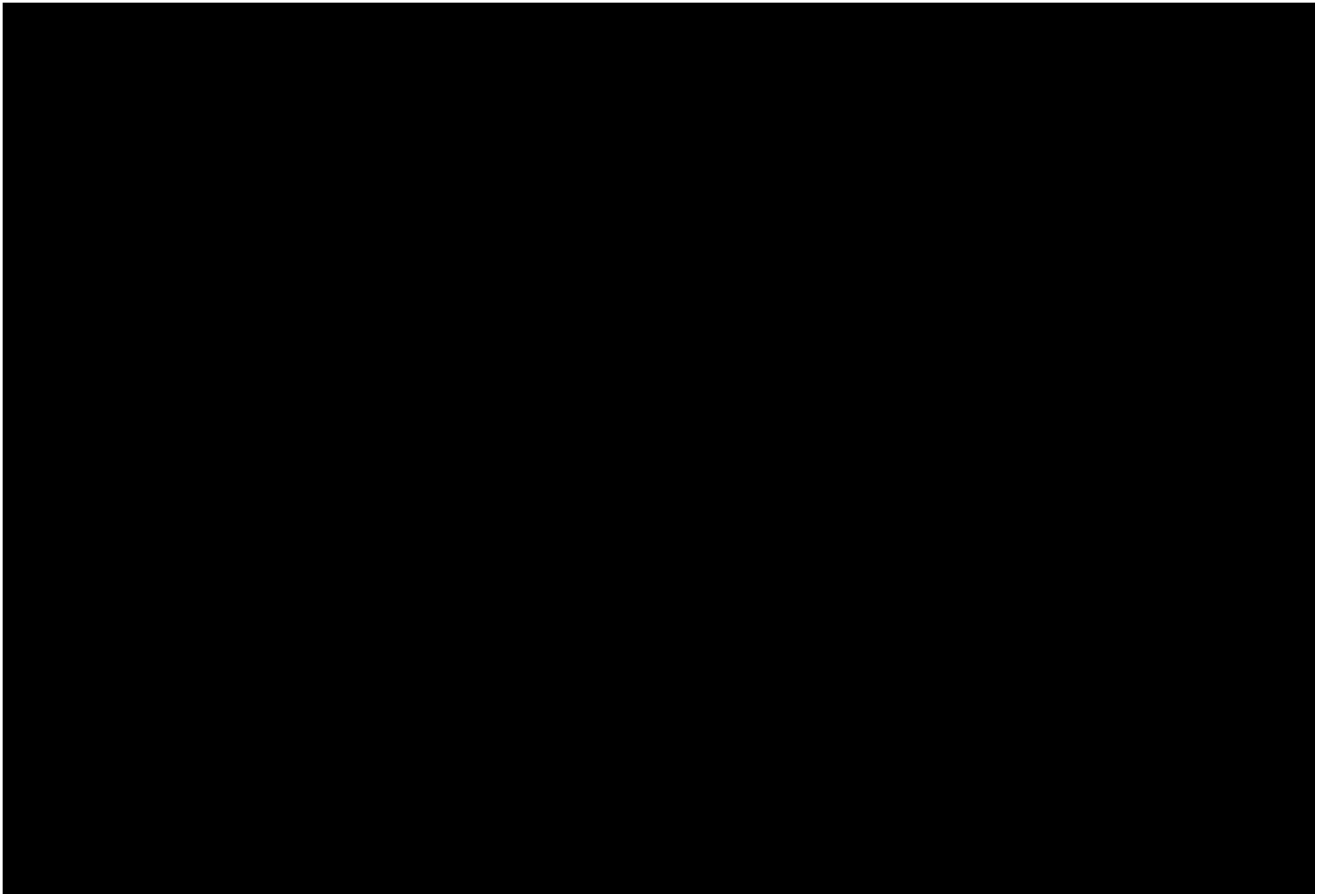
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

Roosevelt Public Power District

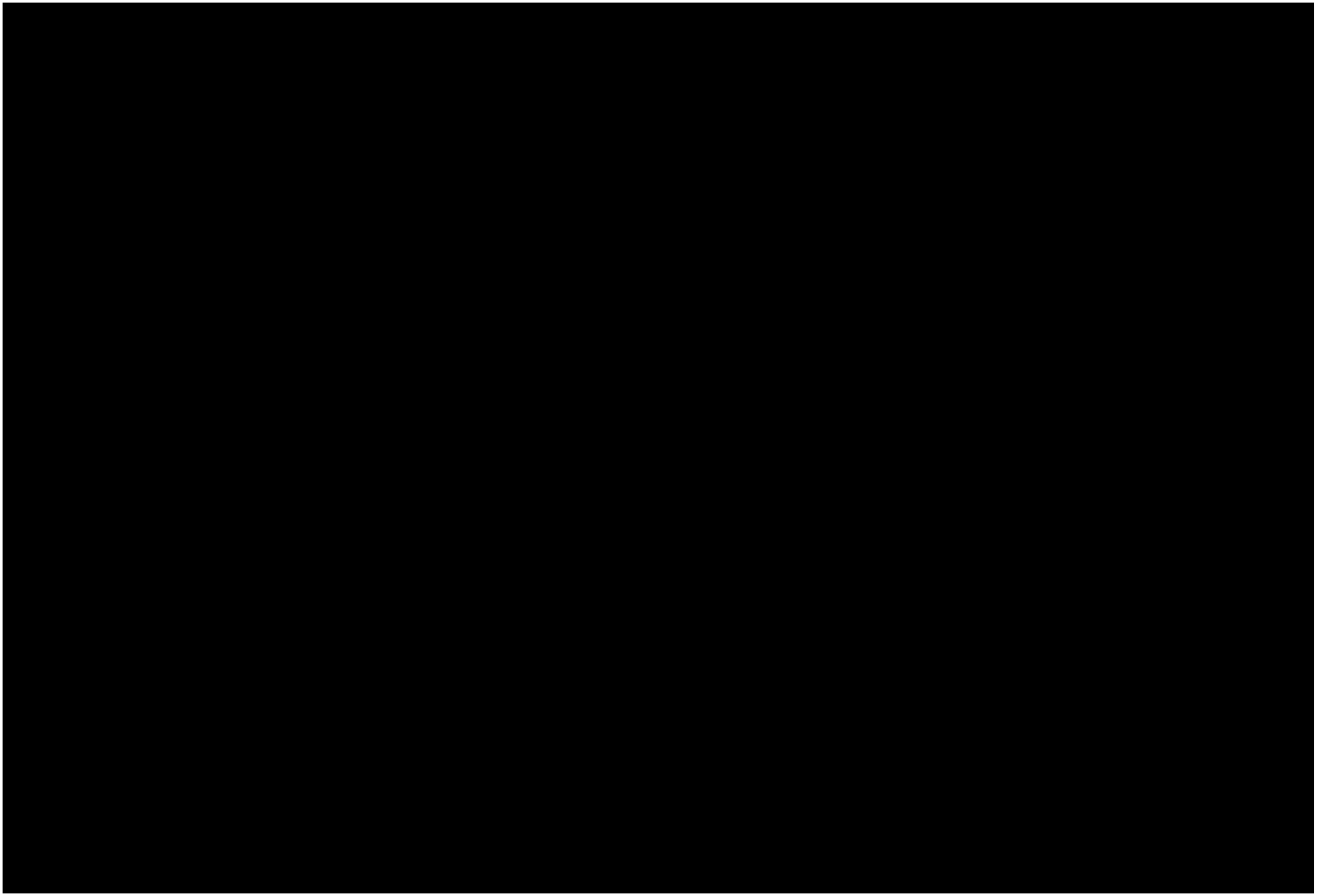
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Roosevelt Public Power District

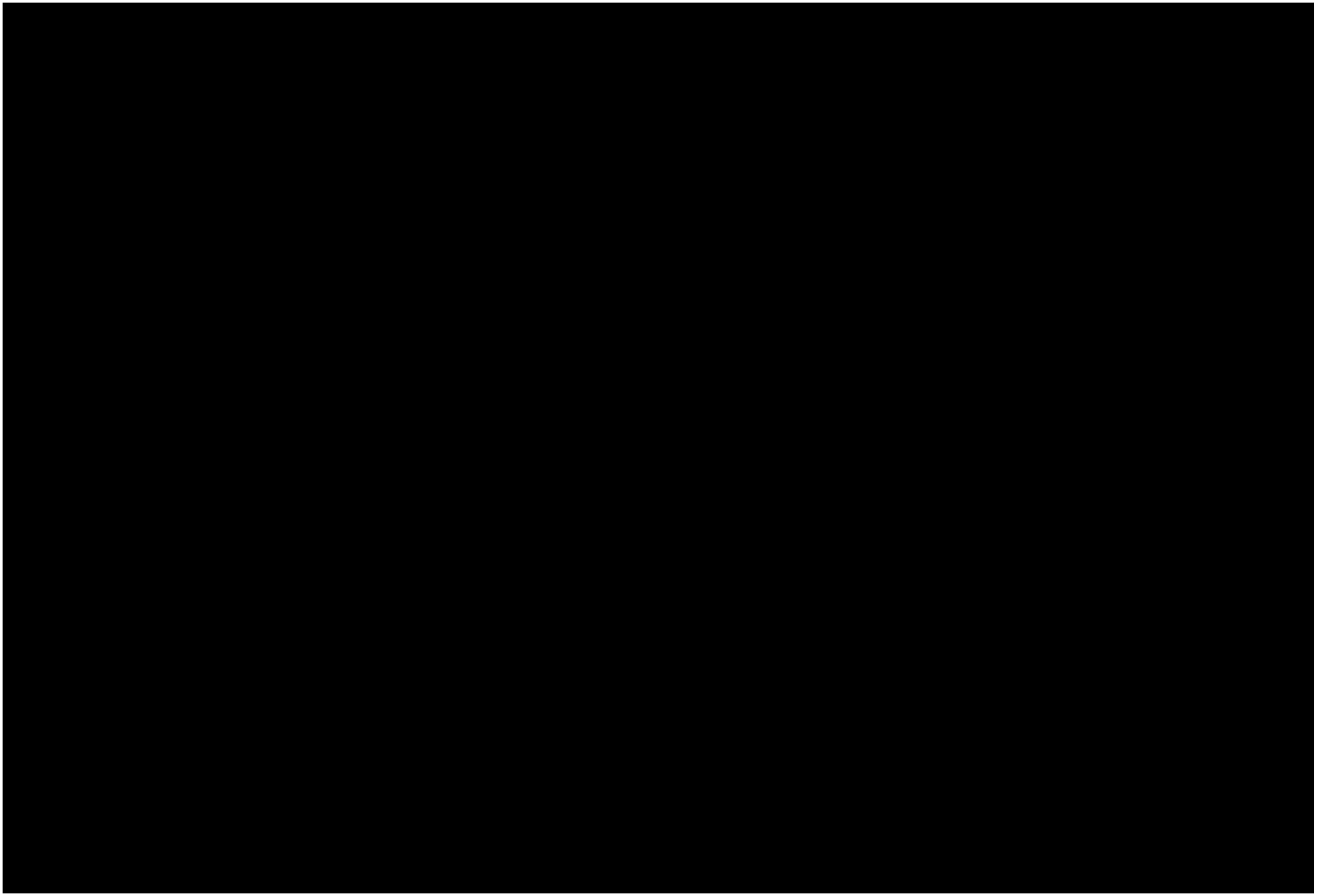
Date of On Peak Day - 09/04/2021



Member Forecasted On Peak Demand Day for October 2021

Roosevelt Public Power District

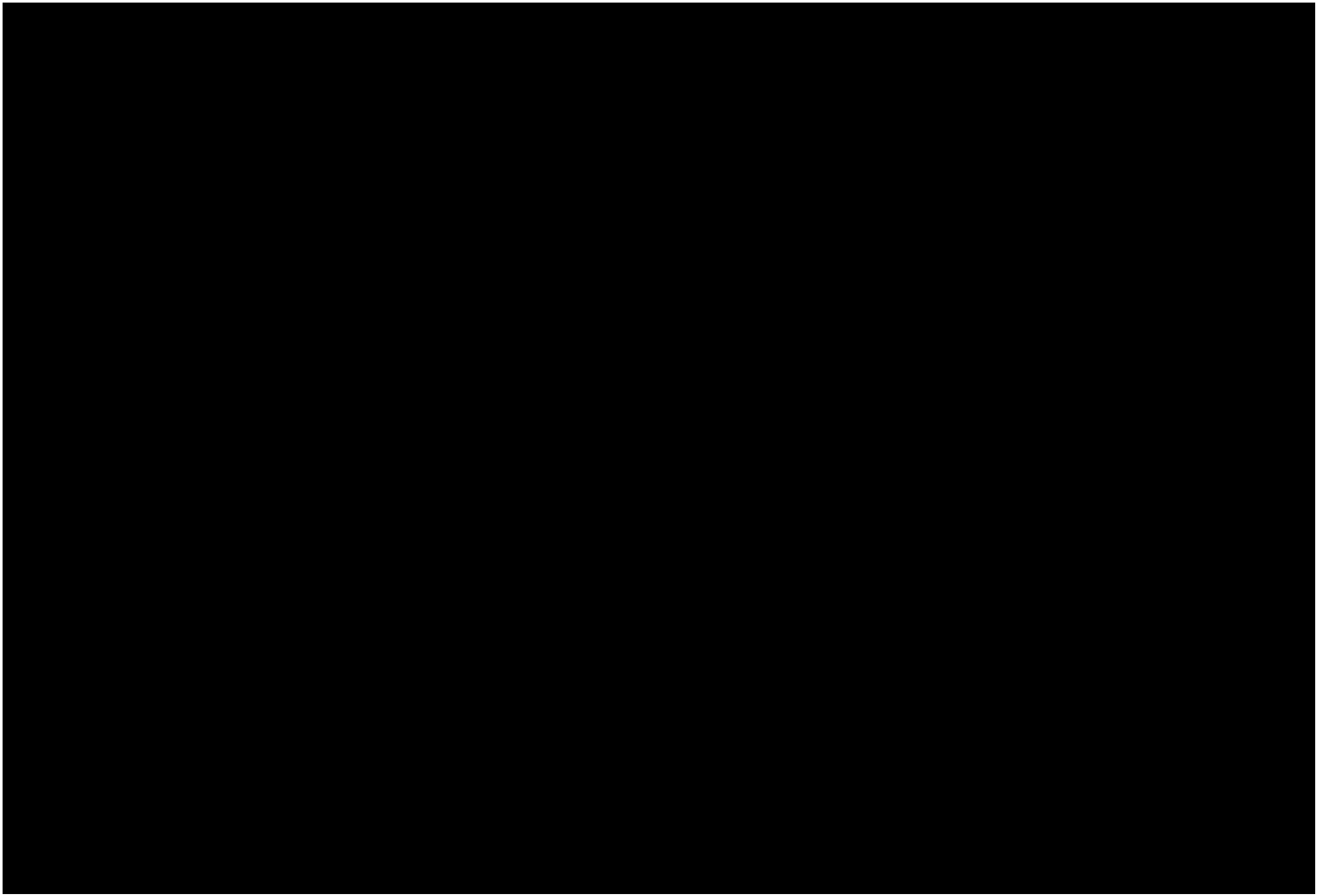
Date of On Peak Day - 10/29/2021



Member Forecasted On Peak Demand Day for November 2021

Roosevelt Public Power District

Date of On Peak Day - 11/21/2021



Member Forecasted On Peak Demand Day for December 2021

Roosevelt Public Power District

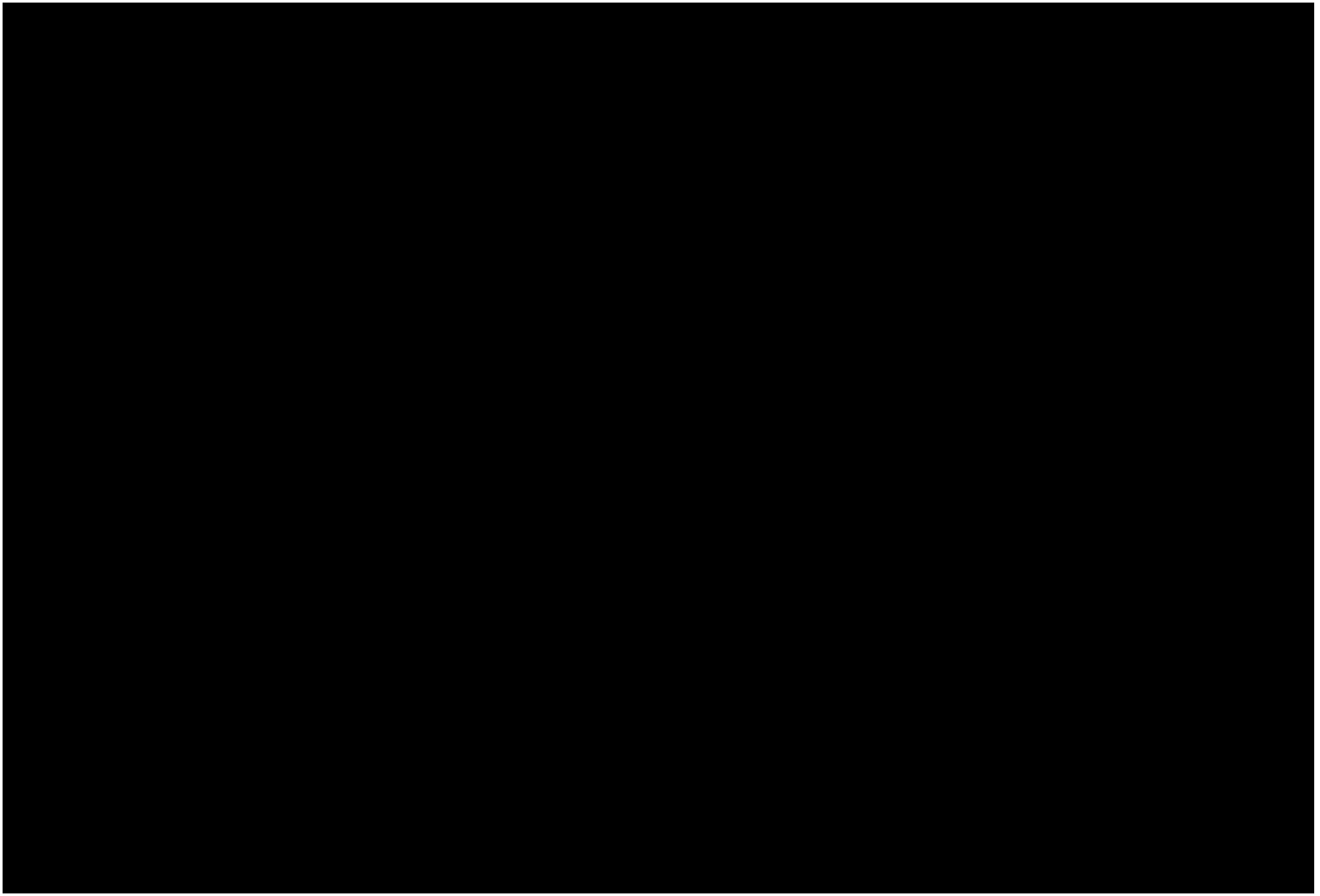
Date of On Peak Day - 12/30/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Sierra Electric Cooperative, Inc.

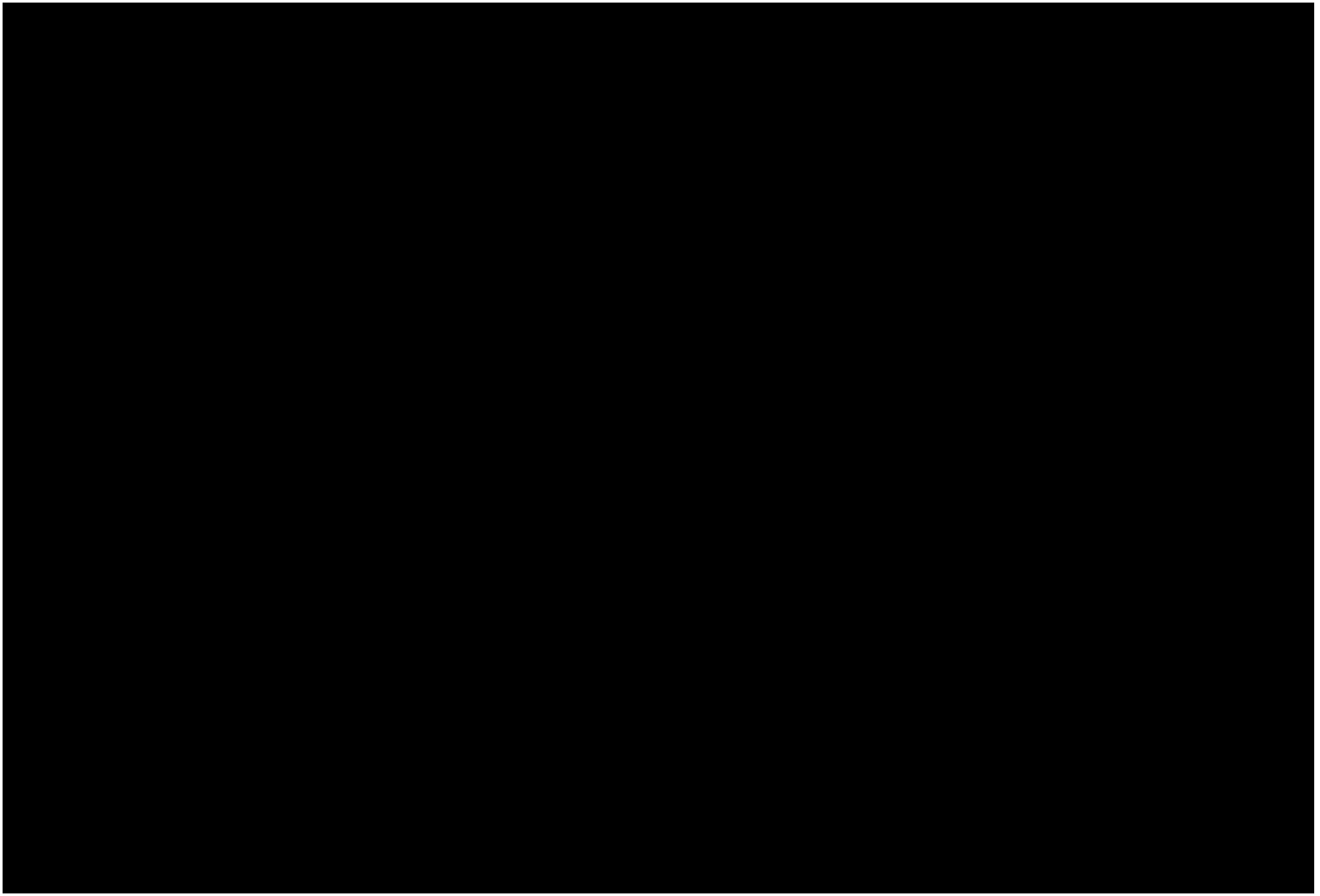
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Sierra Electric Cooperative, Inc.

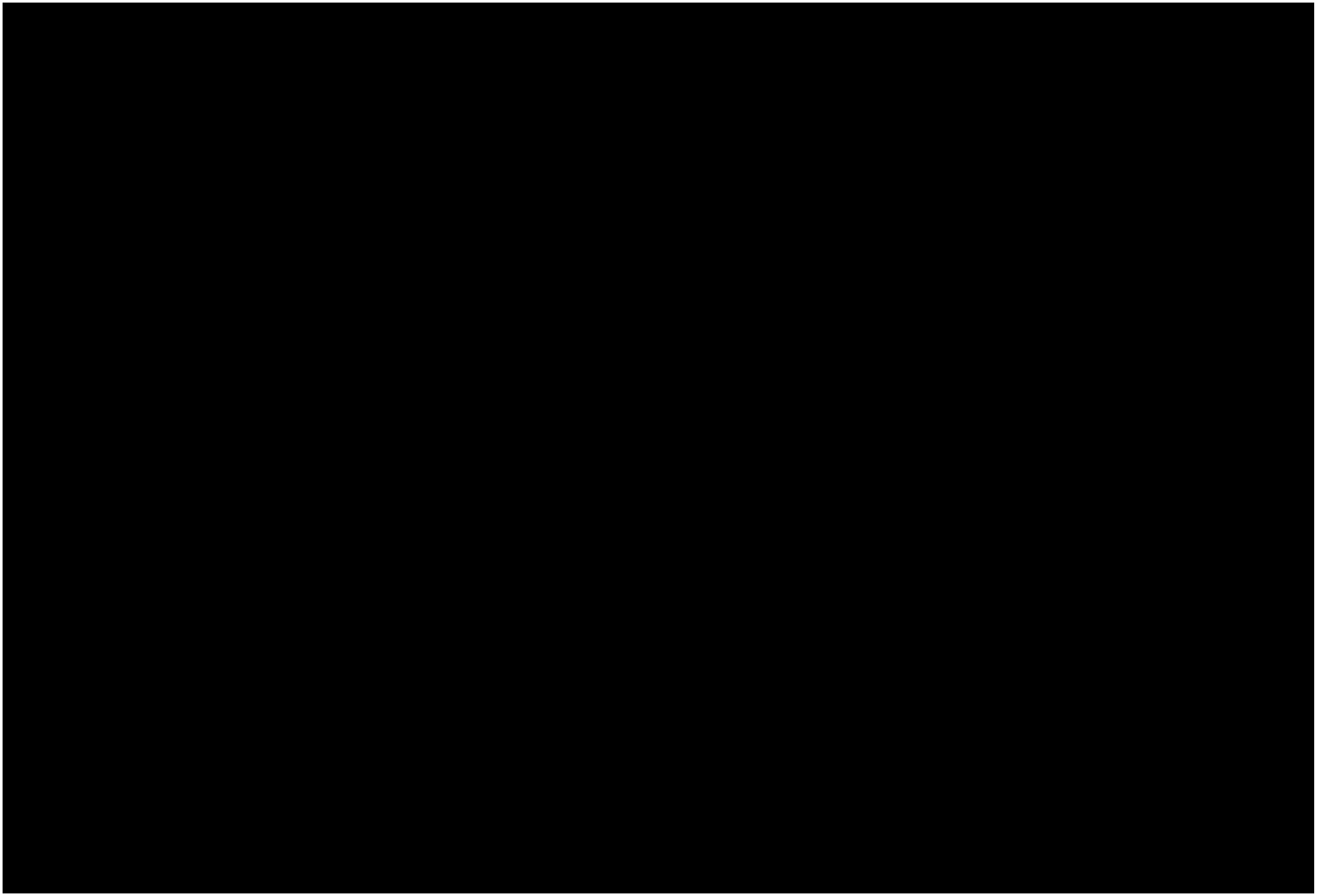
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Sierra Electric Cooperative, Inc.

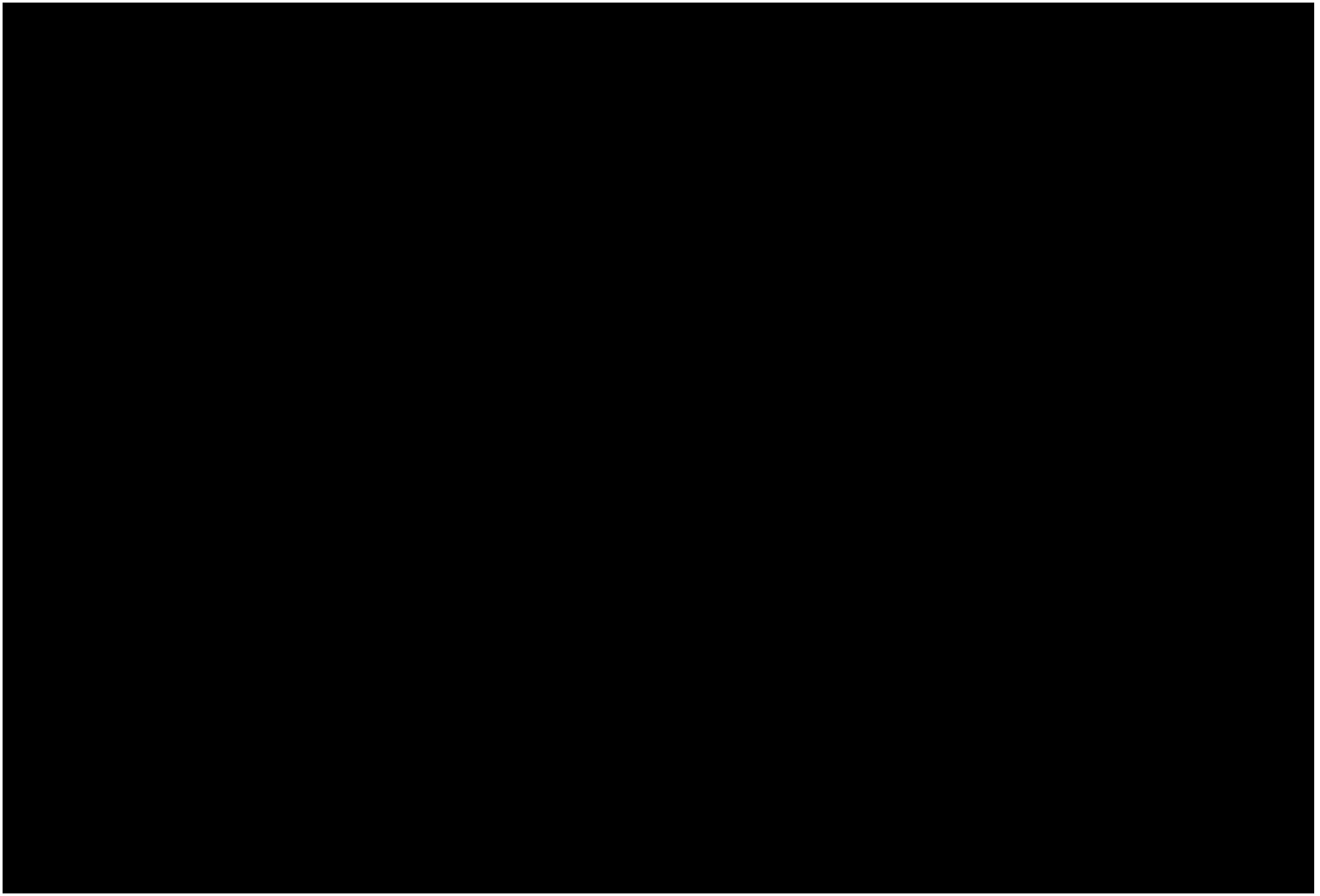
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Sierra Electric Cooperative, Inc.

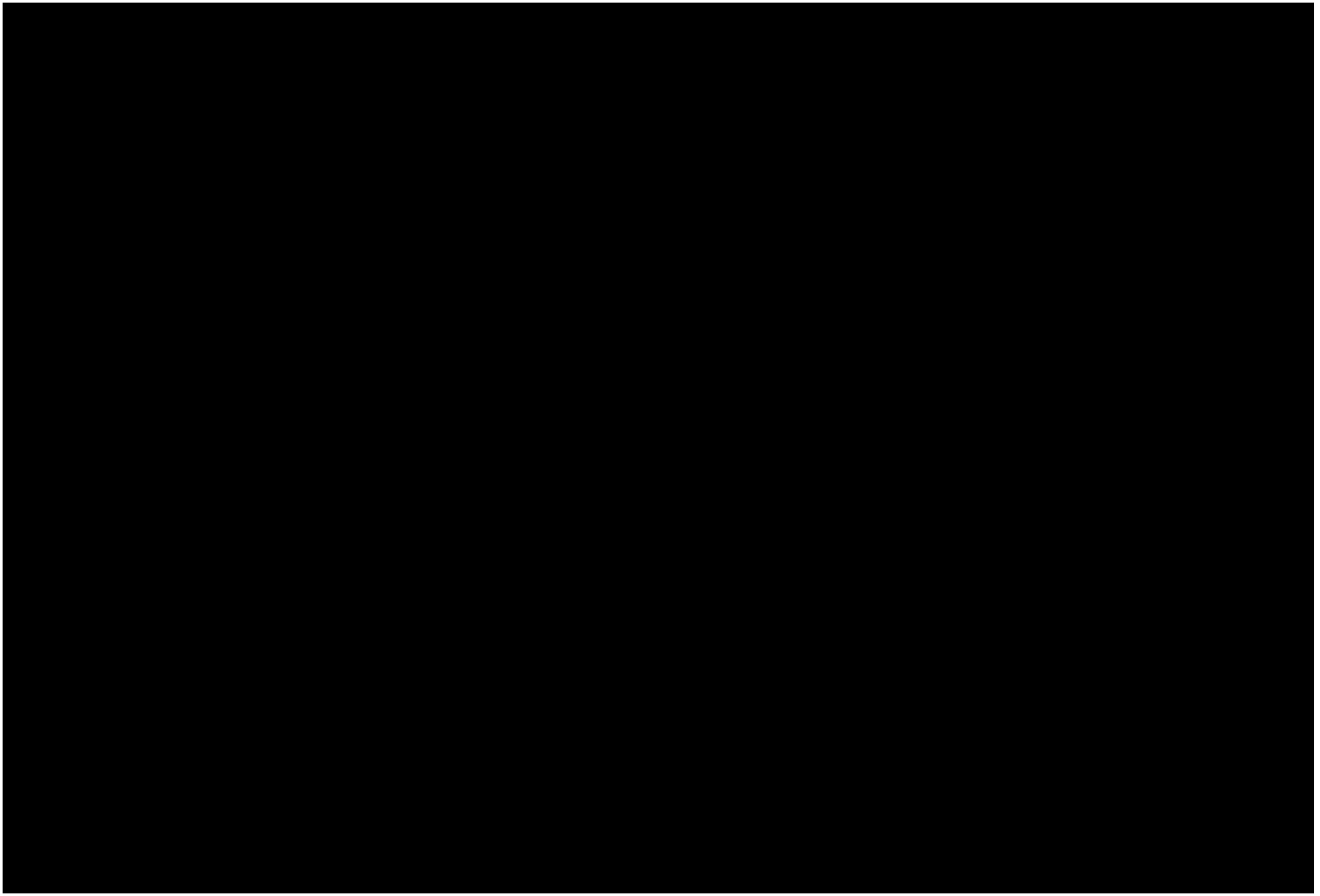
Date of On Peak Day - 04/30/2021



Member Forecasted On Peak Demand Day for May 2021

Sierra Electric Cooperative, Inc.

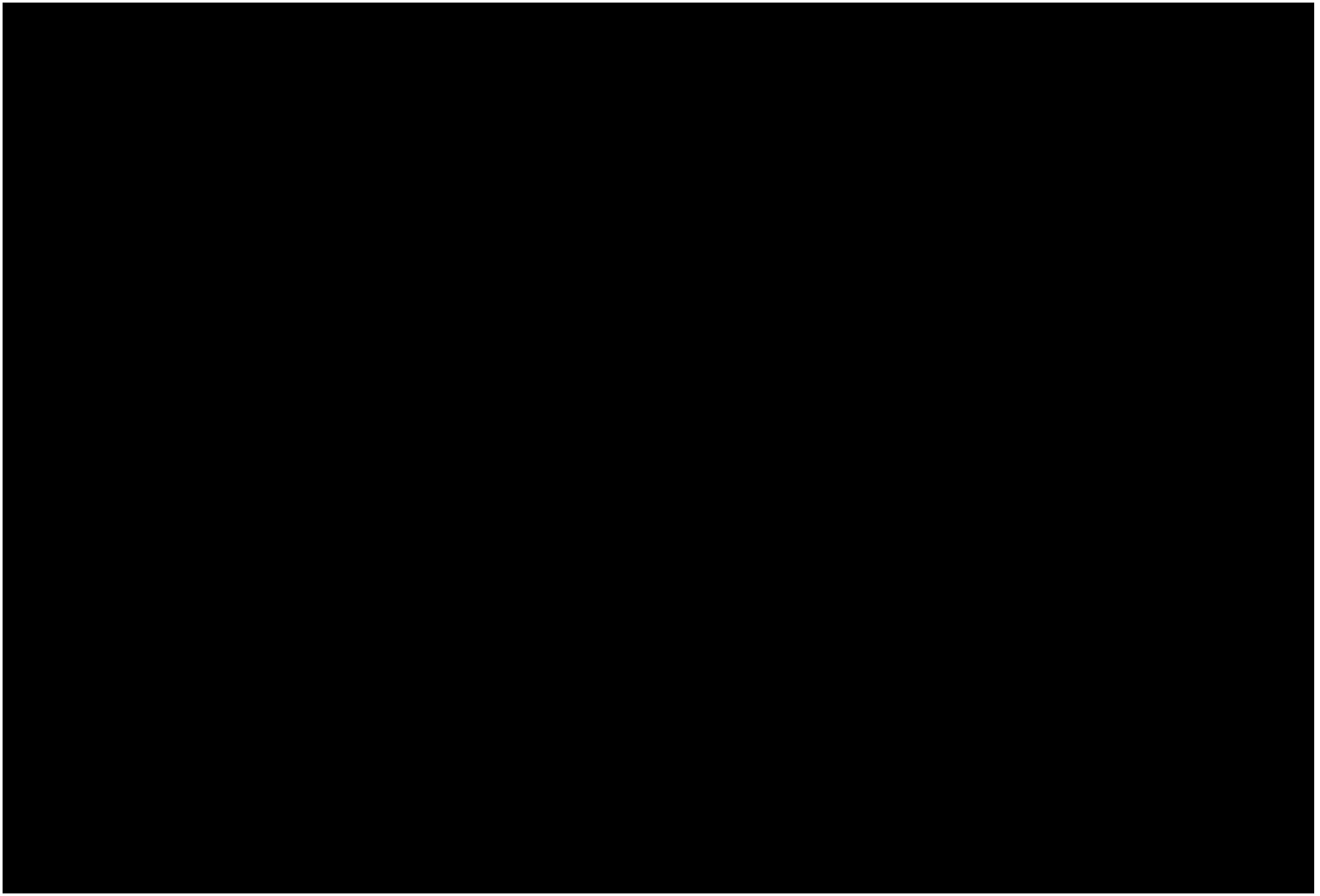
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

Sierra Electric Cooperative, Inc.

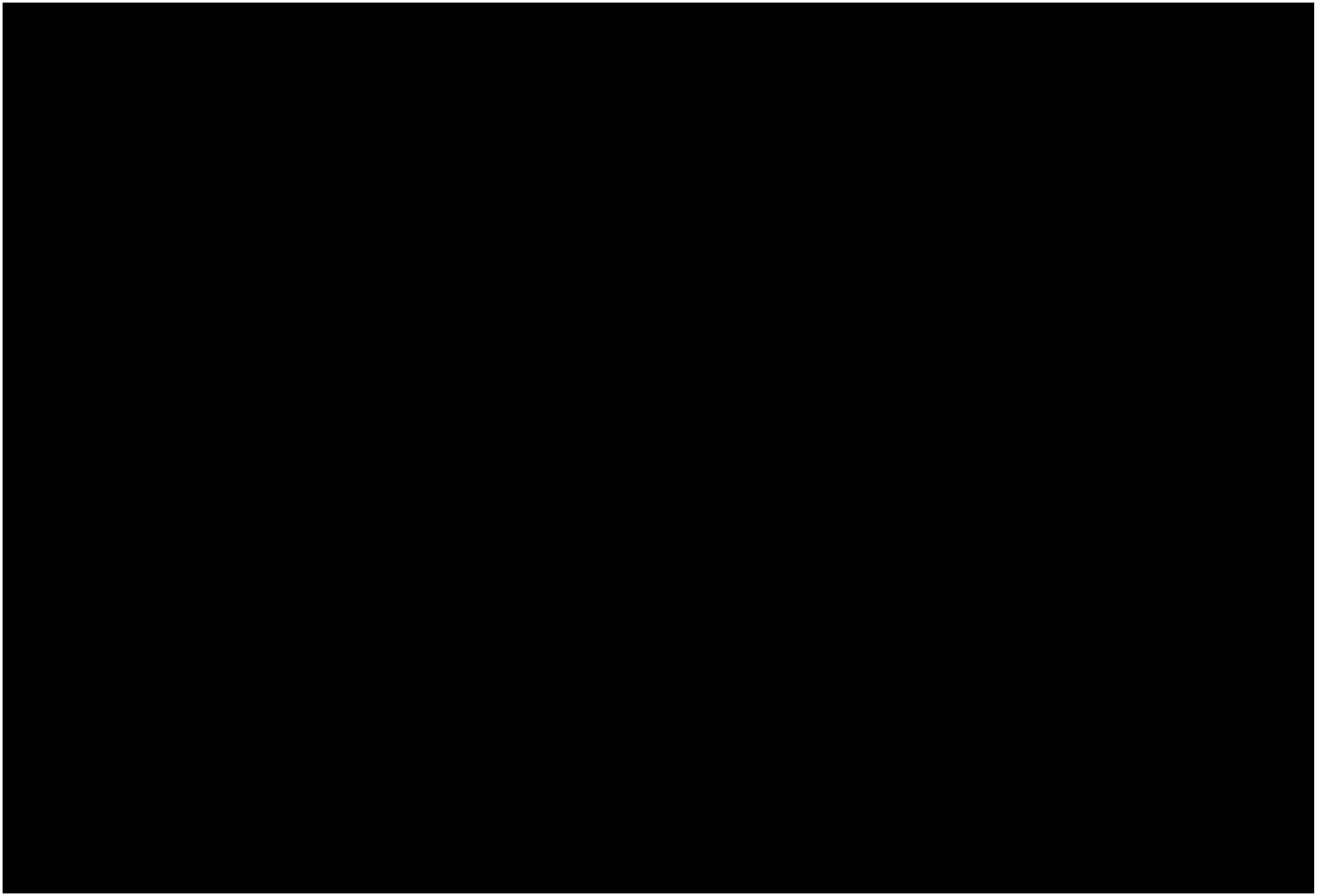
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Sierra Electric Cooperative, Inc.

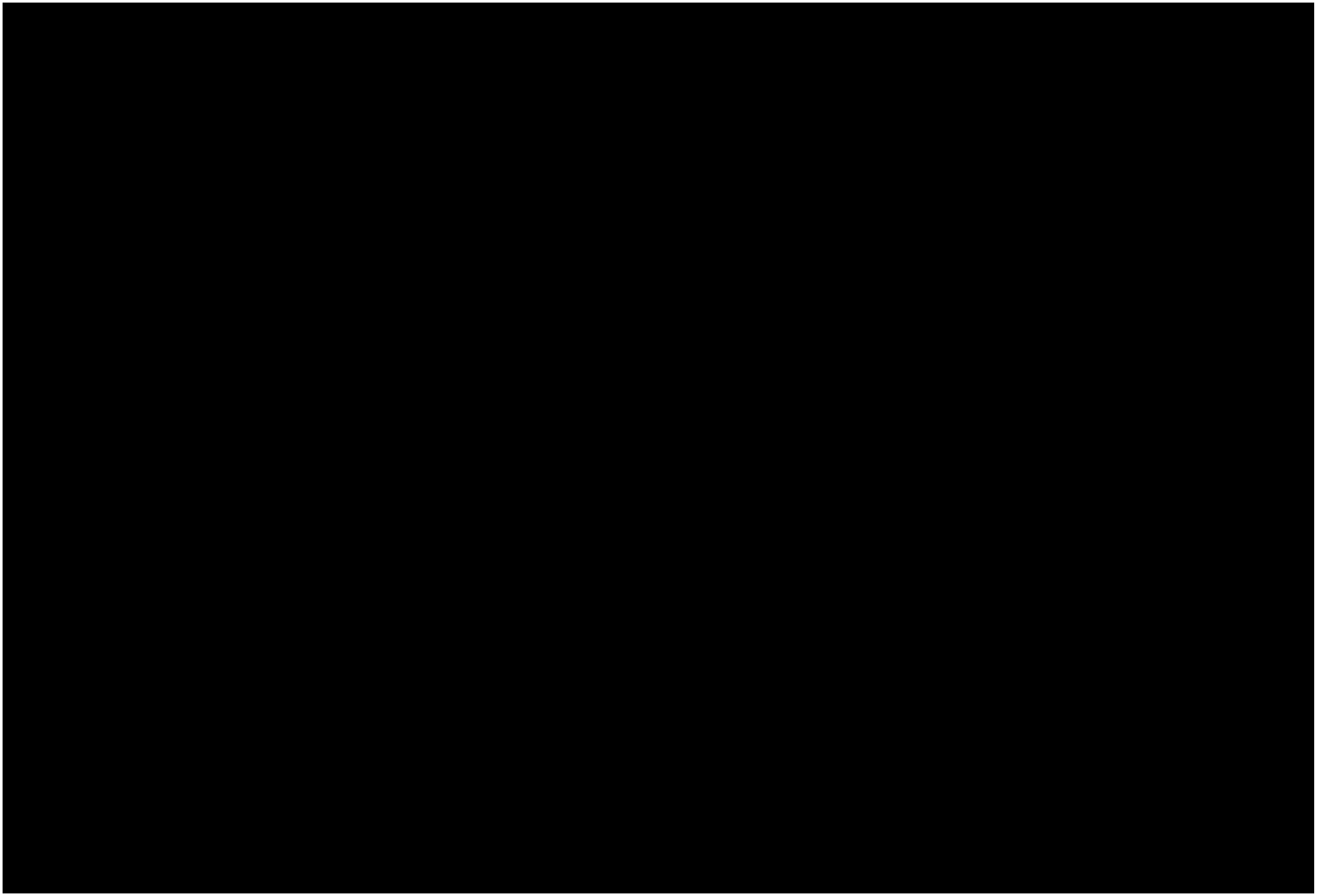
Date of On Peak Day - 07/15/2021



Member Forecasted On Peak Demand Day for August 2021

Sierra Electric Cooperative, Inc.

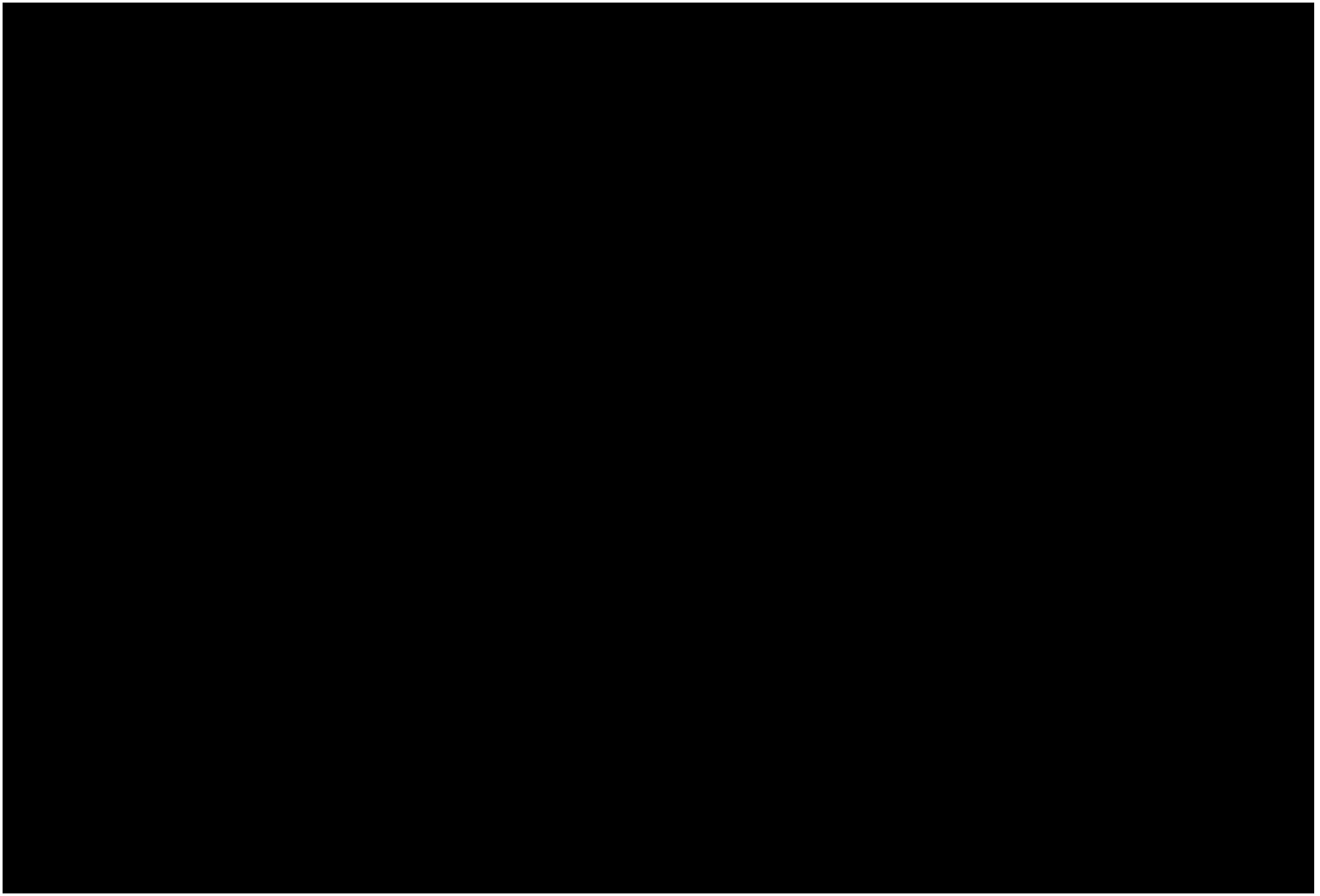
Date of On Peak Day - 08/06/2021



Member Forecasted On Peak Demand Day for September 2021

Sierra Electric Cooperative, Inc.

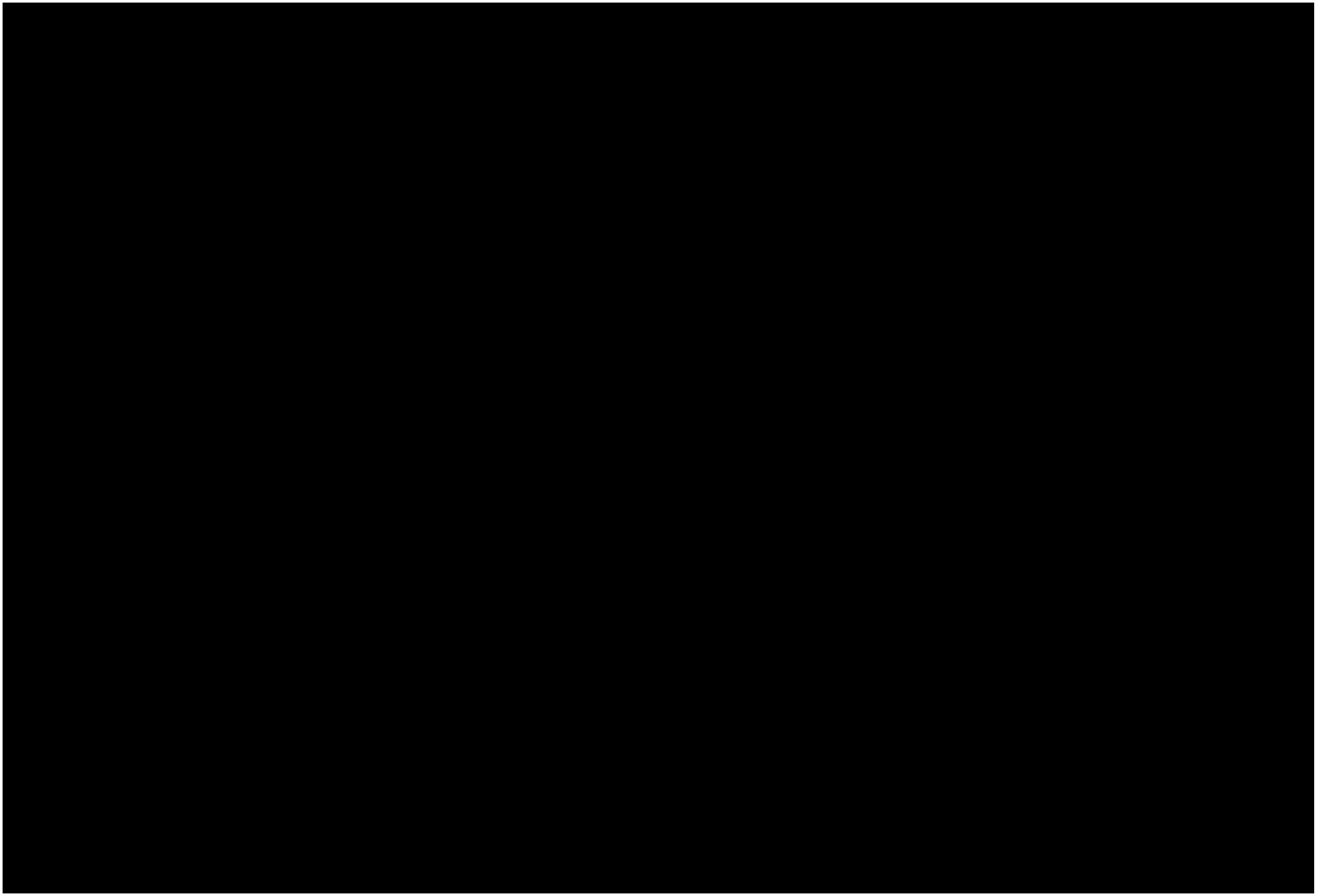
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

Sierra Electric Cooperative, Inc.

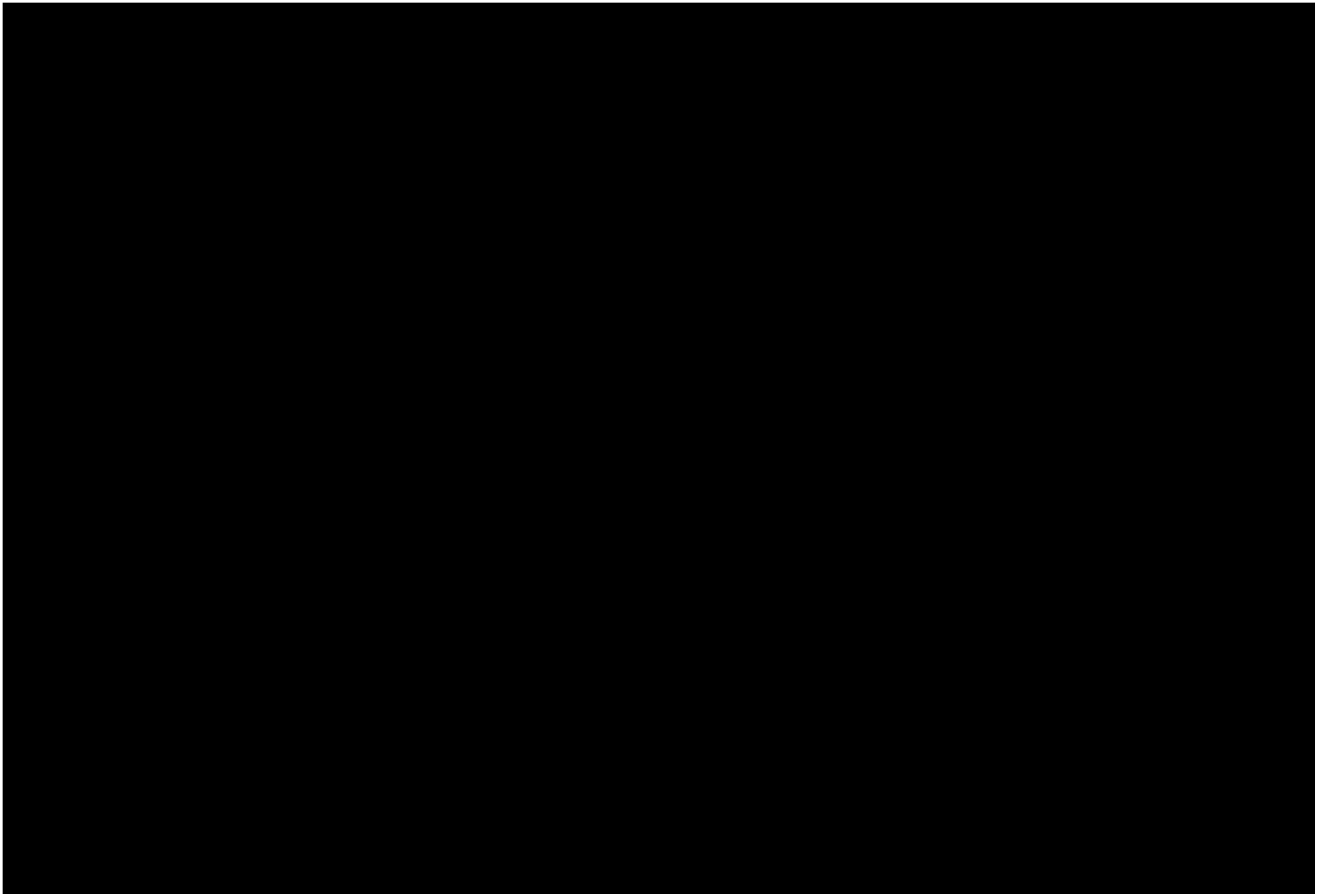
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

Sierra Electric Cooperative, Inc.

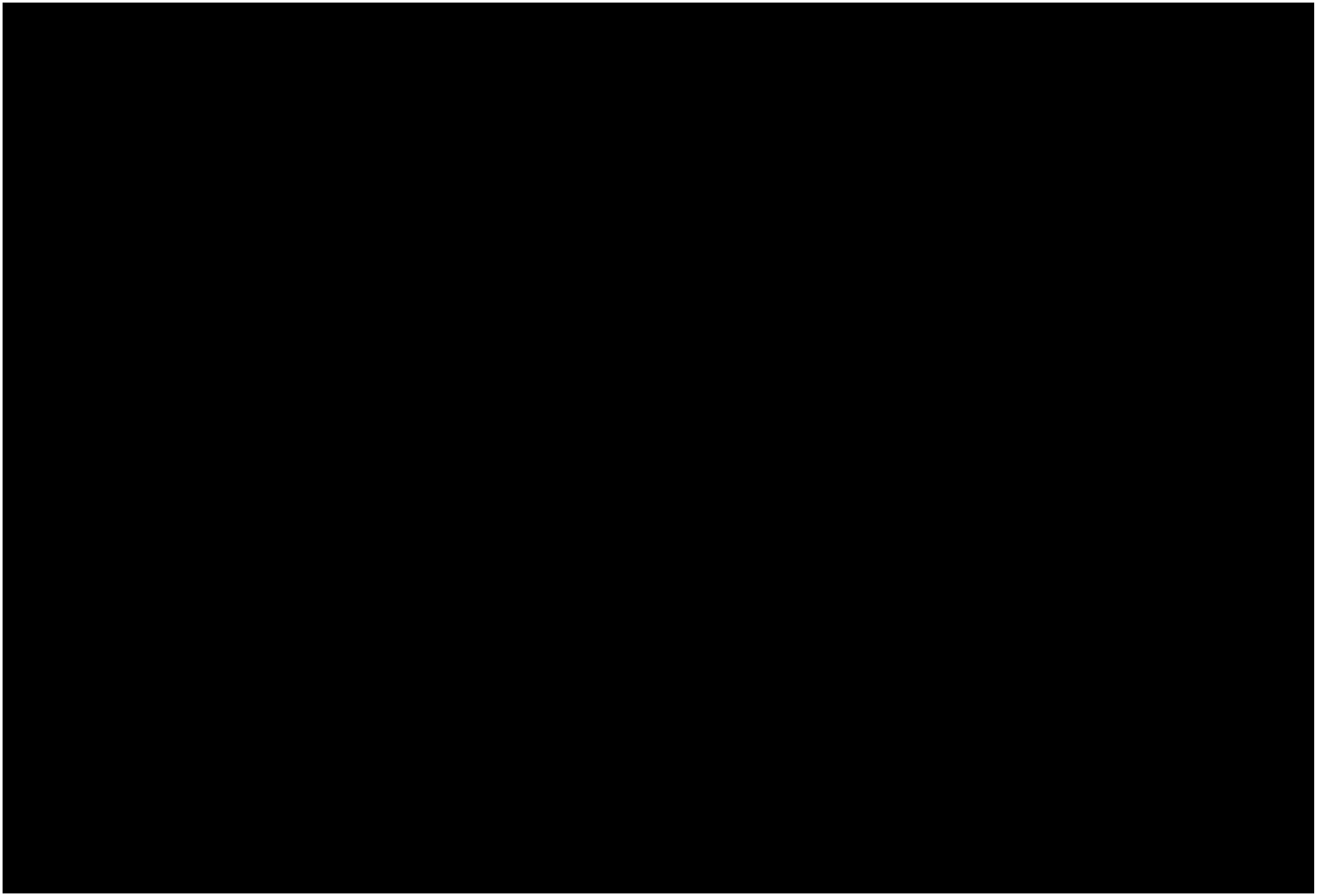
Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Sierra Electric Cooperative, Inc.

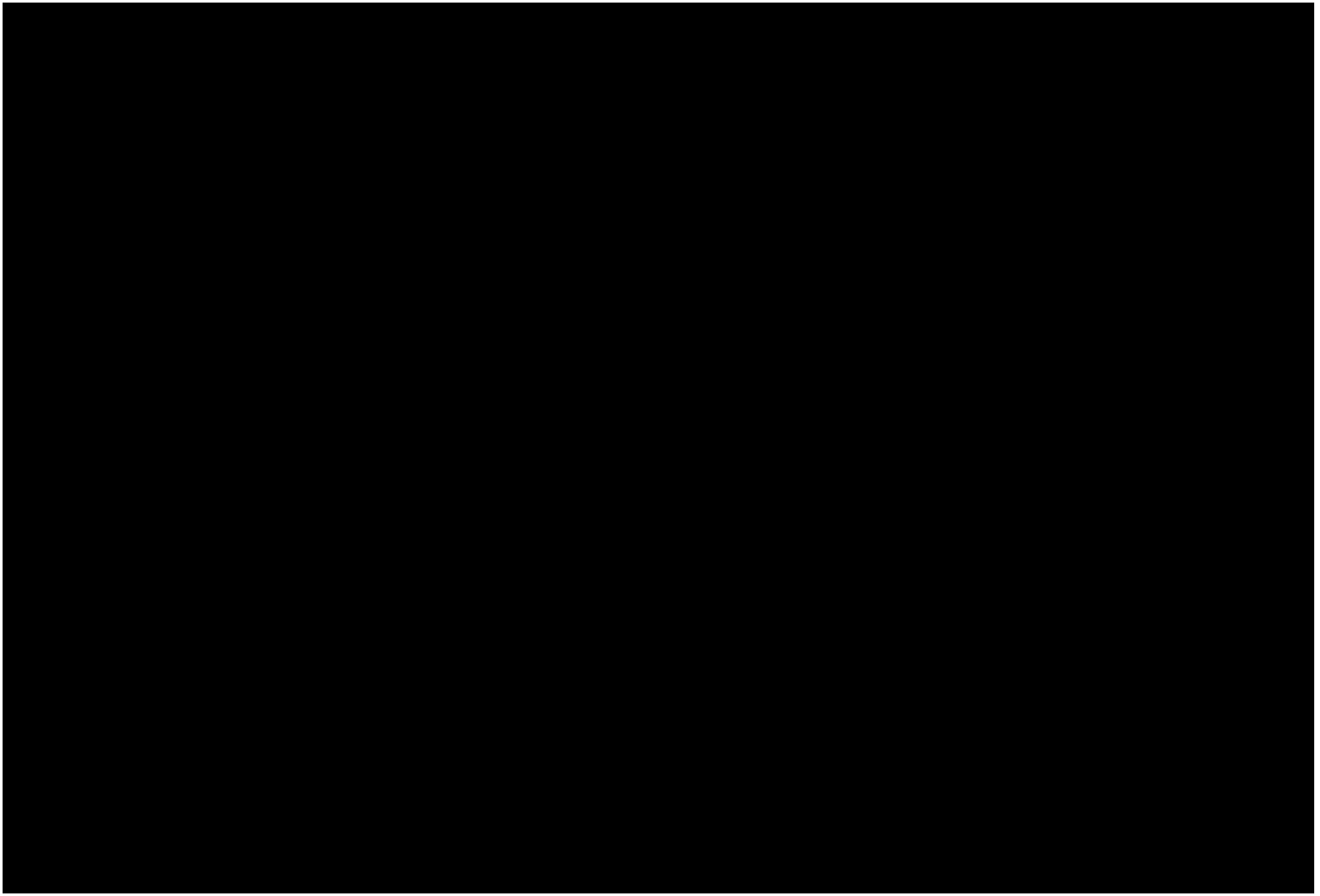
Date of On Peak Day - 12/28/2021



Member Forecasted On Peak Demand Day for January 2021

Sangre de Cristo Electric Association, Inc.

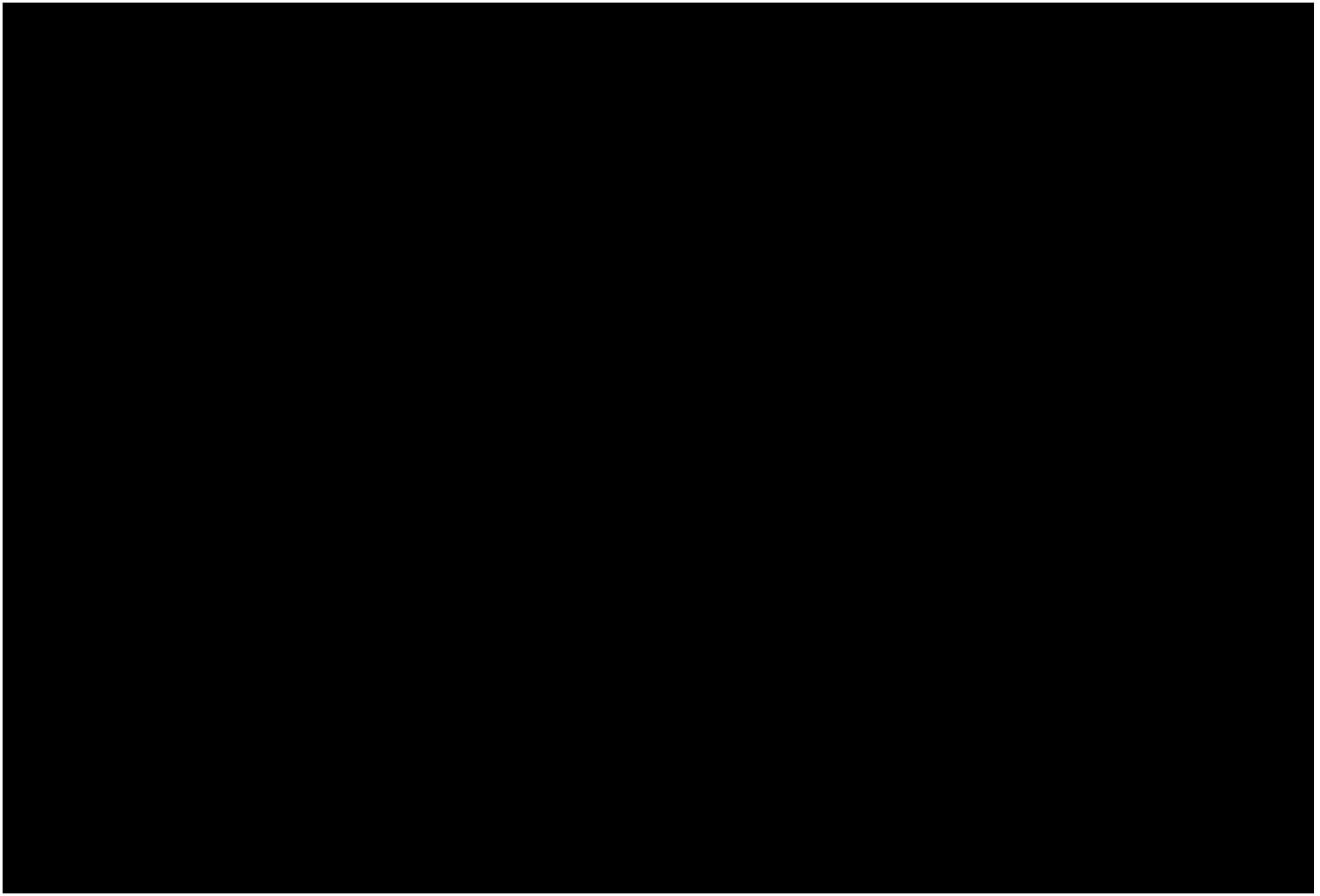
Date of On Peak Day - 01/27/2021



Member Forecasted On Peak Demand Day for February 2021

Sangre de Cristo Electric Association, Inc.

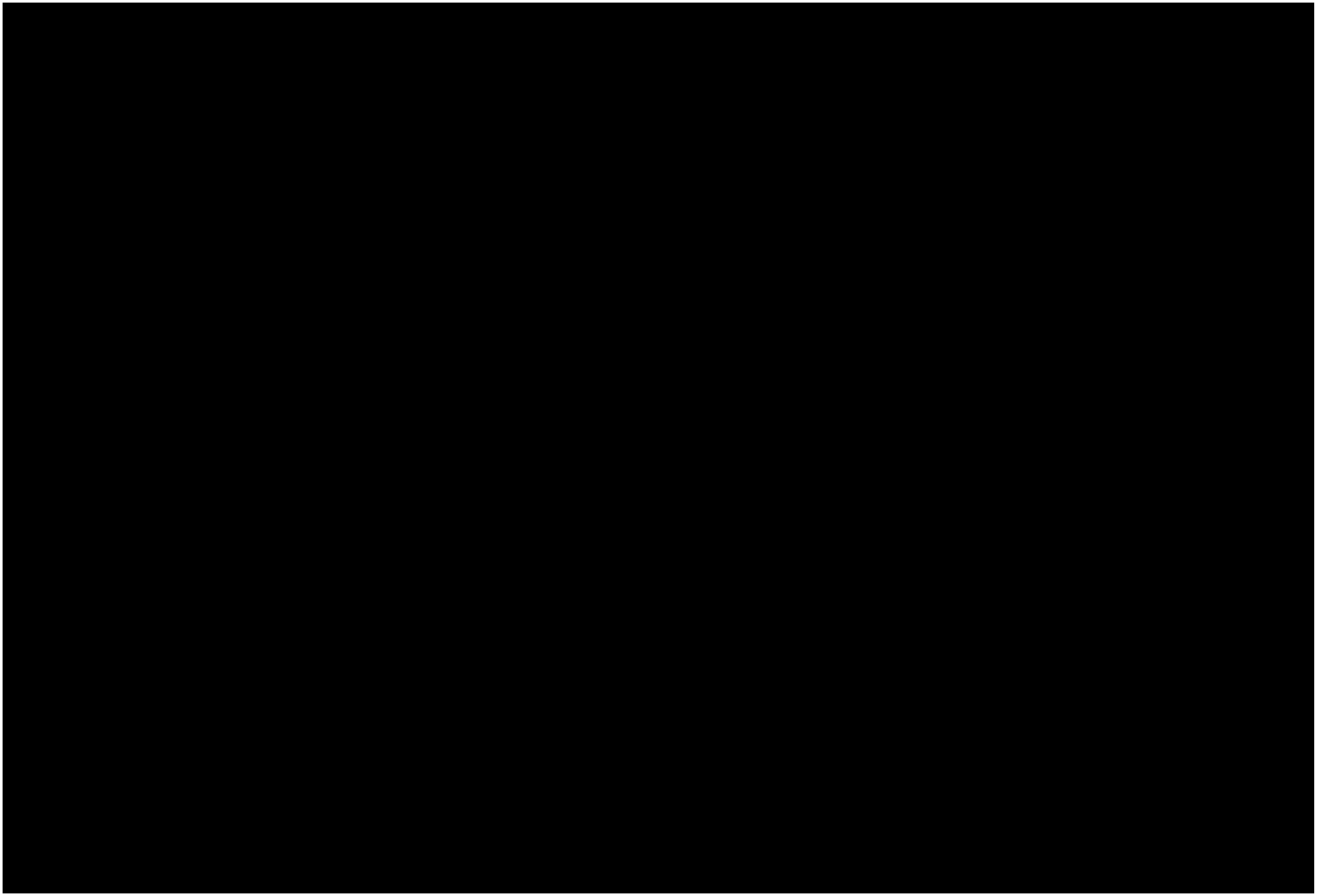
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Sangre de Cristo Electric Association, Inc.

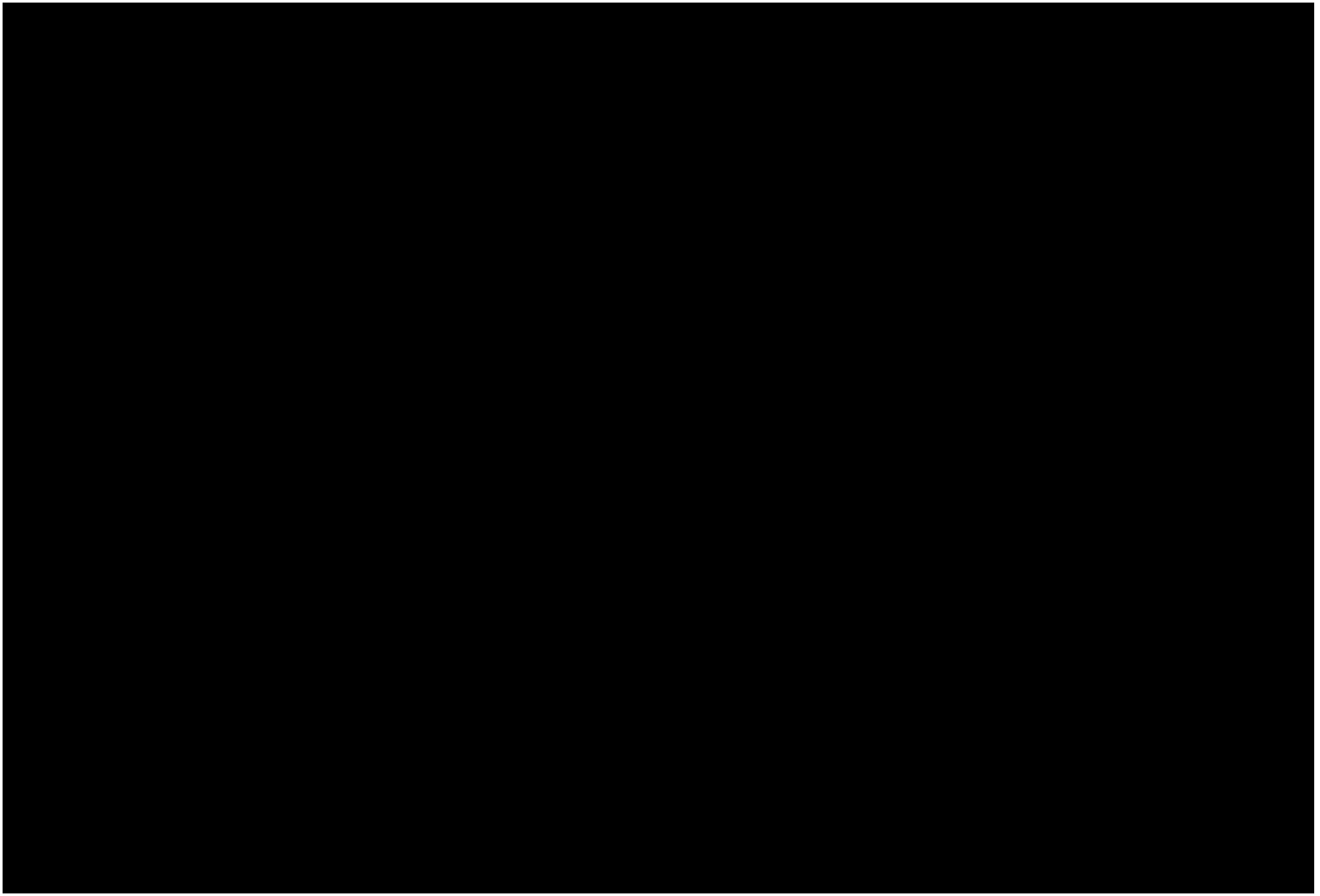
Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Sangre de Cristo Electric Association, Inc.

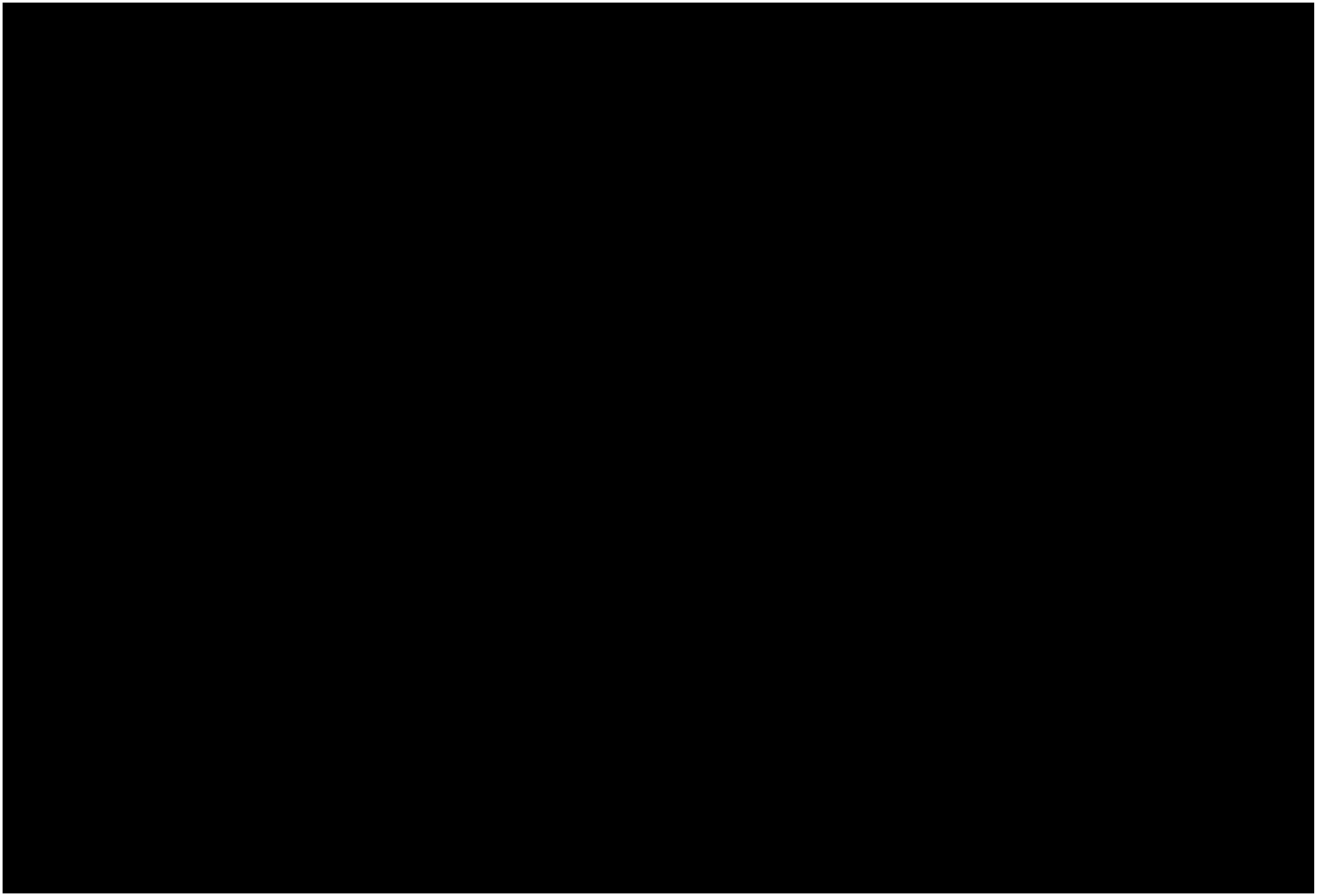
Date of On Peak Day - 04/16/2021



Member Forecasted On Peak Demand Day for May 2021

Sangre de Cristo Electric Association, Inc.

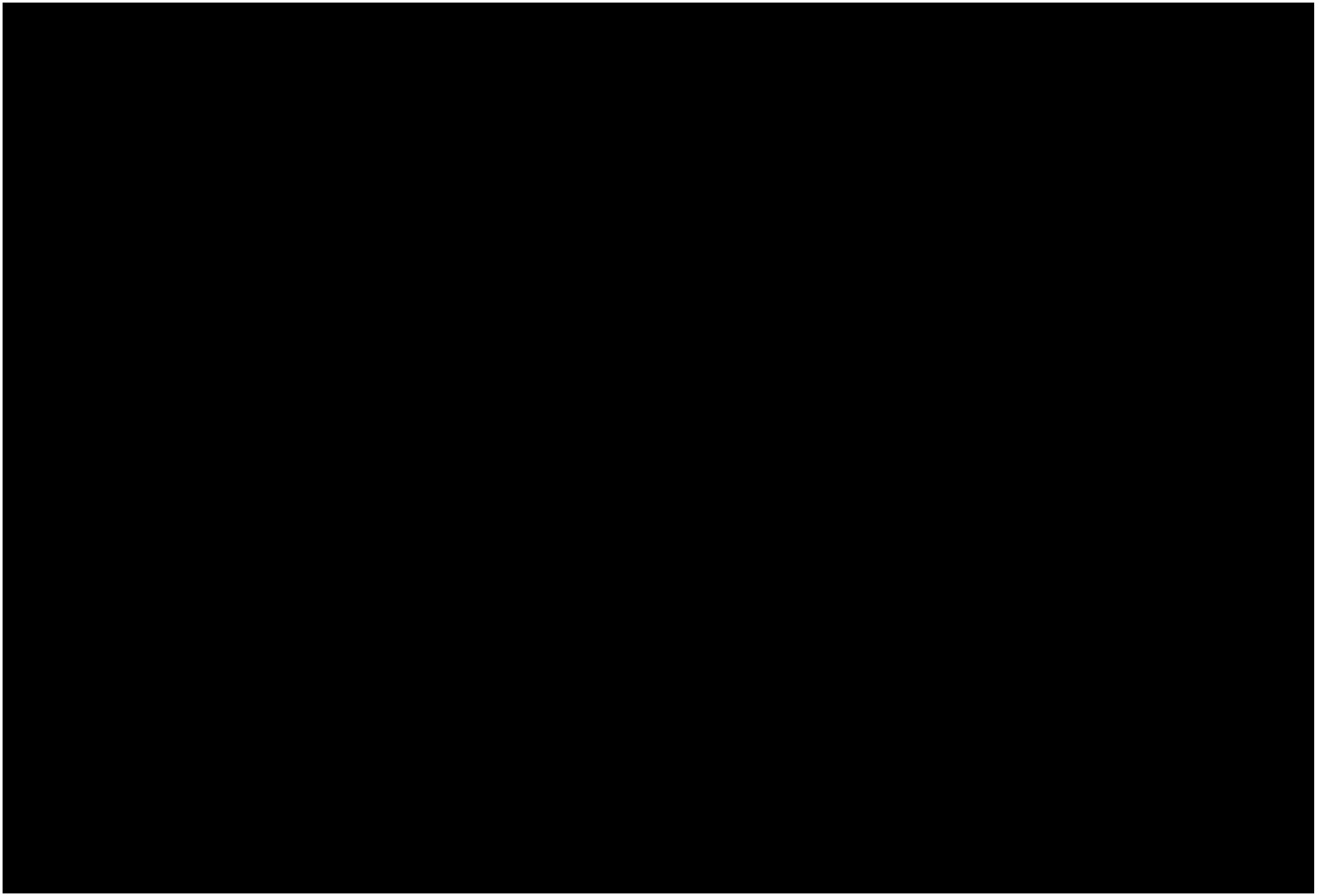
Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

Sangre de Cristo Electric Association, Inc.

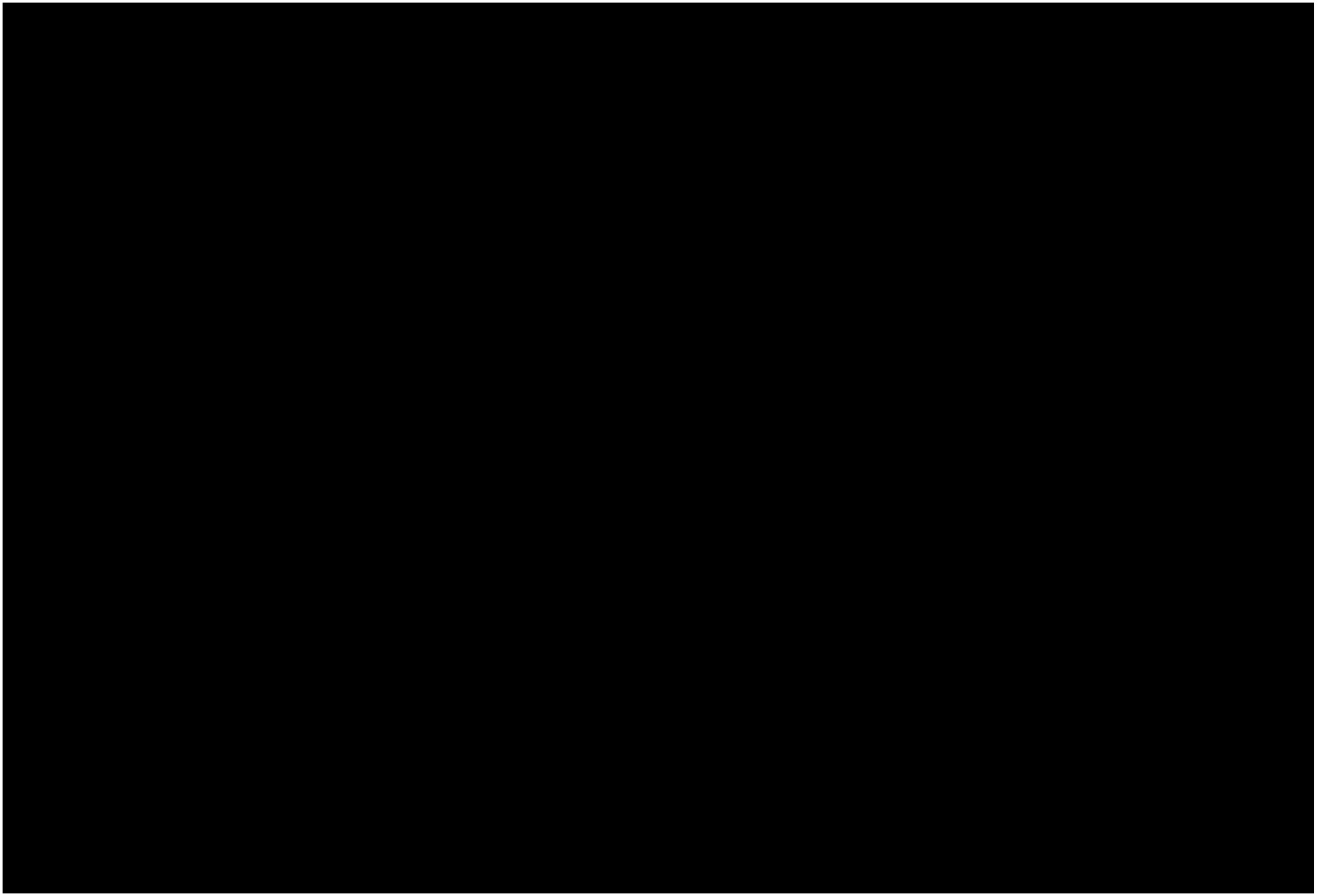
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Sangre de Cristo Electric Association, Inc.

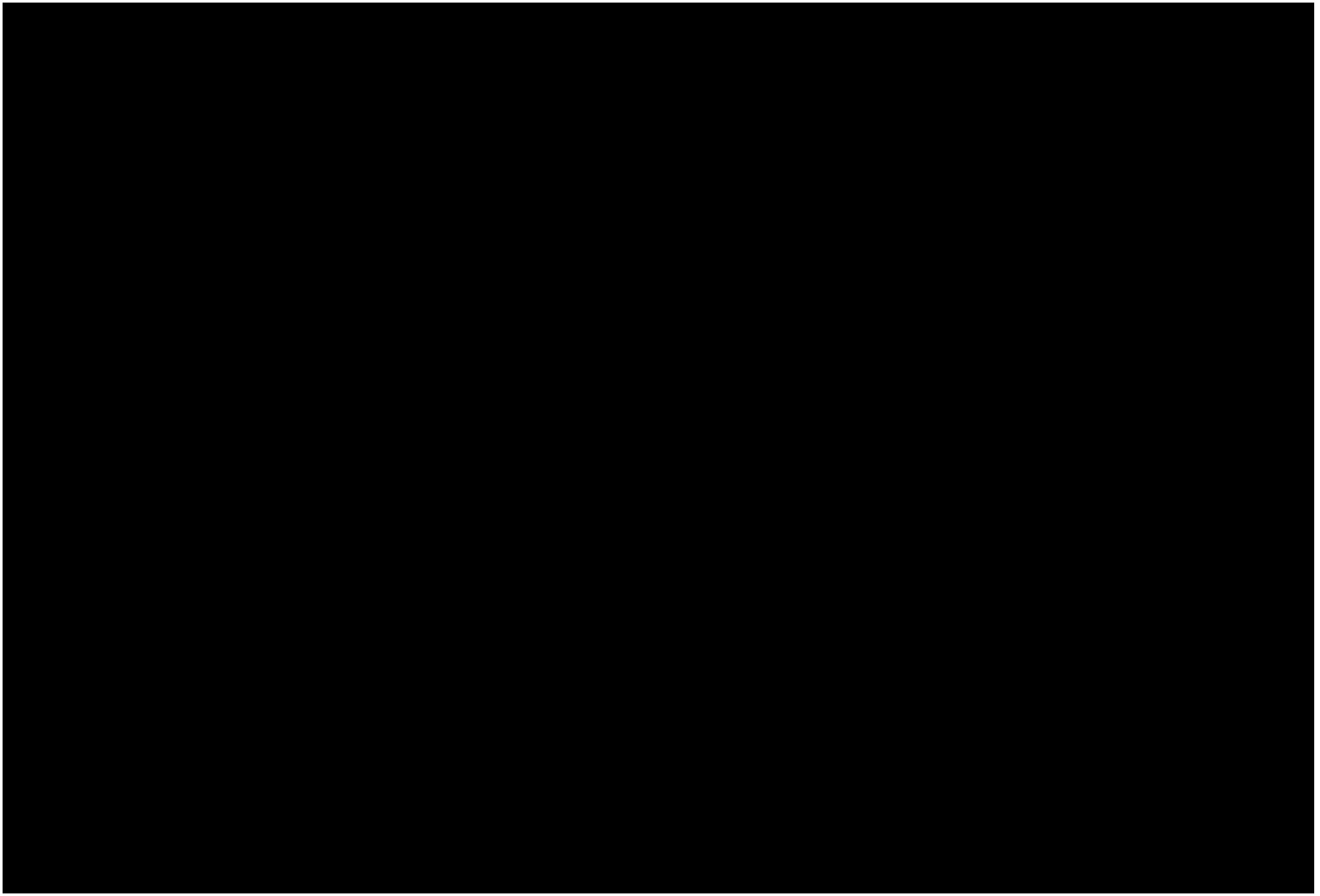
Date of On Peak Day - 07/28/2021



Member Forecasted On Peak Demand Day for August 2021

Sangre de Cristo Electric Association, Inc.

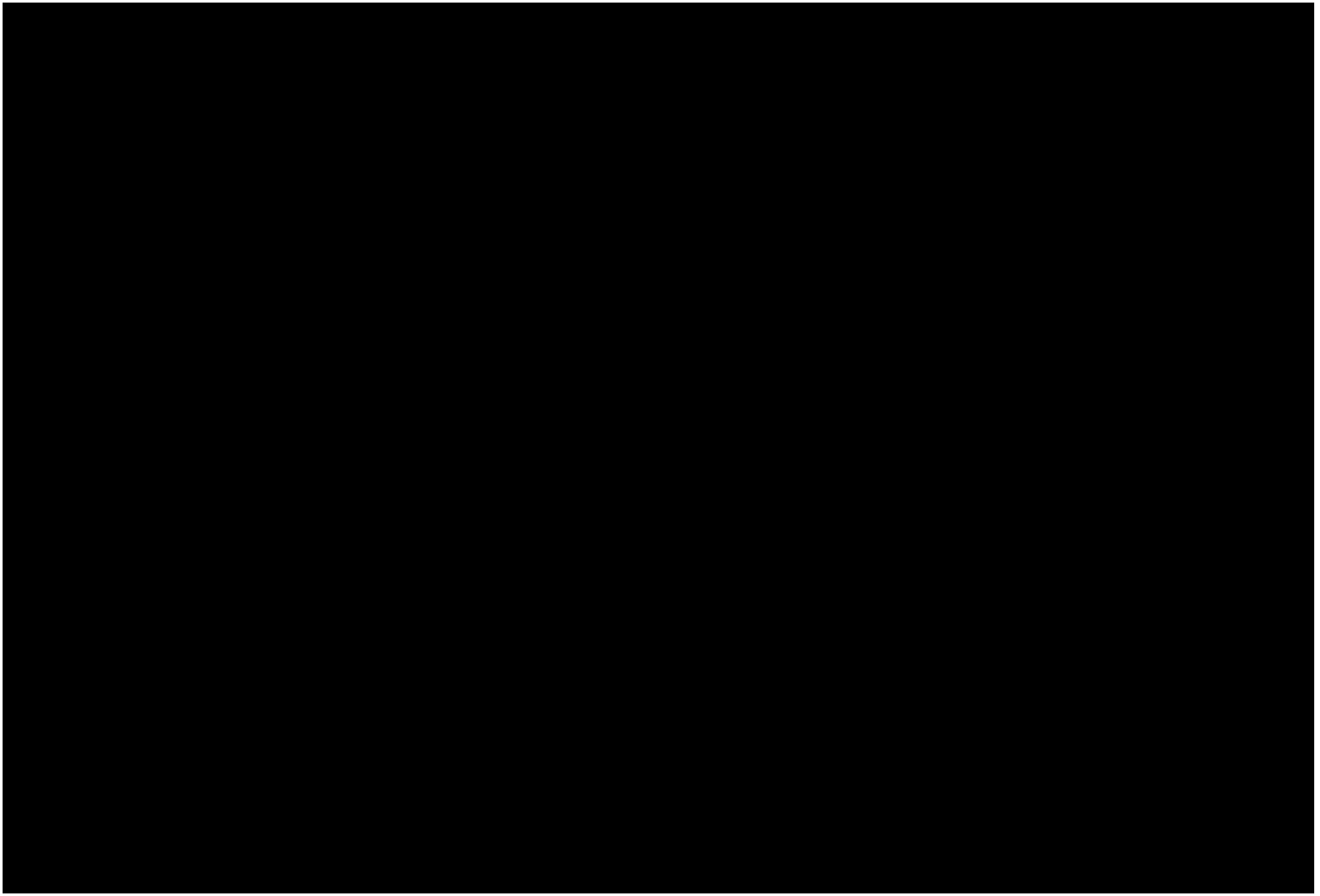
Date of On Peak Day - 08/07/2021



Member Forecasted On Peak Demand Day for September 2021

Sangre de Cristo Electric Association, Inc.

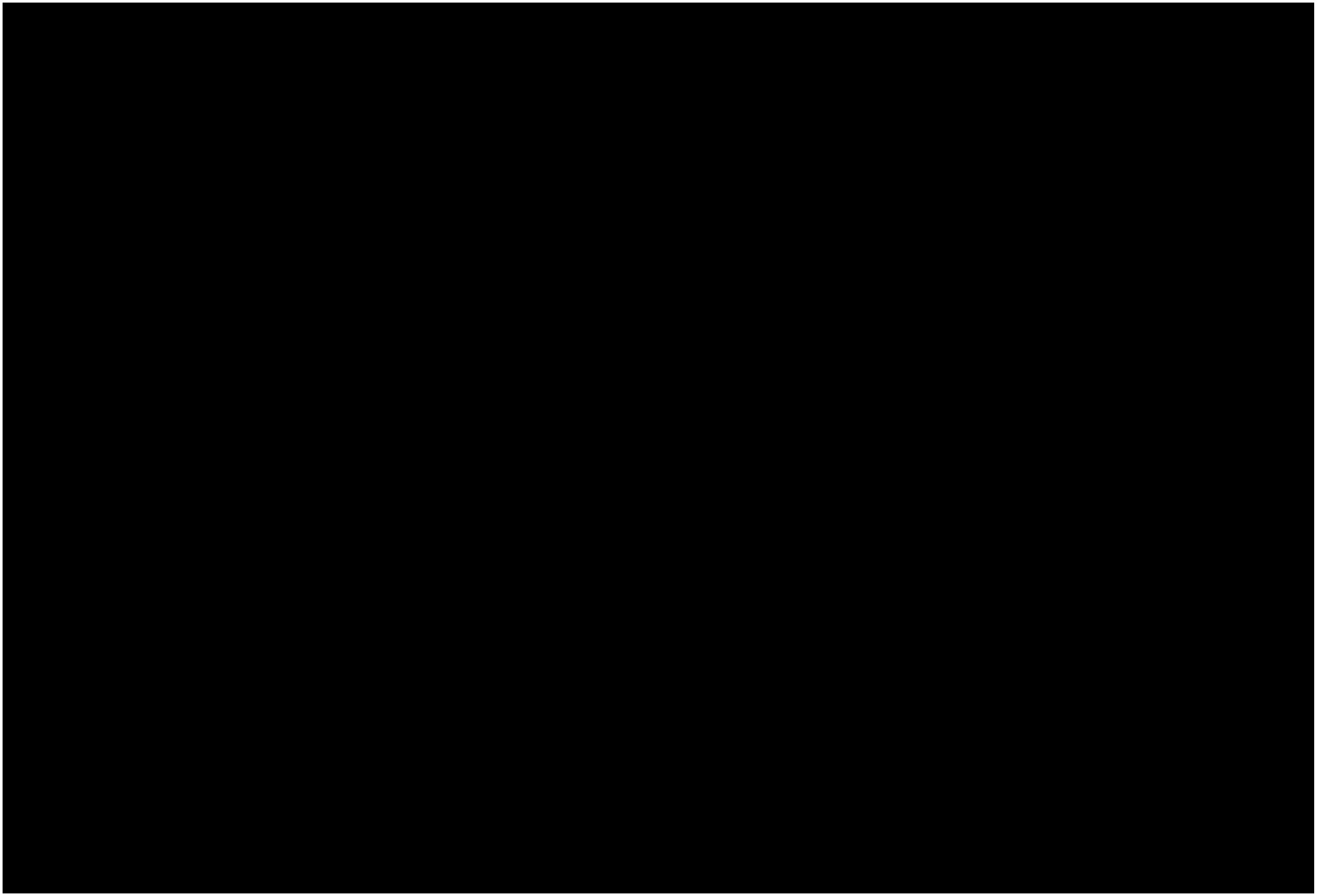
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Sangre de Cristo Electric Association, Inc.

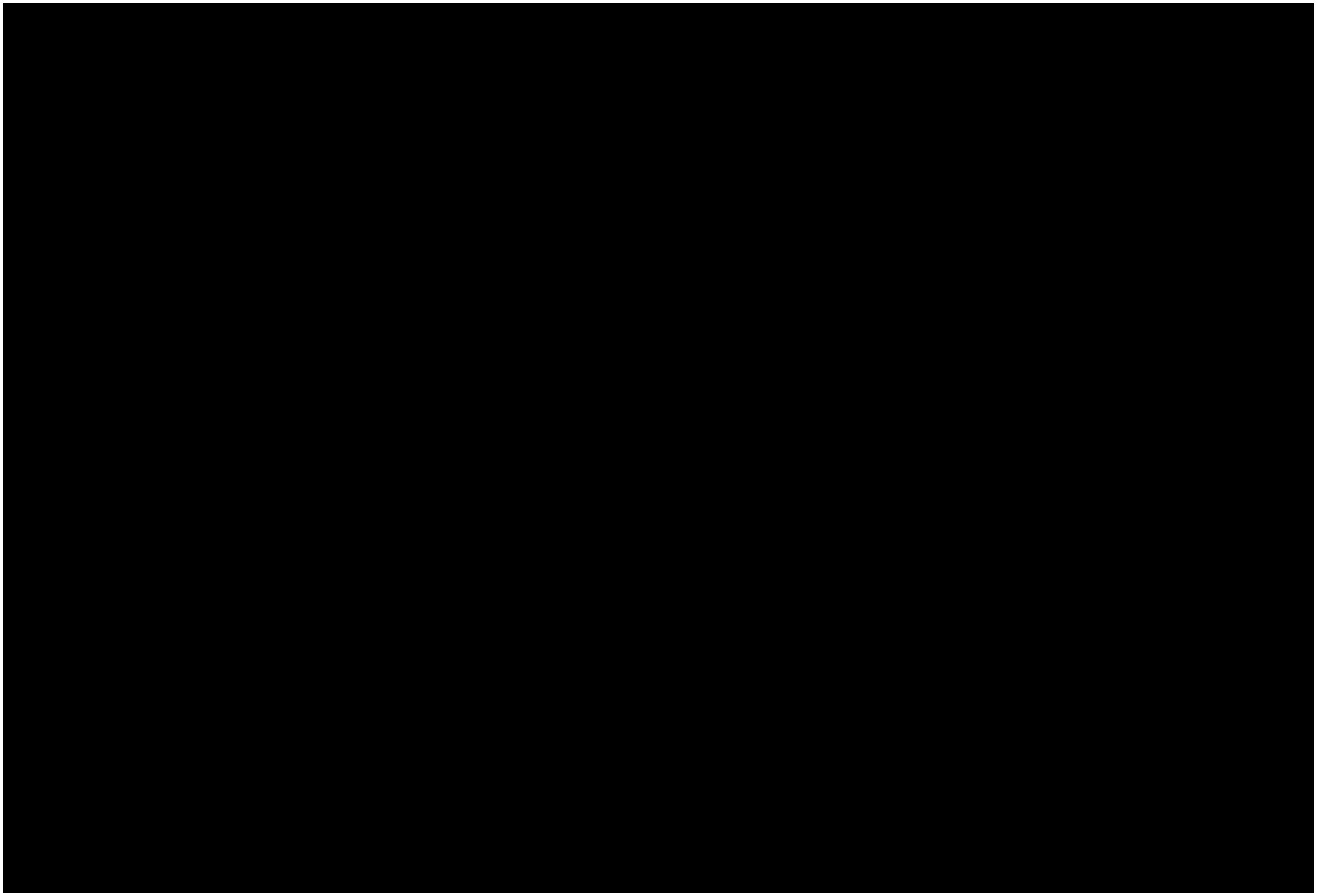
Date of On Peak Day - 10/27/2021



Member Forecasted On Peak Demand Day for November 2021

Sangre de Cristo Electric Association, Inc.

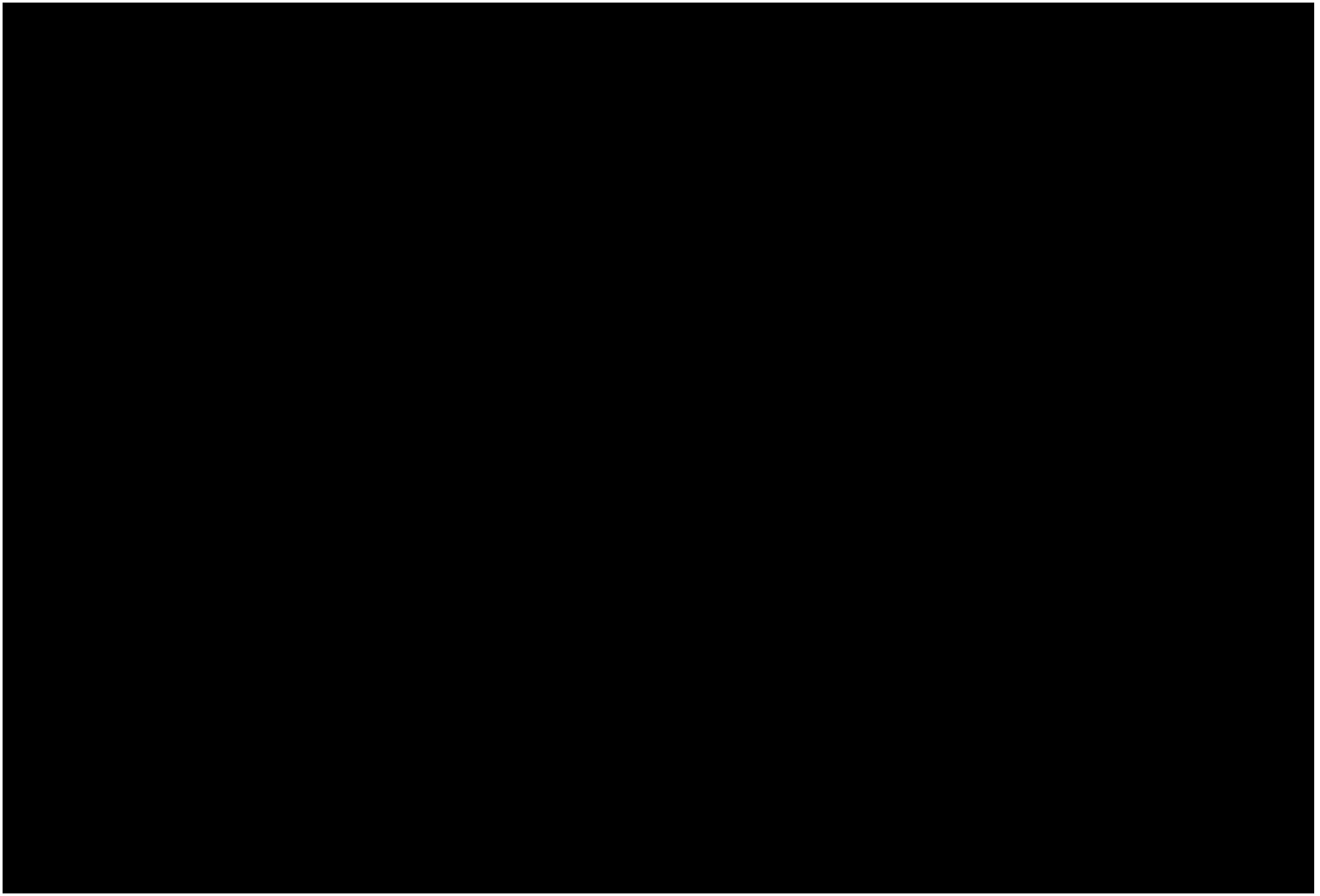
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Sangre de Cristo Electric Association, Inc.

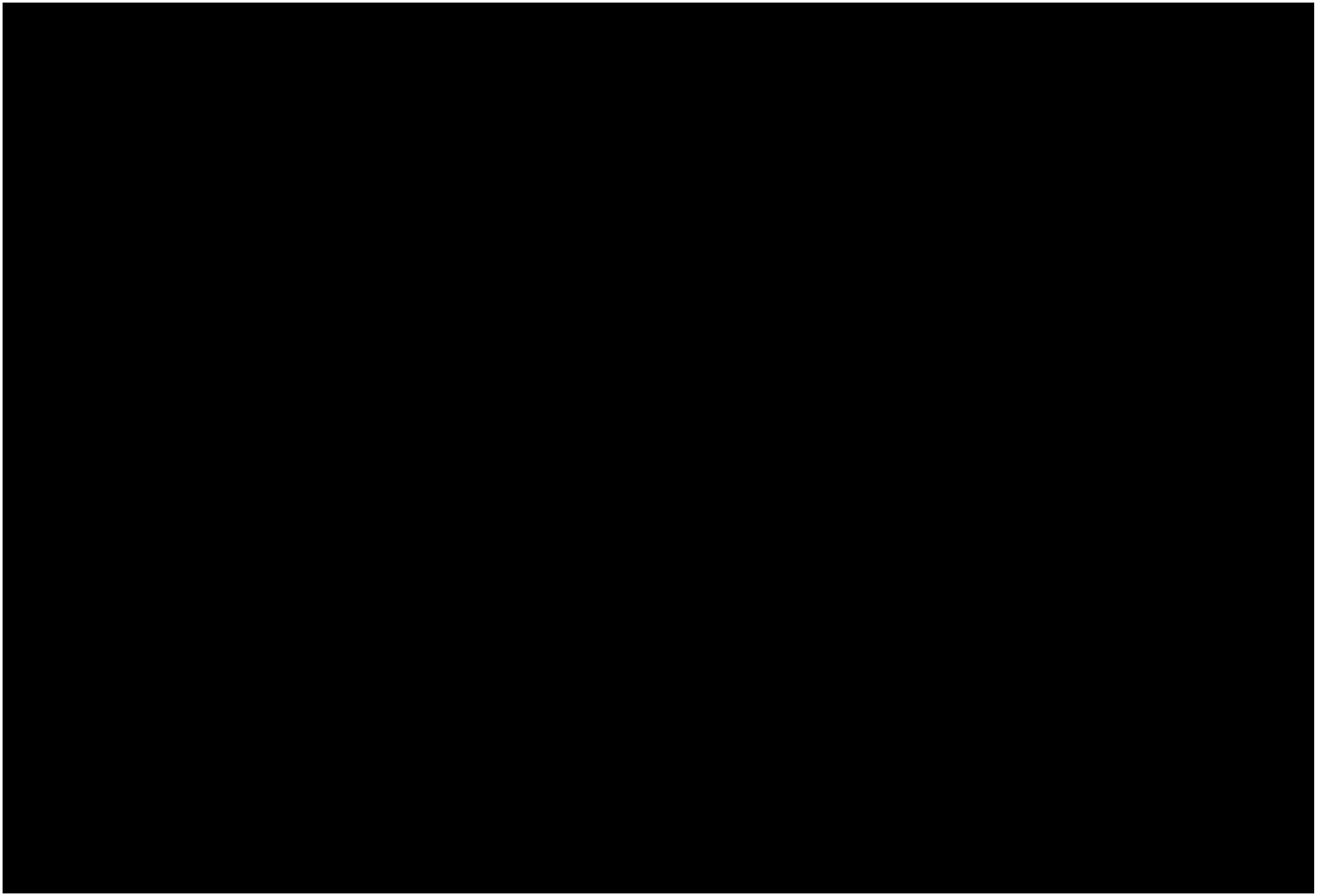
Date of On Peak Day - 12/30/2021



Member Forecasted On Peak Demand Day for January 2021

Southeast Colorado Power Association

Date of On Peak Day - 01/03/2021



Member Forecasted On Peak Demand Day for February 2021

Southeast Colorado Power Association

Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Southeast Colorado Power Association

Date of On Peak Day - 03/30/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

Southeast Colorado Power Association

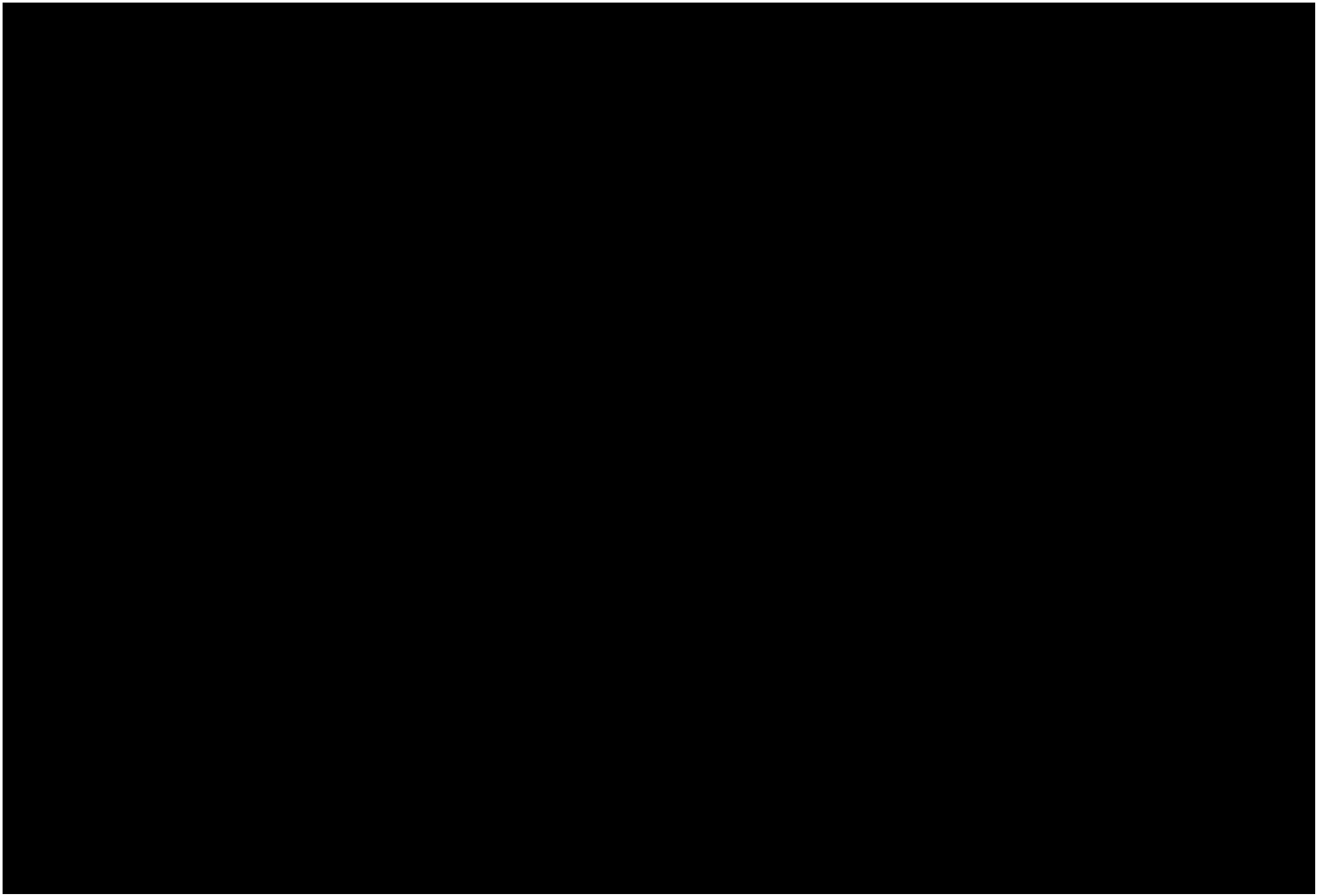
Date of On Peak Day - 04/13/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Southeast Colorado Power Association

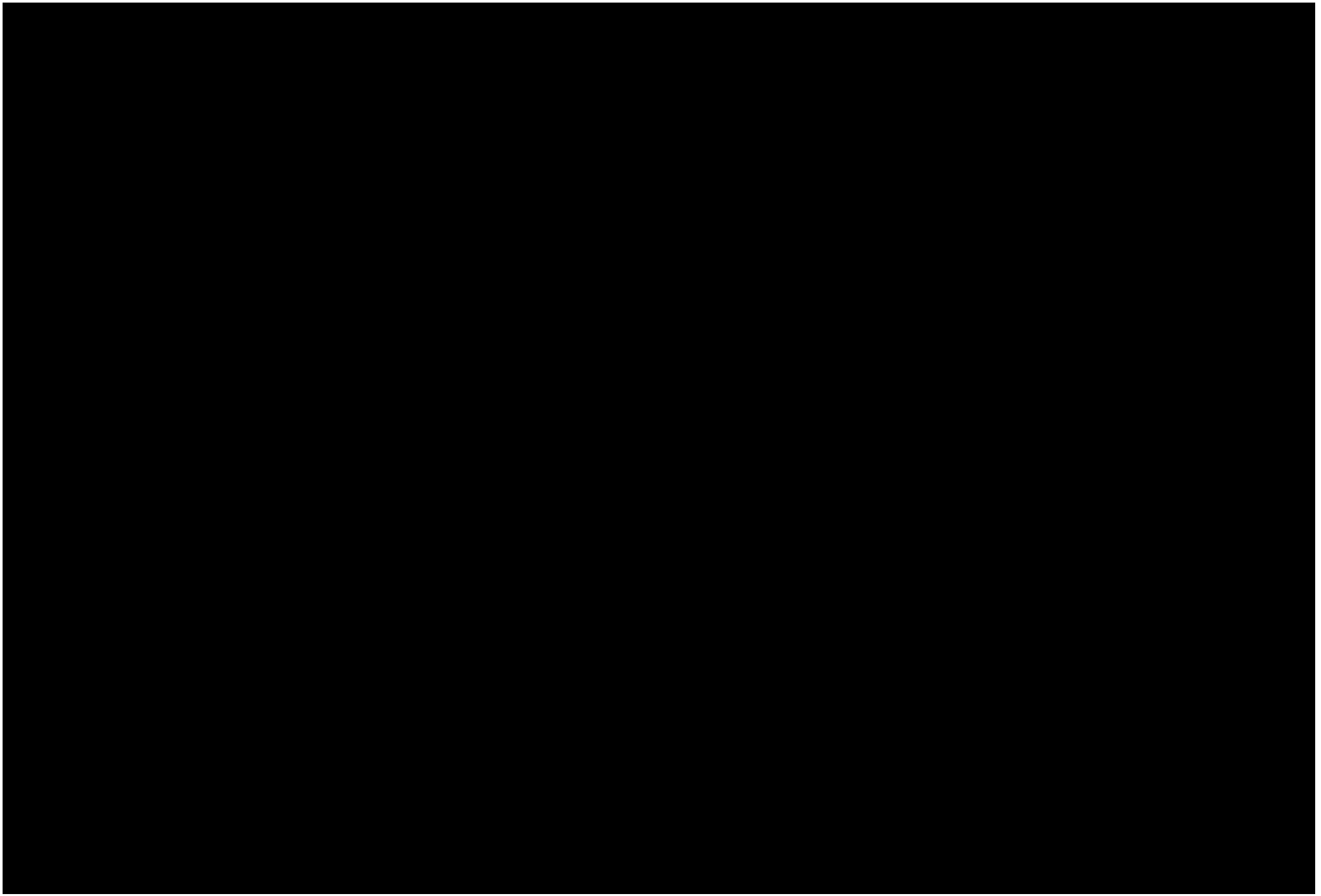
Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

Southeast Colorado Power Association

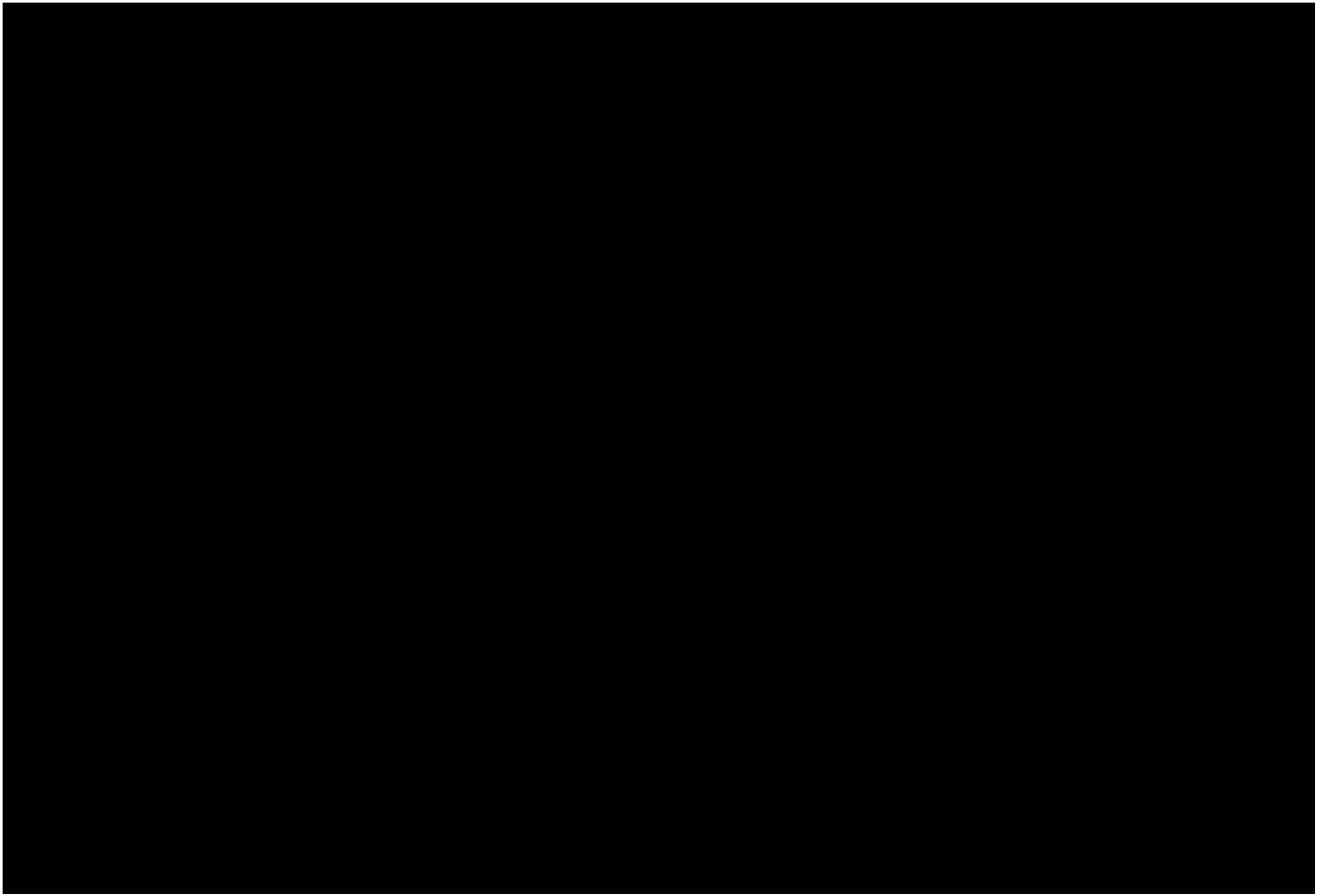
Date of On Peak Day - 06/15/2021



Member Forecasted On Peak Demand Day for July 2021

Southeast Colorado Power Association

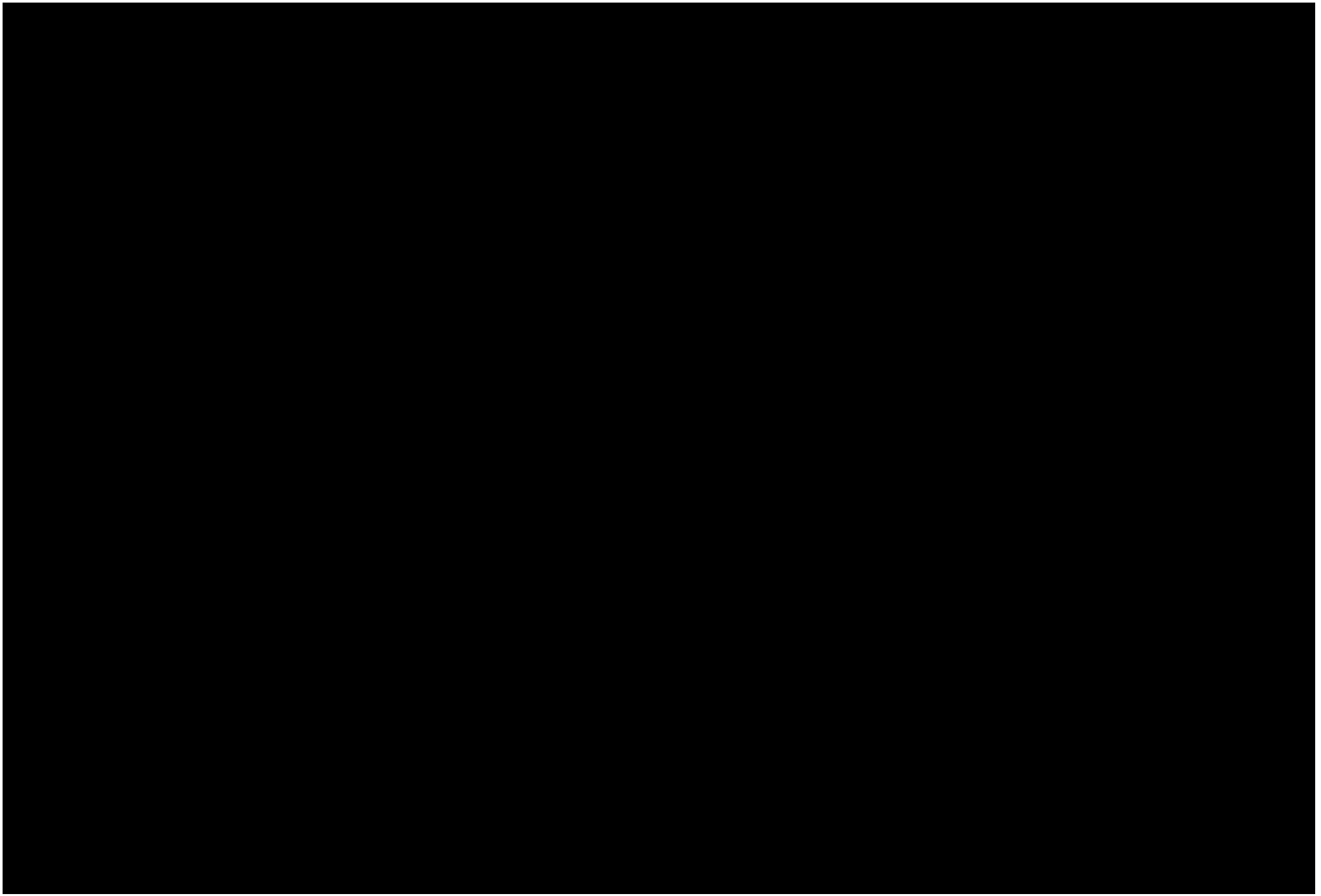
Date of On Peak Day - 07/21/2021



Member Forecasted On Peak Demand Day for August 2021

Southeast Colorado Power Association

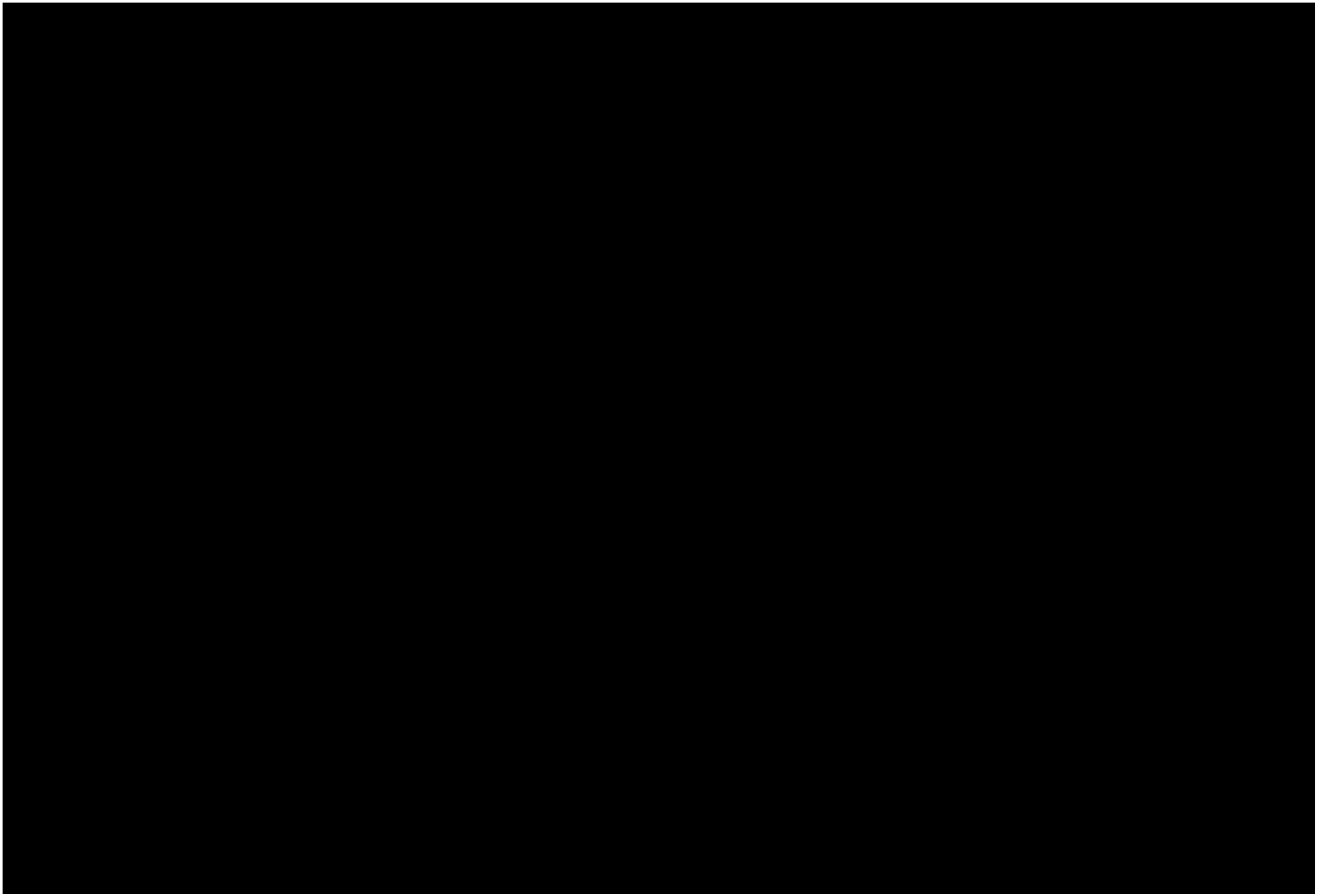
Date of On Peak Day - 08/29/2021



Member Forecasted On Peak Demand Day for September 2021

Southeast Colorado Power Association

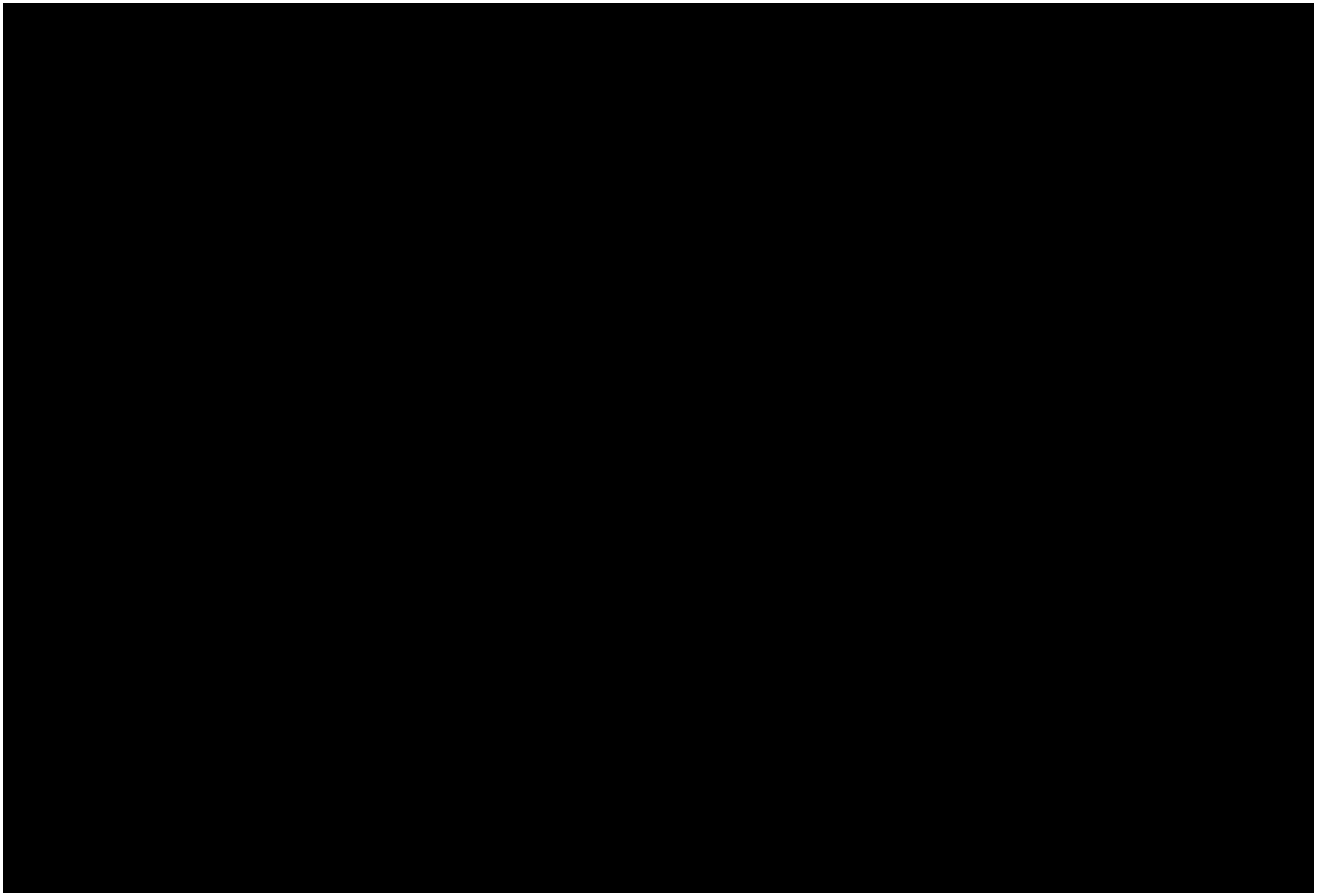
Date of On Peak Day - 09/05/2021



Member Forecasted On Peak Demand Day for October 2021

Southeast Colorado Power Association

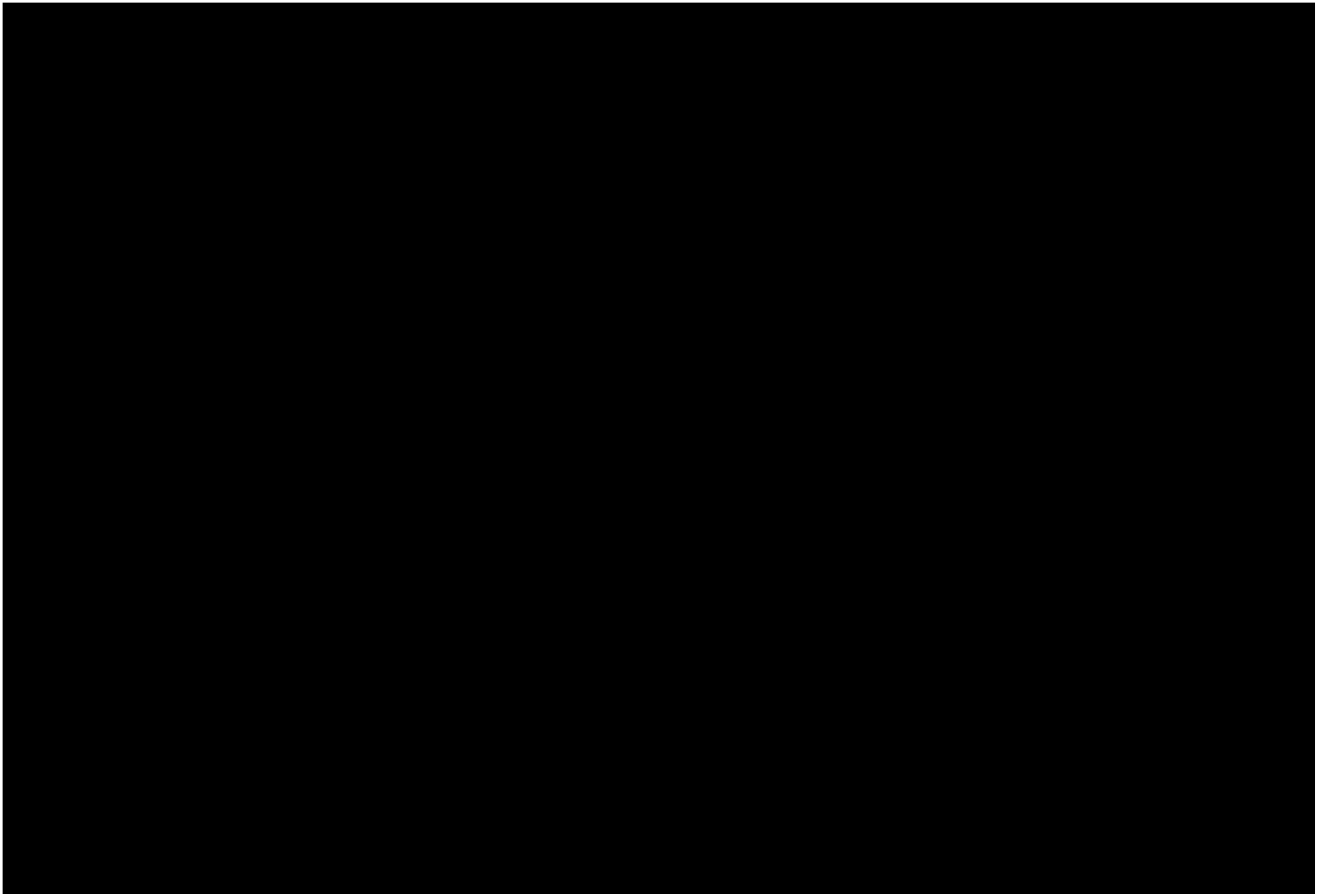
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

Southeast Colorado Power Association

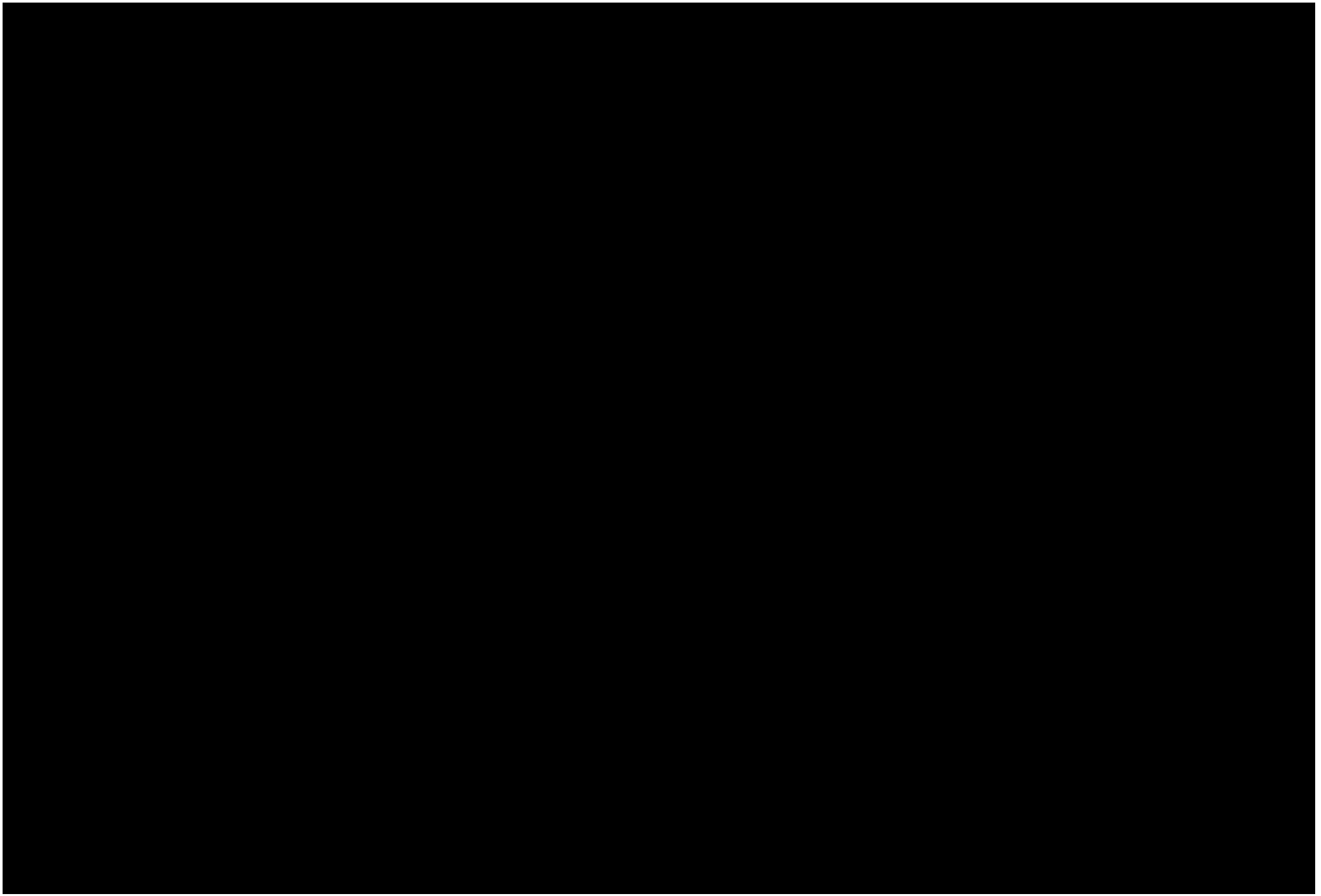
Date of On Peak Day - 11/18/2021



Member Forecasted On Peak Demand Day for December 2021

Southeast Colorado Power Association

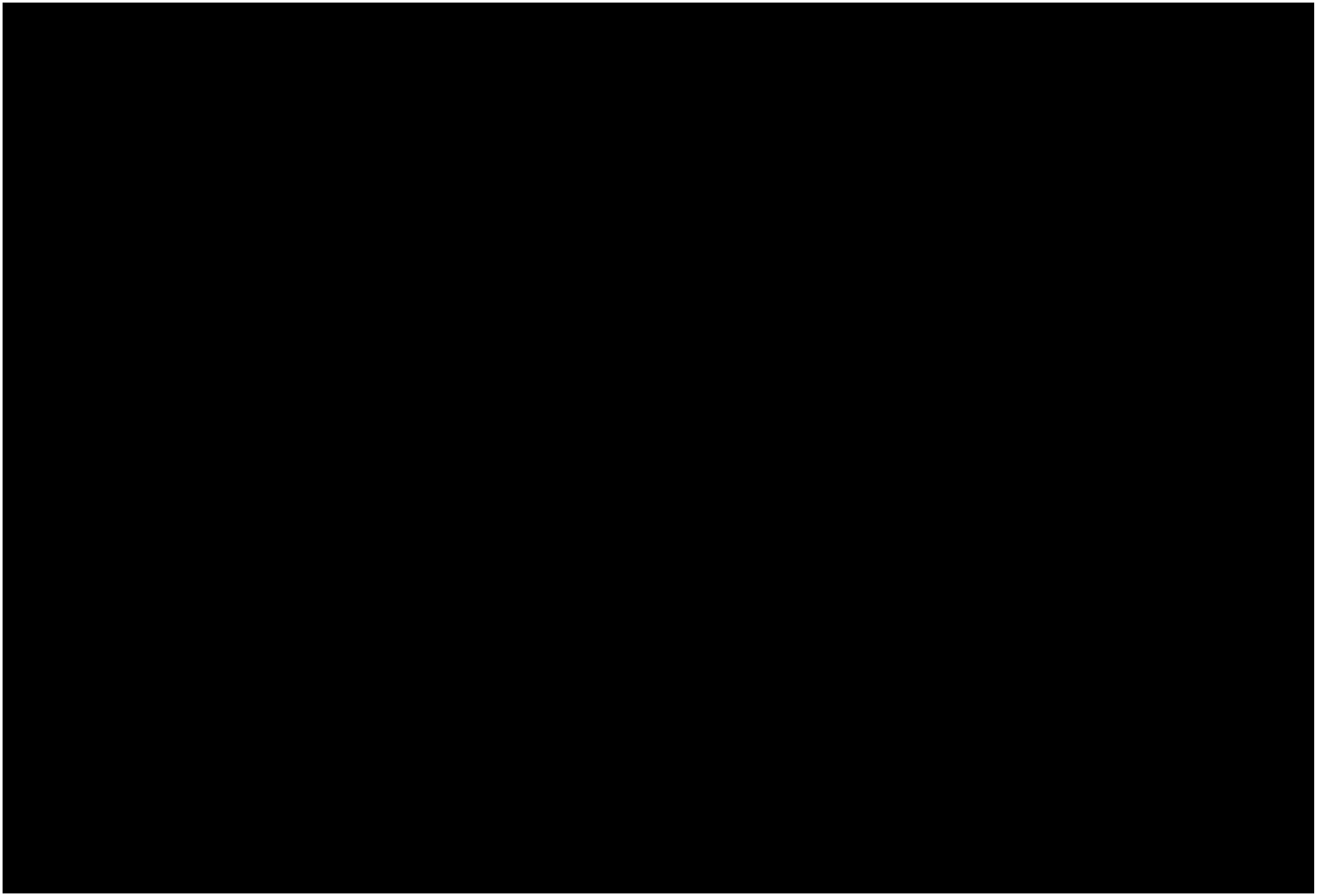
Date of On Peak Day - 12/29/2021



Member Forecasted On Peak Demand Day for January 2021

San Isabel Electric Association, Inc.

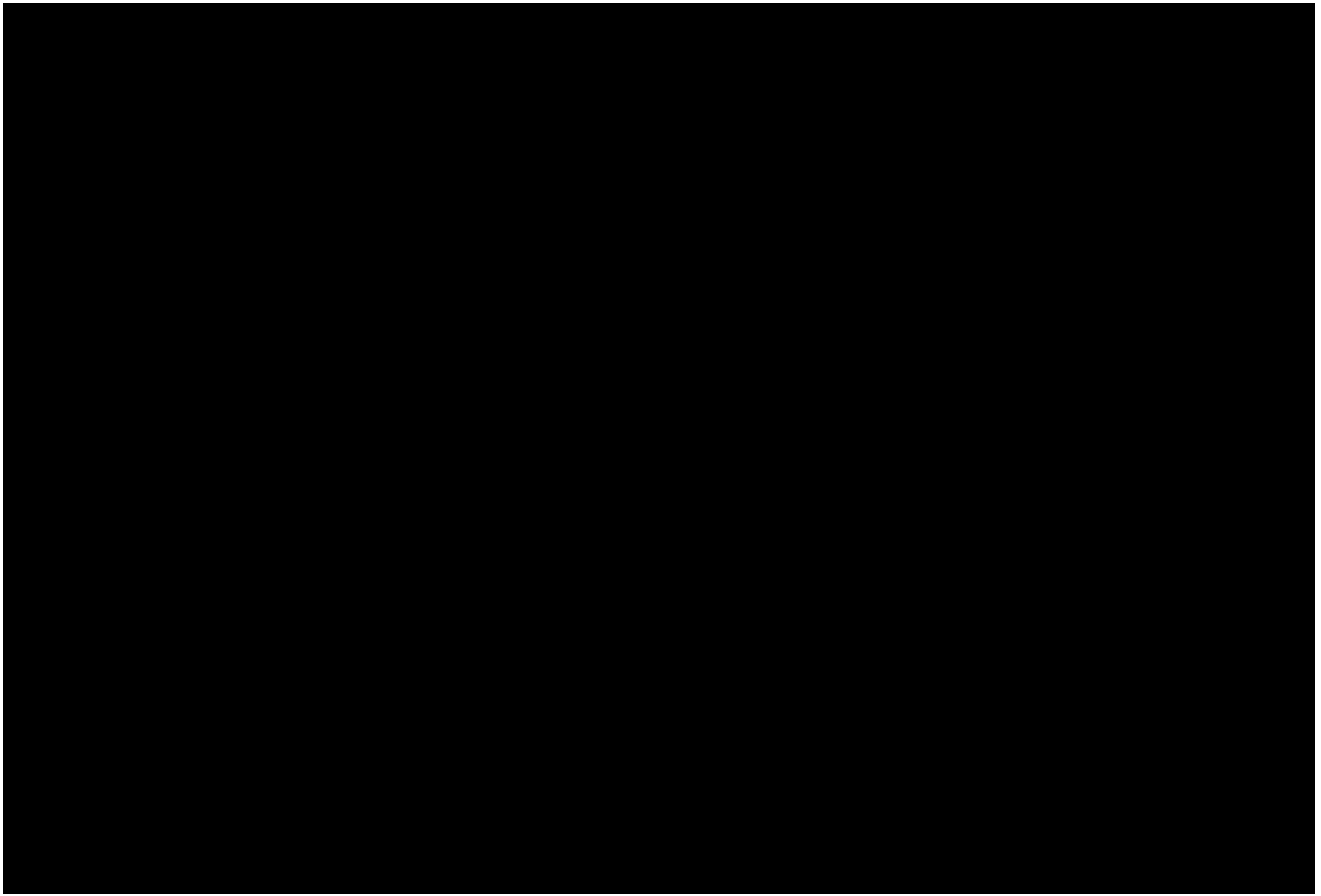
Date of On Peak Day - 01/16/2021



Member Forecasted On Peak Demand Day for February 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 03/02/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

San Isabel Electric Association, Inc.

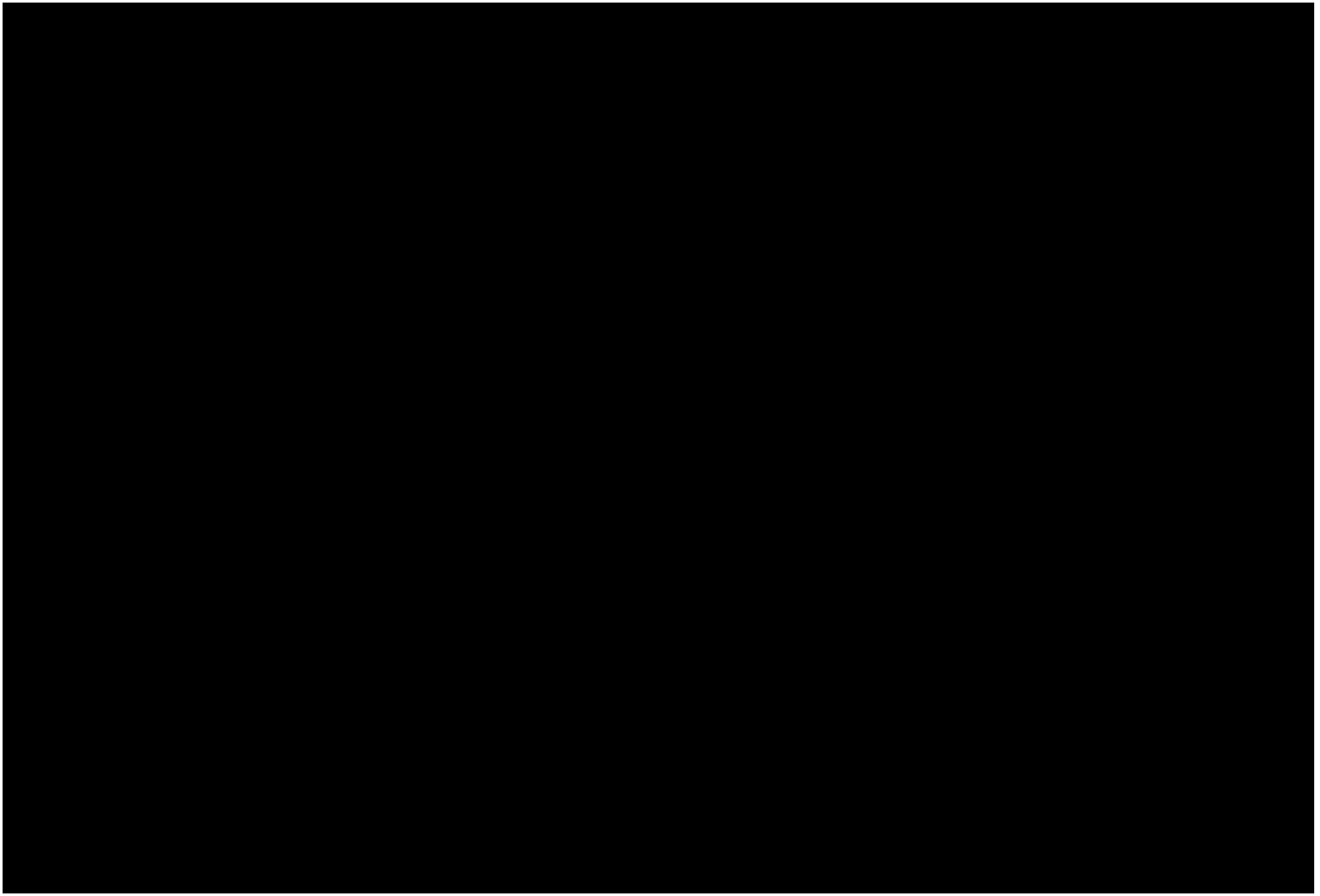
Date of On Peak Day - 04/15/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

San Isabel Electric Association, Inc.

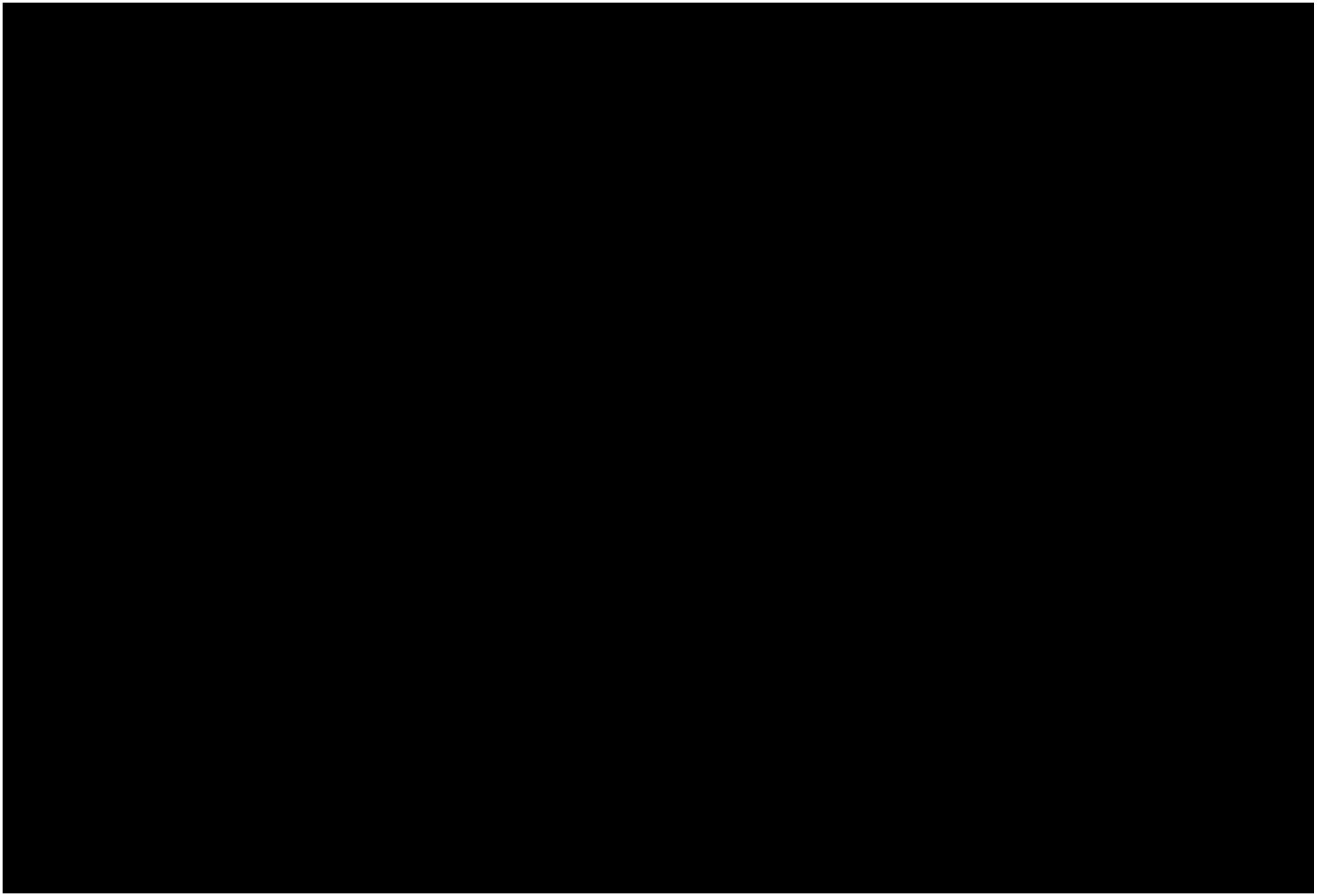
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

San Isabel Electric Association, Inc.

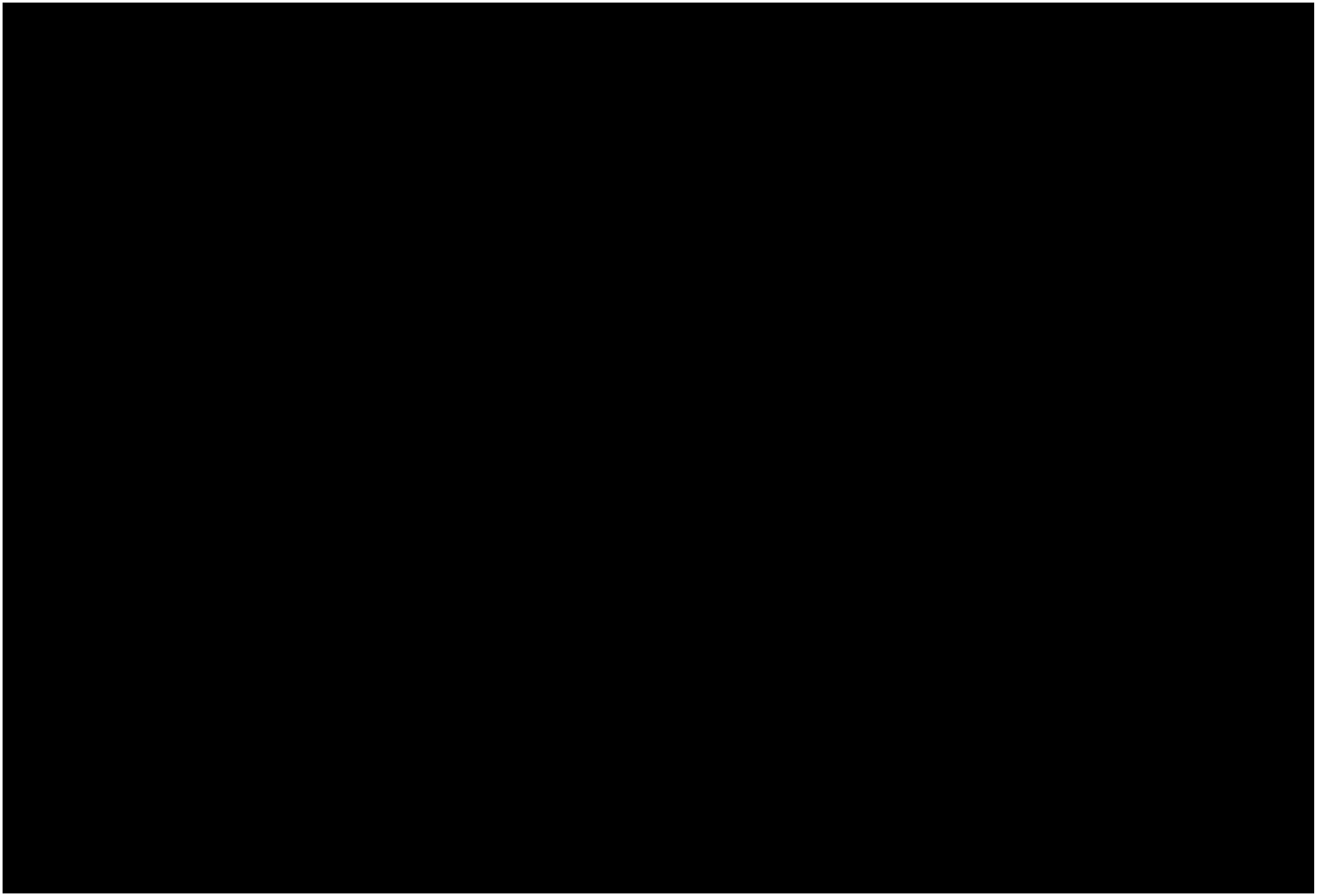
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

San Isabel Electric Association, Inc.

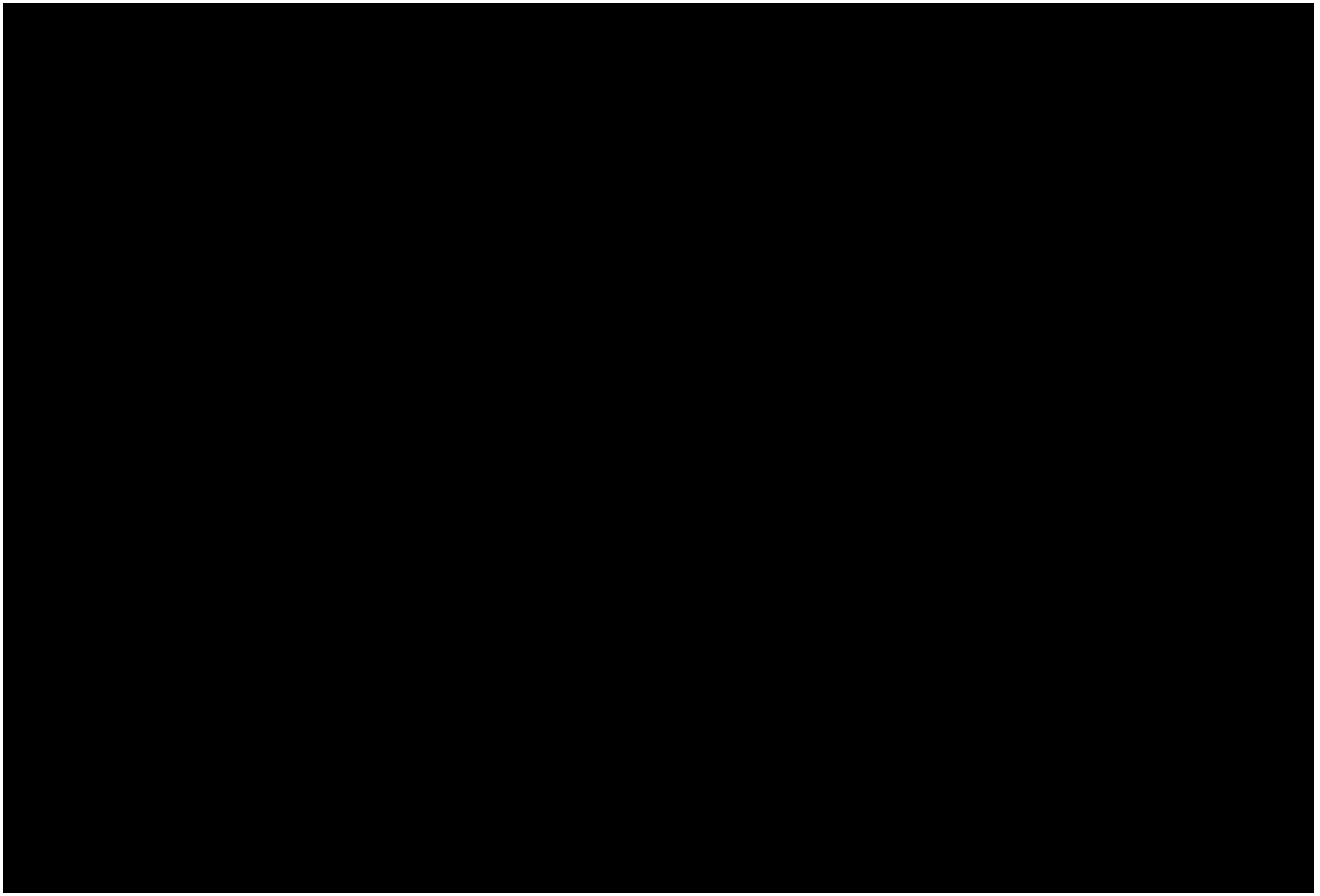
Date of On Peak Day - 07/10/2021



Member Forecasted On Peak Demand Day for August 2021

San Isabel Electric Association, Inc.

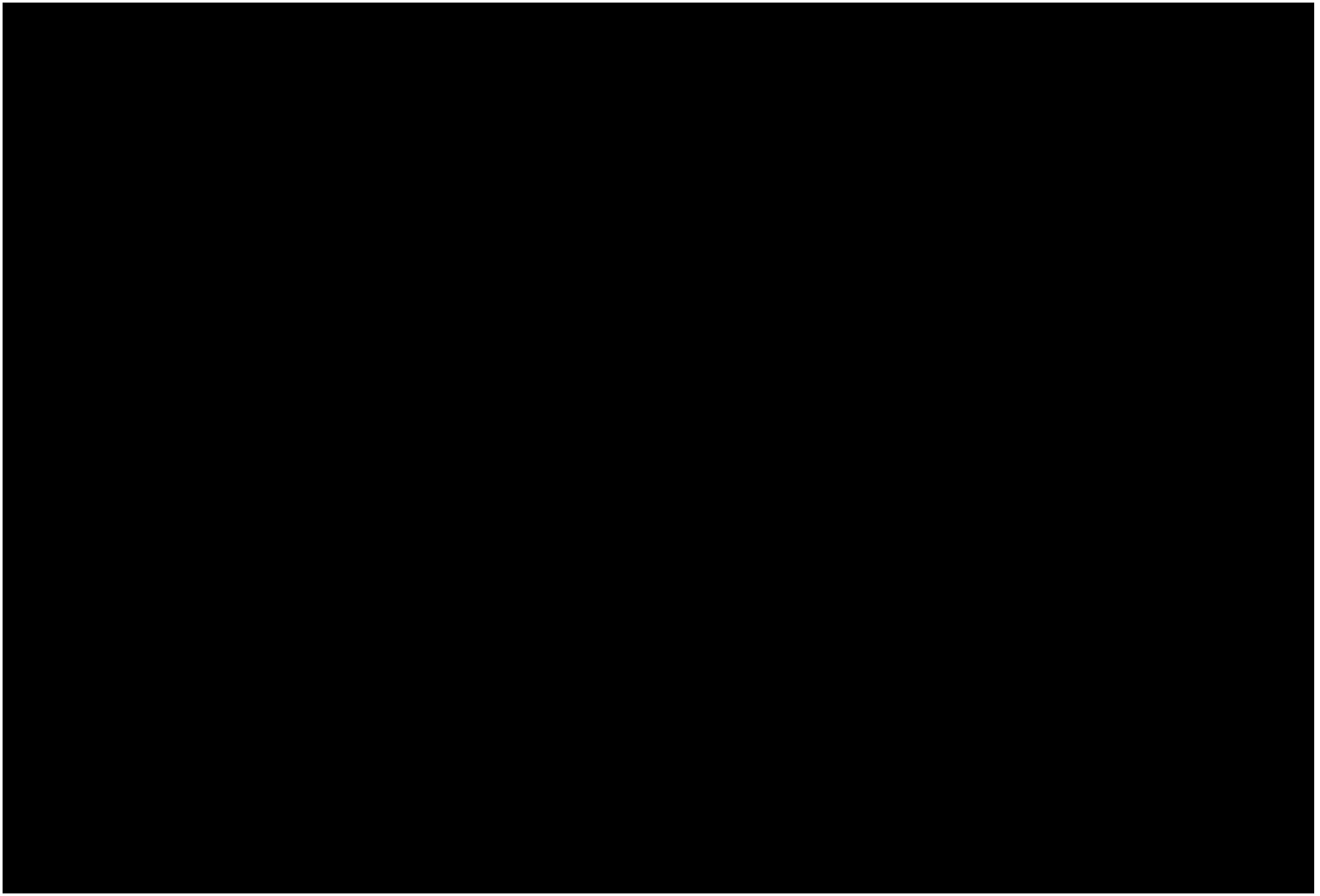
Date of On Peak Day - 08/21/2021



Member Forecasted On Peak Demand Day for September 2021

San Isabel Electric Association, Inc.

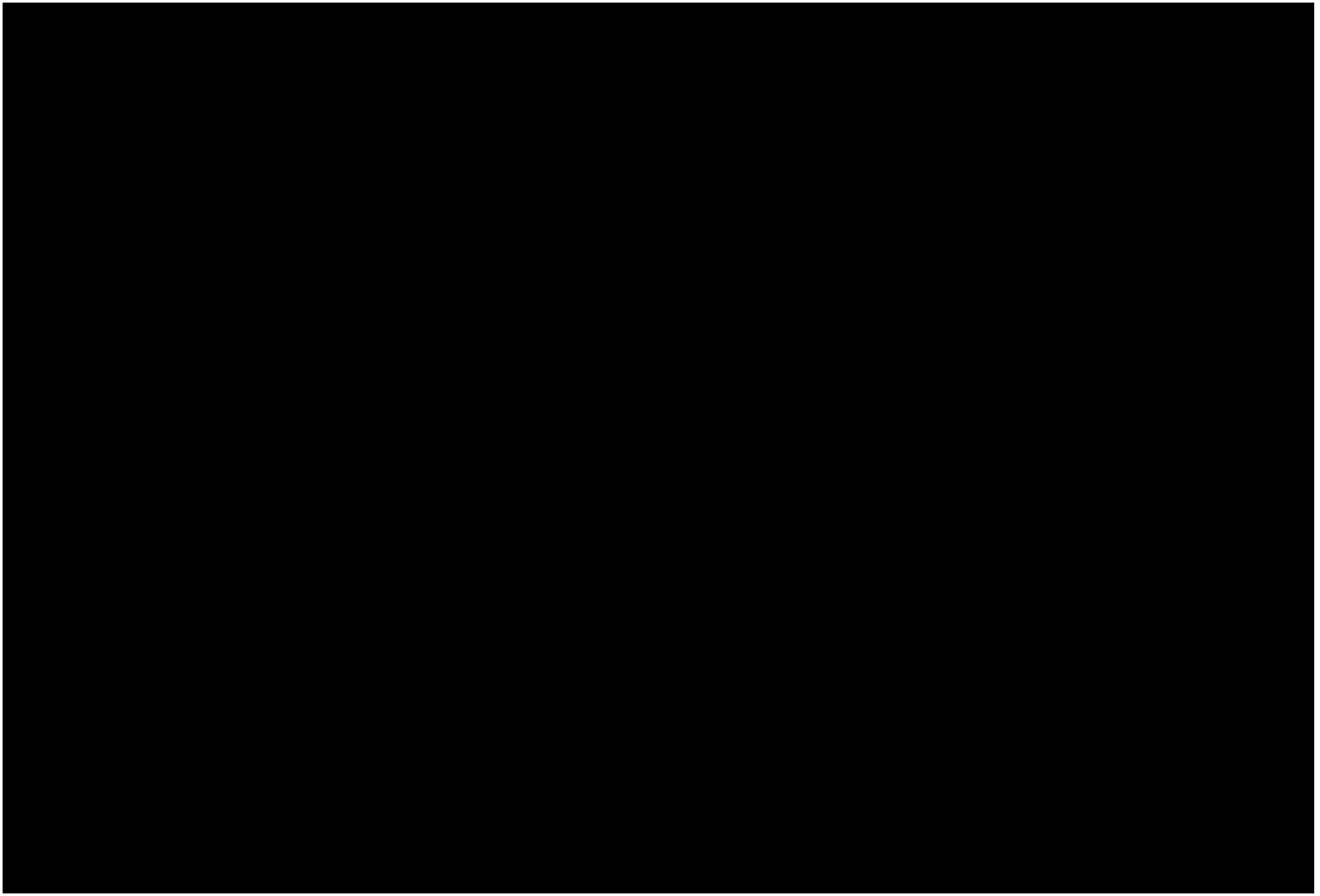
Date of On Peak Day - 09/13/2021



Member Forecasted On Peak Demand Day for October 2021

San Isabel Electric Association, Inc.

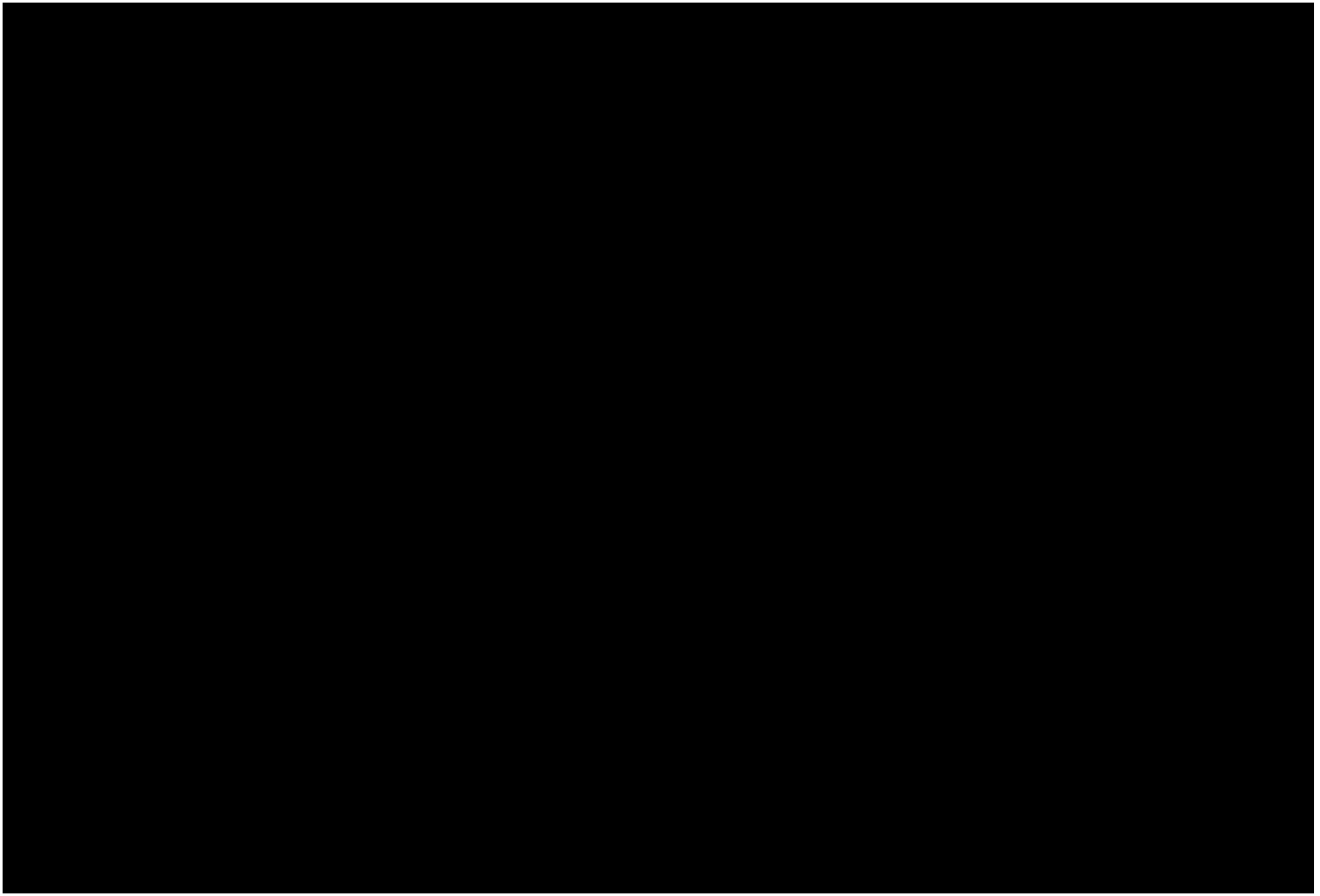
Date of On Peak Day - 10/01/2021



Member Forecasted On Peak Demand Day for November 2021

San Isabel Electric Association, Inc.

Date of On Peak Day - 11/08/2021



Member Forecasted On Peak Demand Day for December 2021

San Isabel Electric Association, Inc.

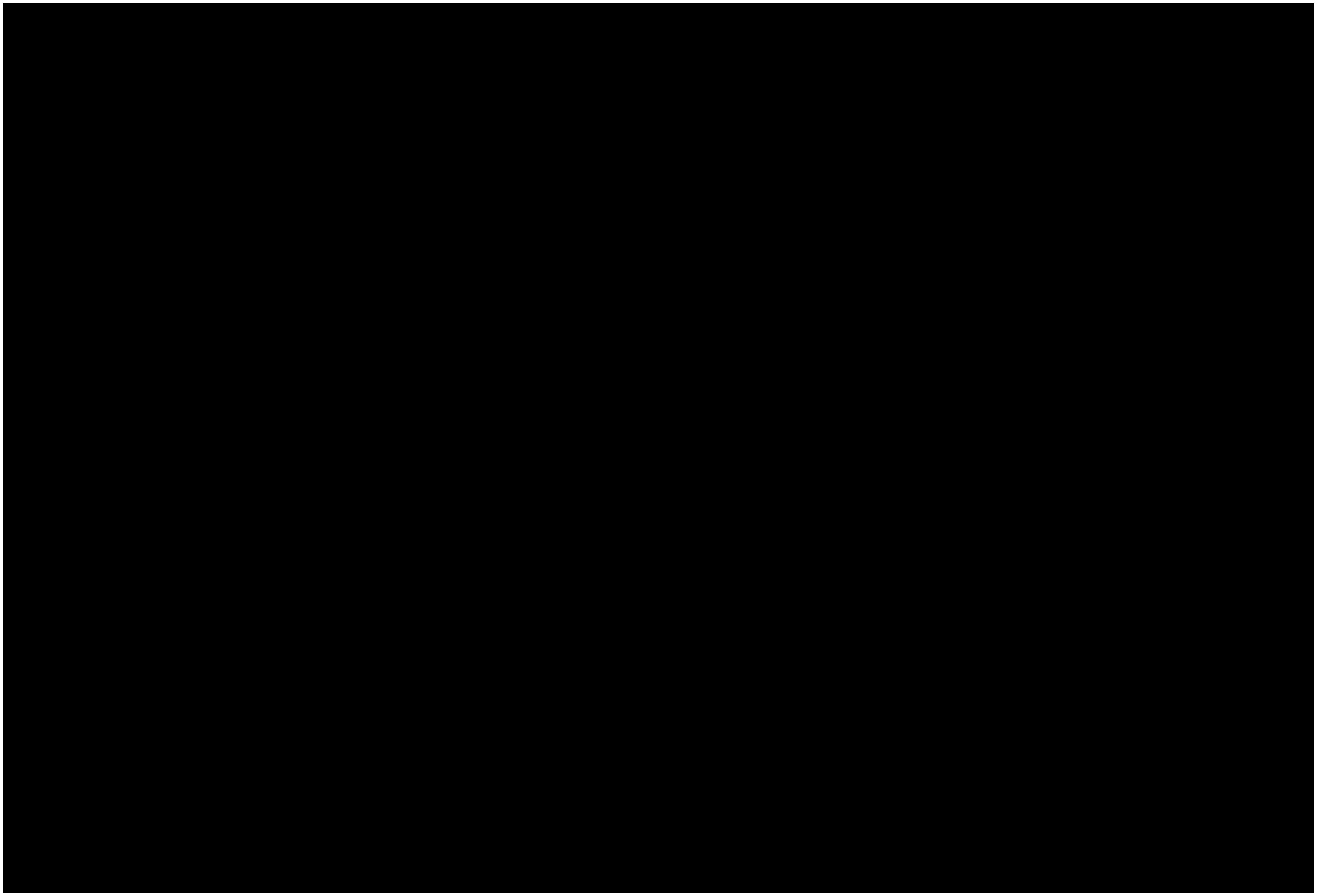
Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

San Luis Valley Rural Electric Cooperative, Inc.

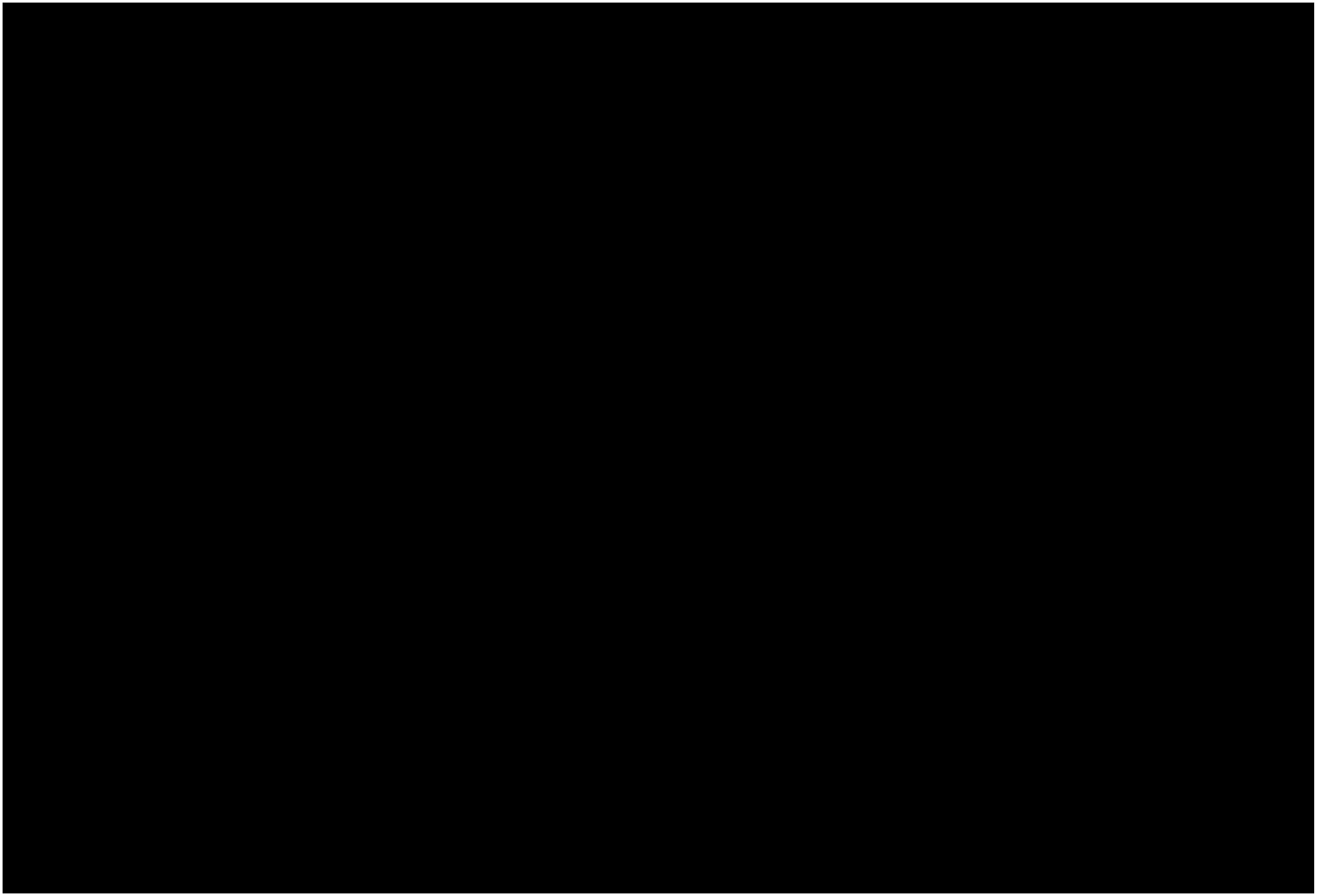
Date of On Peak Day - 01/29/2021



Member Forecasted On Peak Demand Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.

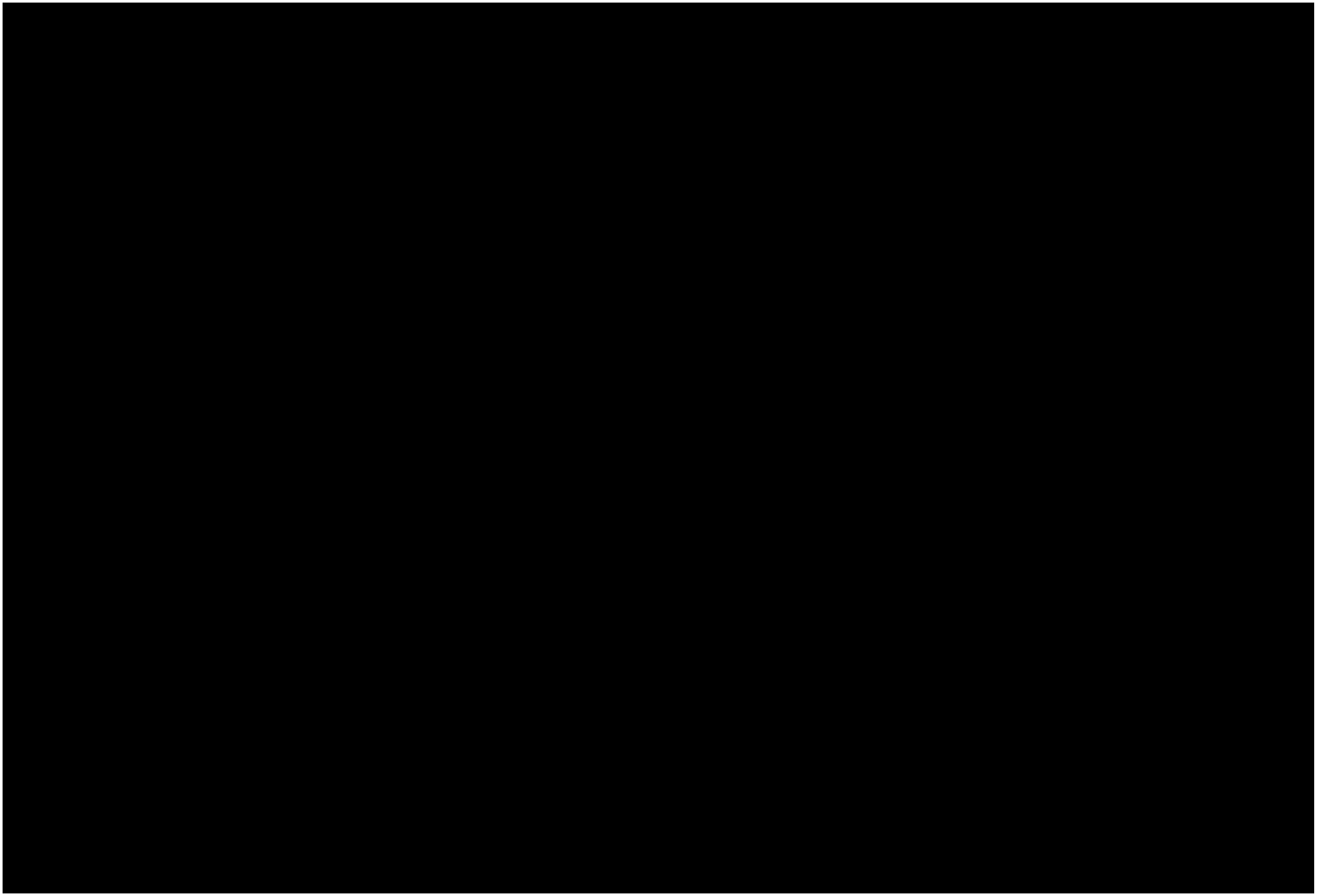
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.

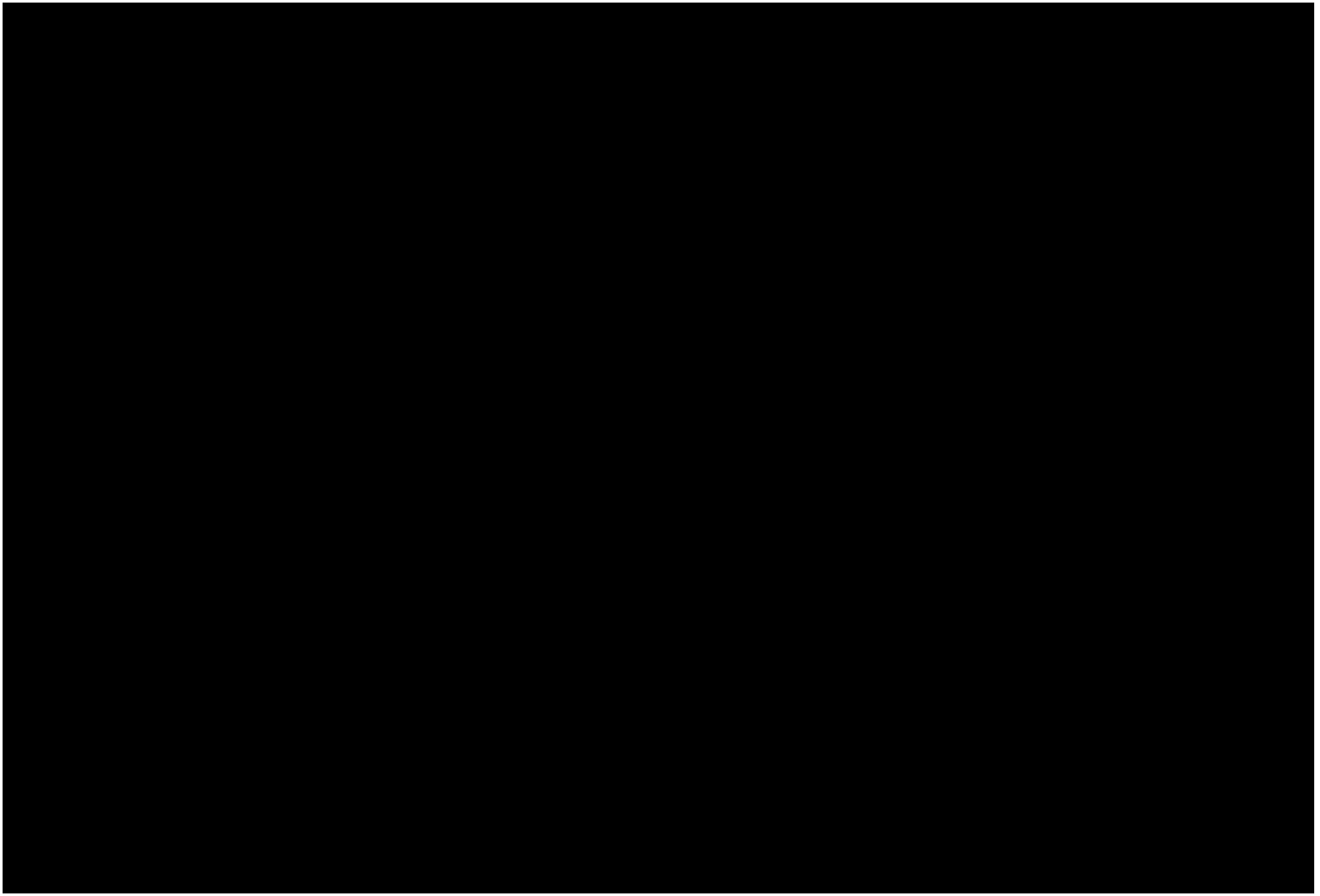
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.

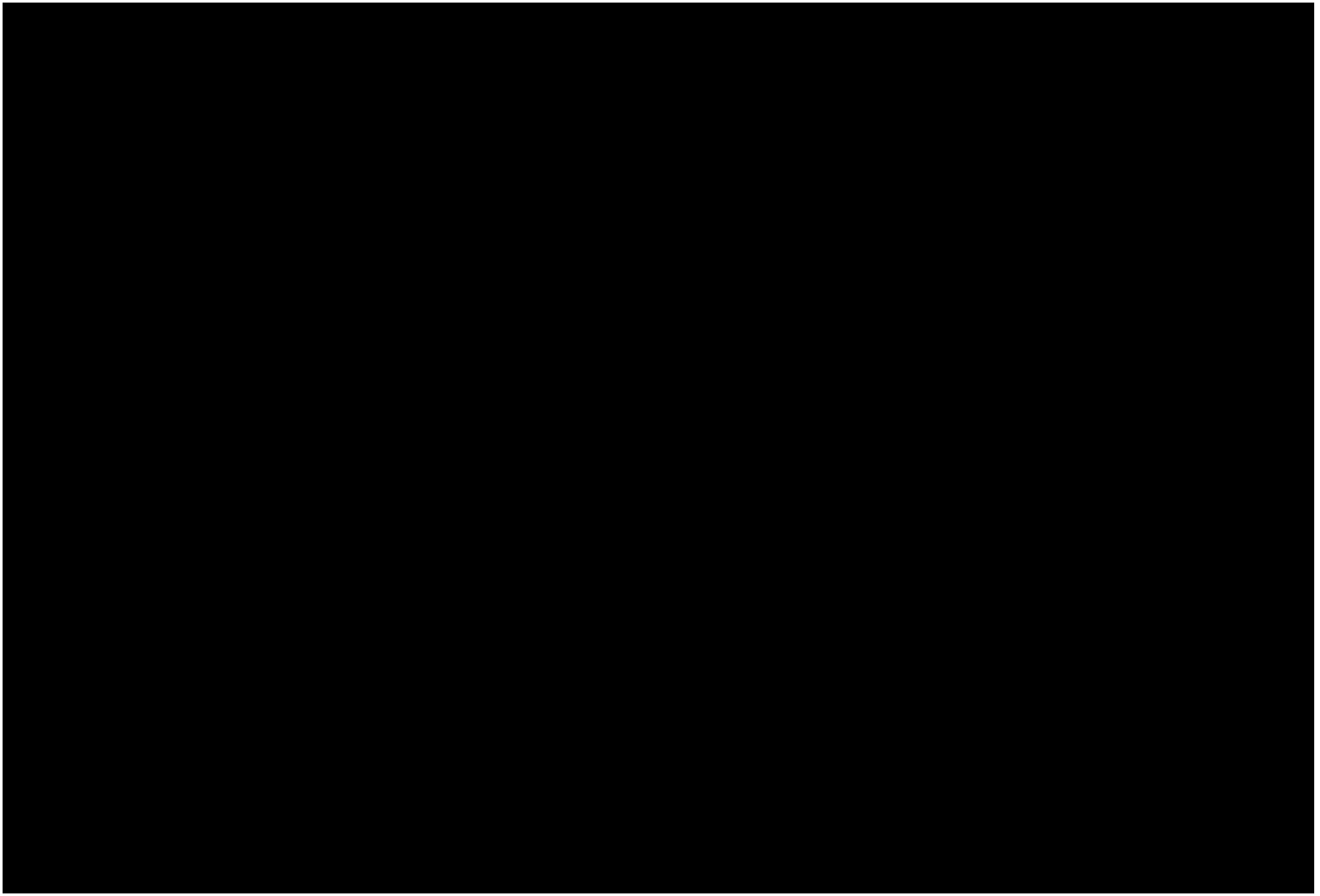
Date of On Peak Day - 04/22/2021



Member Forecasted On Peak Demand Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.

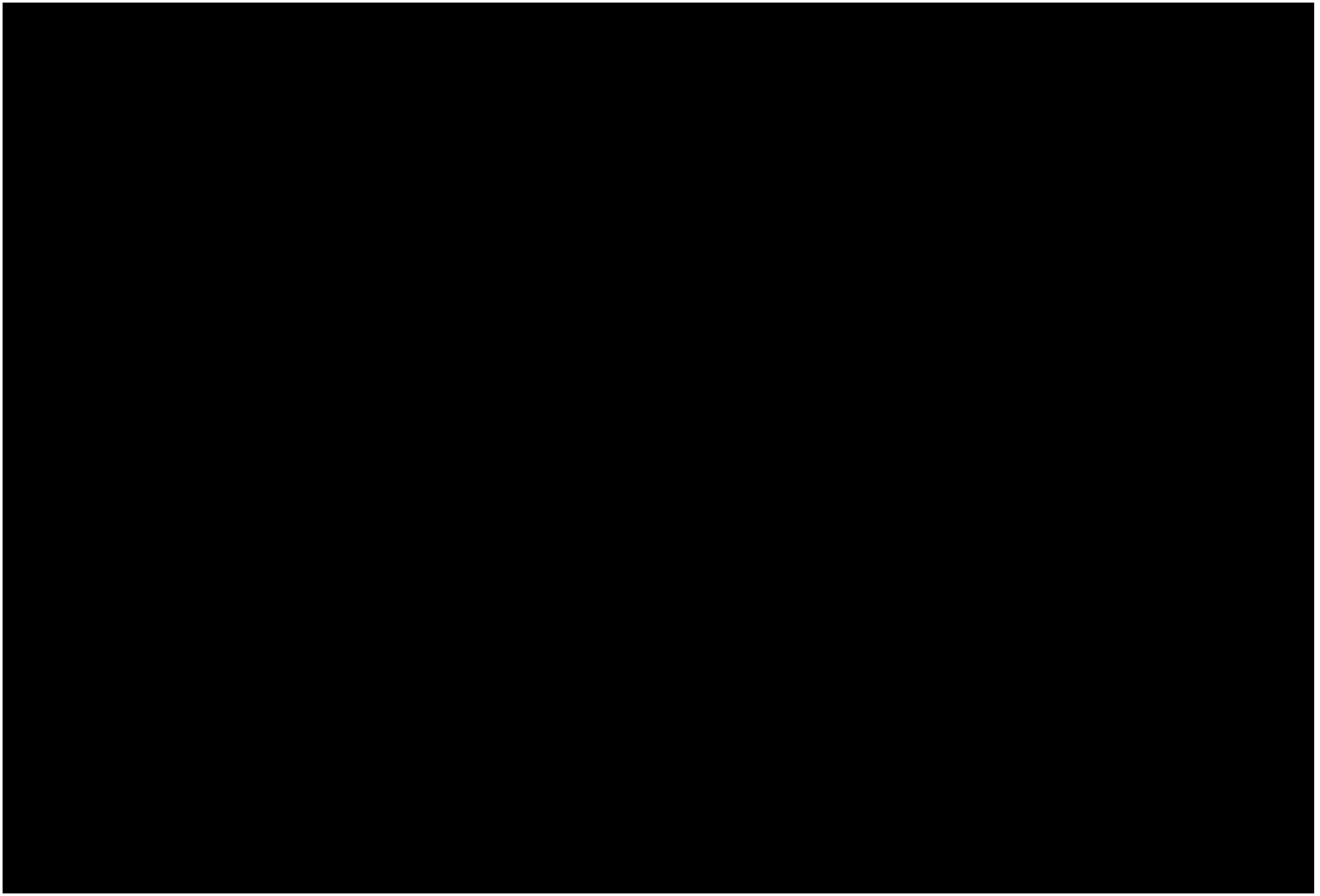
Date of On Peak Day - 05/24/2021



Member Forecasted On Peak Demand Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.

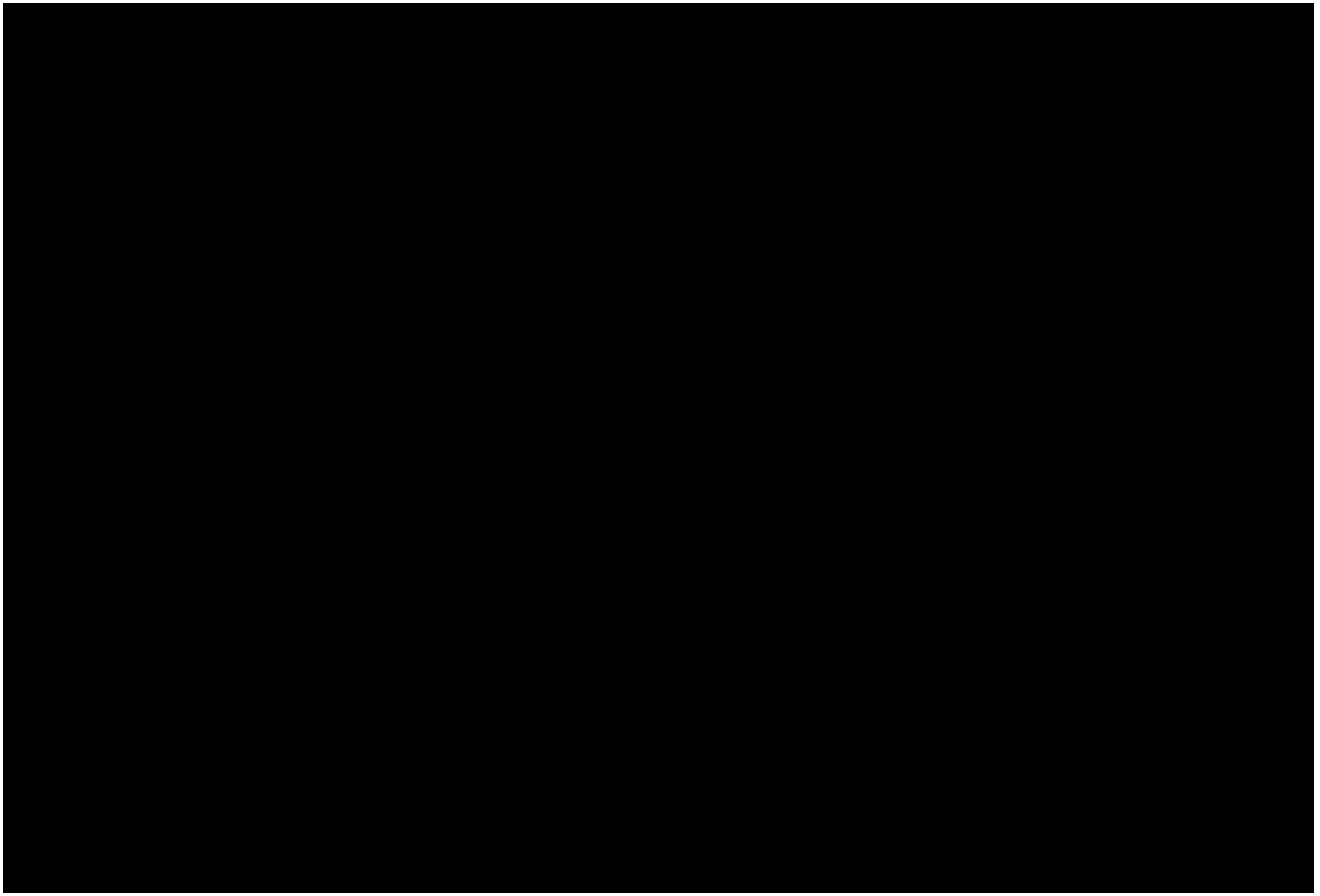
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.

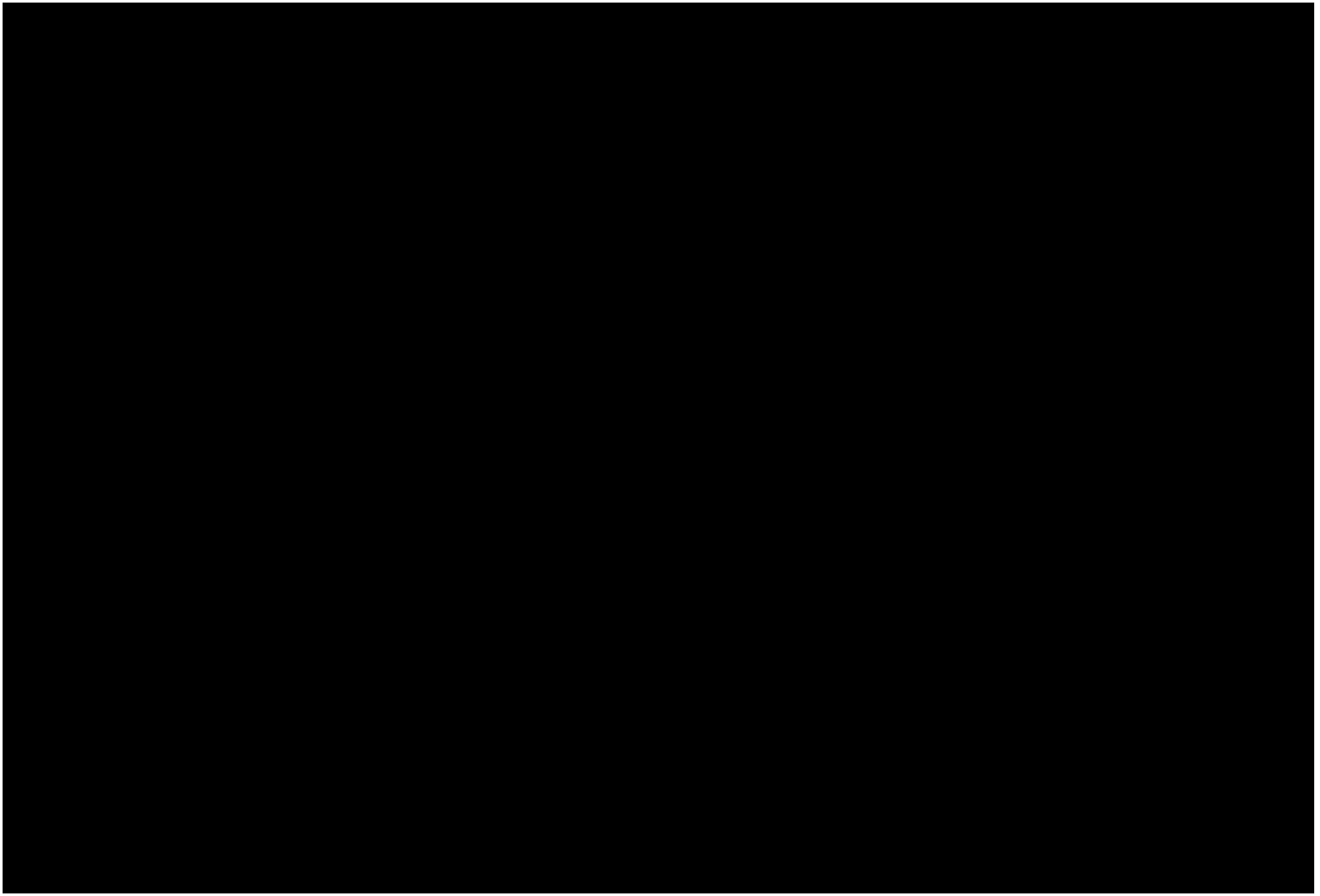
Date of On Peak Day - 07/12/2021



Member Forecasted On Peak Demand Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.

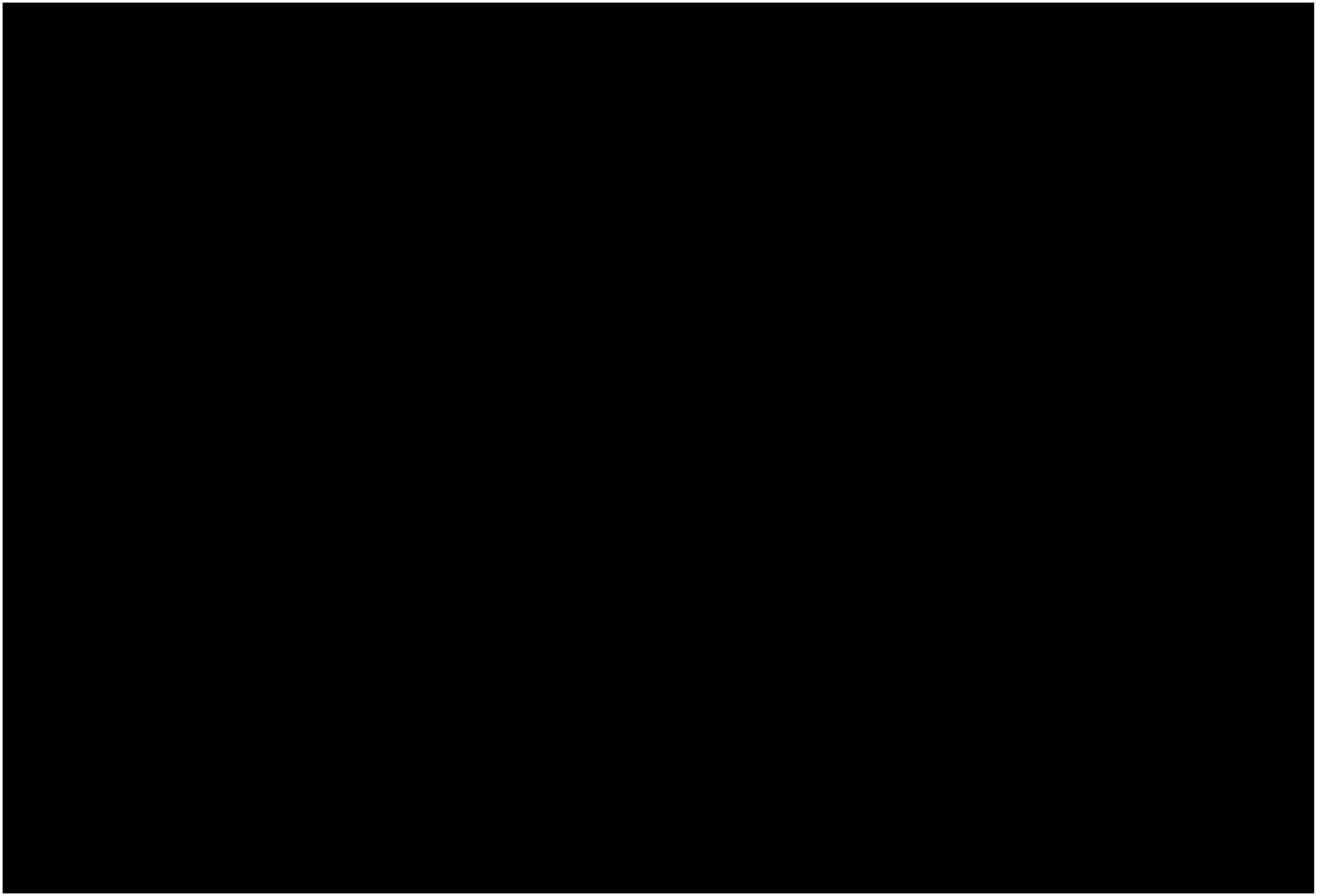
Date of On Peak Day - 08/16/2021



Member Forecasted On Peak Demand Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

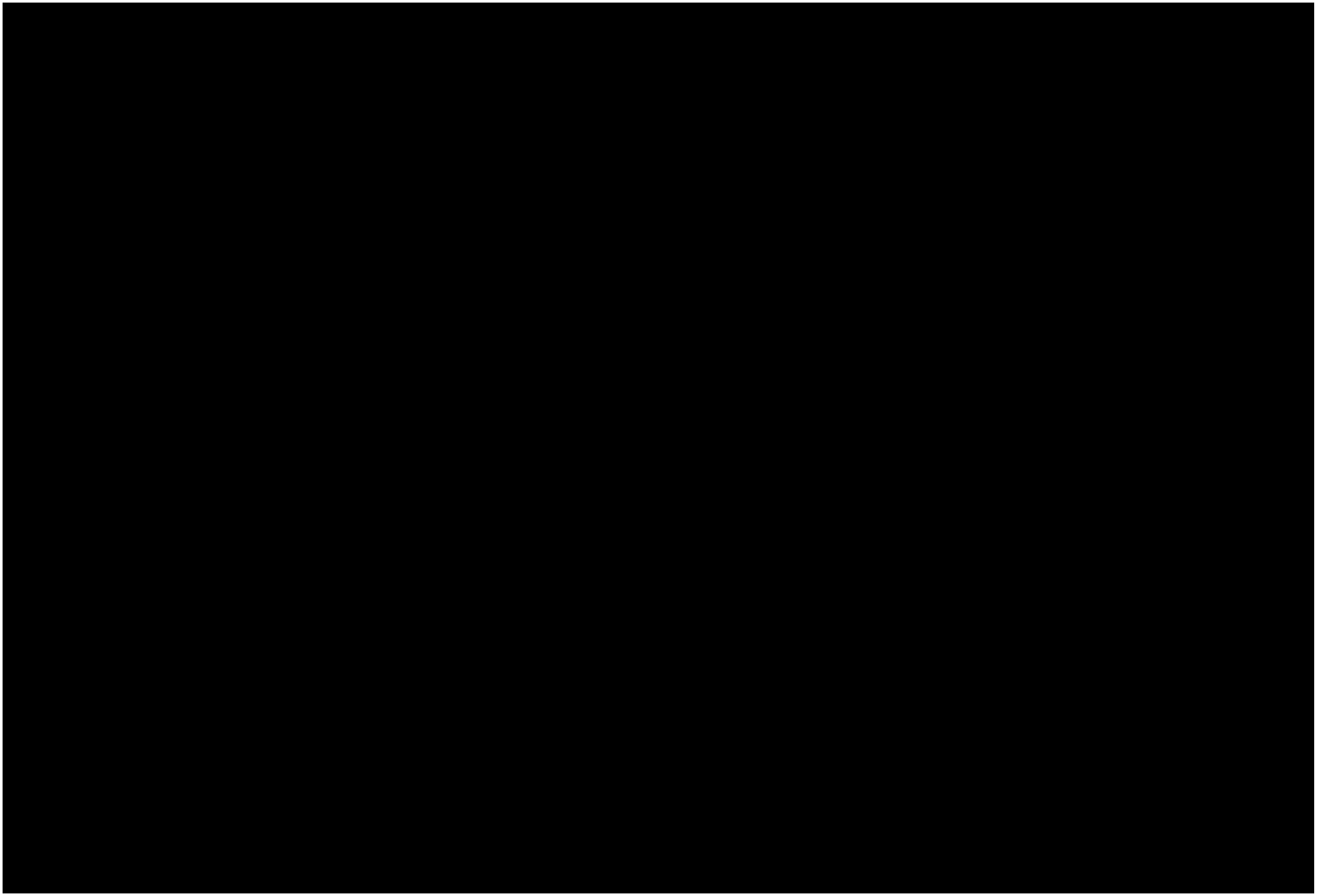
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.

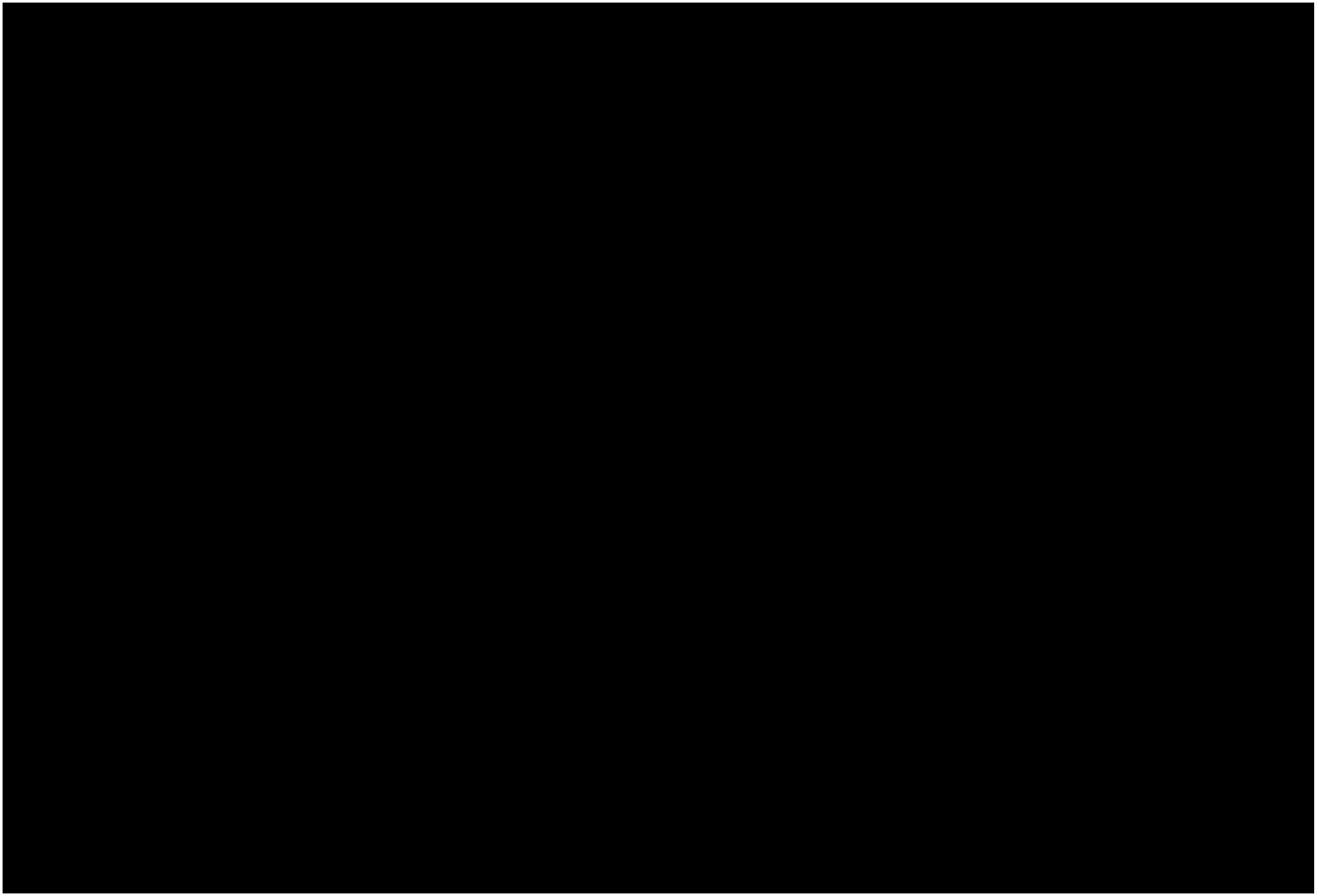
Date of On Peak Day - 10/16/2021



Member Forecasted On Peak Demand Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.

Date of On Peak Day - 11/12/2021



Member Forecasted On Peak Demand Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.

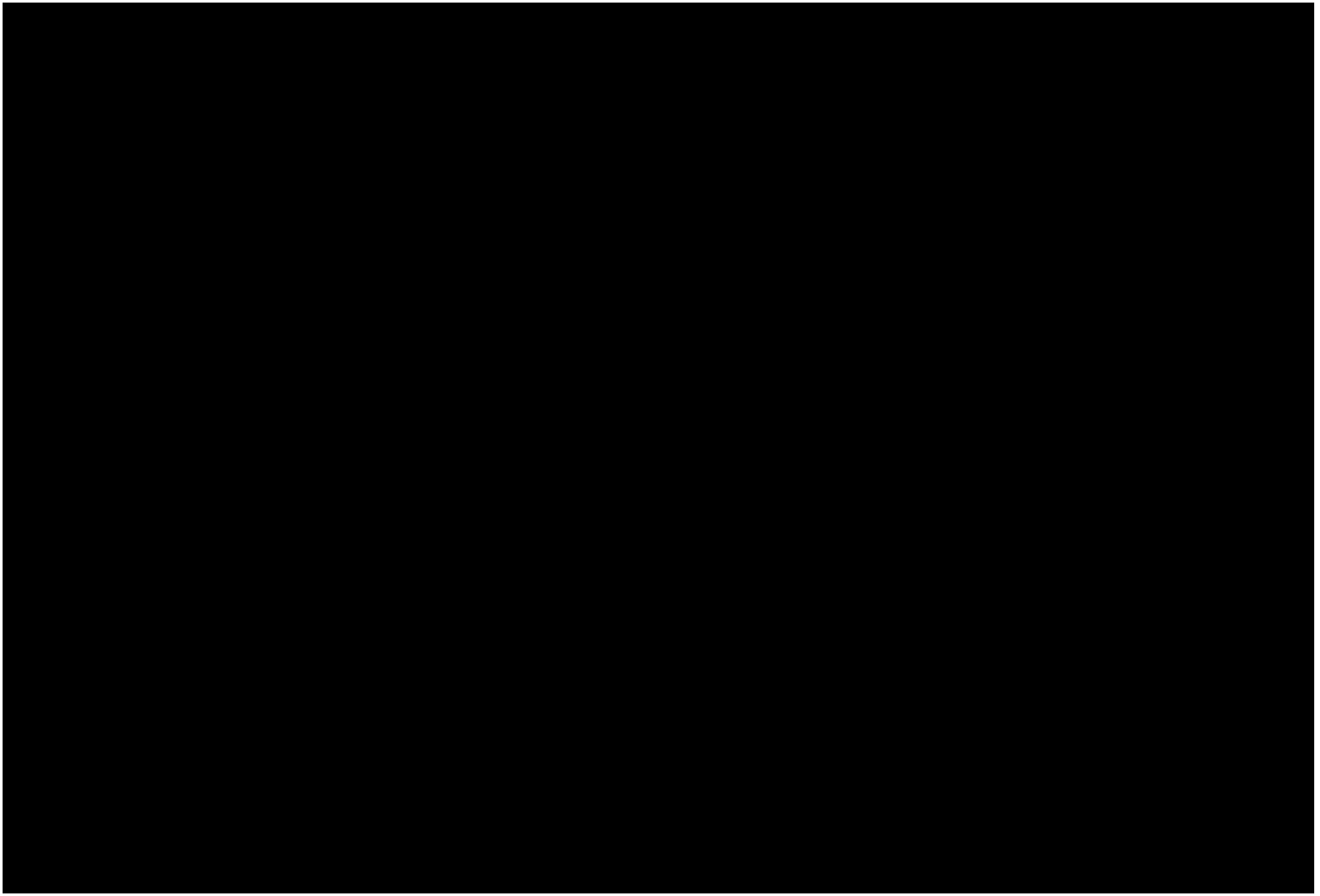
Date of On Peak Day - 12/31/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

San Miguel Power Association, Inc.

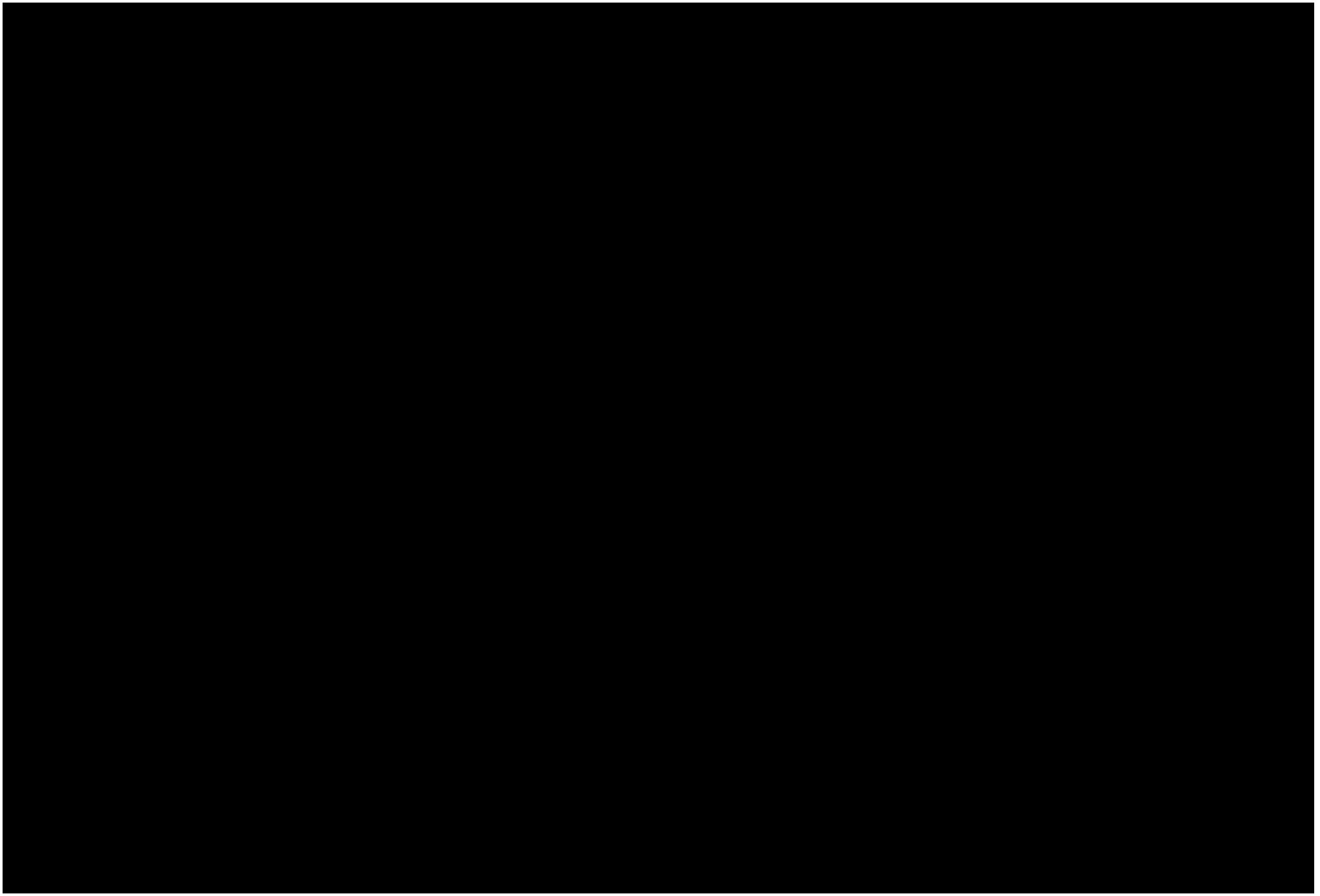
Date of On Peak Day - 01/01/2021



Member Forecasted On Peak Demand Day for February 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

San Miguel Power Association, Inc.

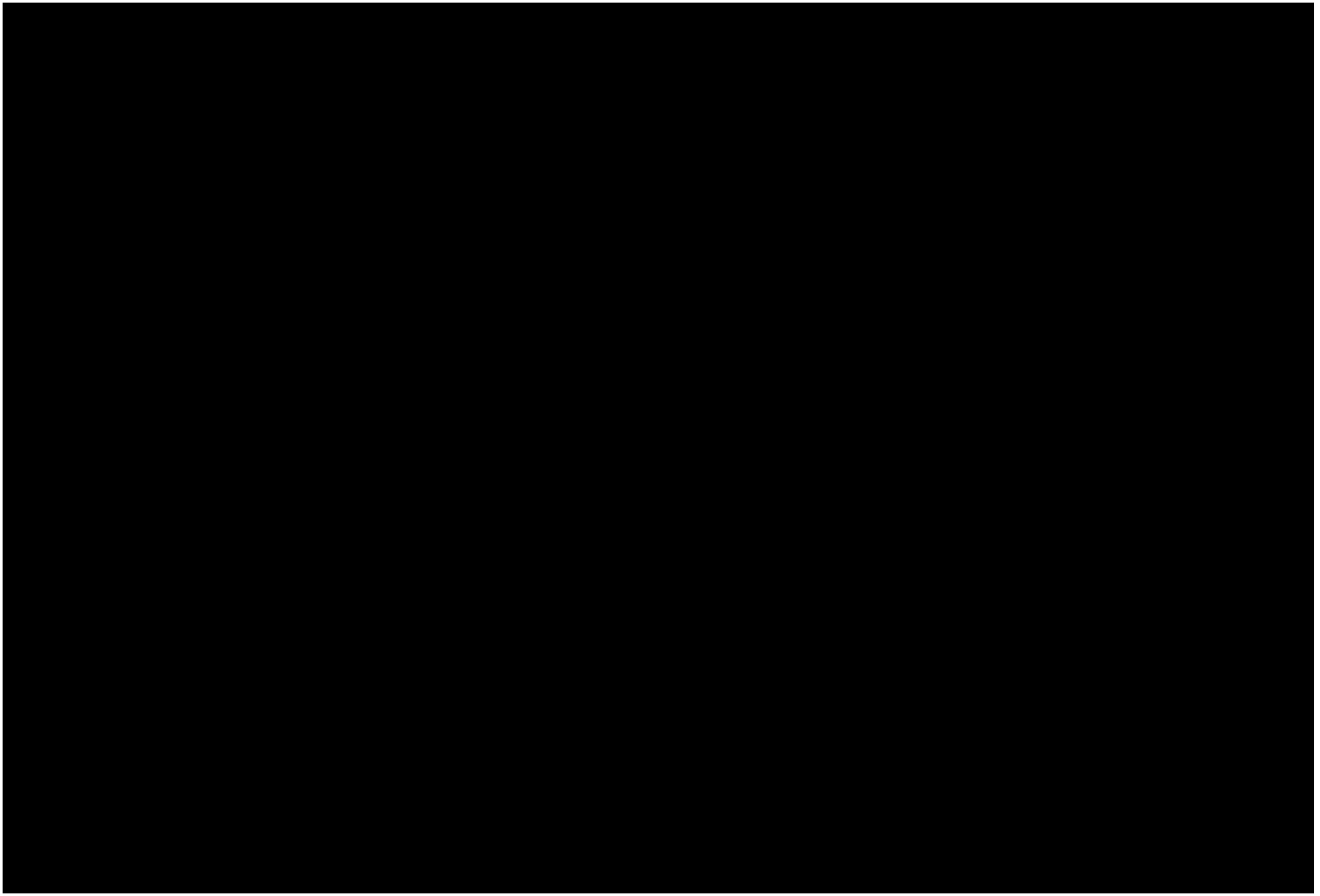
Date of On Peak Day - 03/01/2021

[redacted]

Member Forecasted On Peak Demand Day for April 2021

San Miguel Power Association, Inc.

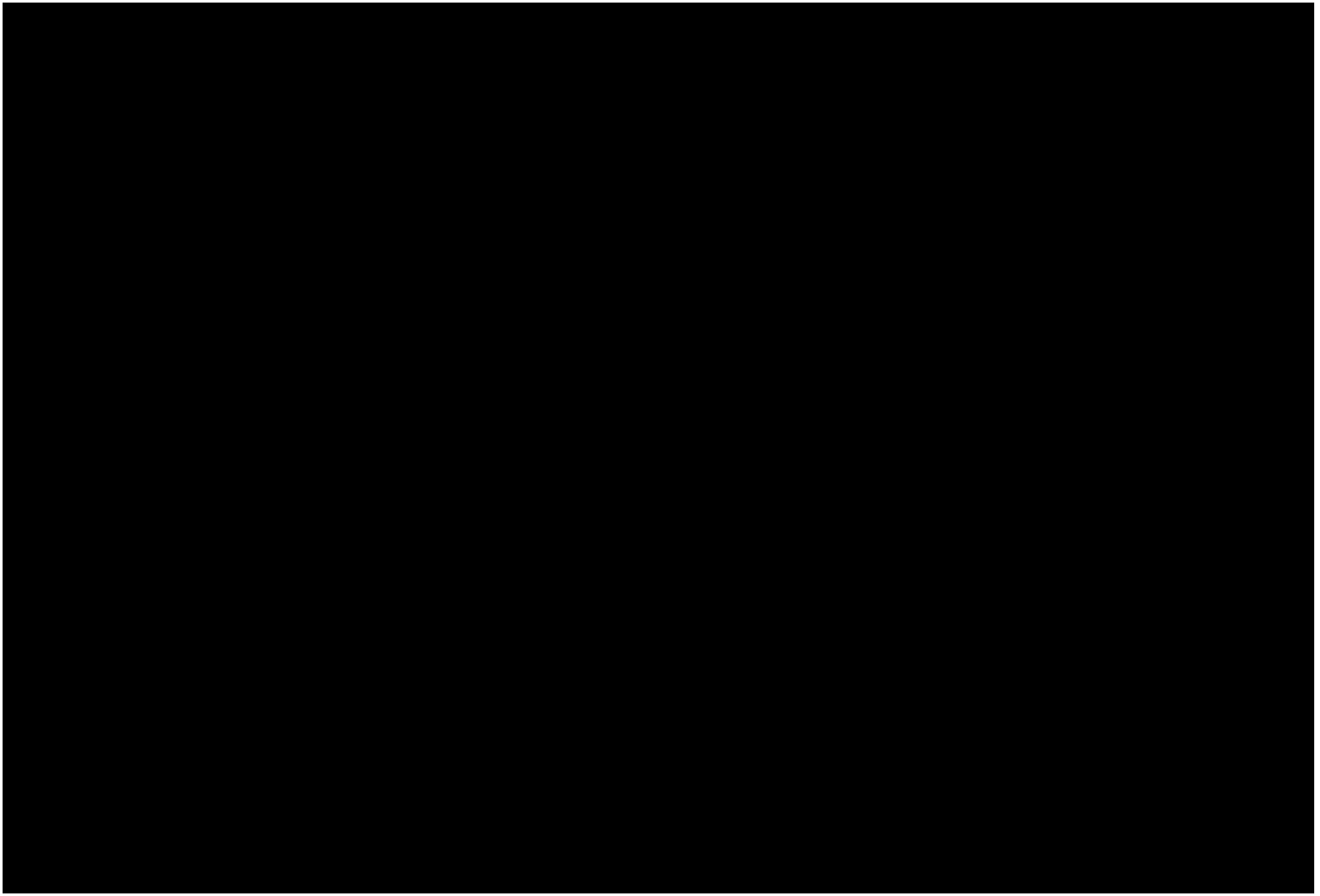
Date of On Peak Day - 04/03/2021



Member Forecasted On Peak Demand Day for May 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 05/18/2021



Member Forecasted On Peak Demand Day for June 2021

San Miguel Power Association, Inc.

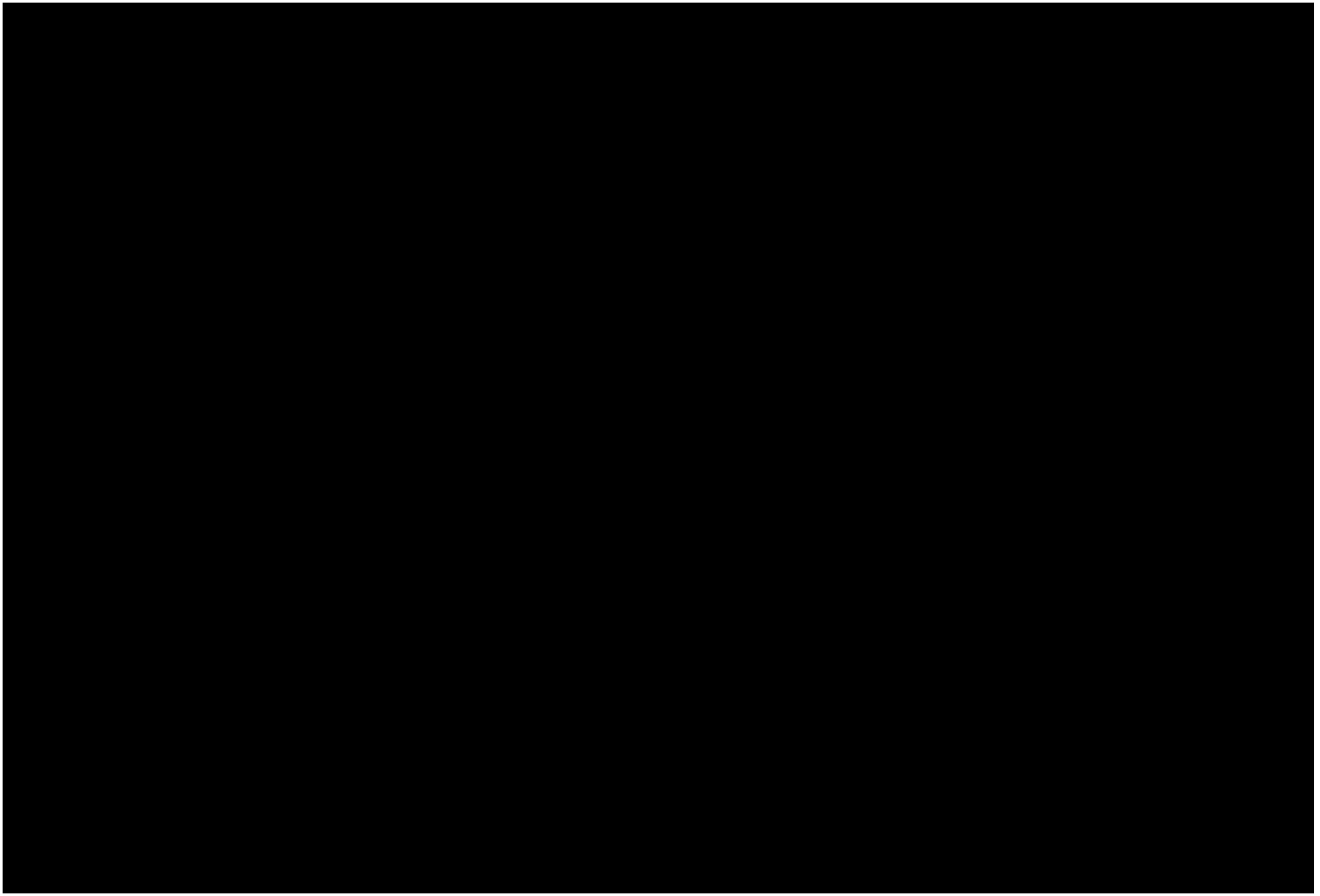
Date of On Peak Day - 06/30/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

San Miguel Power Association, Inc.

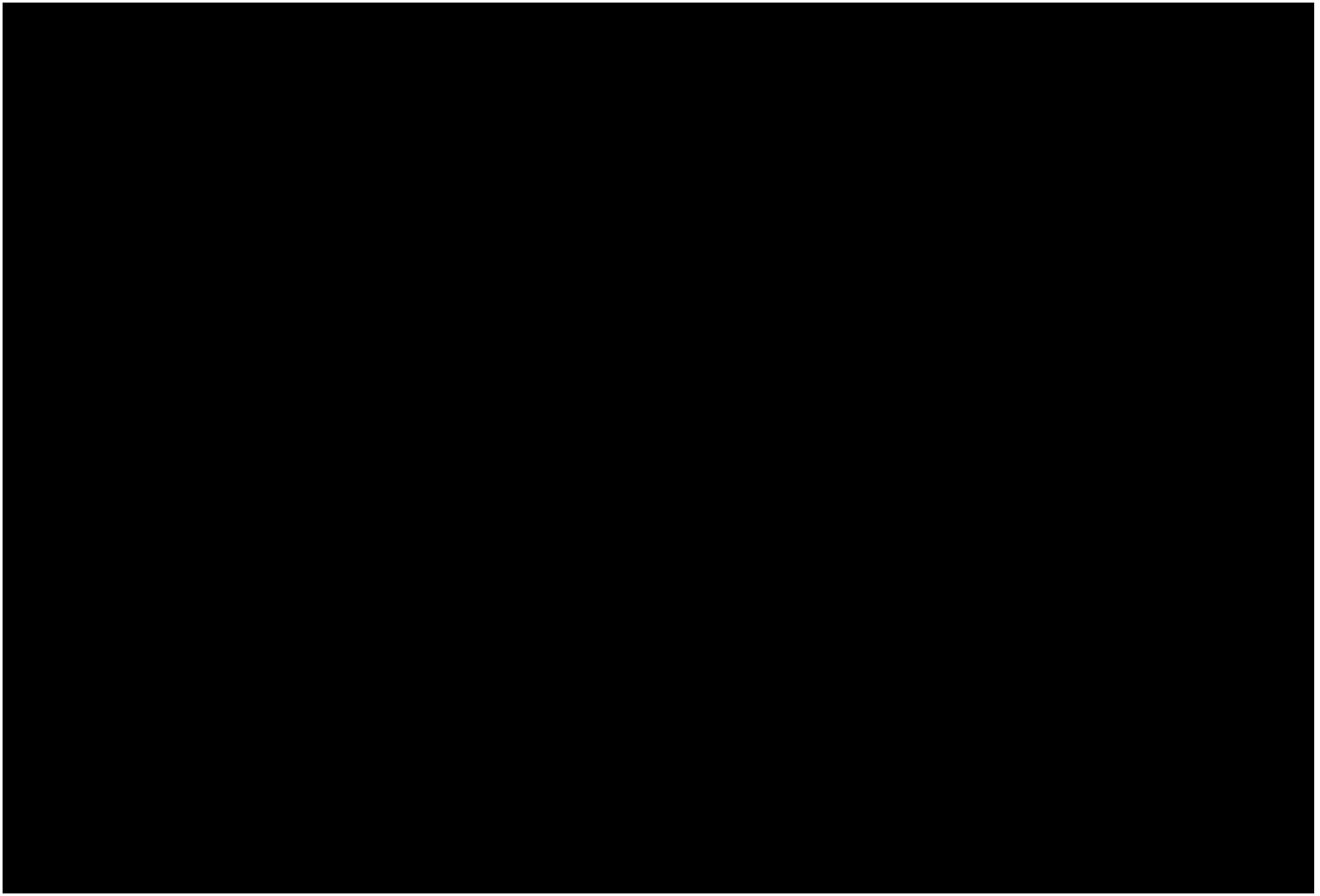
Date of On Peak Day - 07/30/2021



Member Forecasted On Peak Demand Day for August 2021

San Miguel Power Association, Inc.

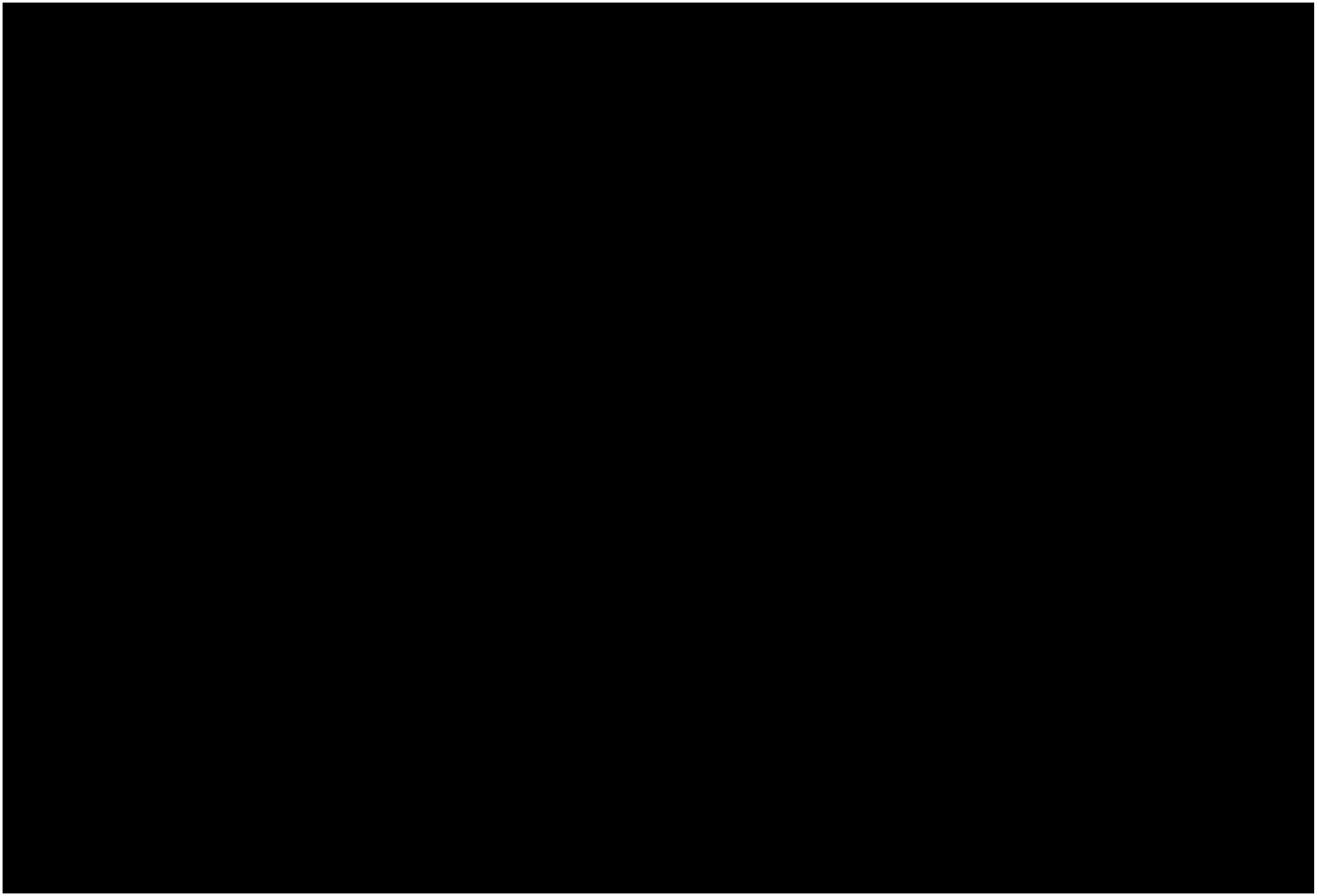
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

San Miguel Power Association, Inc.

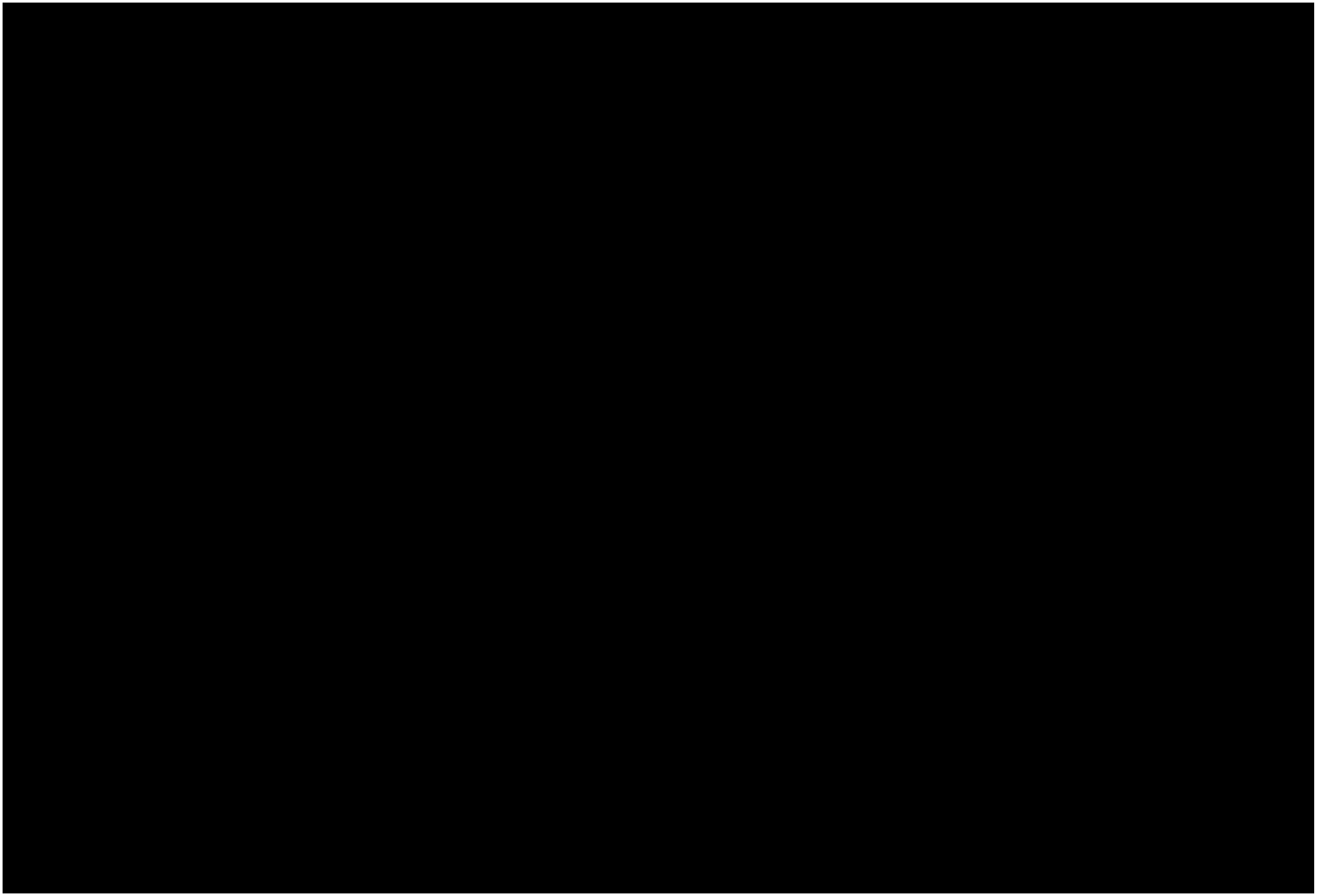
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

San Miguel Power Association, Inc.

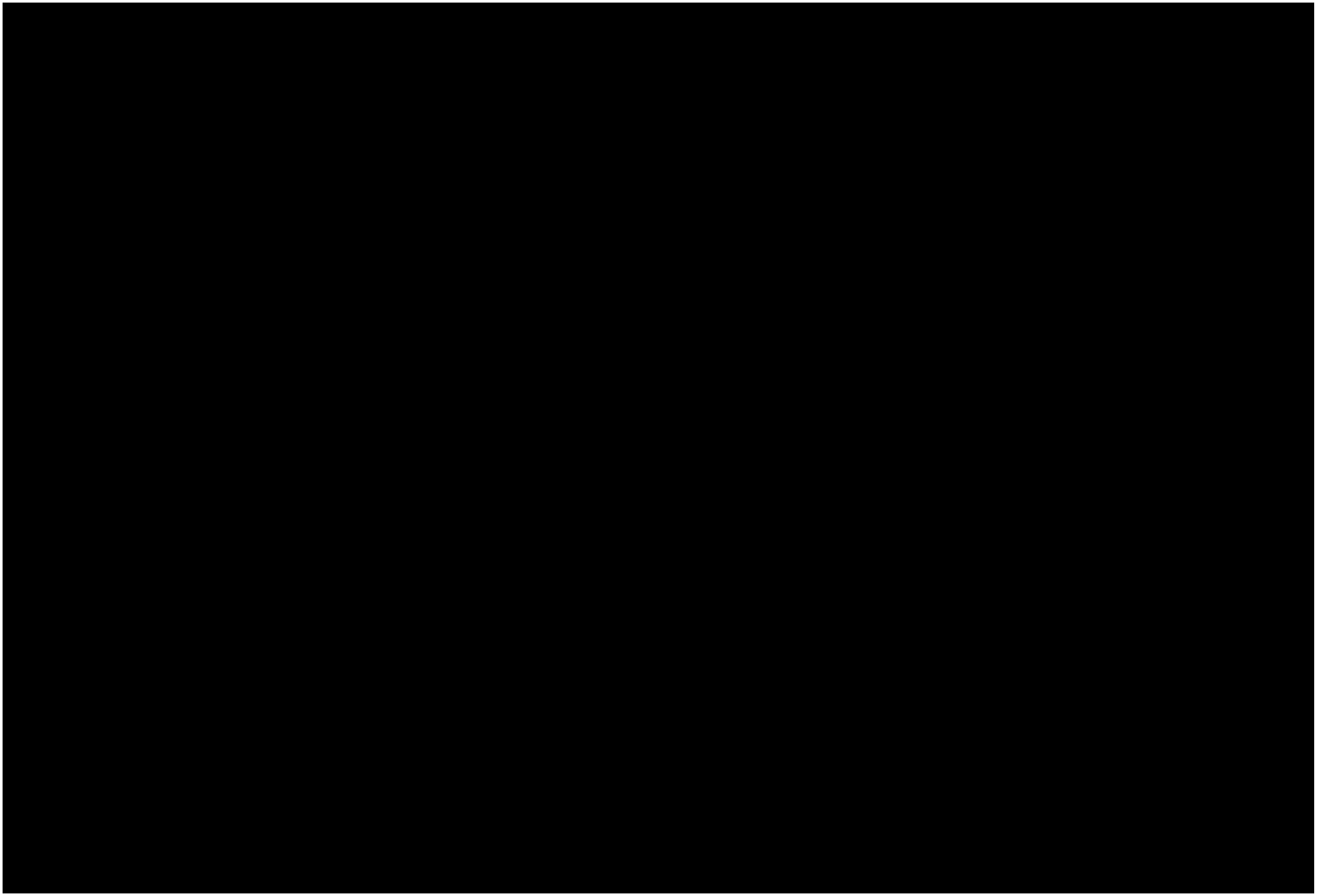
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 11/24/2021



Member Forecasted On Peak Demand Day for December 2021

San Miguel Power Association, Inc.

Date of On Peak Day - 12/25/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Socorro Electric Cooperative, Inc.

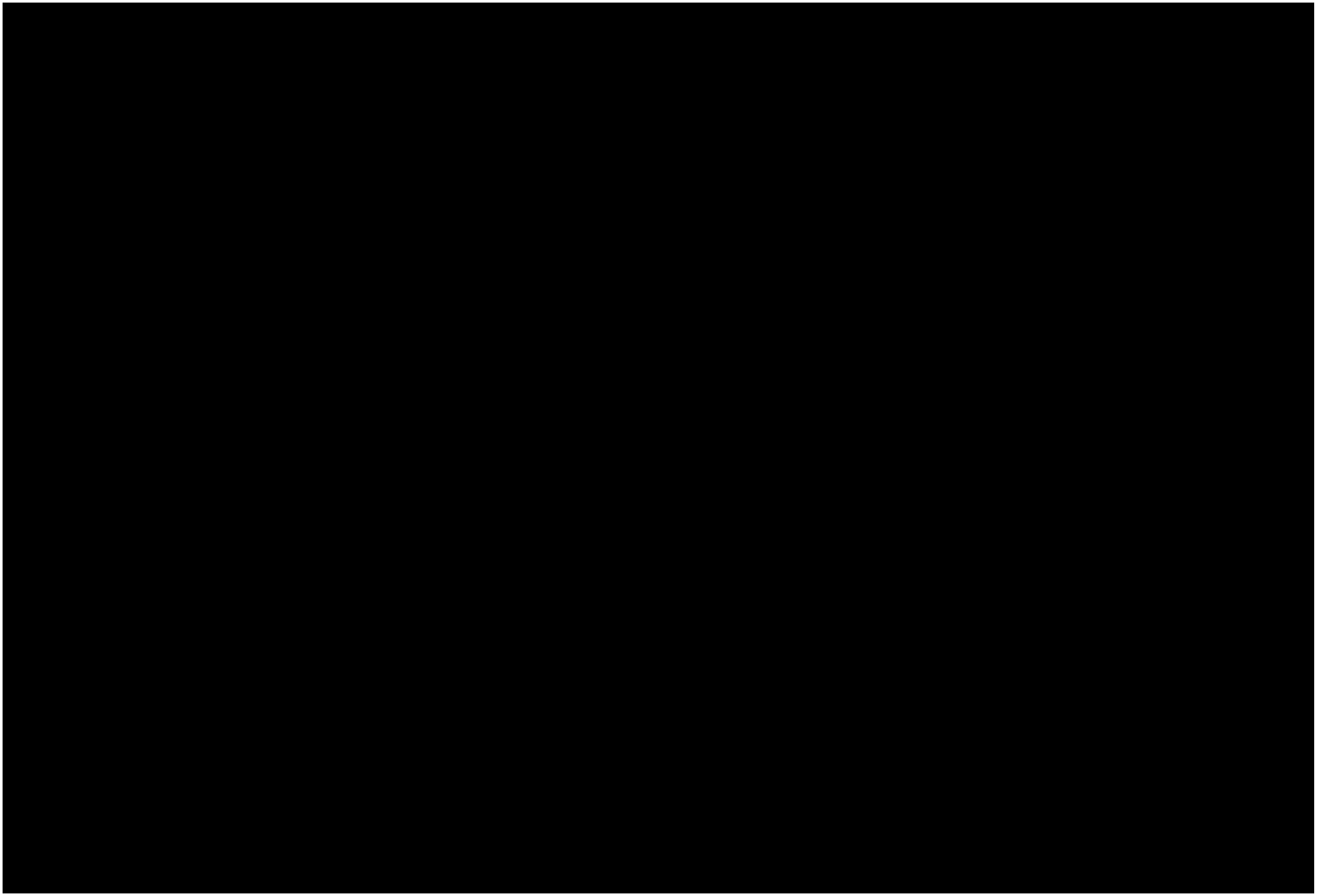
Date of On Peak Day - 01/29/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Socorro Electric Cooperative, Inc.

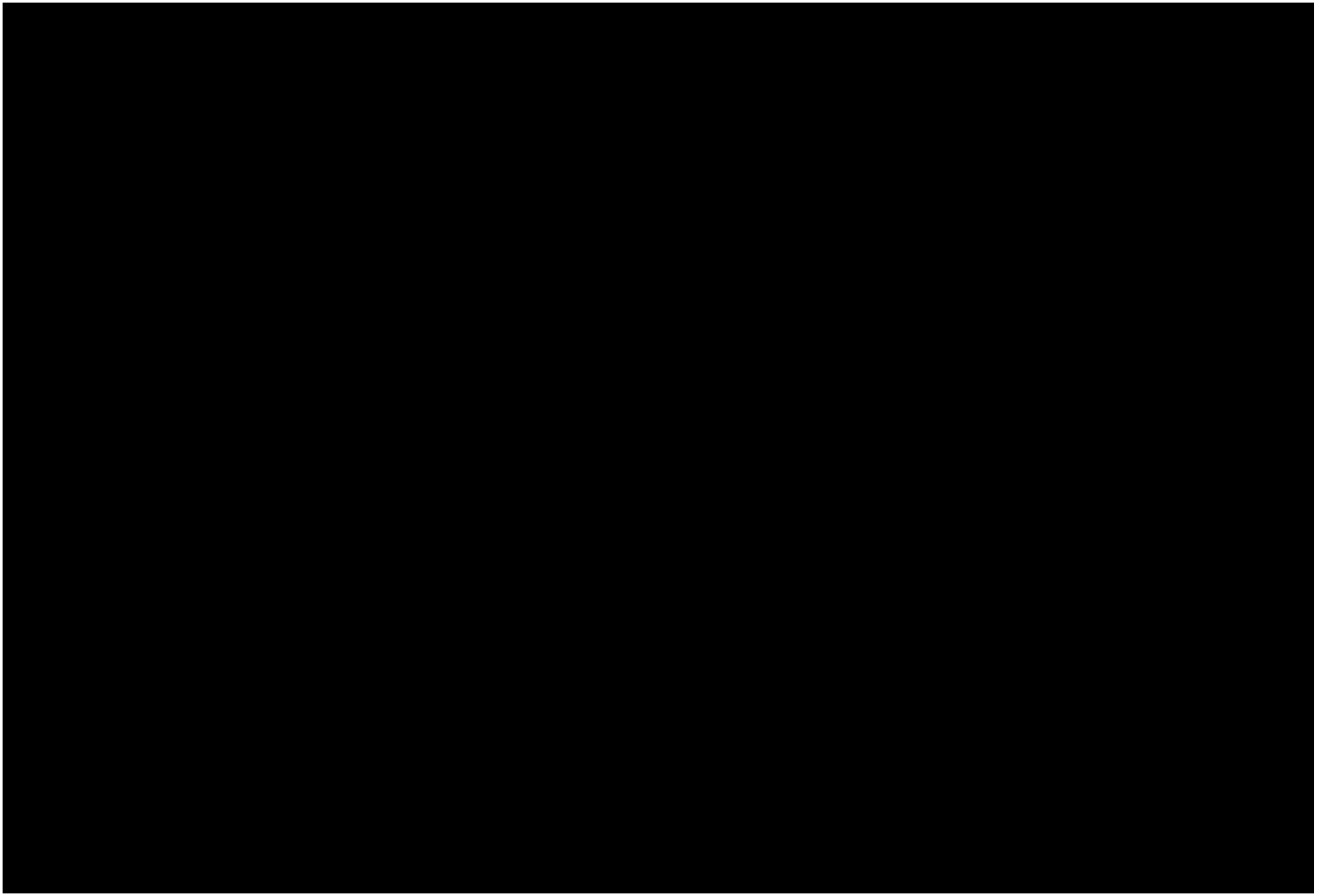
Date of On Peak Day - 02/02/2021



Member Forecasted On Peak Demand Day for March 2021

Socorro Electric Cooperative, Inc.

Date of On Peak Day - 03/02/2021



Member Forecasted On Peak Demand Day for April 2021

Socorro Electric Cooperative, Inc.

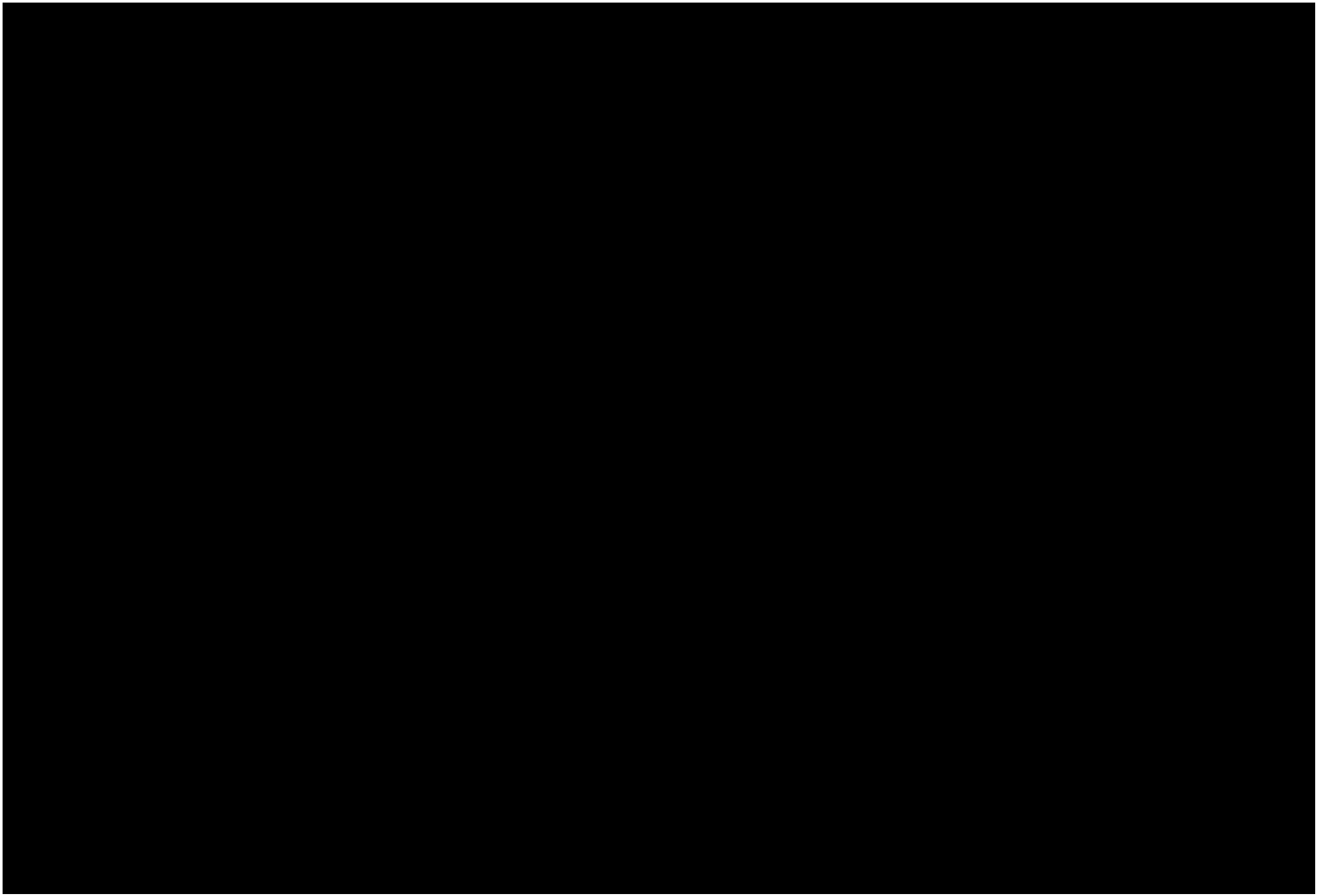
Date of On Peak Day - 04/06/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Socorro Electric Cooperative, Inc.

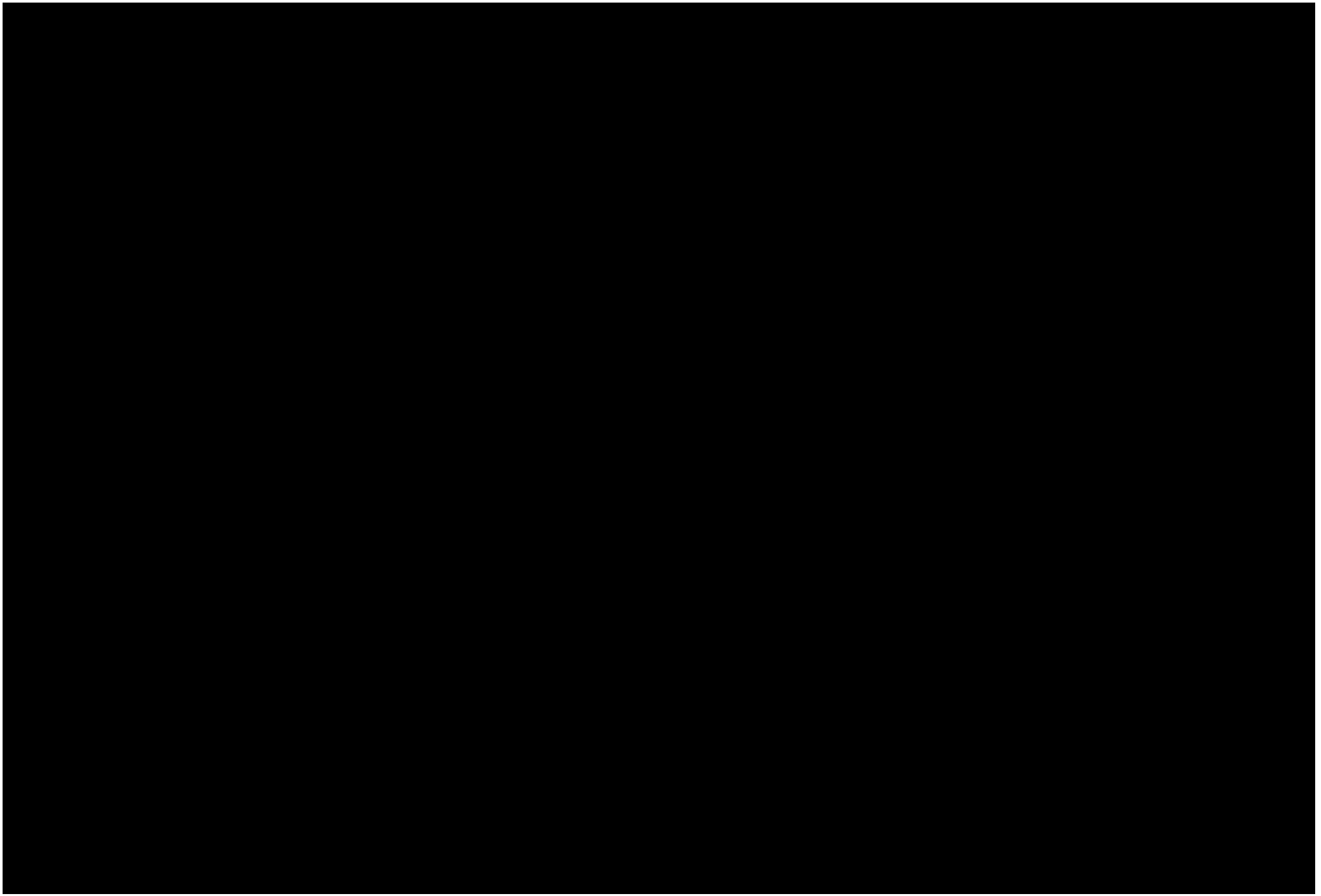
Date of On Peak Day - 05/26/2021



Member Forecasted On Peak Demand Day for June 2021

Socorro Electric Cooperative, Inc.

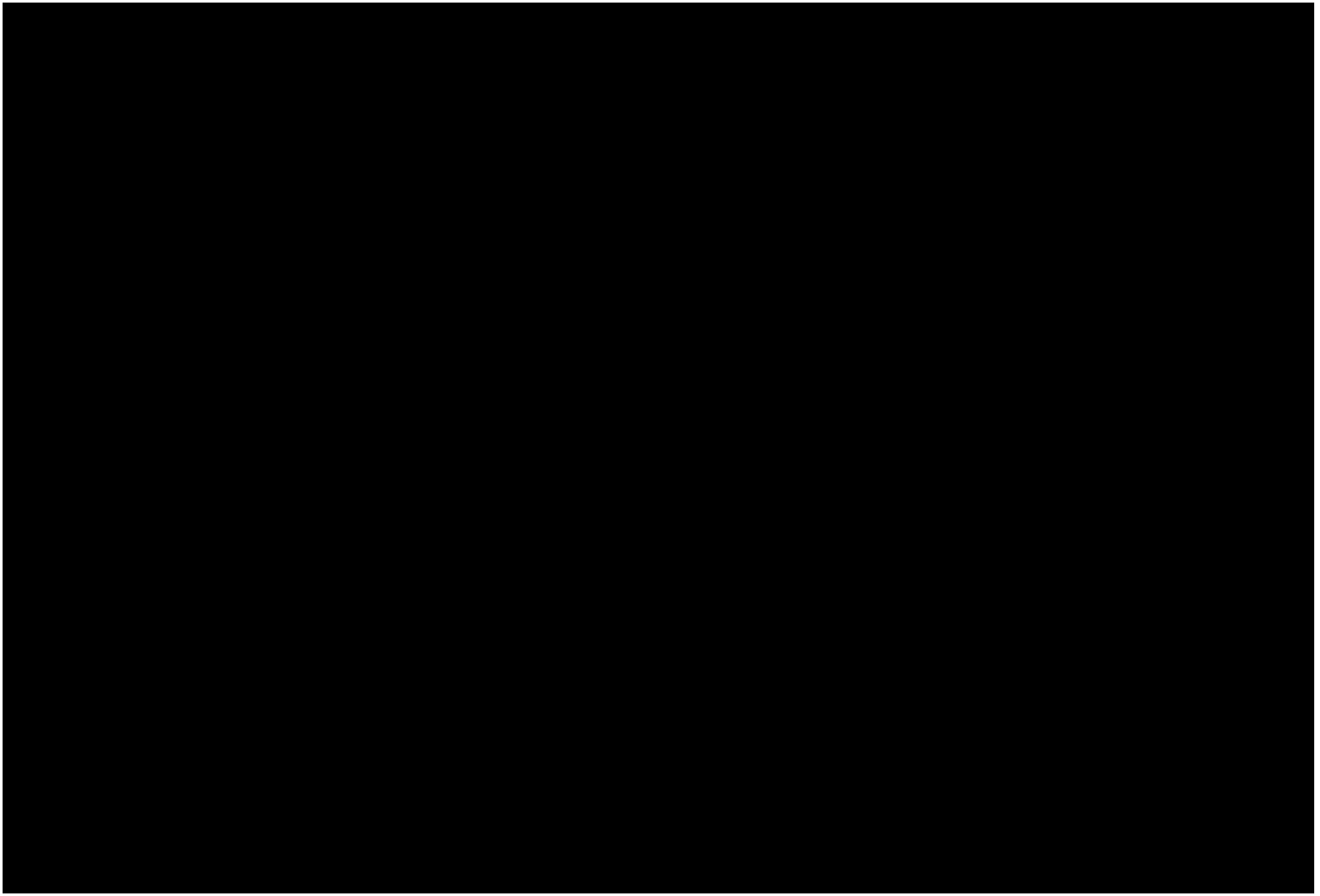
Date of On Peak Day - 06/27/2021



Member Forecasted On Peak Demand Day for July 2021

Socorro Electric Cooperative, Inc.

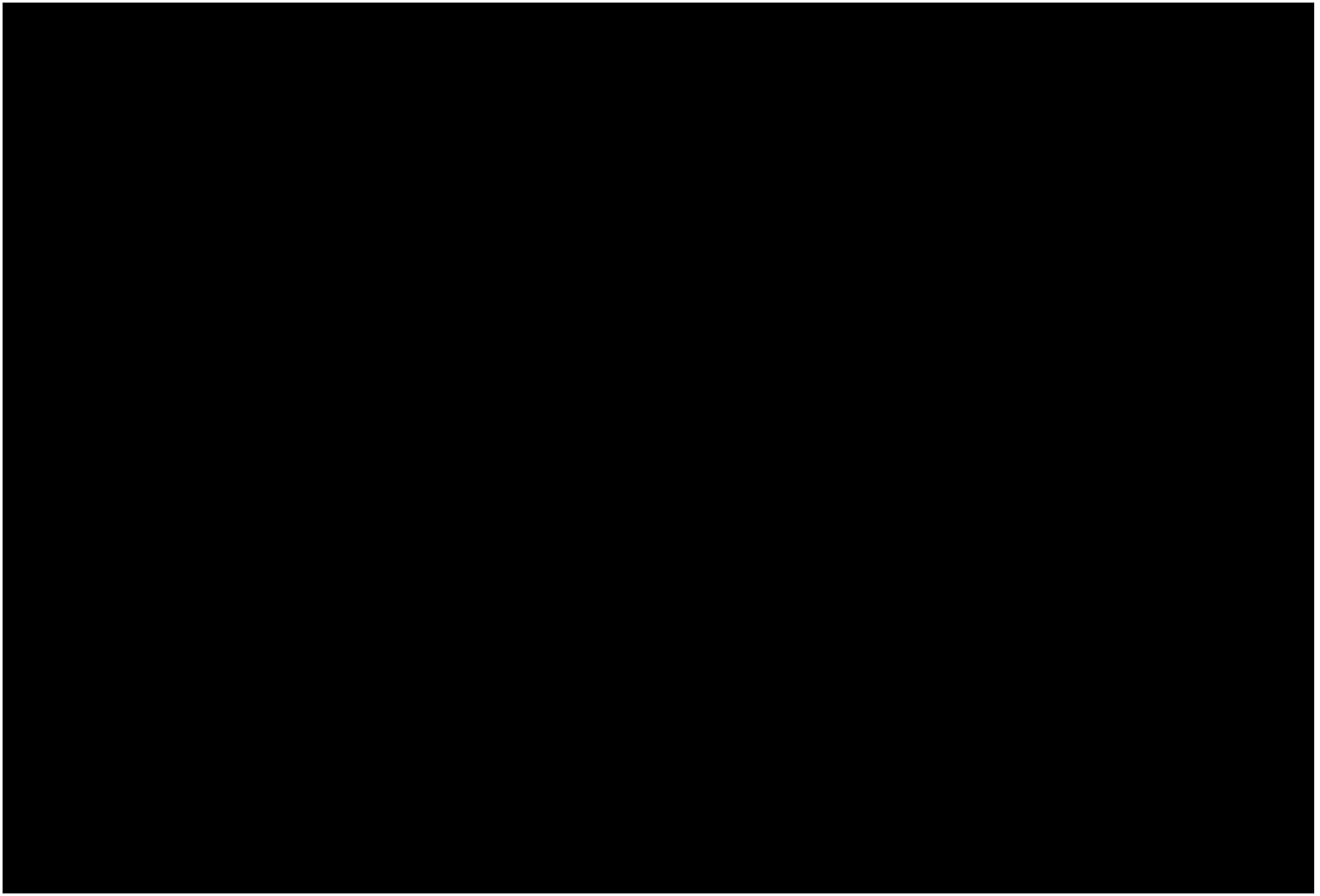
Date of On Peak Day - 07/14/2021



Member Forecasted On Peak Demand Day for August 2021

Socorro Electric Cooperative, Inc.

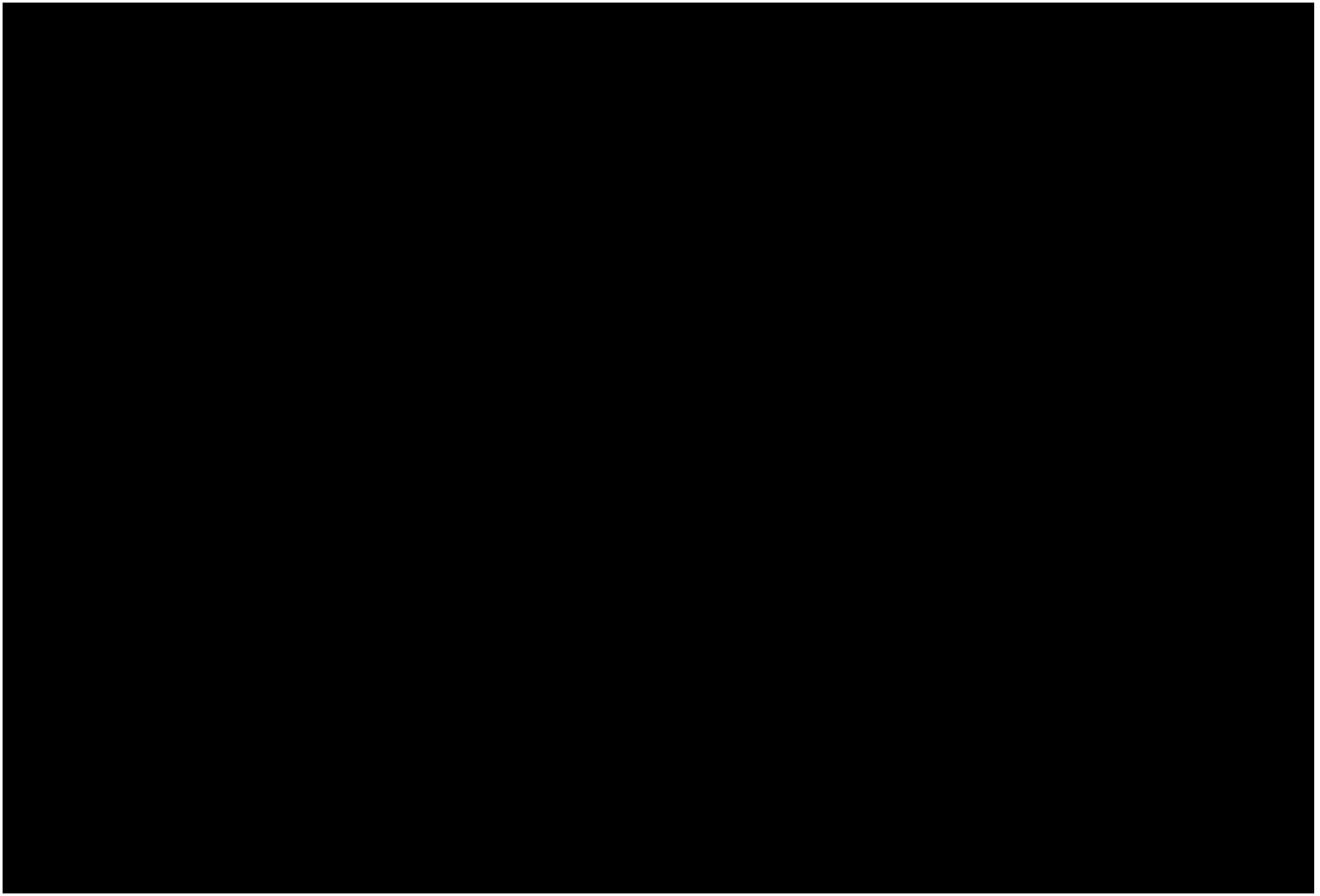
Date of On Peak Day - 08/18/2021



Member Forecasted On Peak Demand Day for September 2021

Socorro Electric Cooperative, Inc.

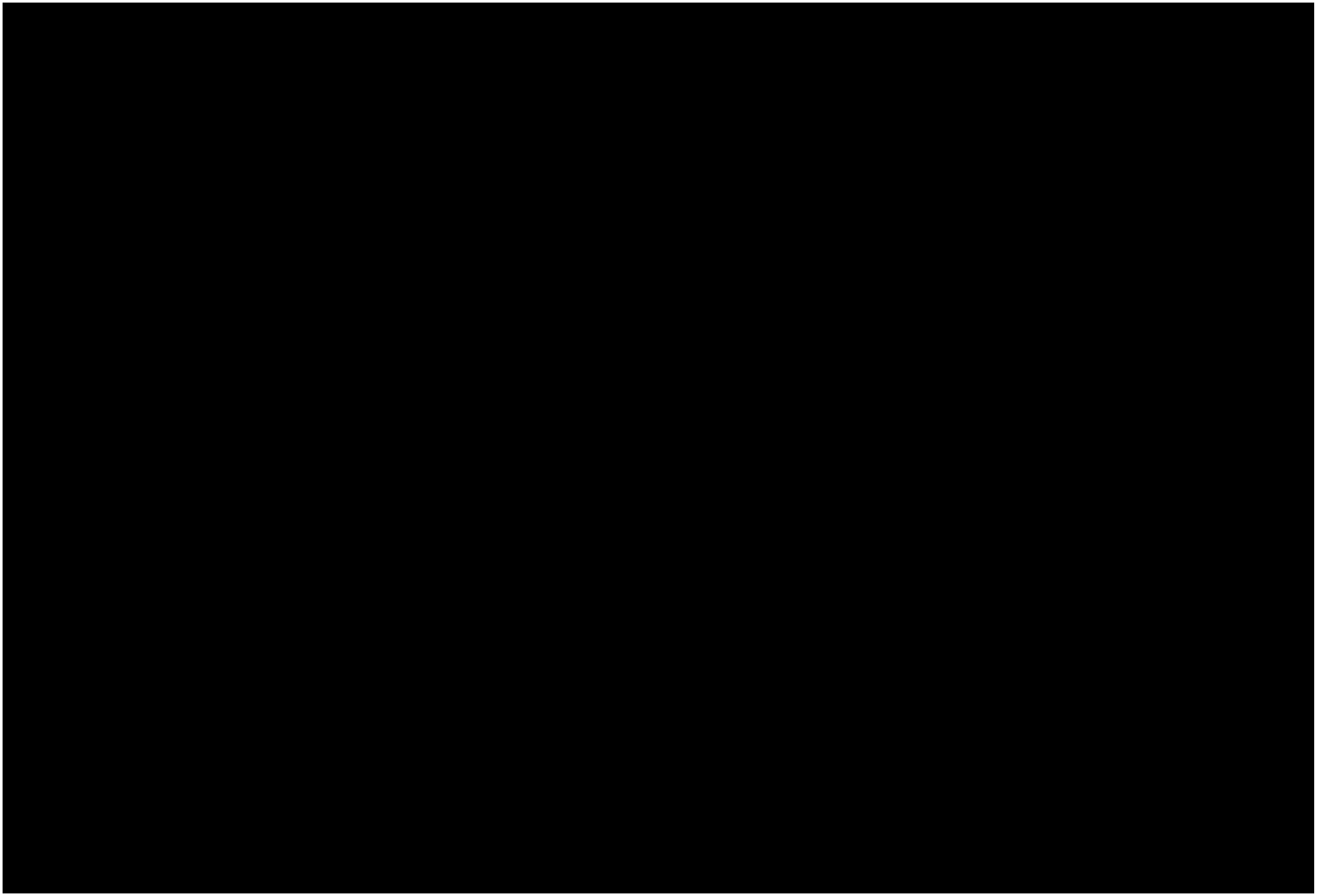
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Socorro Electric Cooperative, Inc.

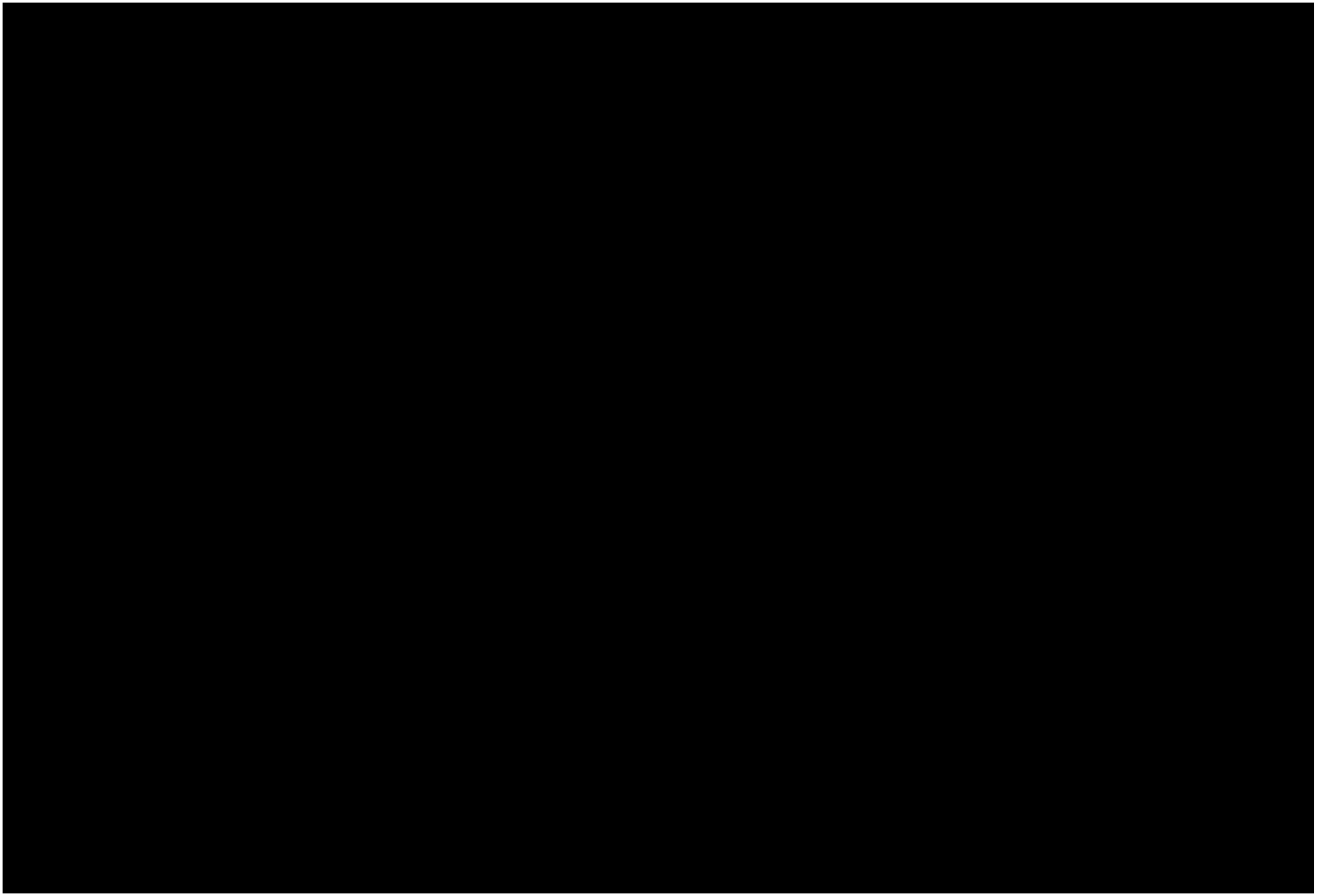
Date of On Peak Day - 10/02/2021



Member Forecasted On Peak Demand Day for November 2021

Socorro Electric Cooperative, Inc.

Date of On Peak Day - 11/16/2021



Member Forecasted On Peak Demand Day for December 2021

Socorro Electric Cooperative, Inc.

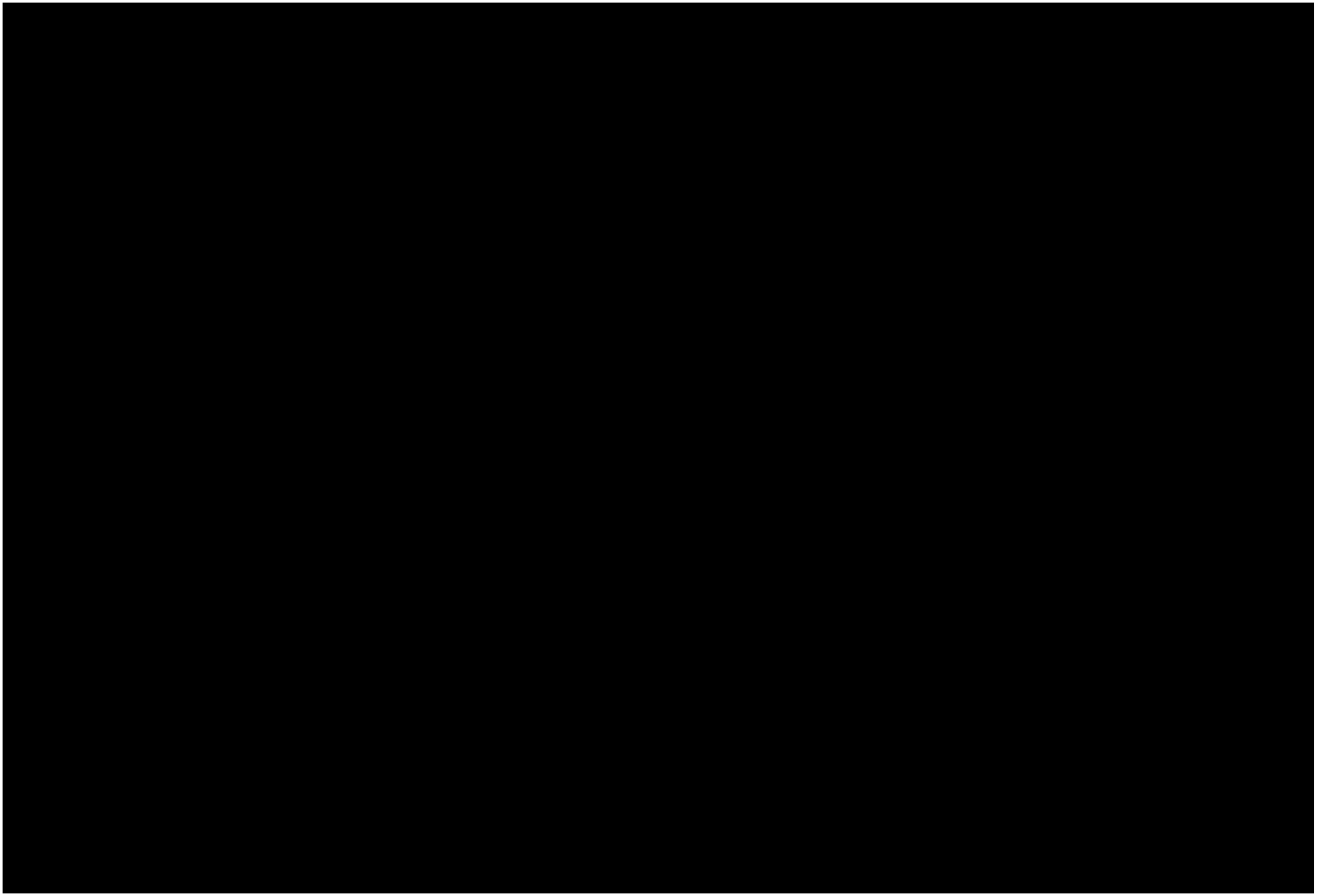
Date of On Peak Day - 12/28/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Springer Electric Cooperative, Inc.

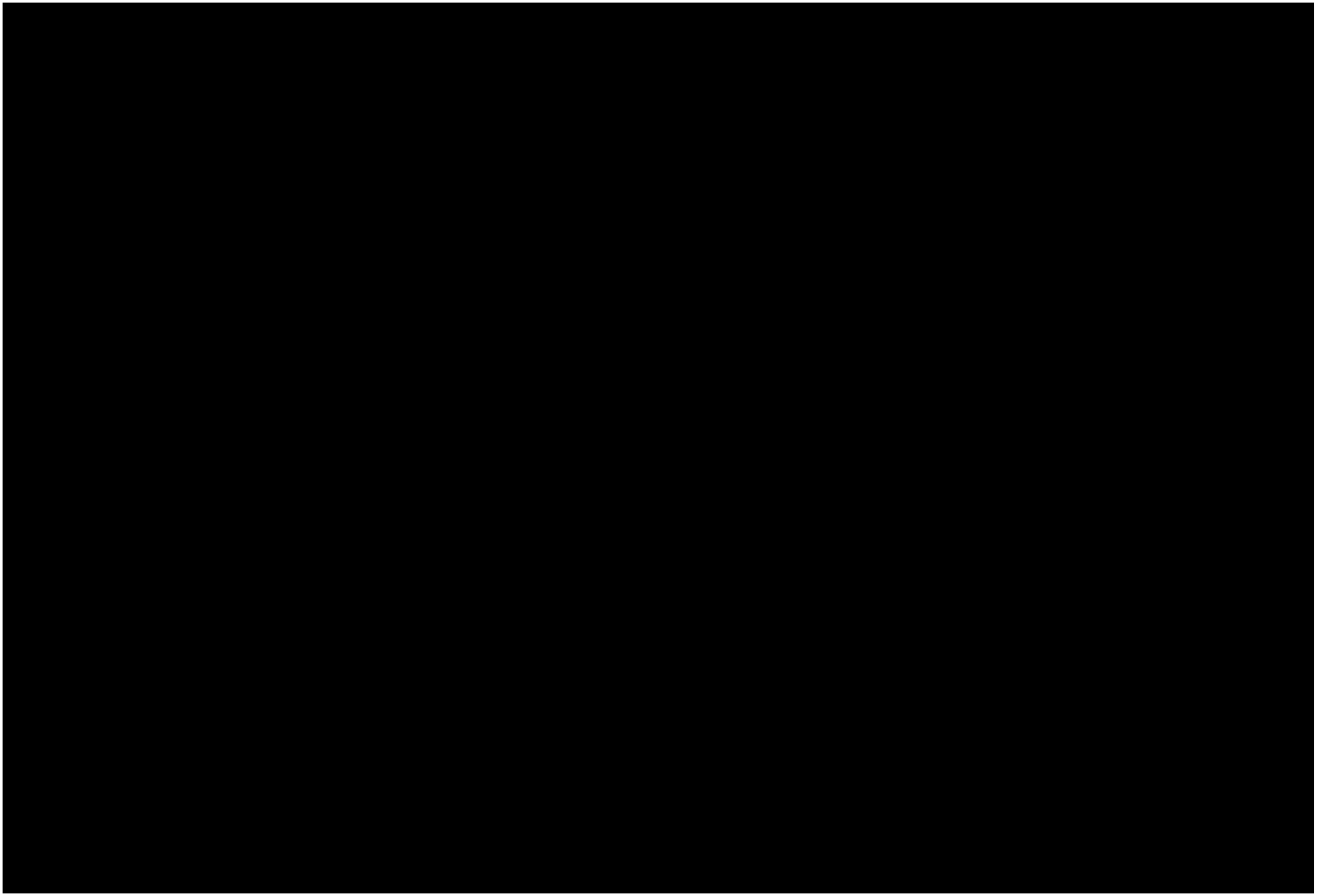
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Springer Electric Cooperative, Inc.

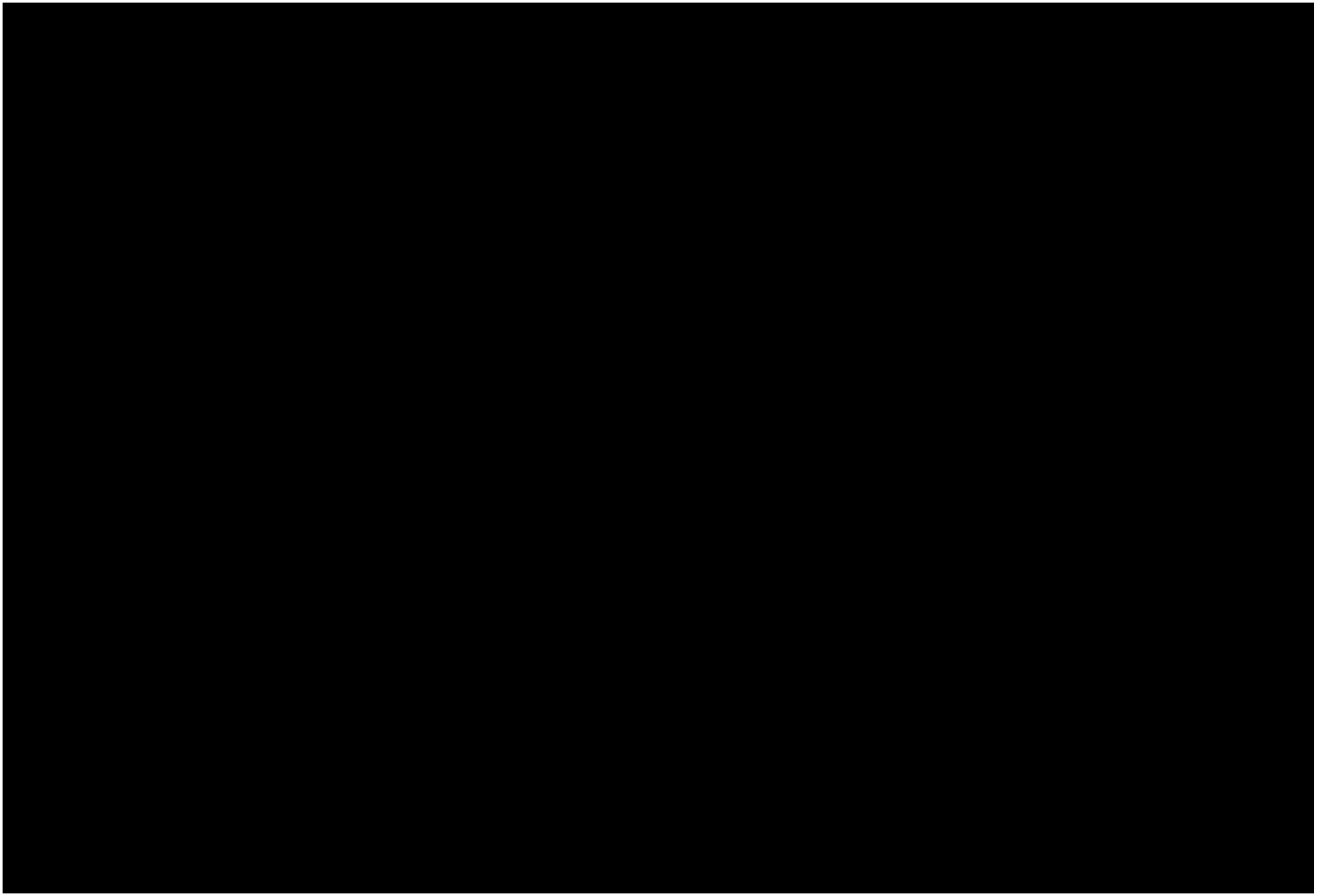
Date of On Peak Day - 02/14/2021



Member Forecasted On Peak Demand Day for March 2021

Springer Electric Cooperative, Inc.

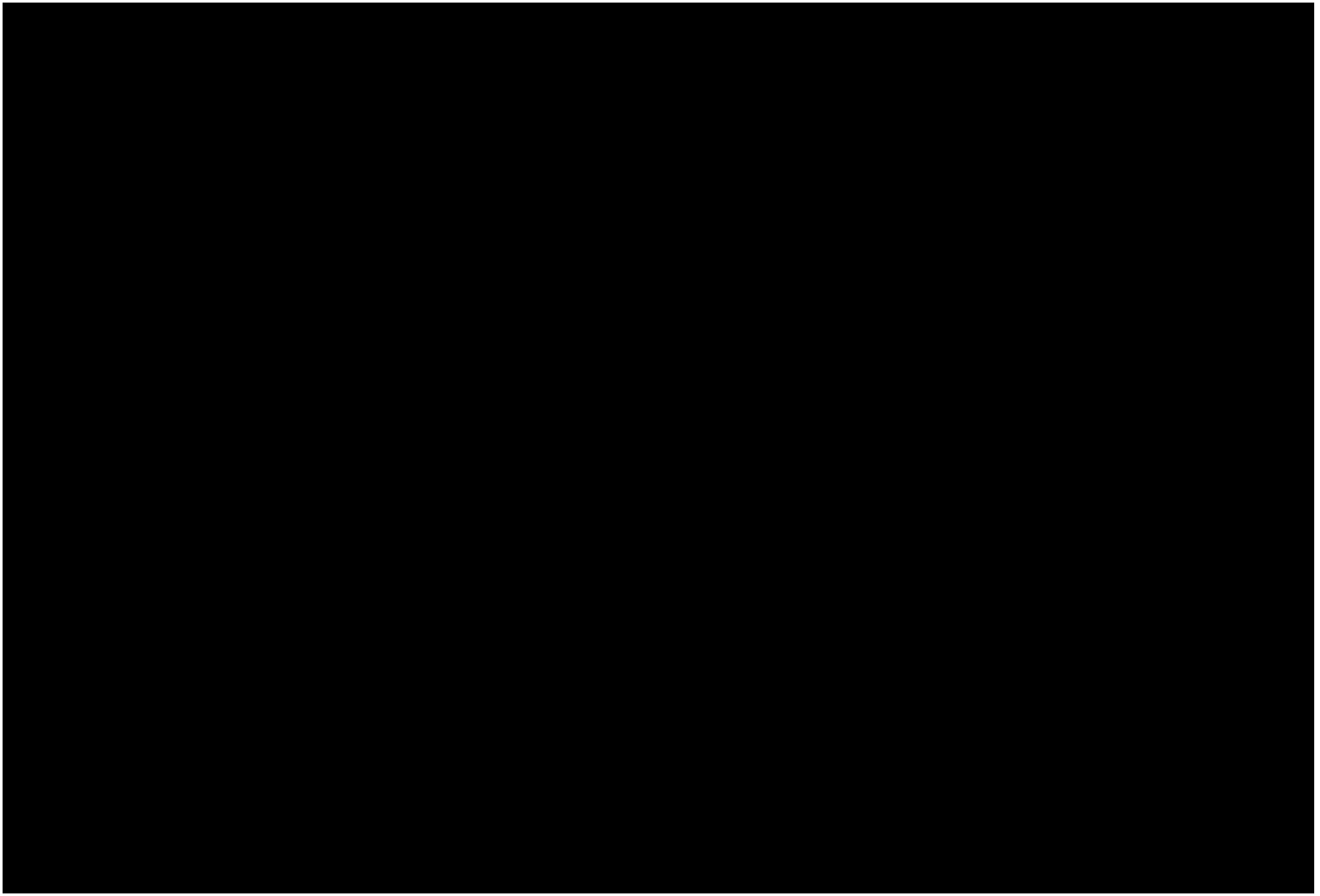
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Springer Electric Cooperative, Inc.

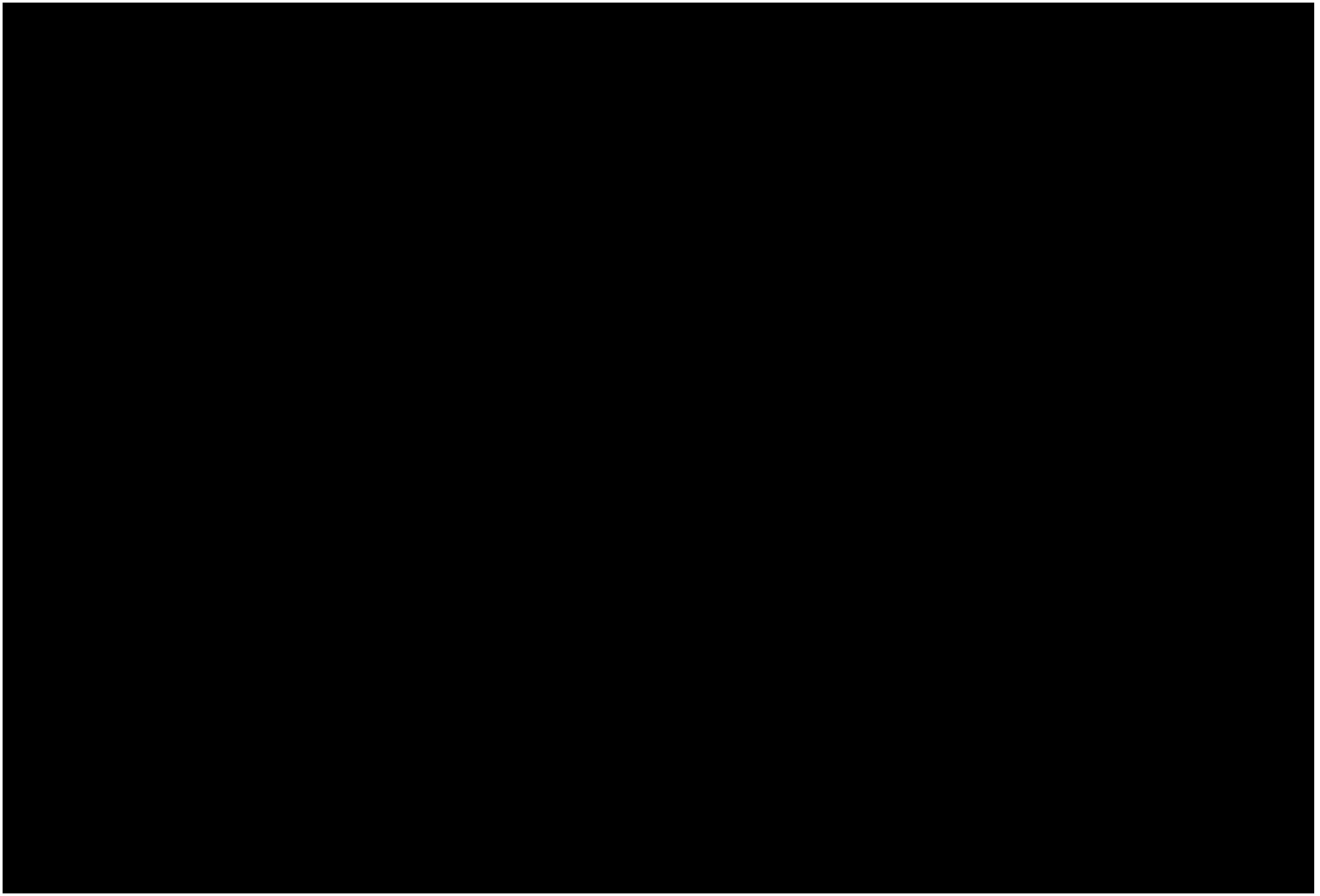
Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Springer Electric Cooperative, Inc.

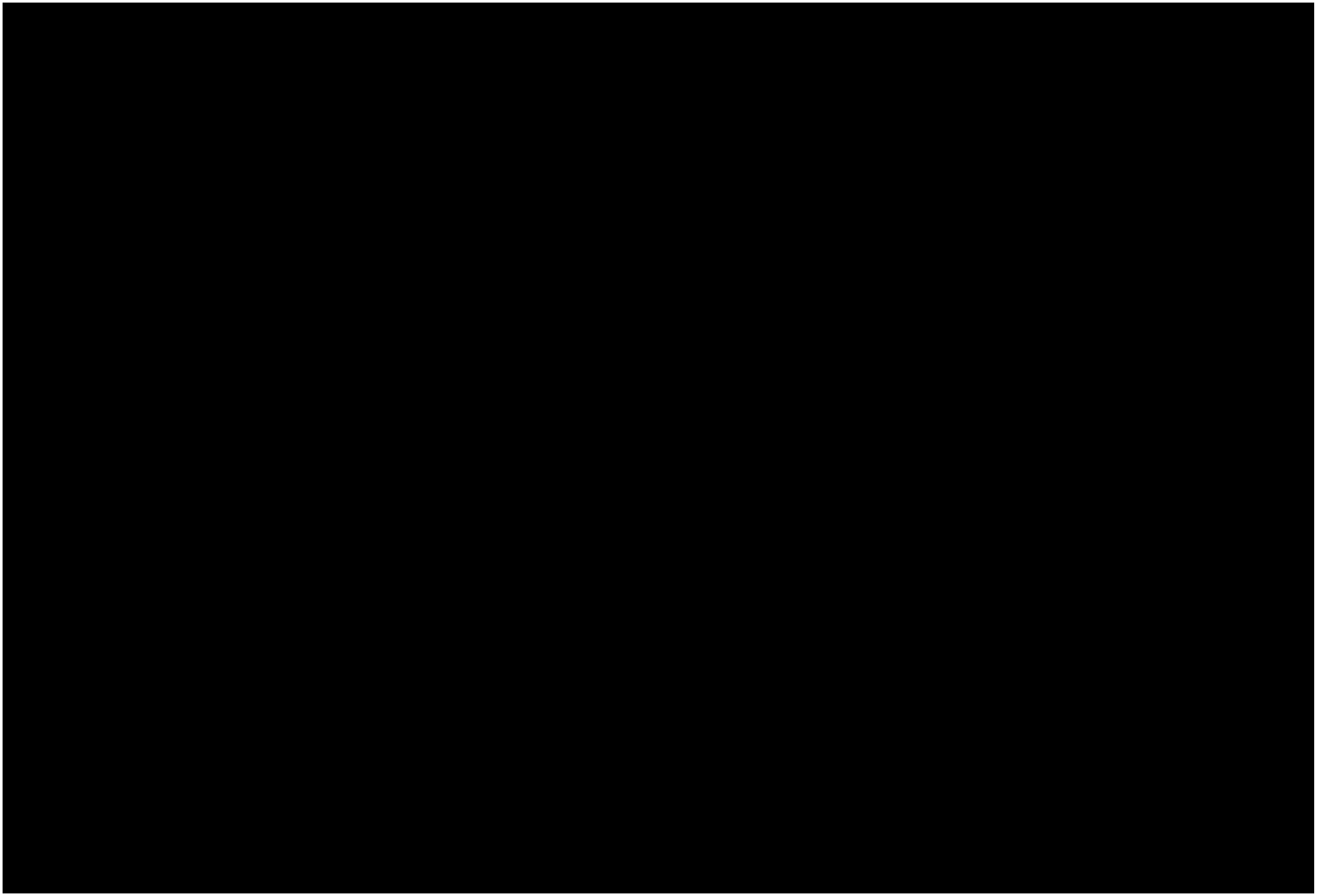
Date of On Peak Day - 05/01/2021



Member Forecasted On Peak Demand Day for June 2021

Springer Electric Cooperative, Inc.

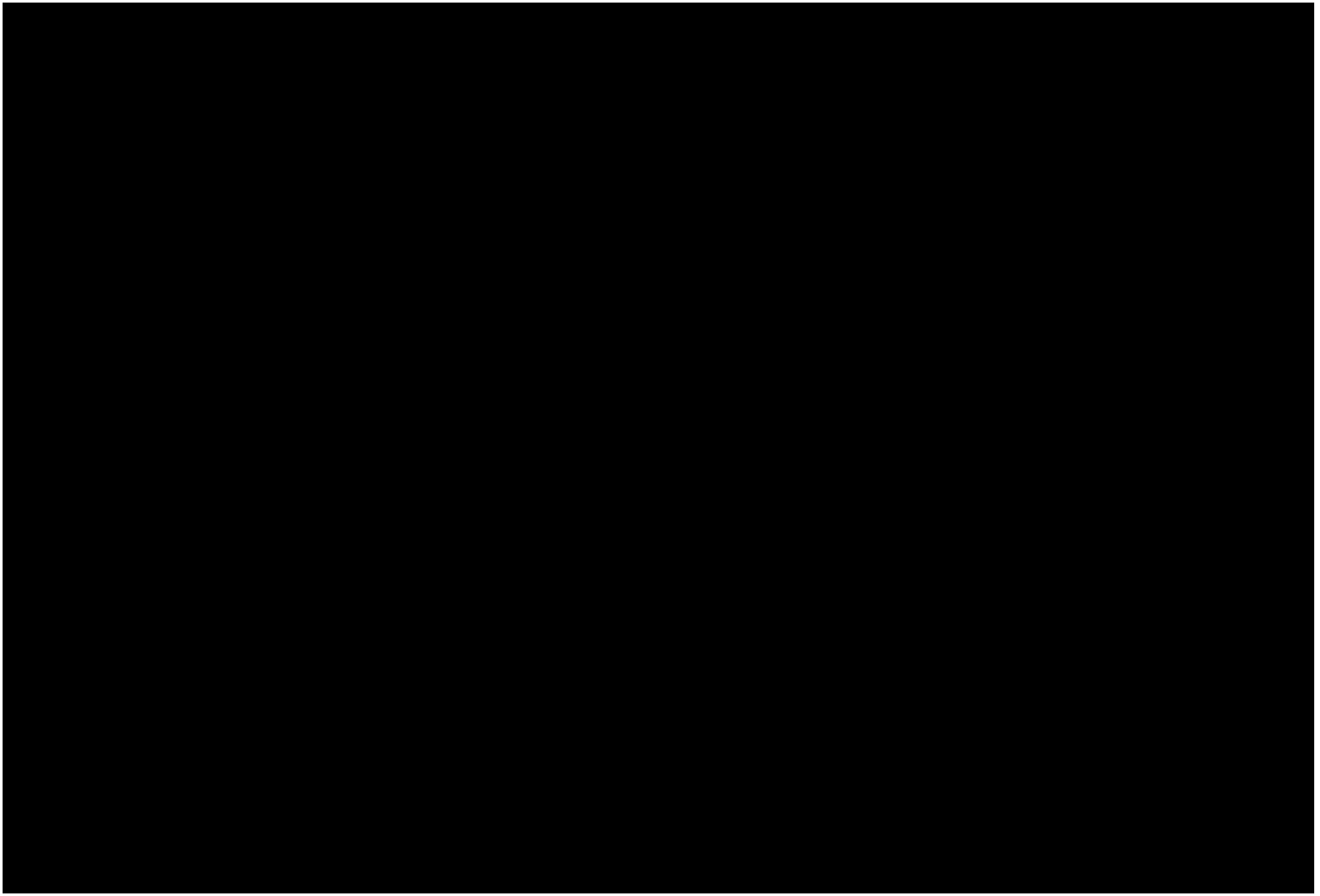
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Springer Electric Cooperative, Inc.

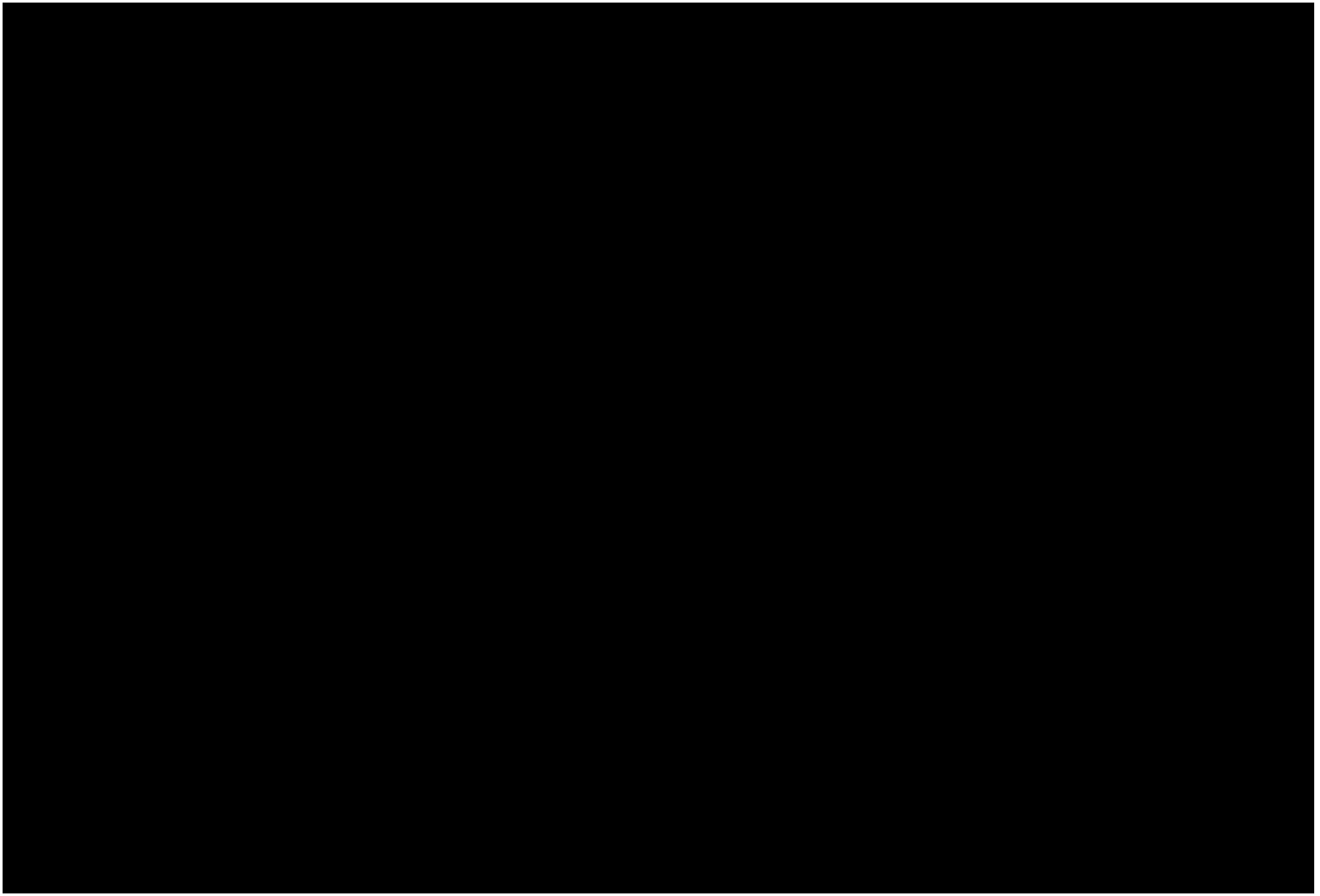
Date of On Peak Day - 07/18/2021



Member Forecasted On Peak Demand Day for August 2021

Springer Electric Cooperative, Inc.

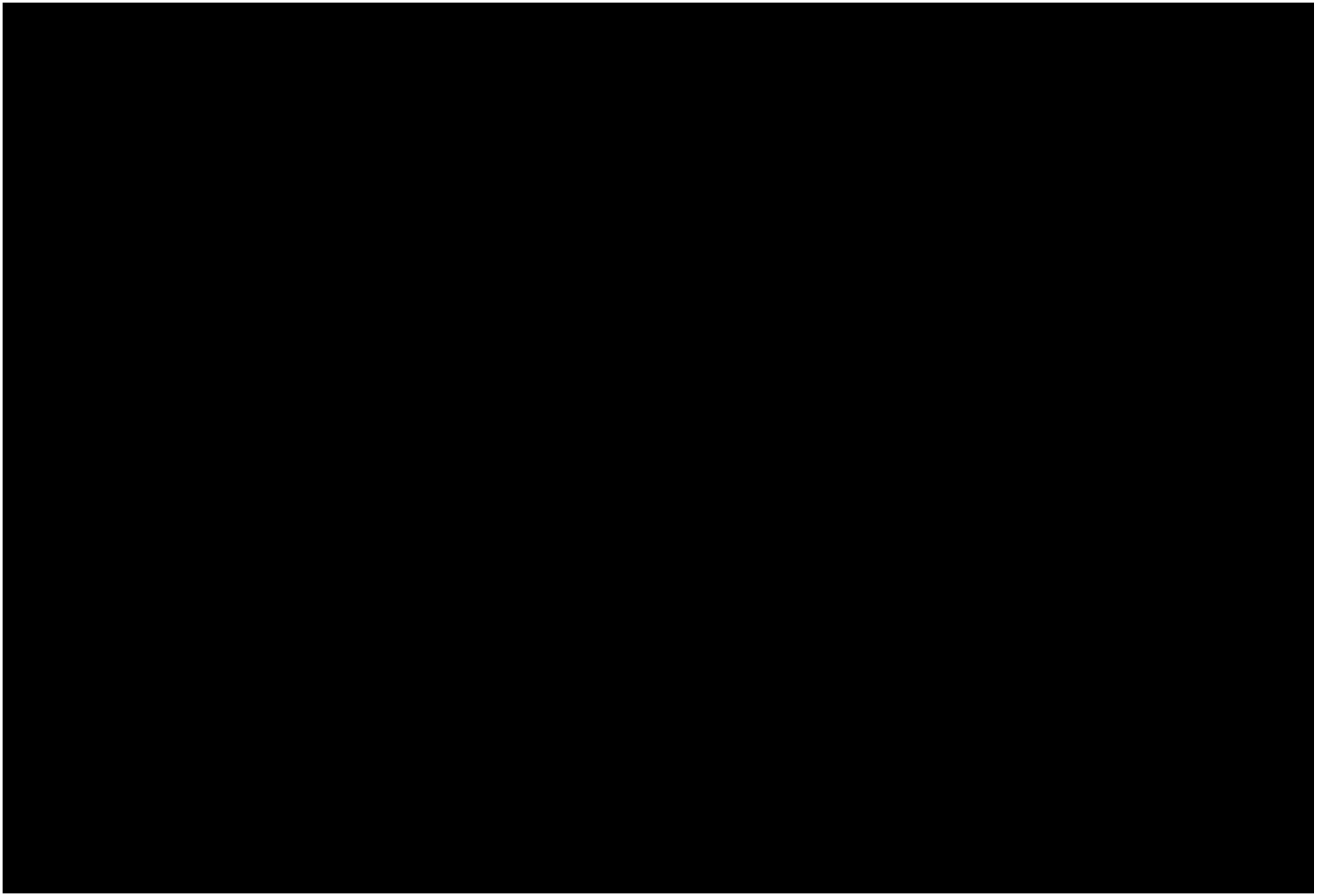
Date of On Peak Day - 08/02/2021



Member Forecasted On Peak Demand Day for September 2021

Springer Electric Cooperative, Inc.

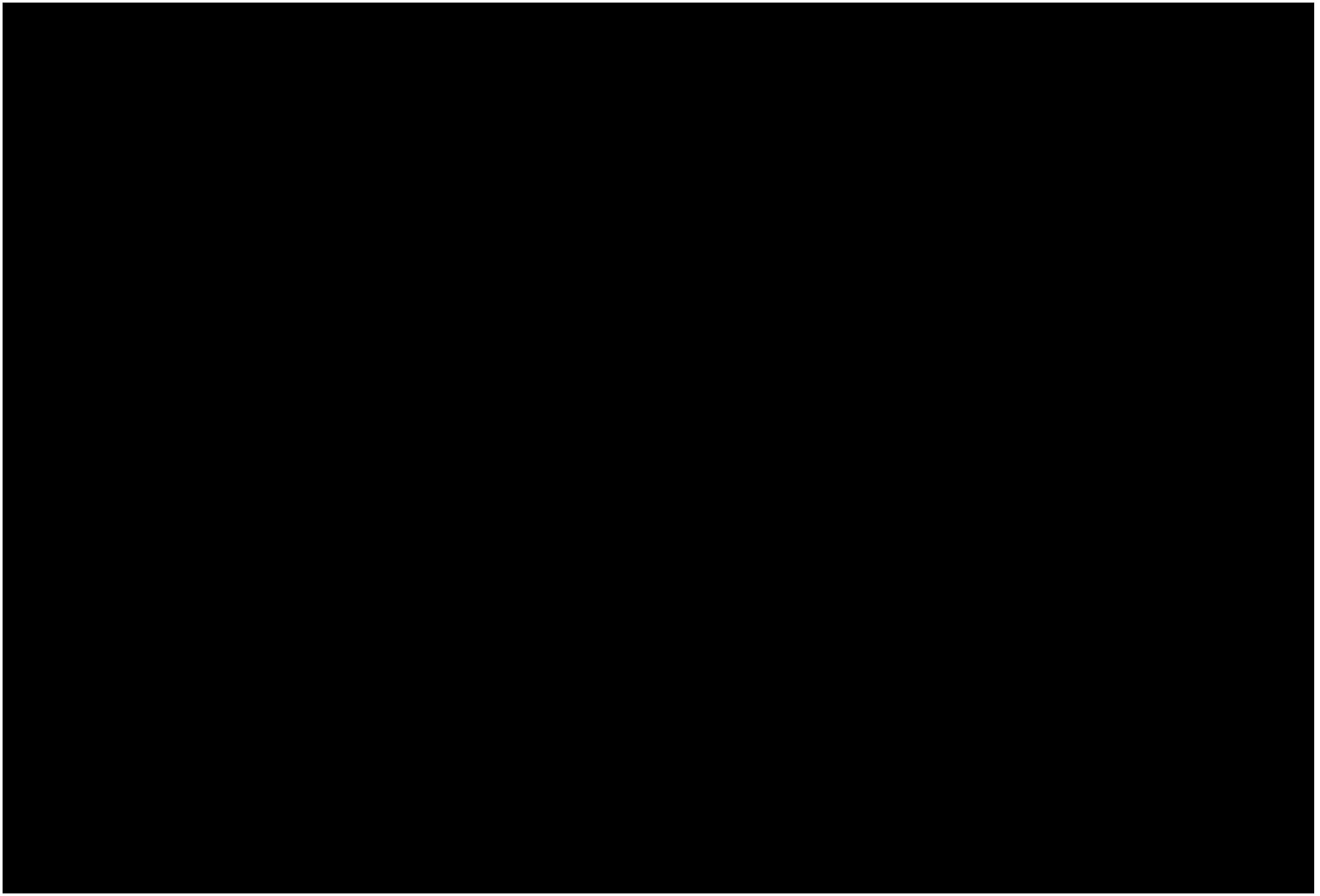
Date of On Peak Day - 09/08/2021



Member Forecasted On Peak Demand Day for October 2021

Springer Electric Cooperative, Inc.

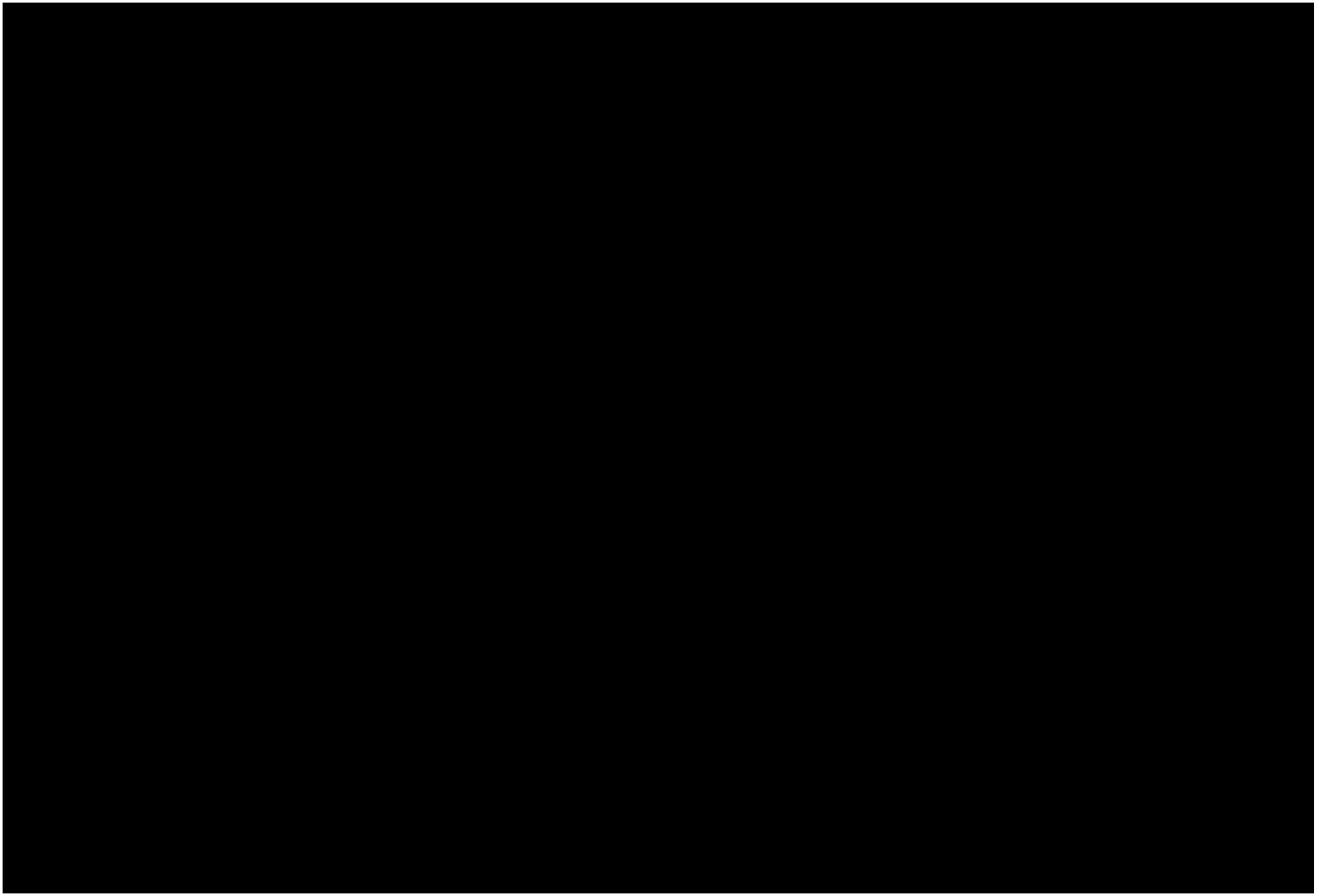
Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

Springer Electric Cooperative, Inc.

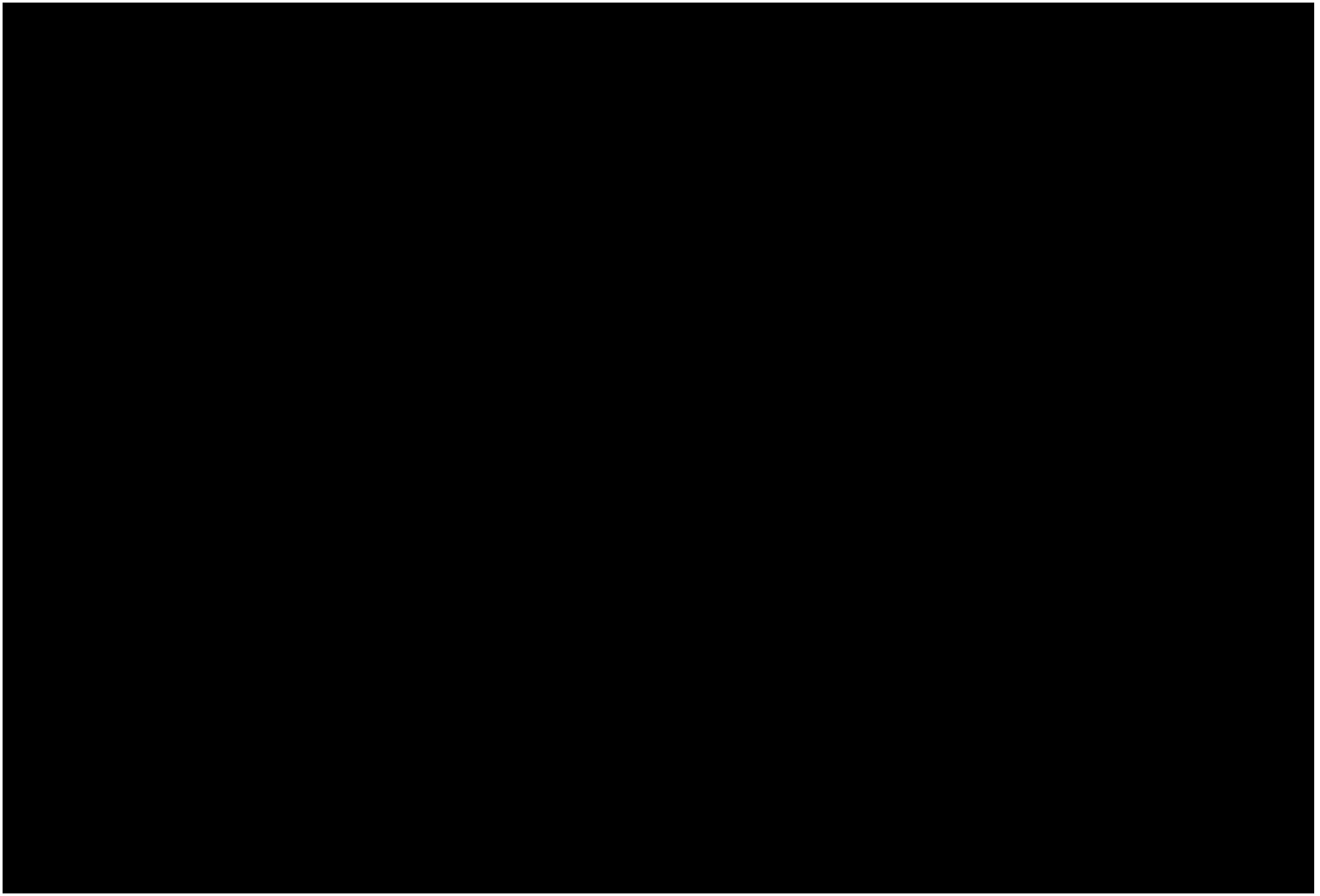
Date of On Peak Day - 11/11/2021



Member Forecasted On Peak Demand Day for December 2021

Springer Electric Cooperative, Inc.

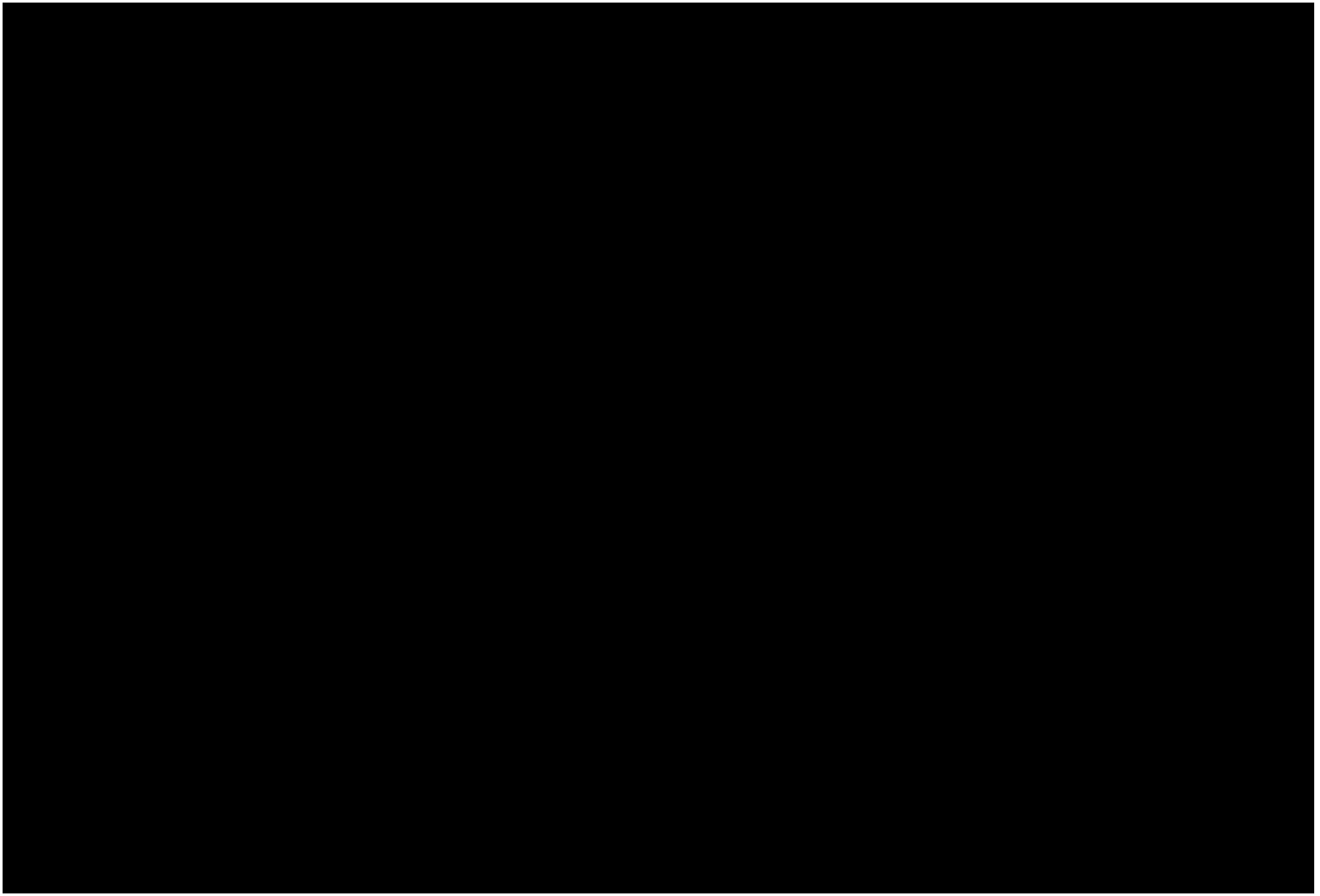
Date of On Peak Day - 12/01/2021



Member Forecasted On Peak Demand Day for January 2021

Southwestern Electric Cooperative, Inc.

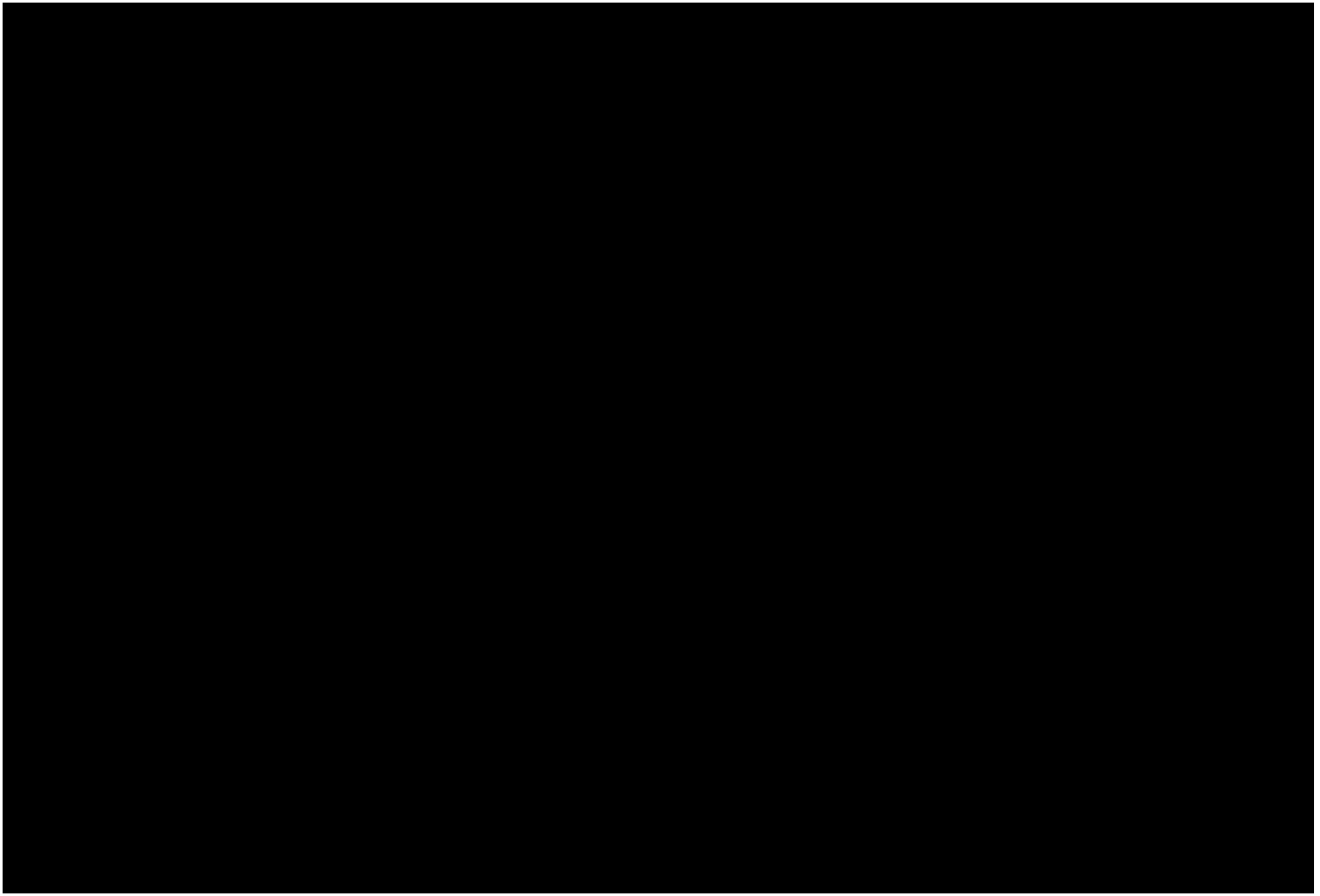
Date of On Peak Day - 01/15/2021



Member Forecasted On Peak Demand Day for February 2021

Southwestern Electric Cooperative, Inc.

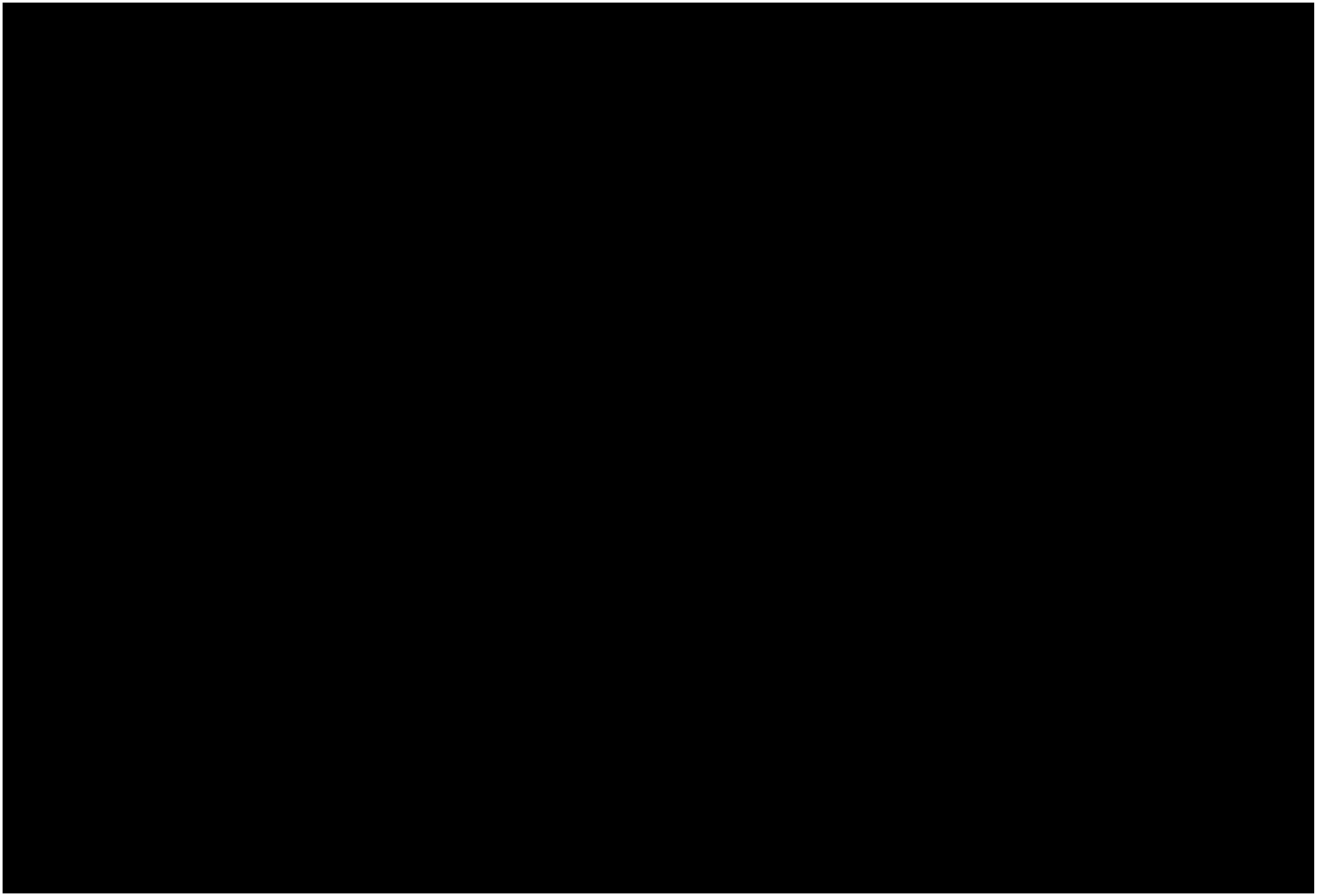
Date of On Peak Day - 02/28/2021



Member Forecasted On Peak Demand Day for March 2021

Southwestern Electric Cooperative, Inc.

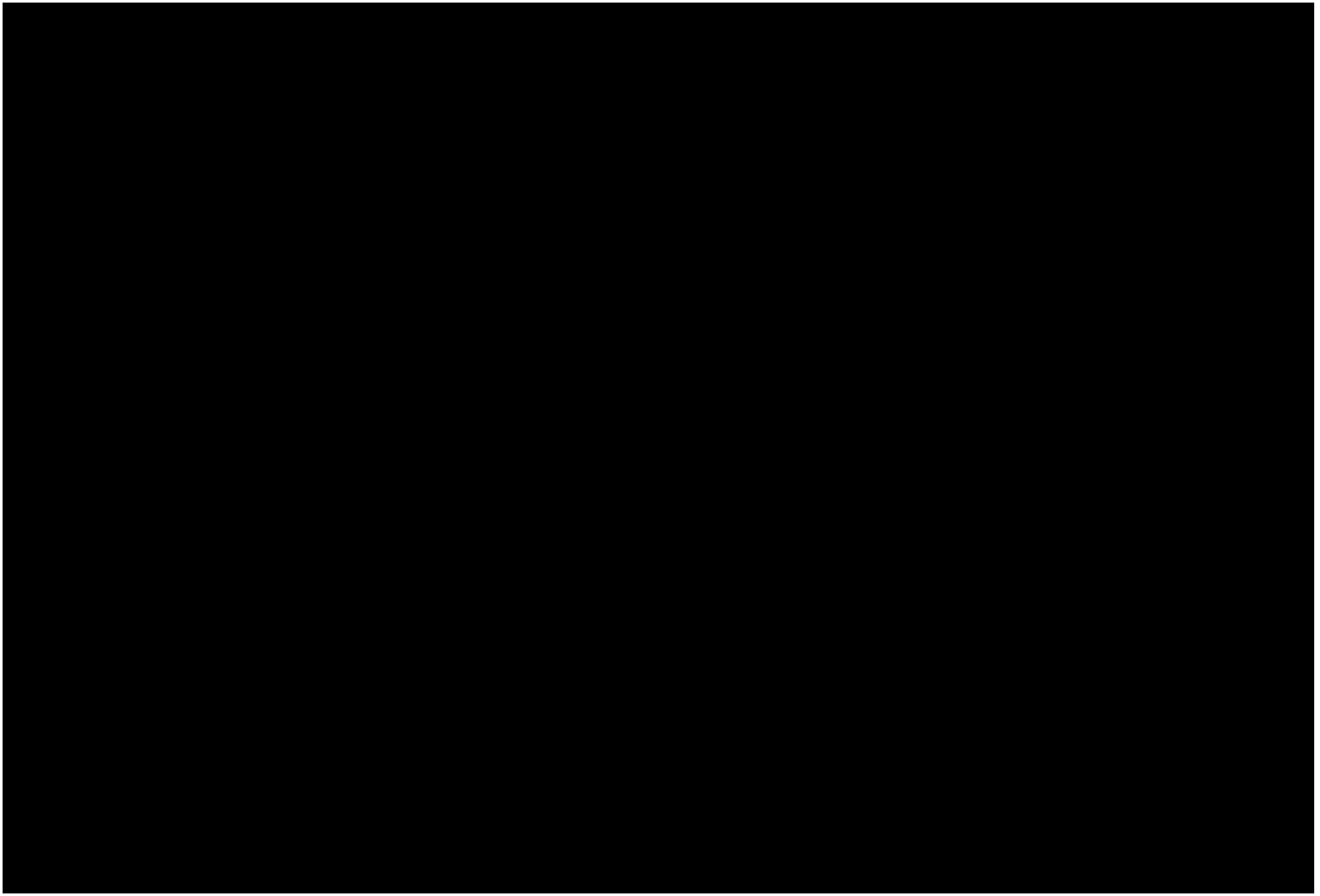
Date of On Peak Day - 03/17/2021



Member Forecasted On Peak Demand Day for April 2021

Southwestern Electric Cooperative, Inc.

Date of On Peak Day - 04/20/2021



Member Forecasted On Peak Demand Day for May 2021

Southwestern Electric Cooperative, Inc.

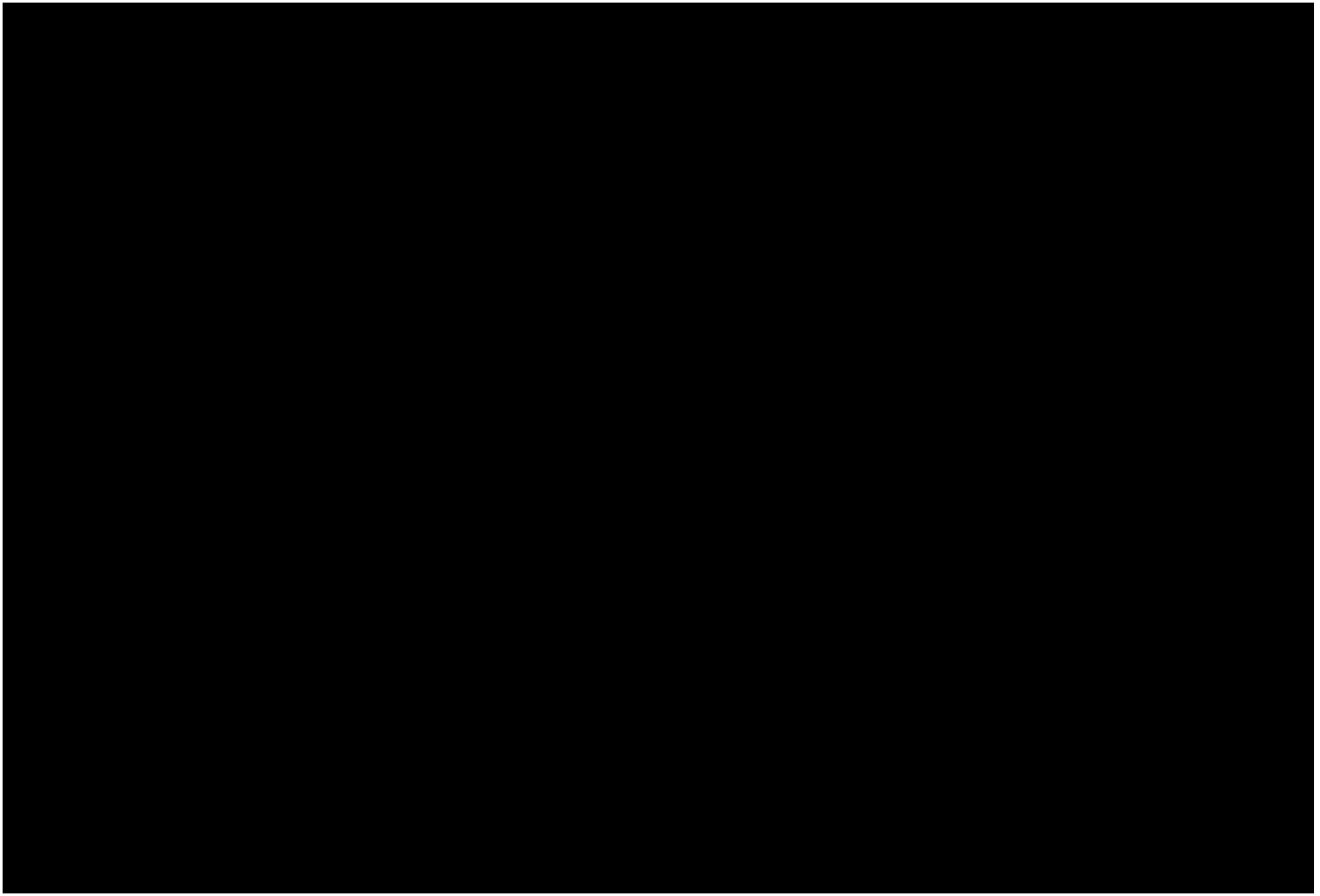
Date of On Peak Day - 05/26/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Southwestern Electric Cooperative, Inc.

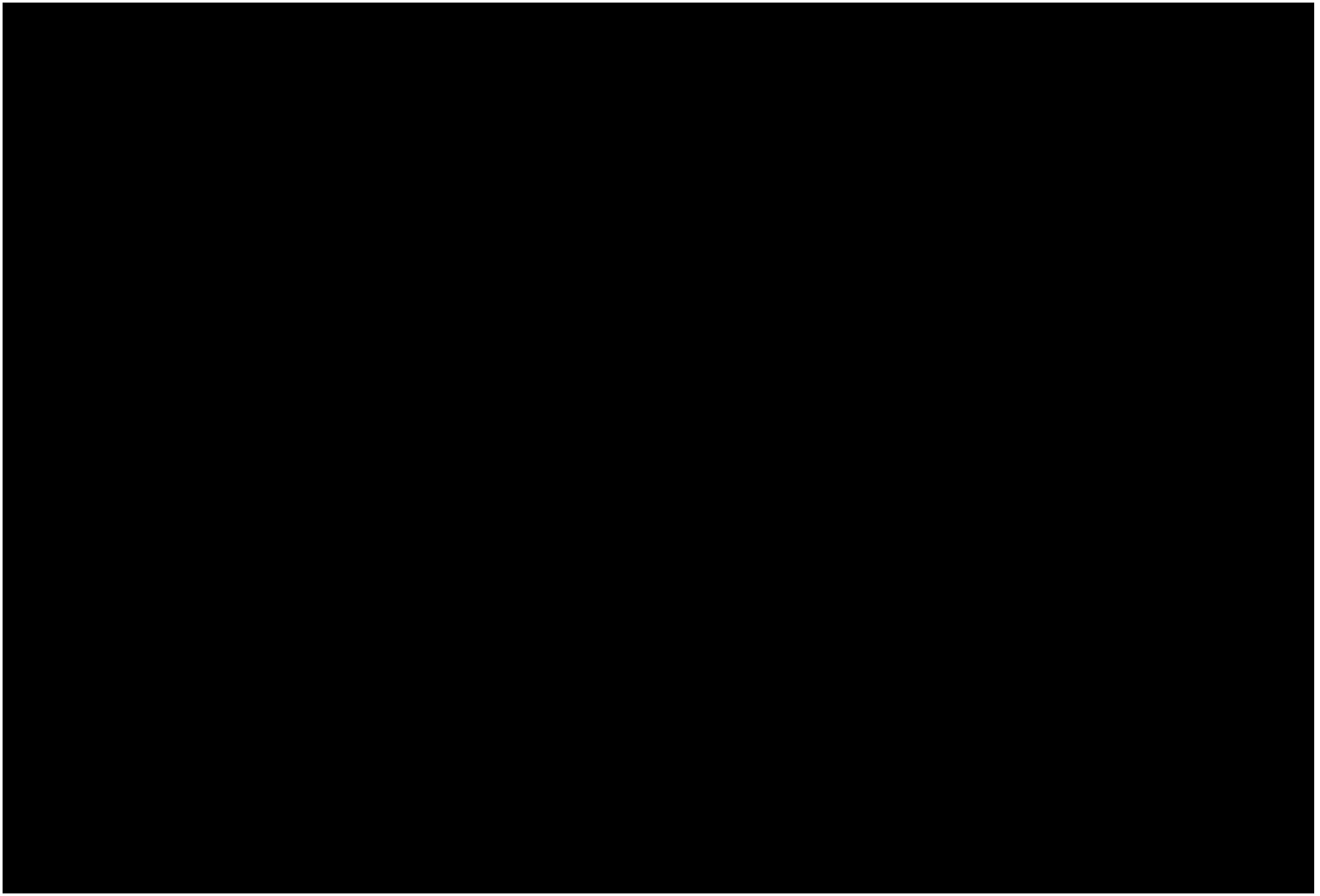
Date of On Peak Day - 06/30/2021



Member Forecasted On Peak Demand Day for July 2021

Southwestern Electric Cooperative, Inc.

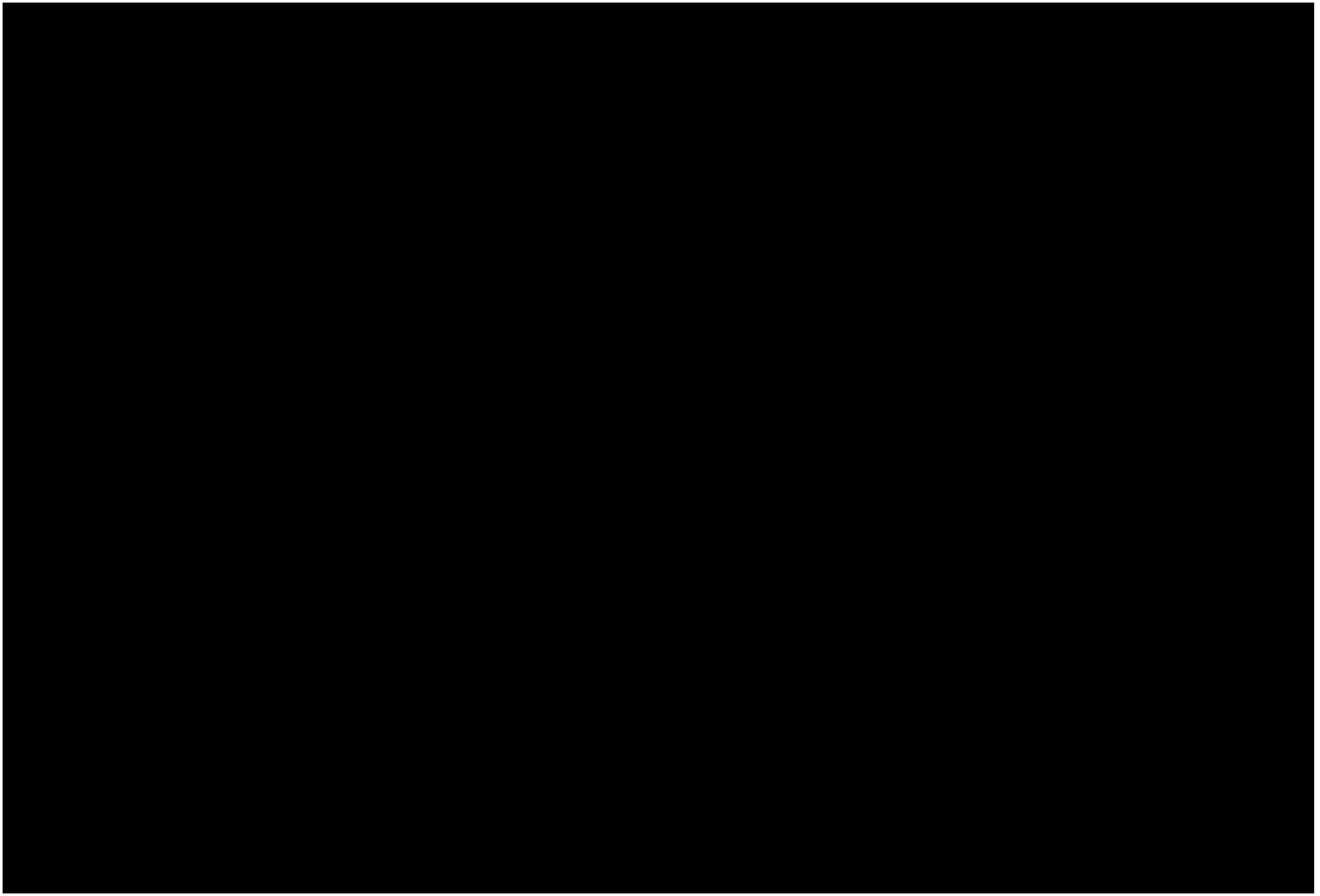
Date of On Peak Day - 07/23/2021



Member Forecasted On Peak Demand Day for August 2021

Southwestern Electric Cooperative, Inc.

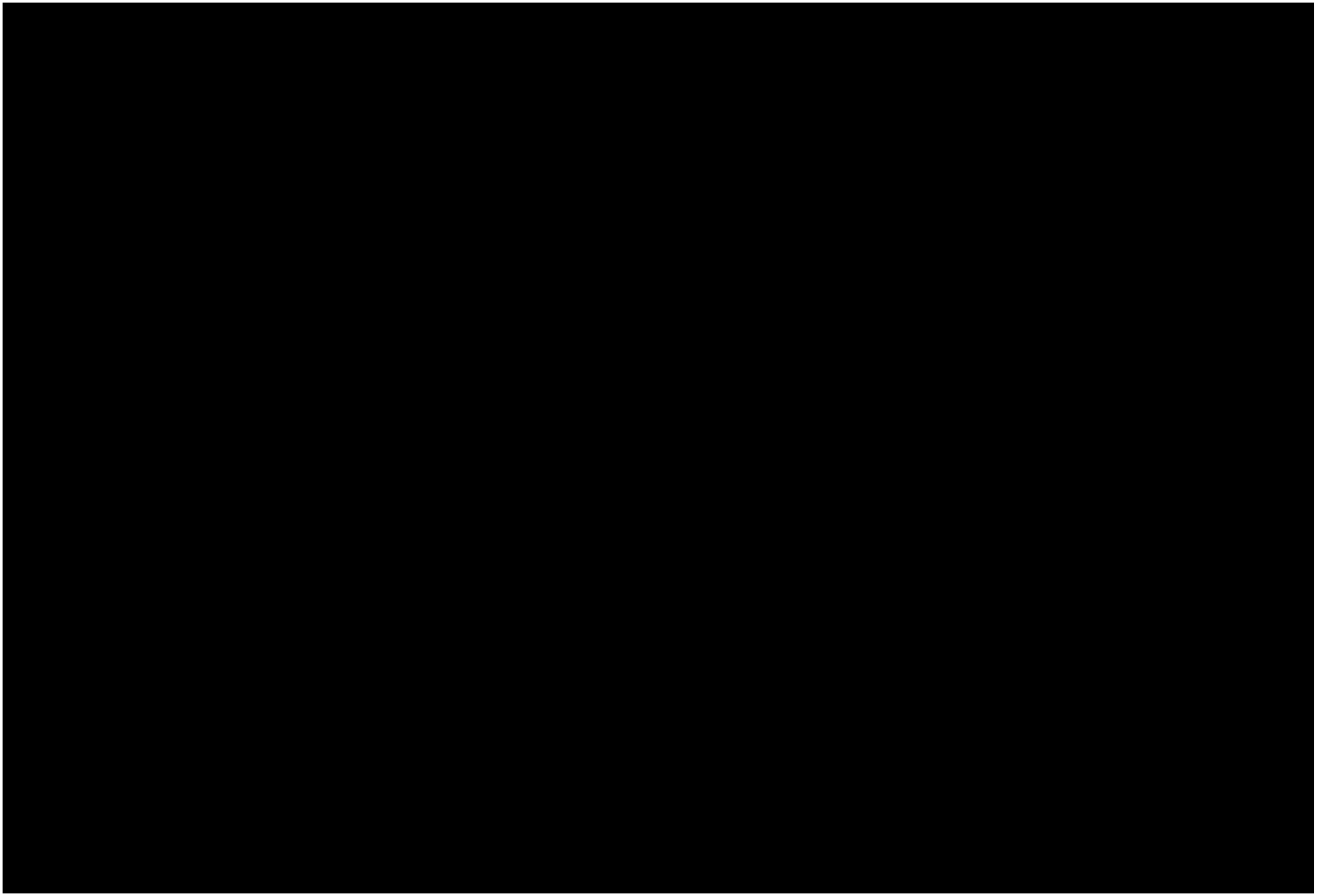
Date of On Peak Day - 08/01/2021



Member Forecasted On Peak Demand Day for September 2021

Southwestern Electric Cooperative, Inc.

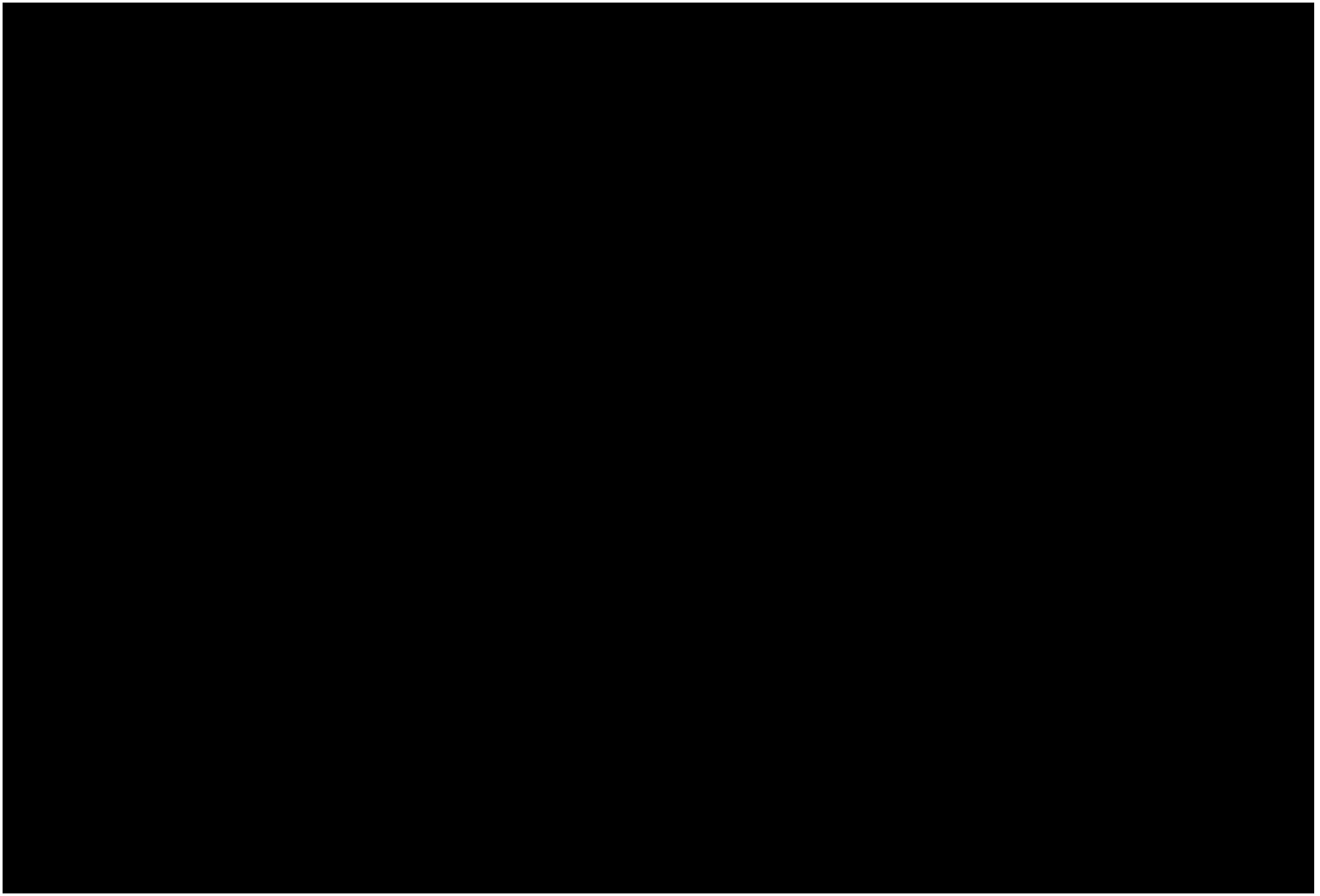
Date of On Peak Day - 09/08/2021



Member Forecasted On Peak Demand Day for October 2021

Southwestern Electric Cooperative, Inc.

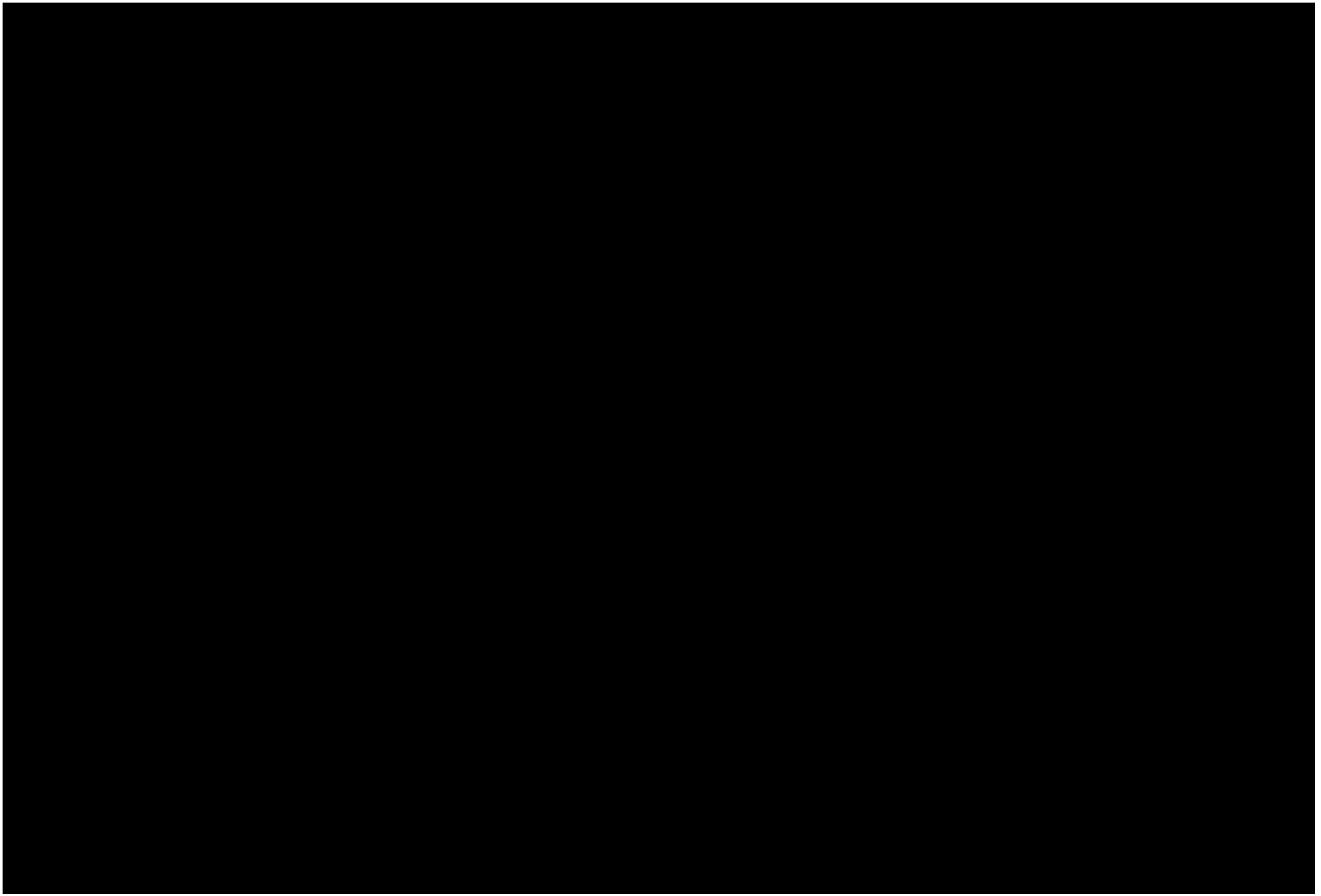
Date of On Peak Day - 10/15/2021



Member Forecasted On Peak Demand Day for November 2021

Southwestern Electric Cooperative, Inc.

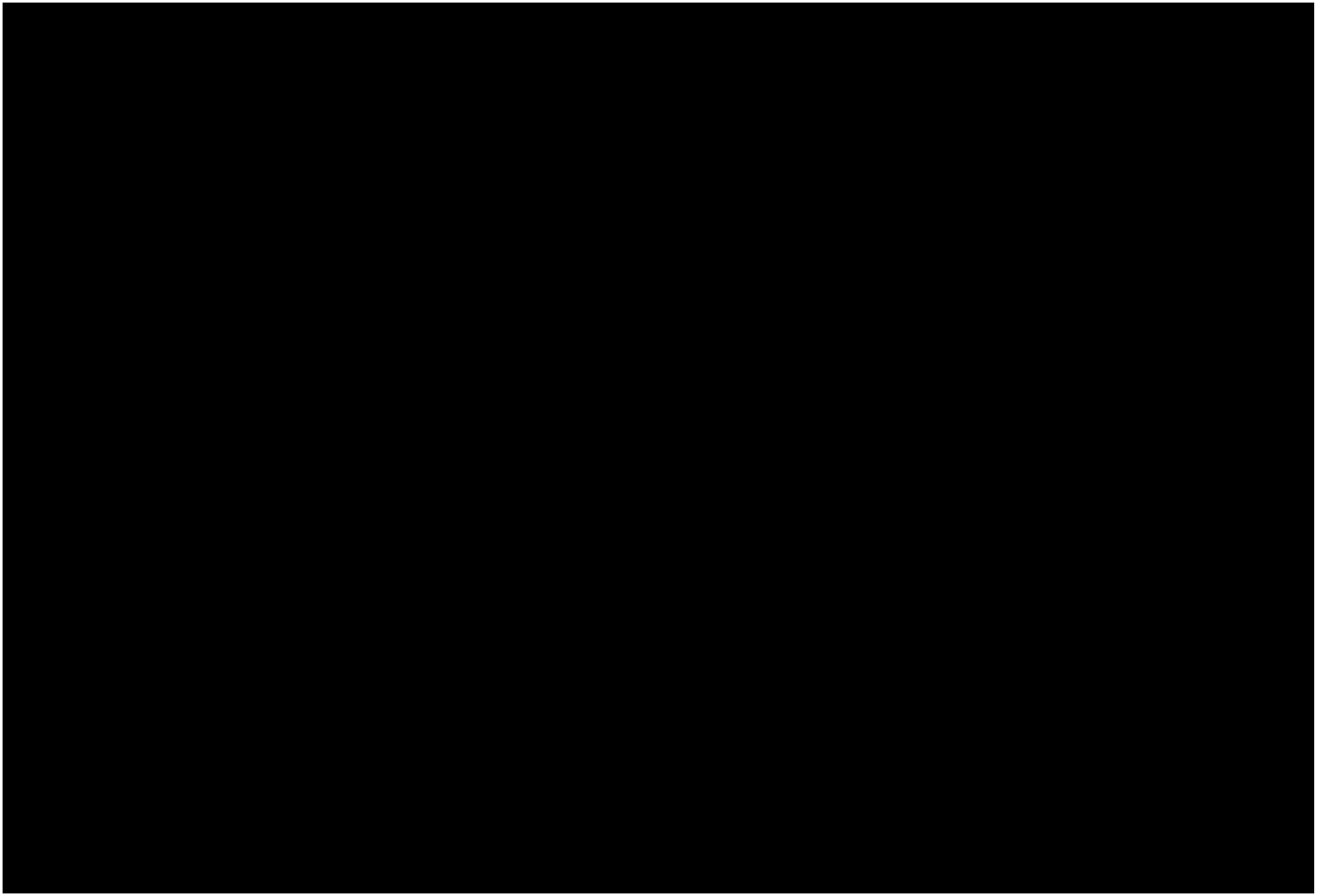
Date of On Peak Day - 11/28/2021



Member Forecasted On Peak Demand Day for December 2021

Southwestern Electric Cooperative, Inc.

Date of On Peak Day - 12/06/2021



Member Forecasted On Peak Demand Day for January 2021

United Power, Inc.

Date of On Peak Day - 01/06/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

United Power, Inc.

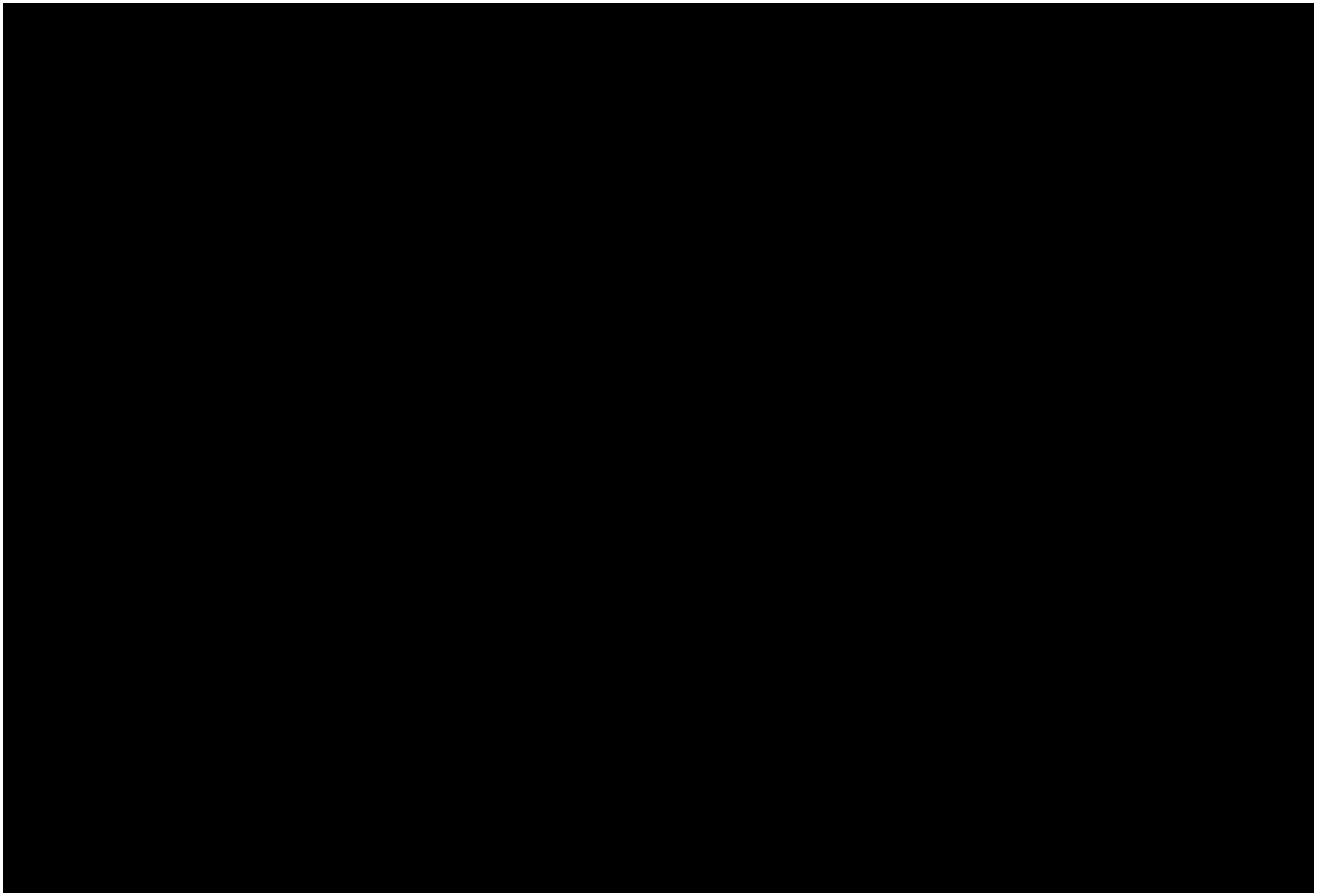
Date of On Peak Day - 02/01/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

United Power, Inc.

Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

United Power, Inc.

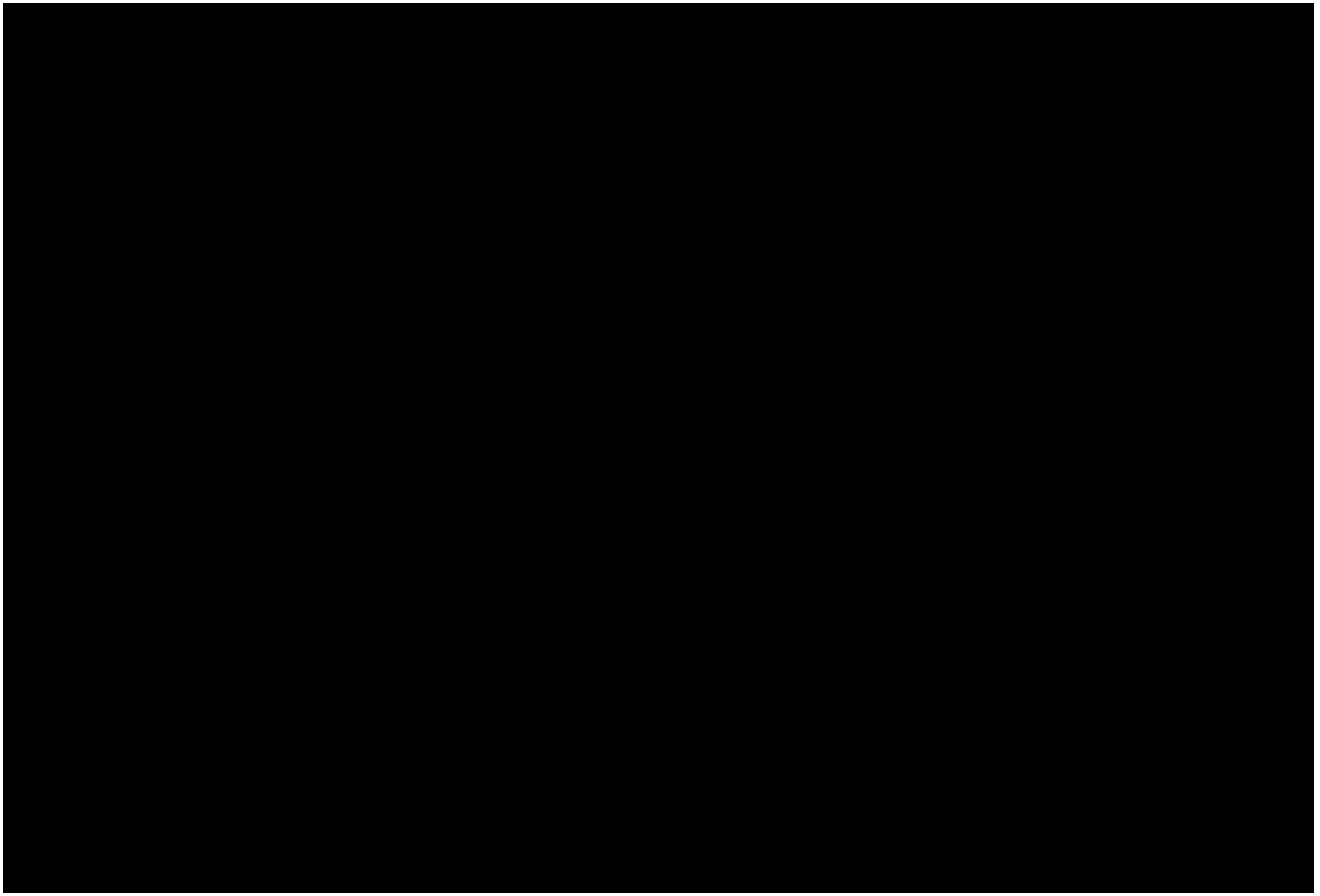
Date of On Peak Day - 04/26/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

United Power, Inc.

Date of On Peak Day - 05/31/2021



Member Forecasted On Peak Demand Day for June 2021

United Power, Inc.

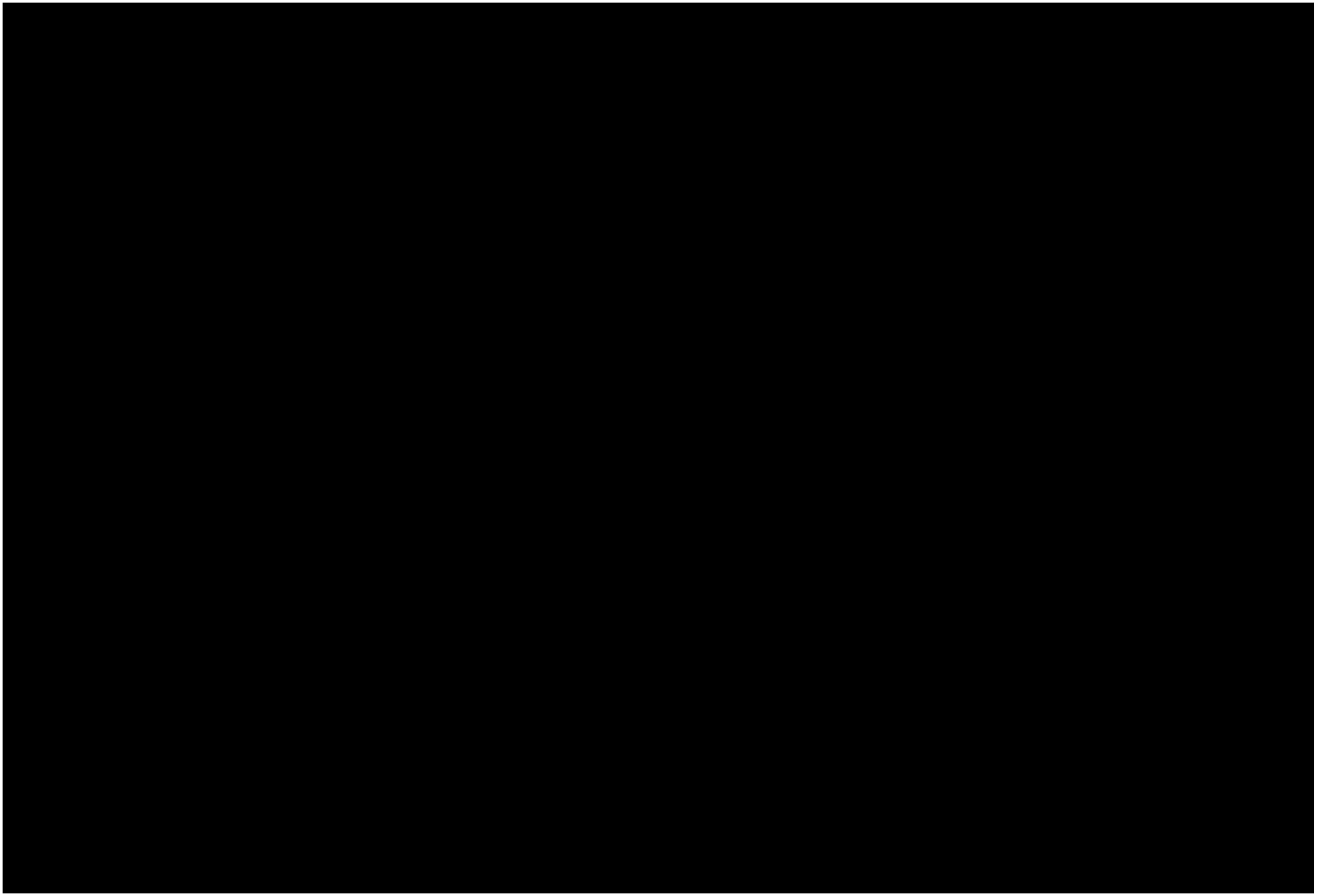
Date of On Peak Day - 06/10/2021

[redacted]

Member Forecasted On Peak Demand Day for July 2021

United Power, Inc.

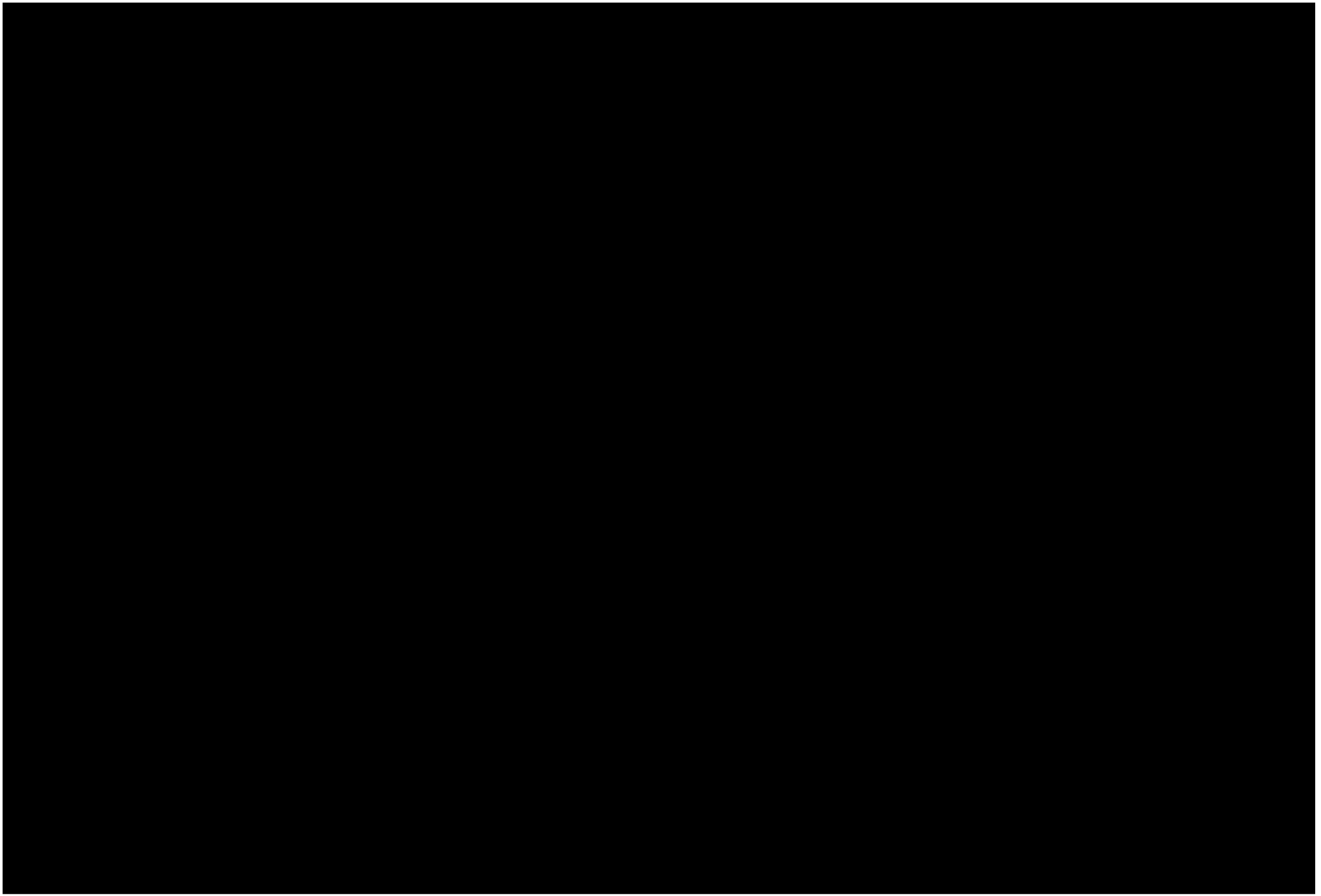
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

United Power, Inc.

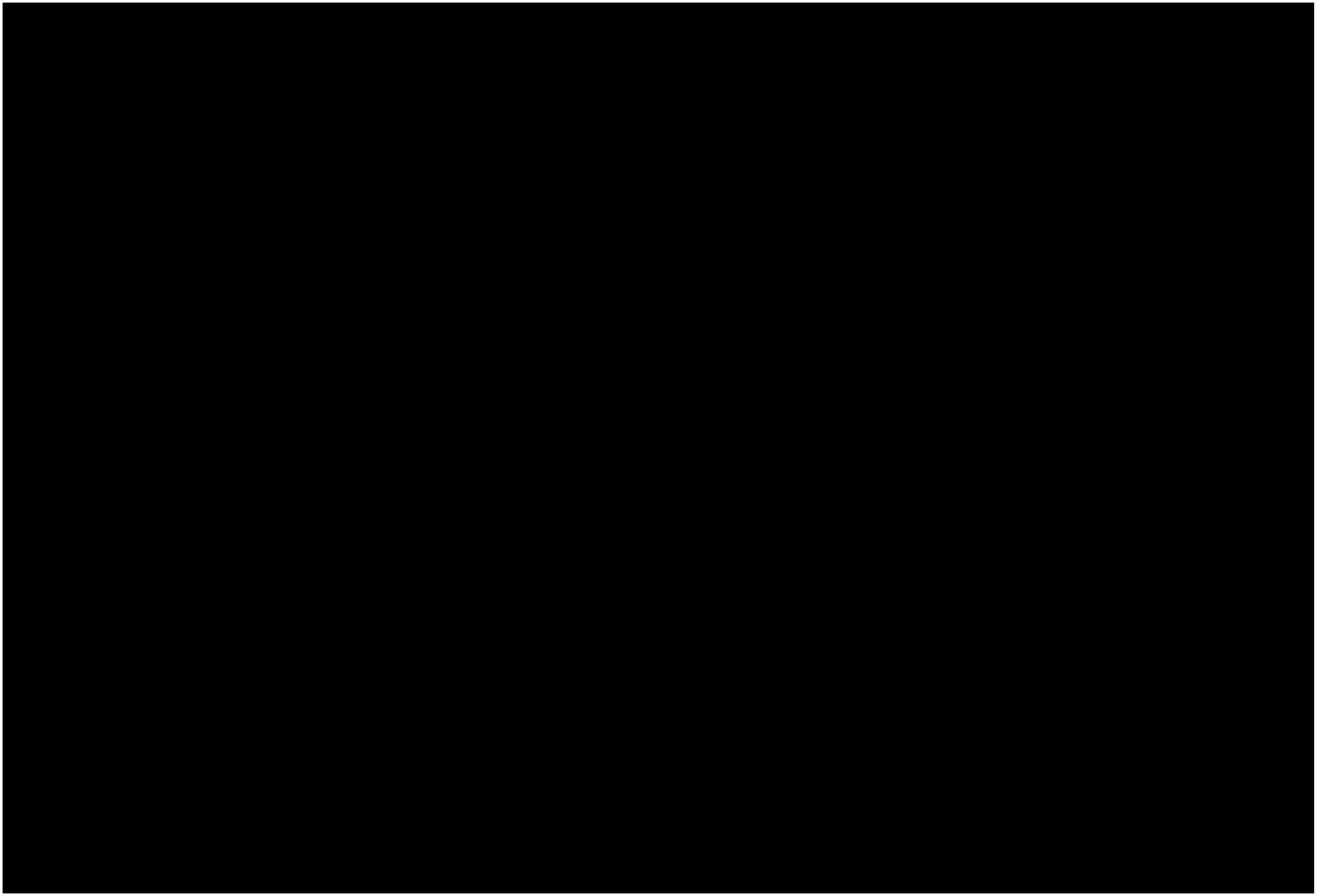
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

United Power, Inc.

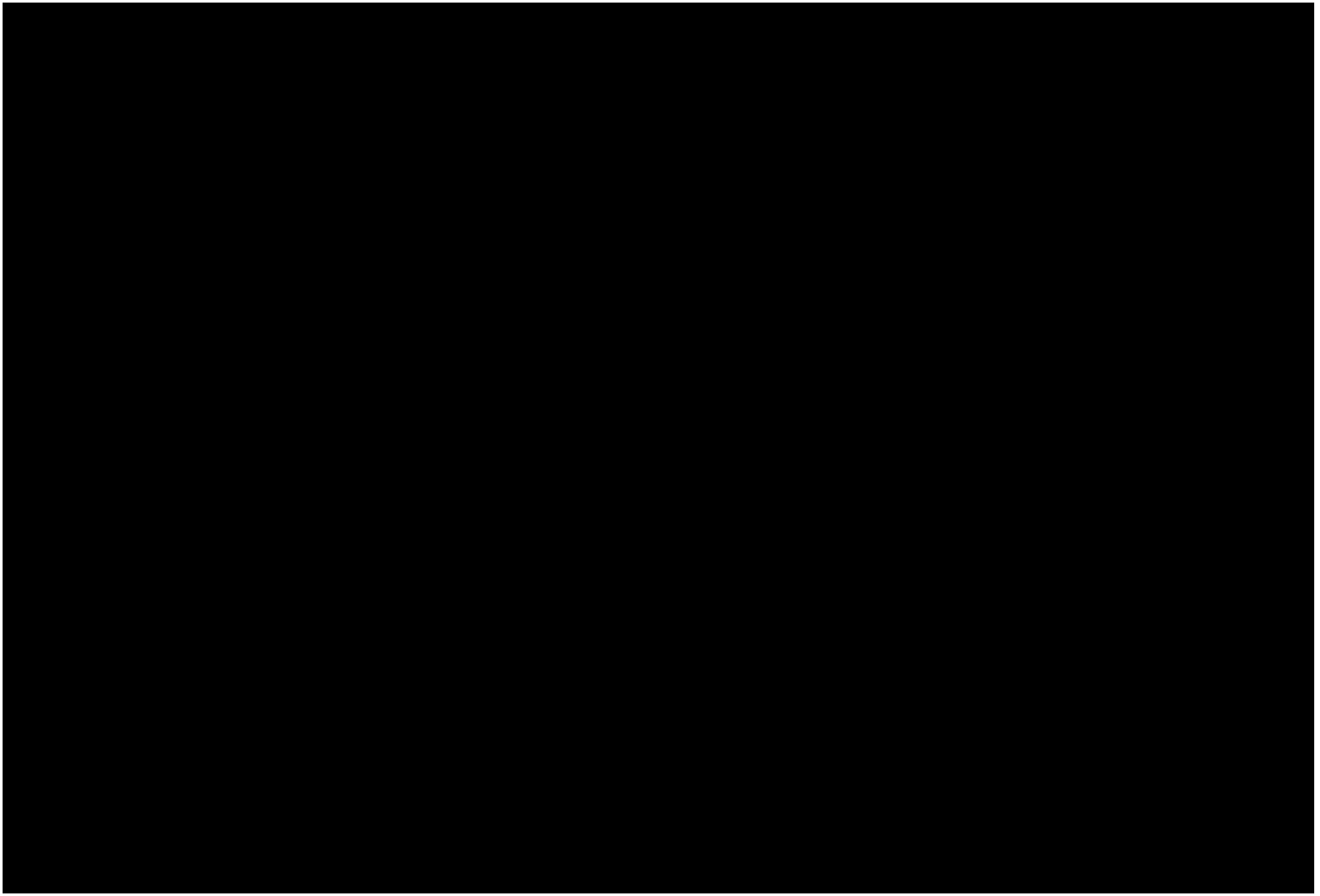
Date of On Peak Day - 09/01/2021



Member Forecasted On Peak Demand Day for October 2021

United Power, Inc.

Date of On Peak Day - 10/13/2021



Member Forecasted On Peak Demand Day for November 2021

United Power, Inc.

Date of On Peak Day - 11/29/2021

[redacted]

Member Forecasted On Peak Demand Day for December 2021

United Power, Inc.

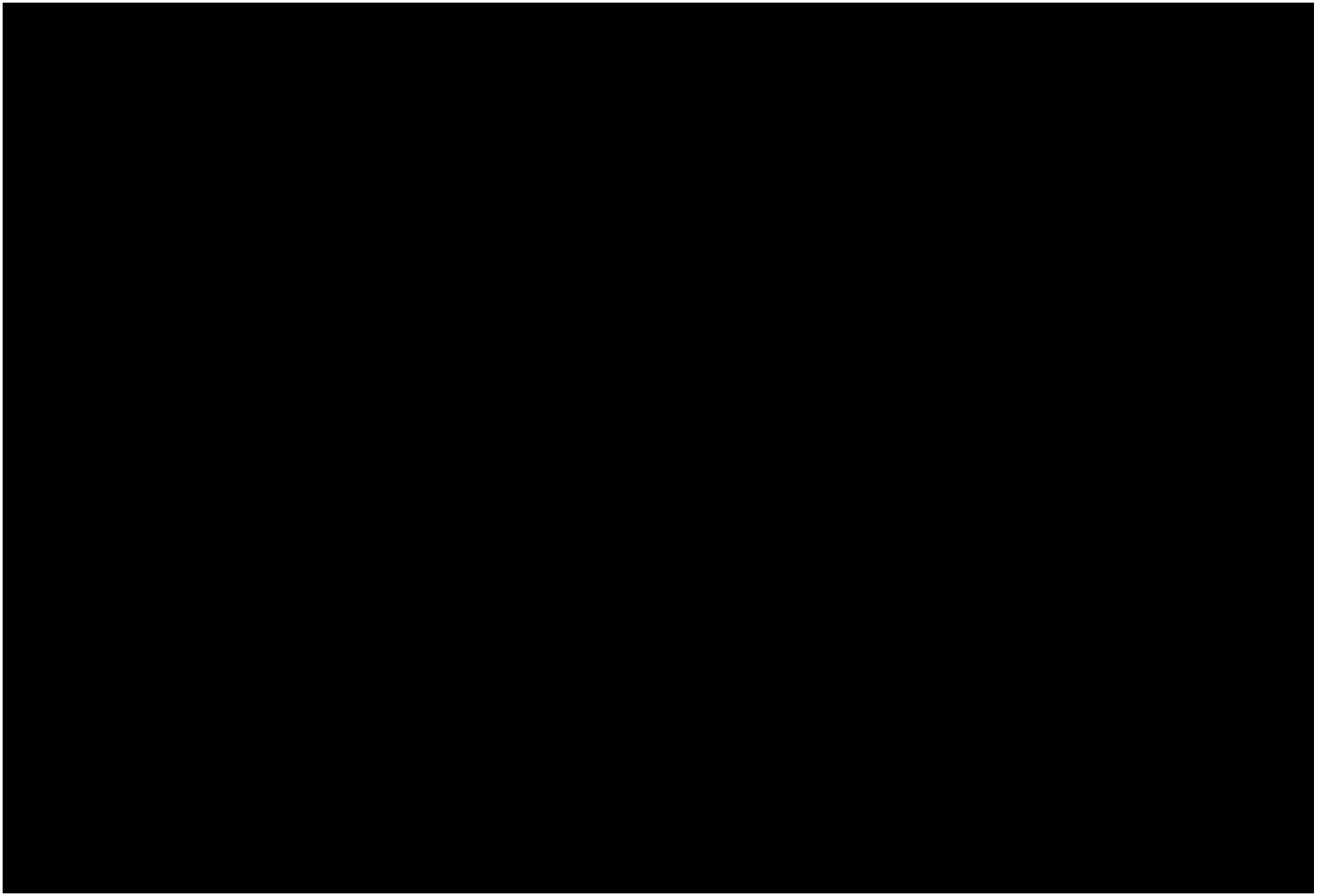
Date of On Peak Day - 12/29/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Wheat Belt Public Power District

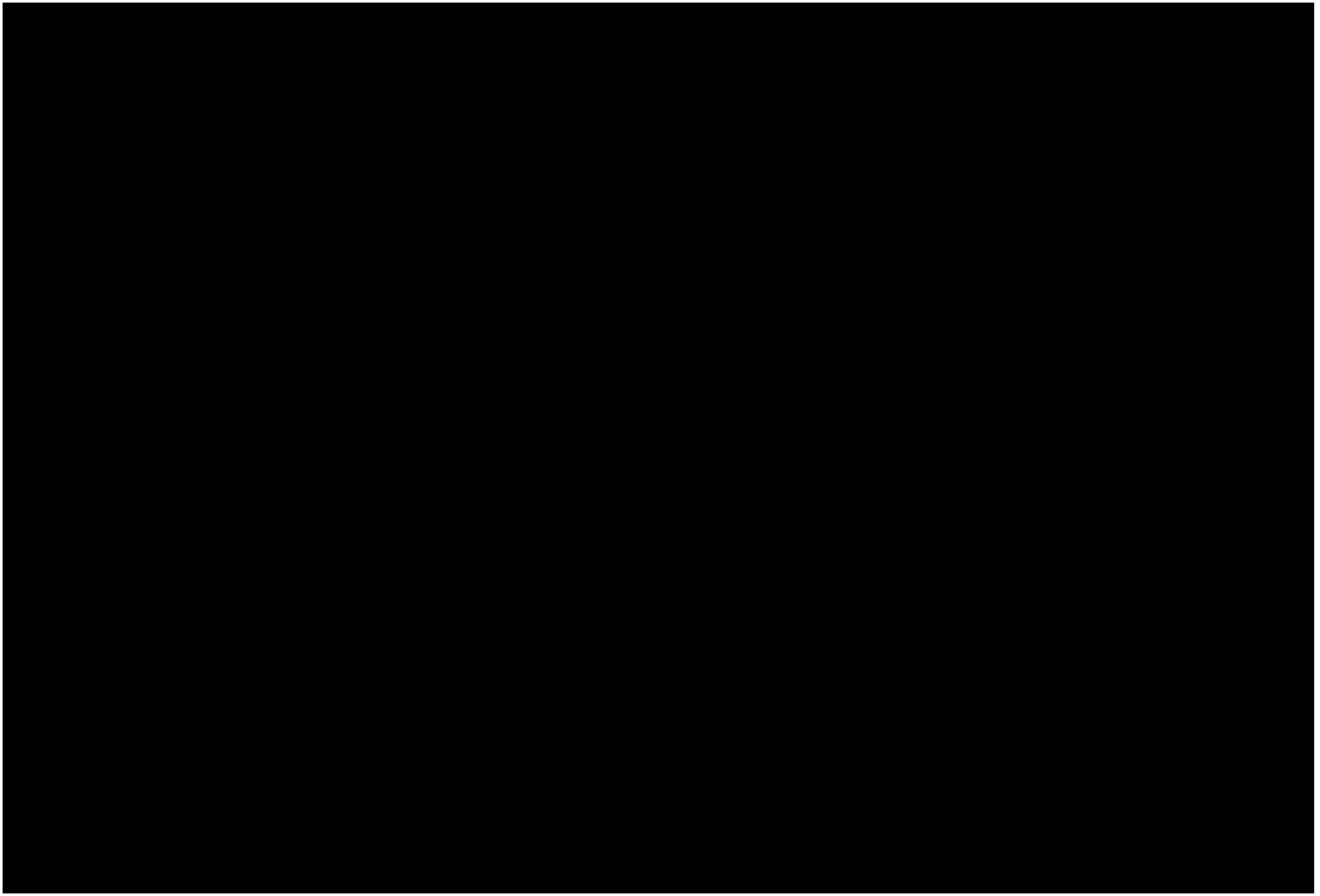
Date of On Peak Day - 01/06/2021



Member Forecasted On Peak Demand Day for February 2021

Wheat Belt Public Power District

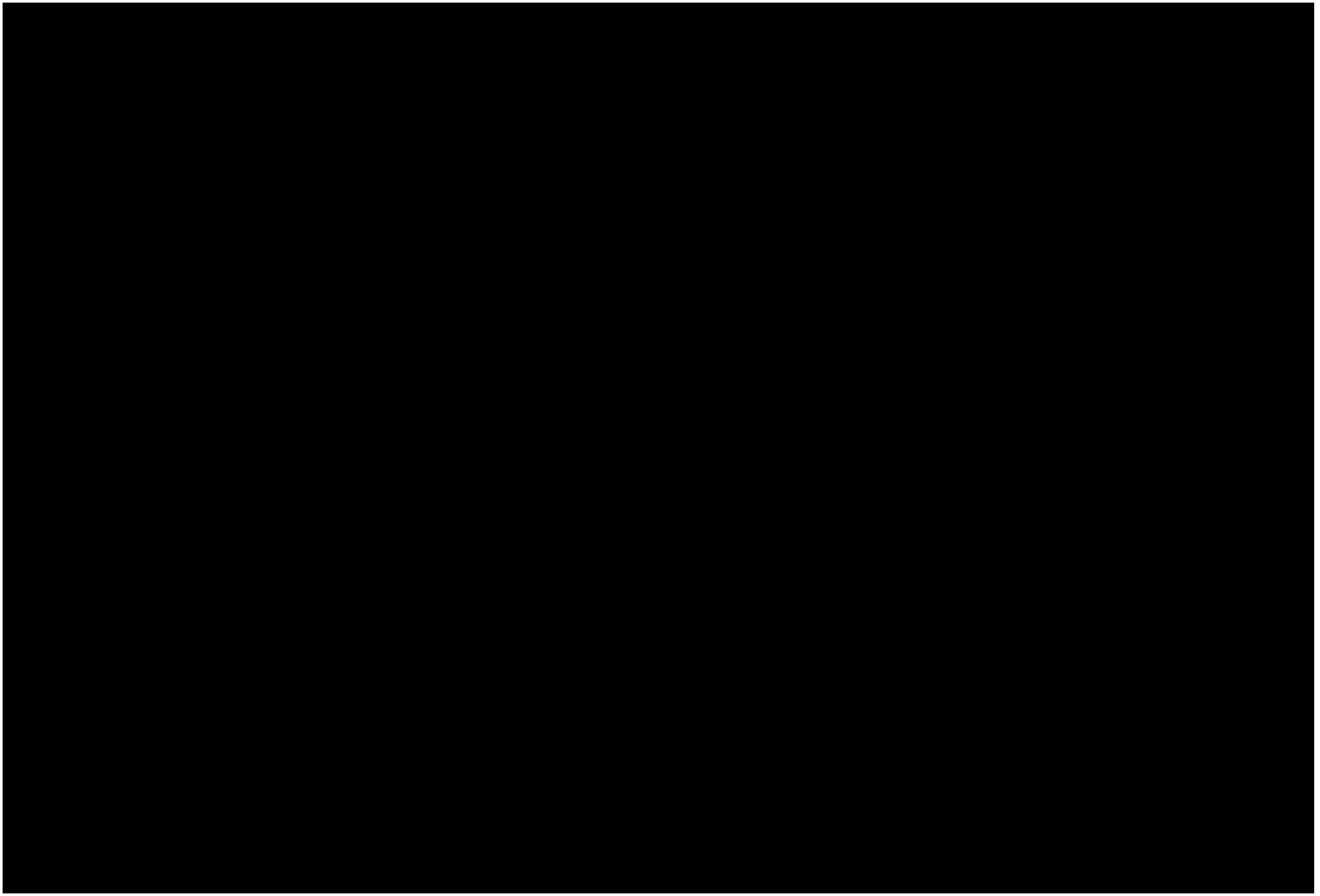
Date of On Peak Day - 02/25/2021



Member Forecasted On Peak Demand Day for March 2021

Wheat Belt Public Power District

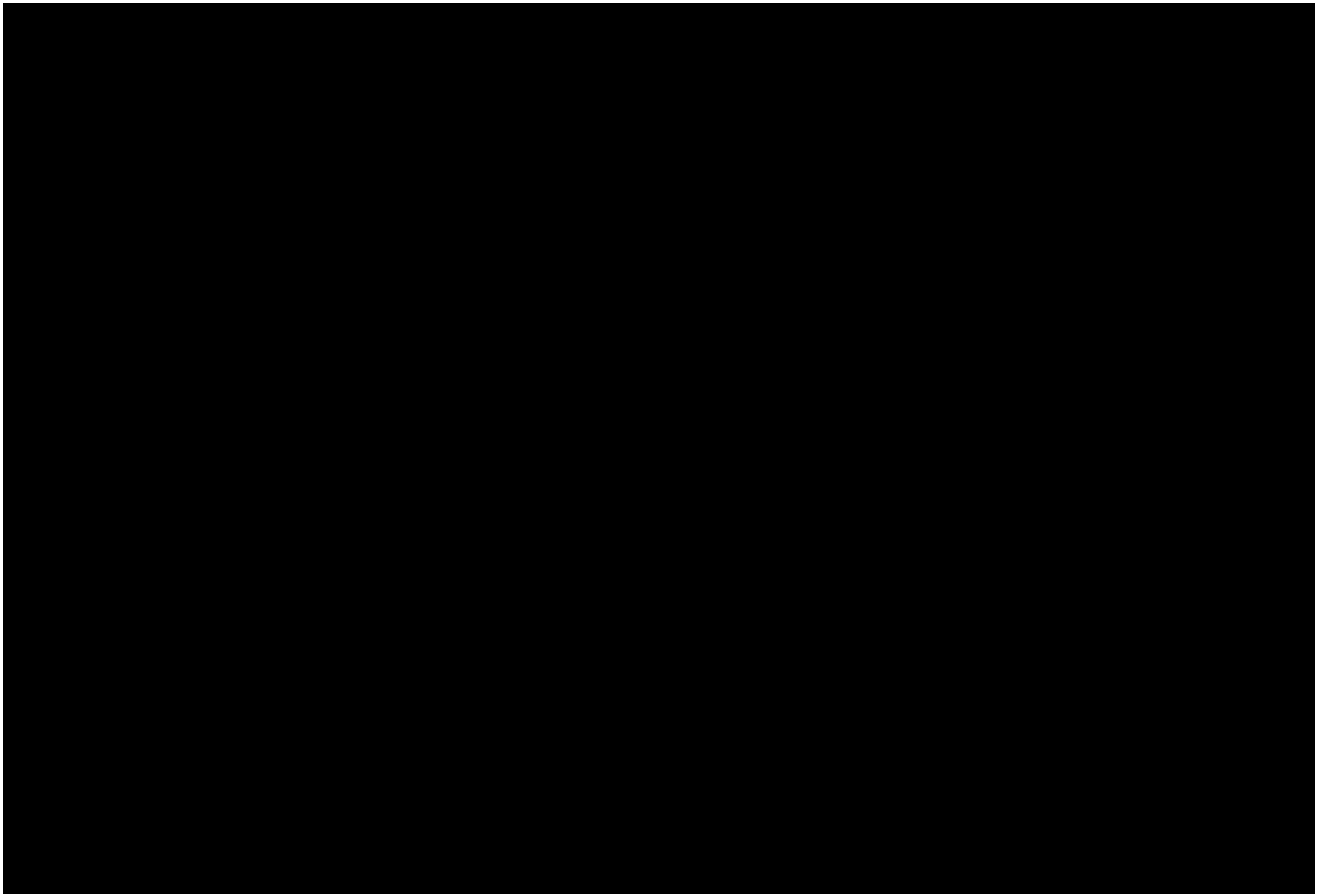
Date of On Peak Day - 03/03/2021



Member Forecasted On Peak Demand Day for April 2021

Wheat Belt Public Power District

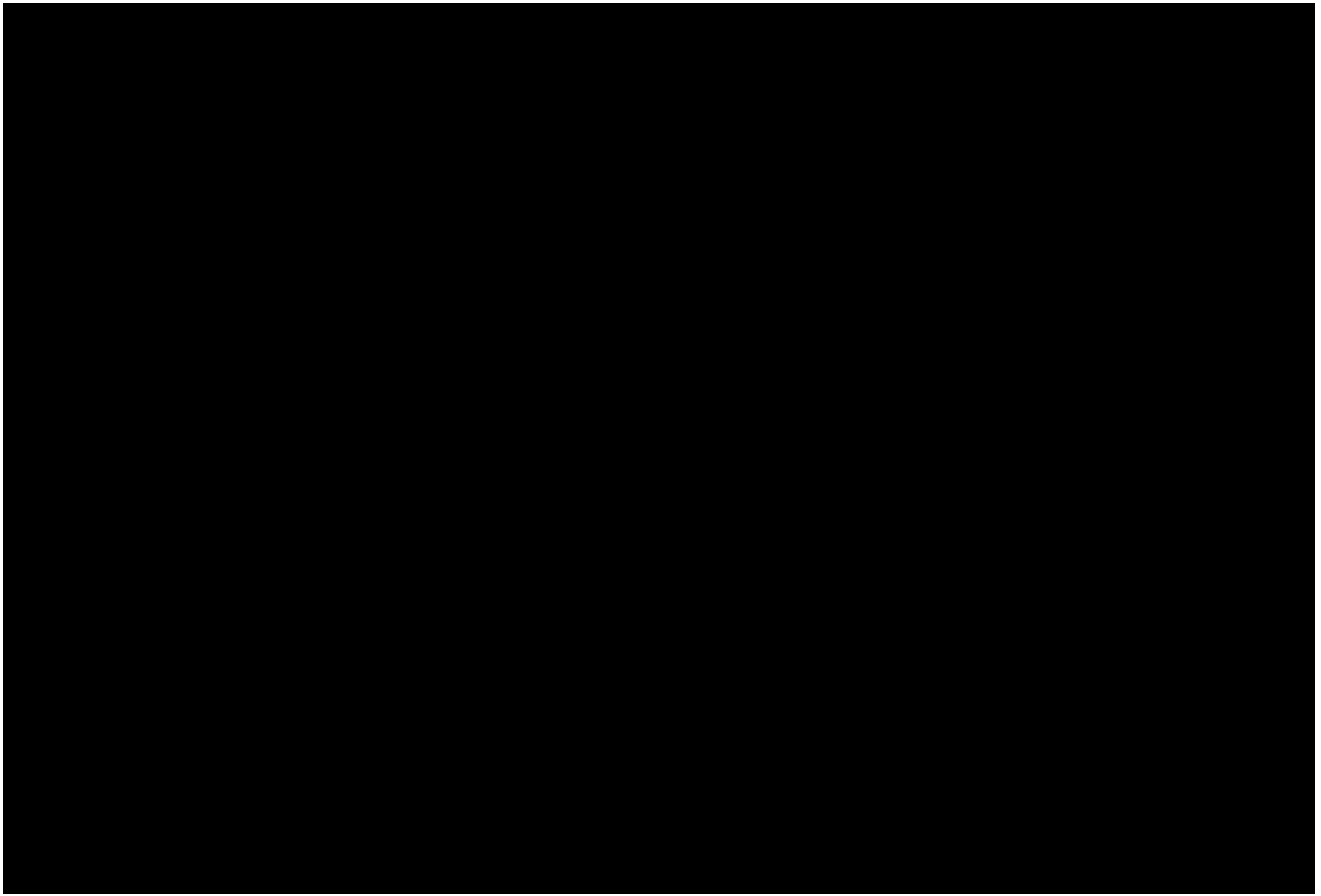
Date of On Peak Day - 04/01/2021



Member Forecasted On Peak Demand Day for May 2021

Wheat Belt Public Power District

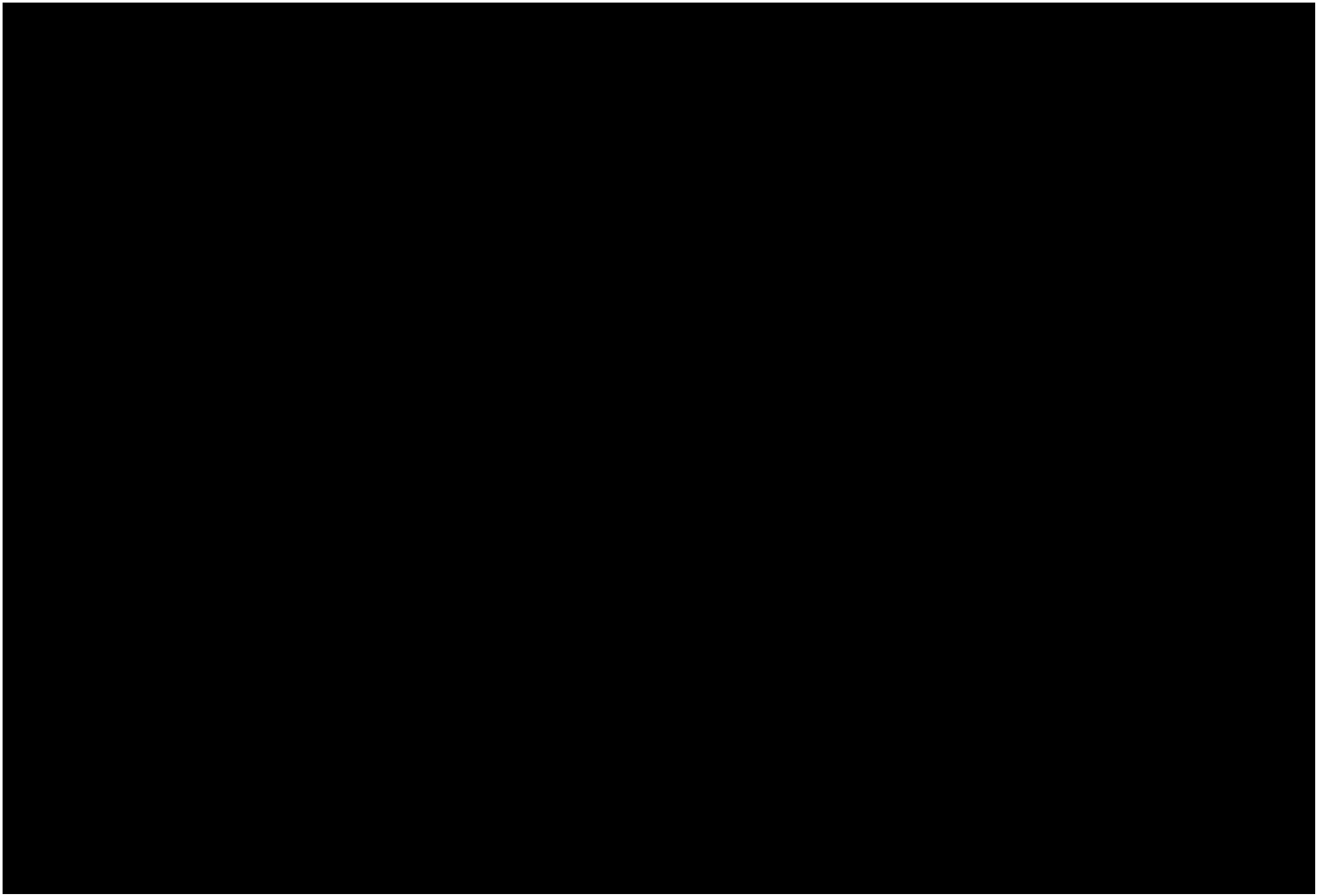
Date of On Peak Day - 05/16/2021



Member Forecasted On Peak Demand Day for June 2021

Wheat Belt Public Power District

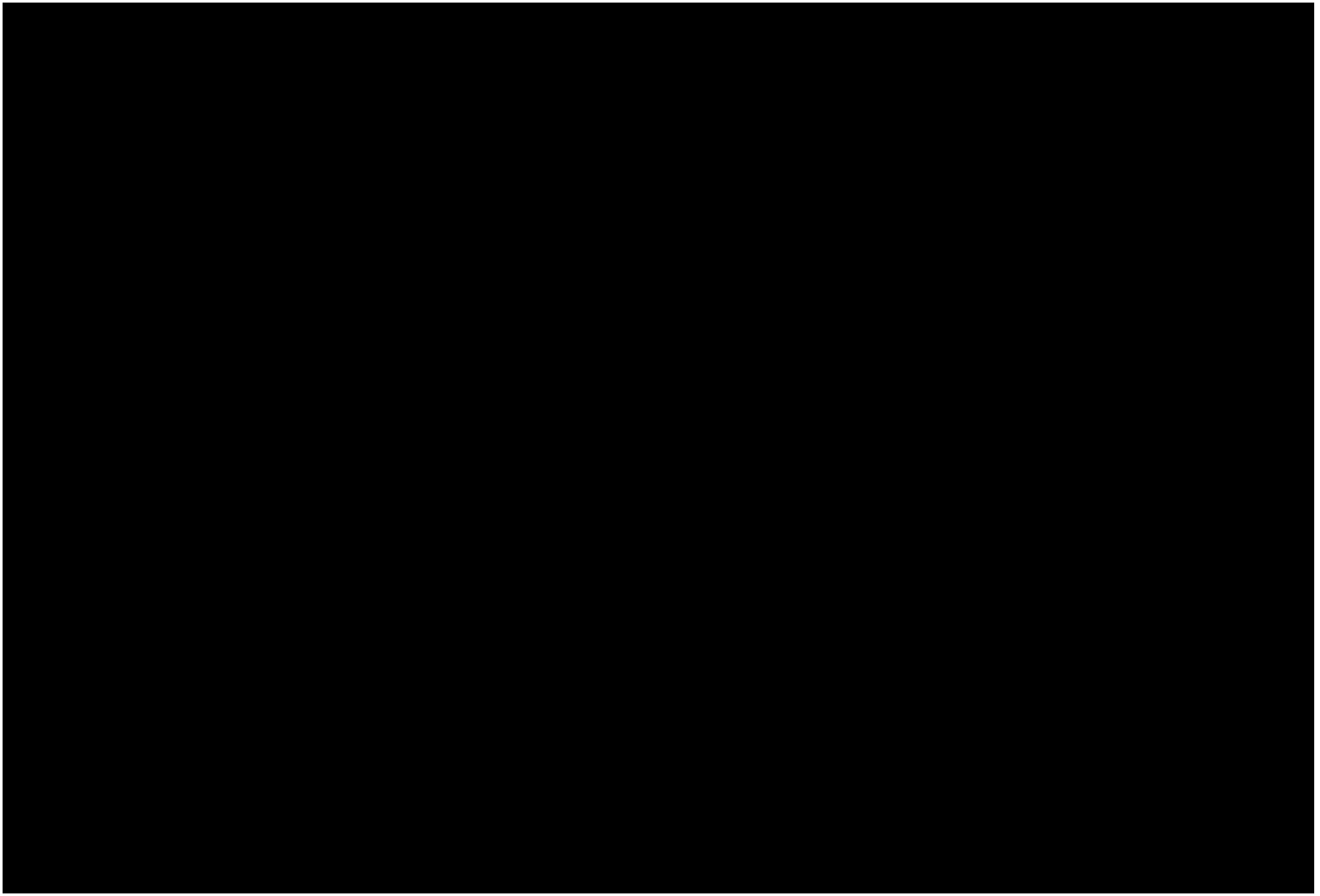
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Wheat Belt Public Power District

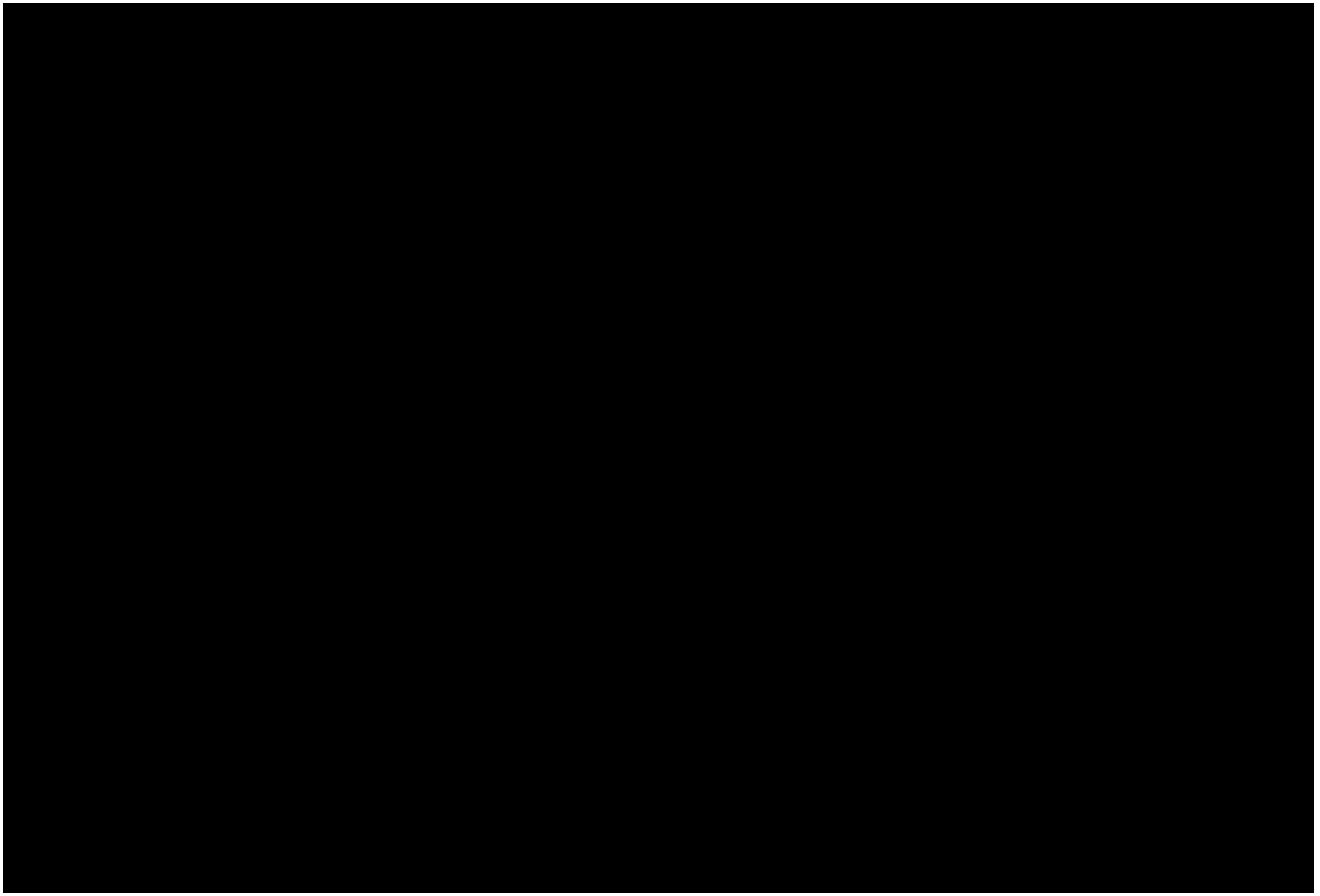
Date of On Peak Day - 07/09/2021



Member Forecasted On Peak Demand Day for August 2021

Wheat Belt Public Power District

Date of On Peak Day - 08/24/2021

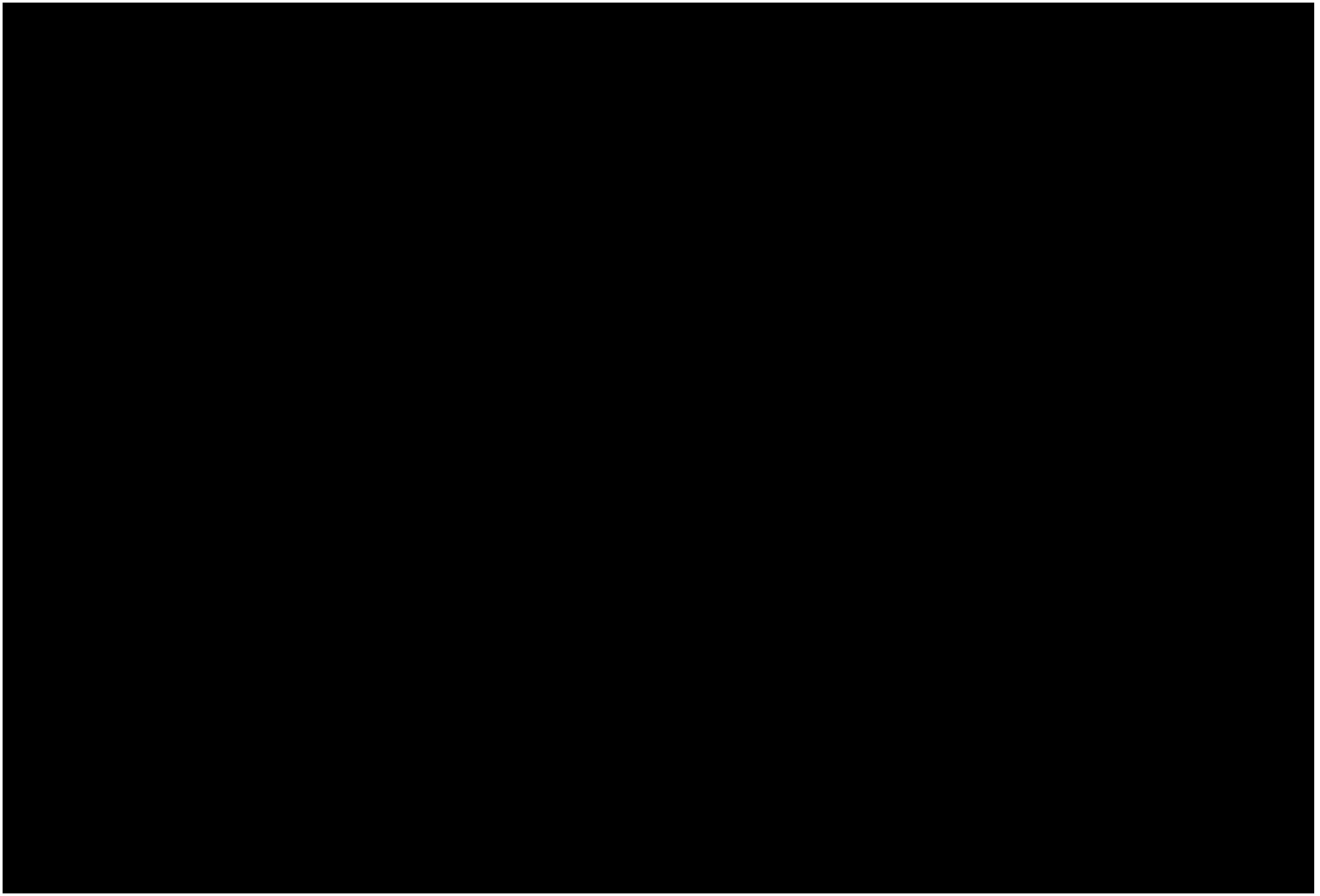


Hearing Exhibit 101
PUBLIC Attachment BN-2
Proceeding No. 20A-0528E
Page 908 of 2886

Member Forecasted On Peak Demand Day for September 2021

Wheat Belt Public Power District

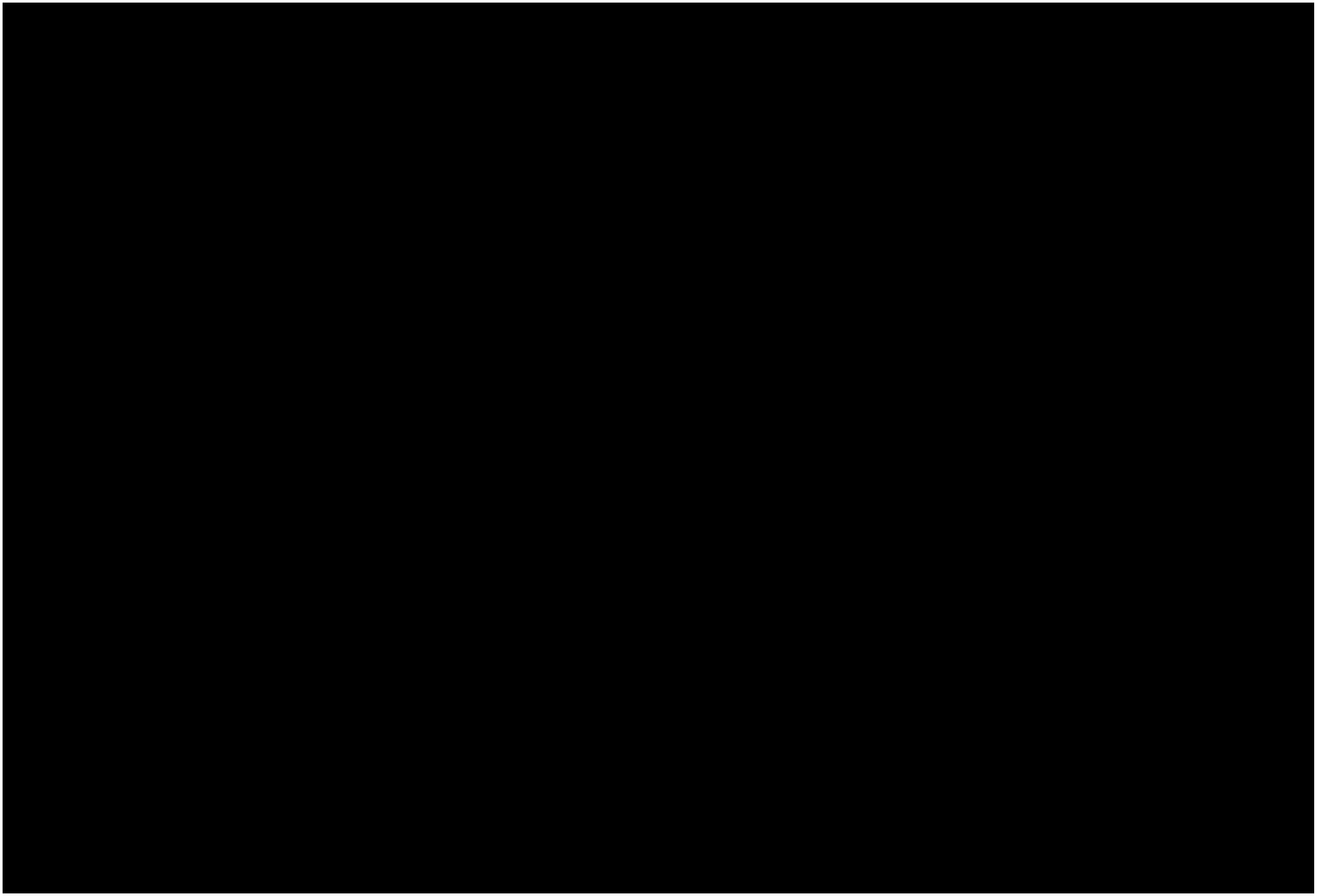
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Wheat Belt Public Power District

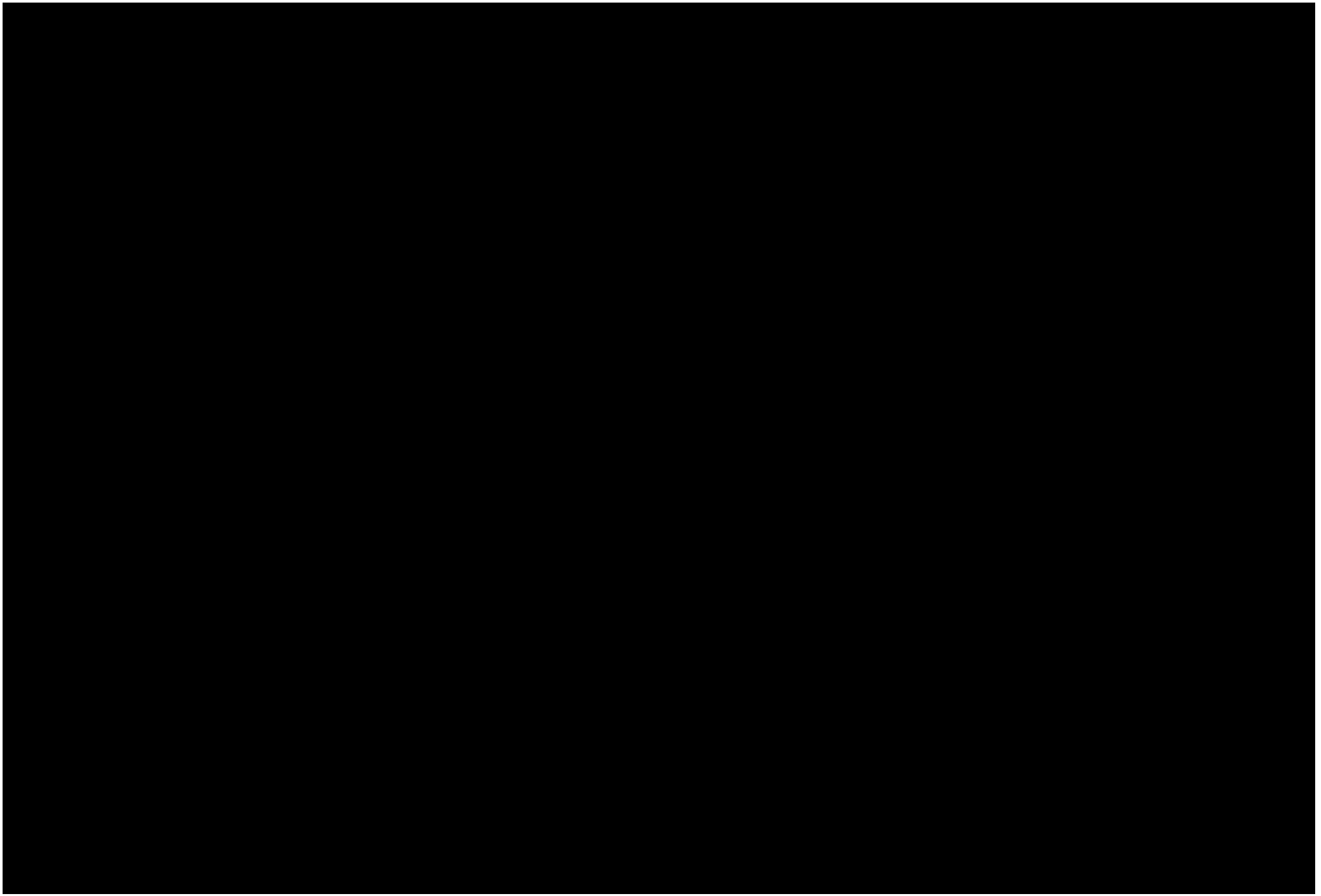
Date of On Peak Day - 10/04/2021



Member Forecasted On Peak Demand Day for November 2021

Wheat Belt Public Power District

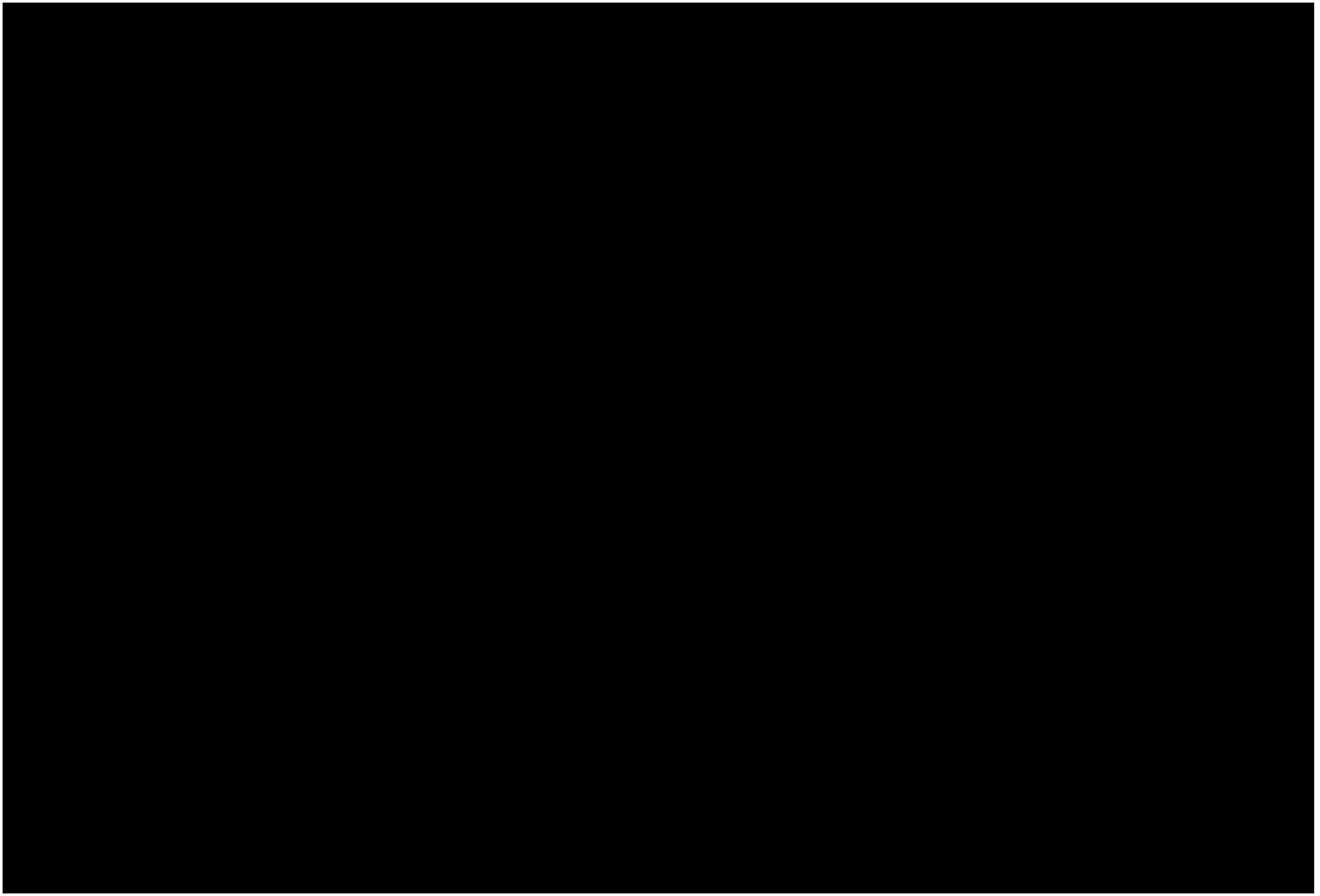
Date of On Peak Day - 11/09/2021



Member Forecasted On Peak Demand Day for December 2021

Wheat Belt Public Power District

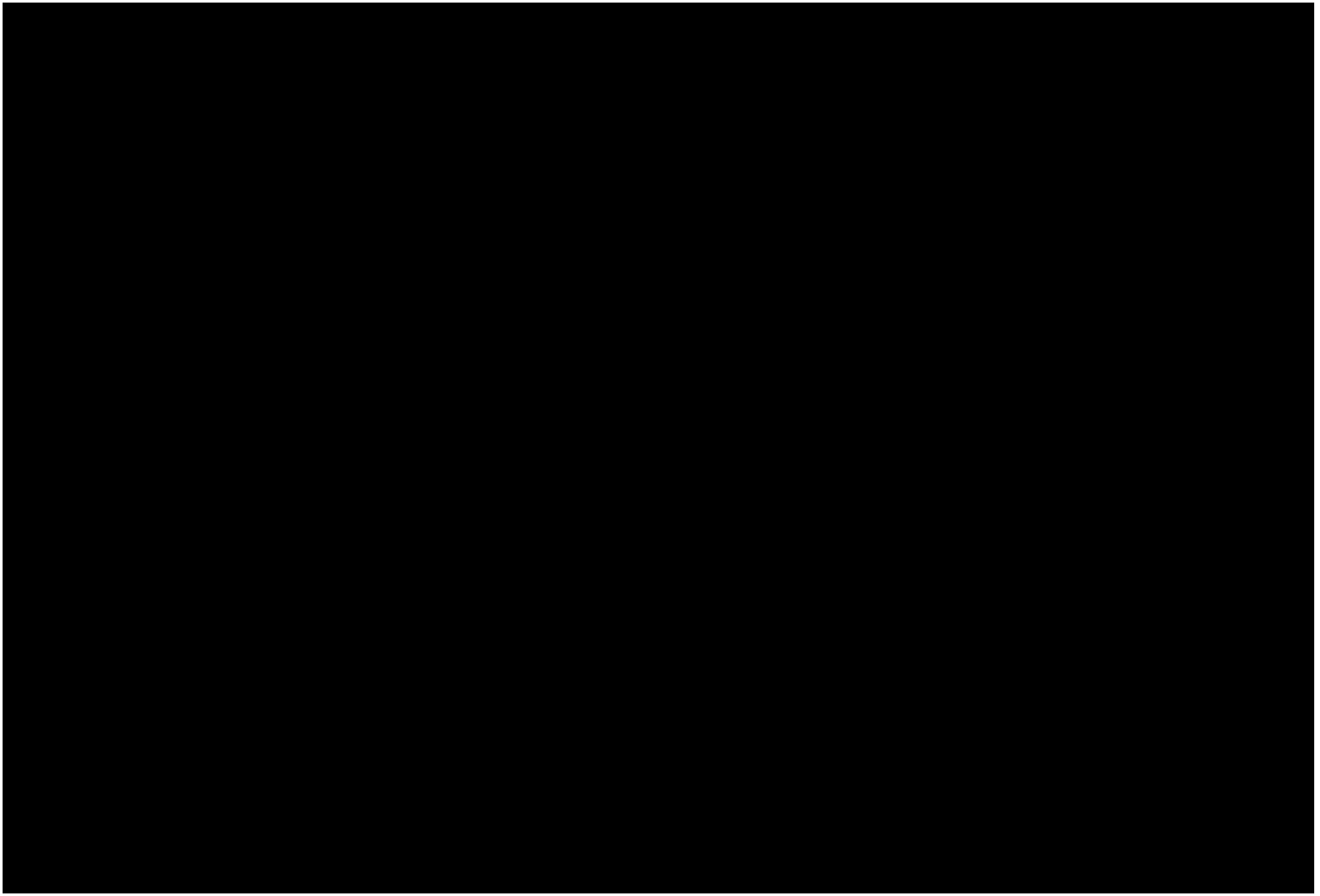
Date of On Peak Day - 12/27/2021



Member Forecasted On Peak Demand Day for January 2021

Wheatland Rural Electric Association, Inc.

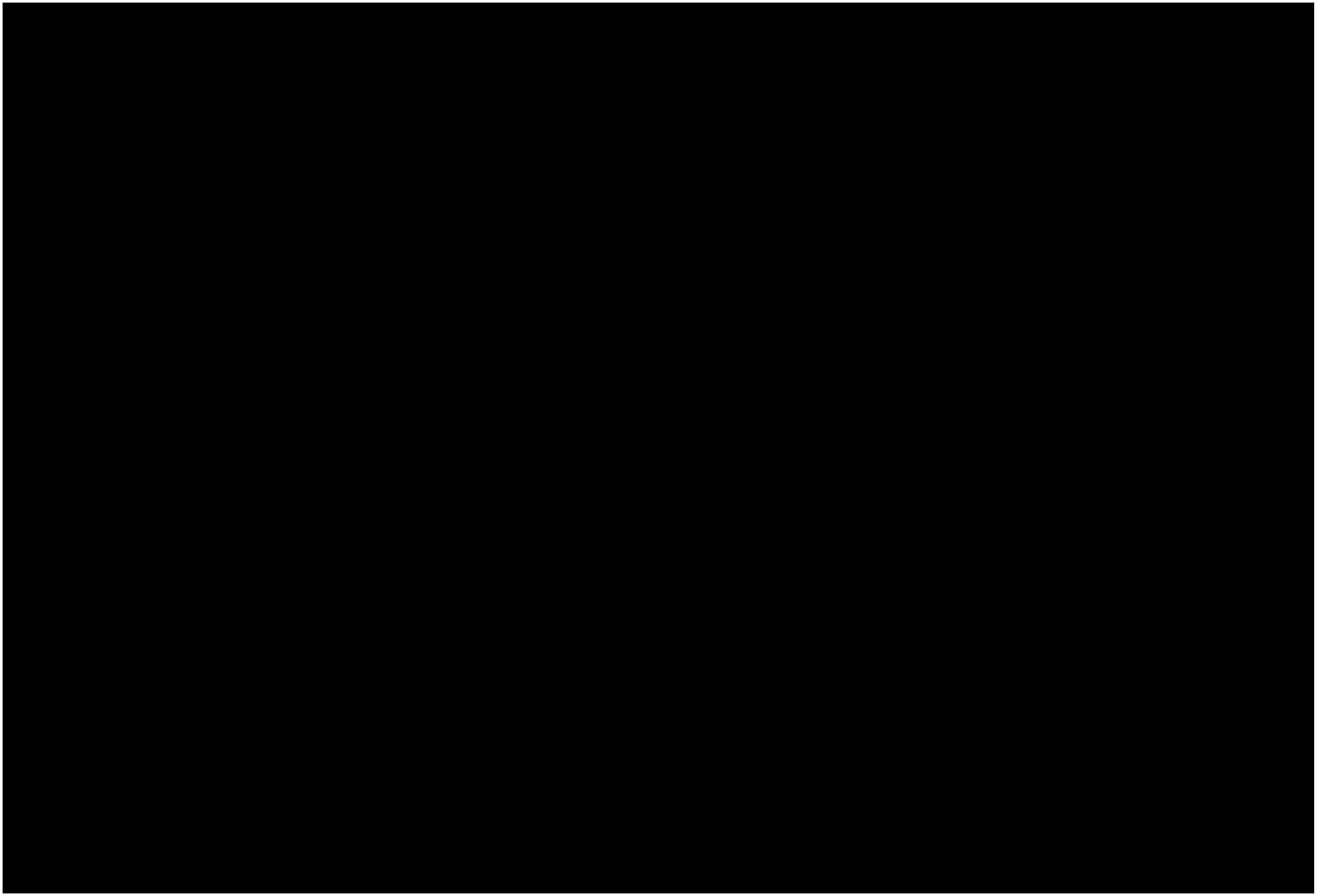
Date of On Peak Day - 01/05/2021



Member Forecasted On Peak Demand Day for February 2021

Wheatland Rural Electric Association, Inc.

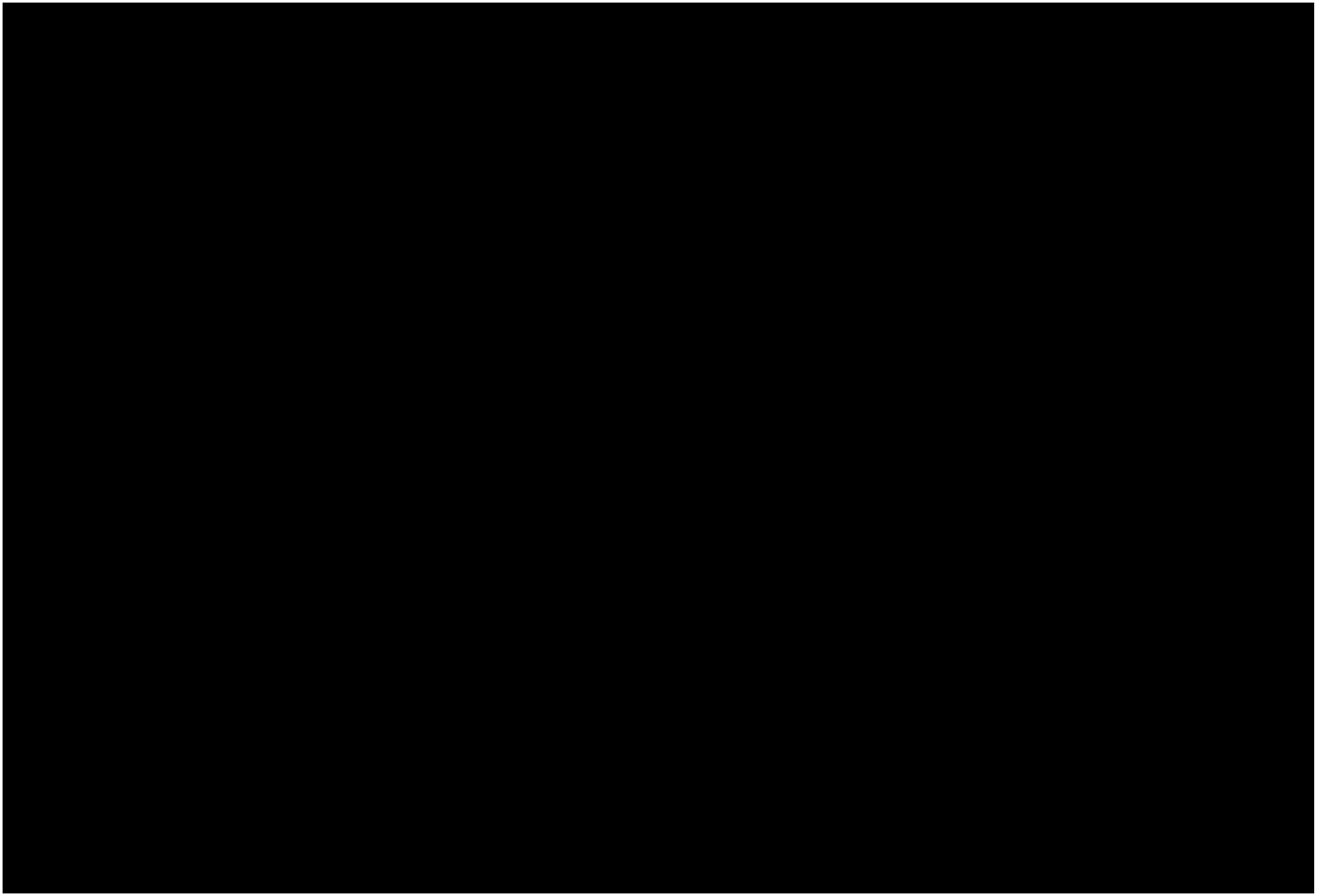
Date of On Peak Day - 02/03/2021



Member Forecasted On Peak Demand Day for March 2021

Wheatland Rural Electric Association, Inc.

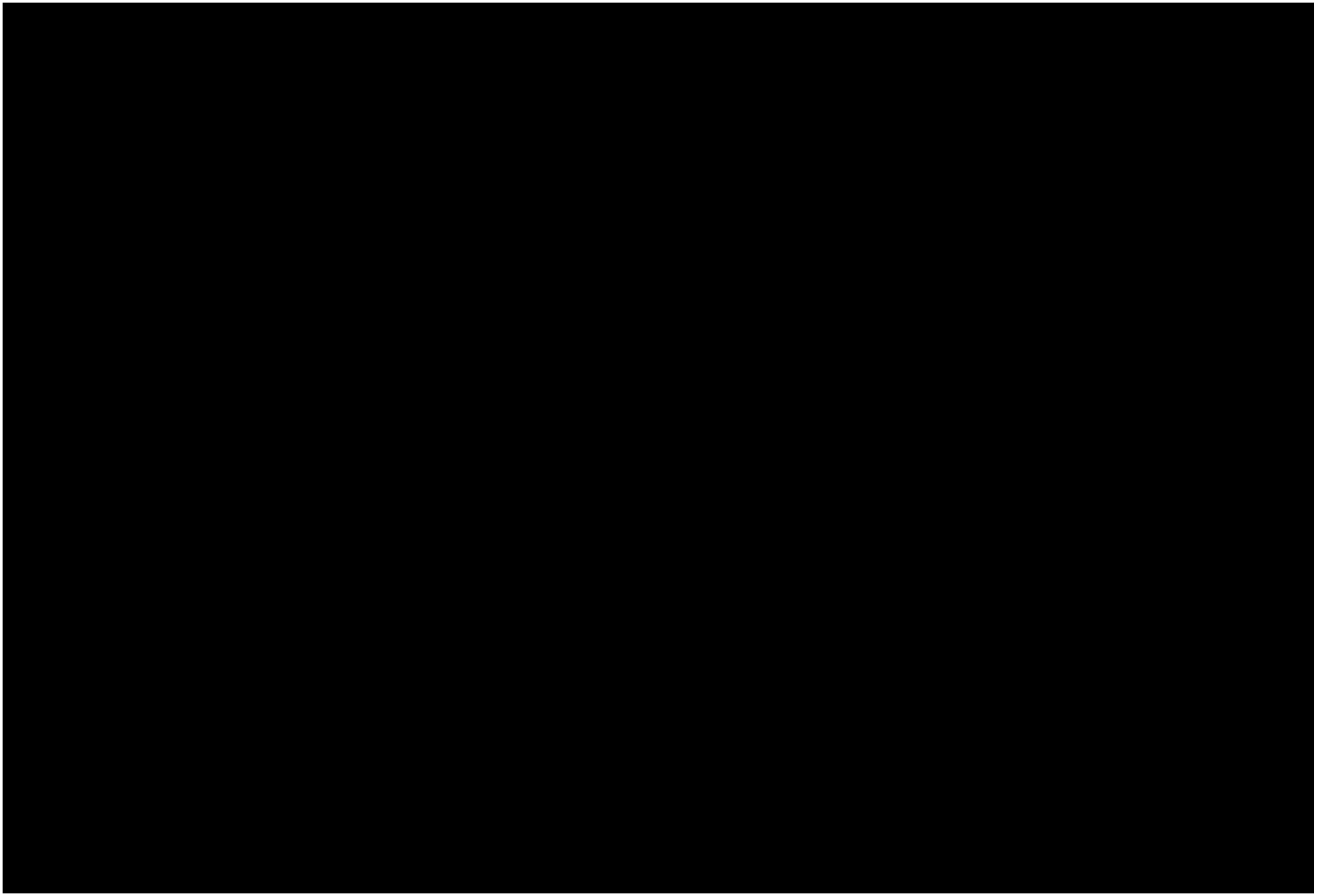
Date of On Peak Day - 03/01/2021



Member Forecasted On Peak Demand Day for April 2021

Wheatland Rural Electric Association, Inc.

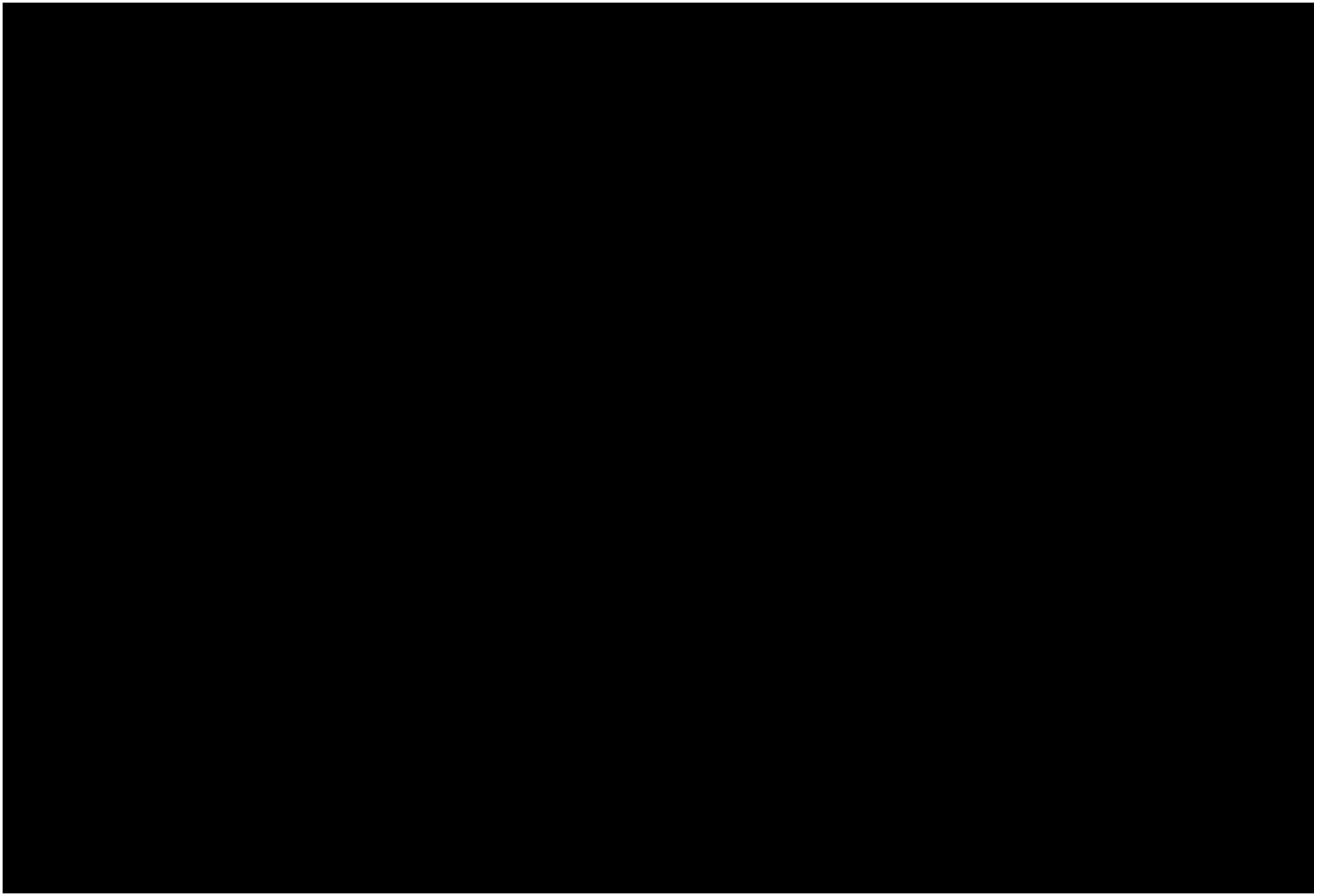
Date of On Peak Day - 04/04/2021



Member Forecasted On Peak Demand Day for May 2021

Wheatland Rural Electric Association, Inc.

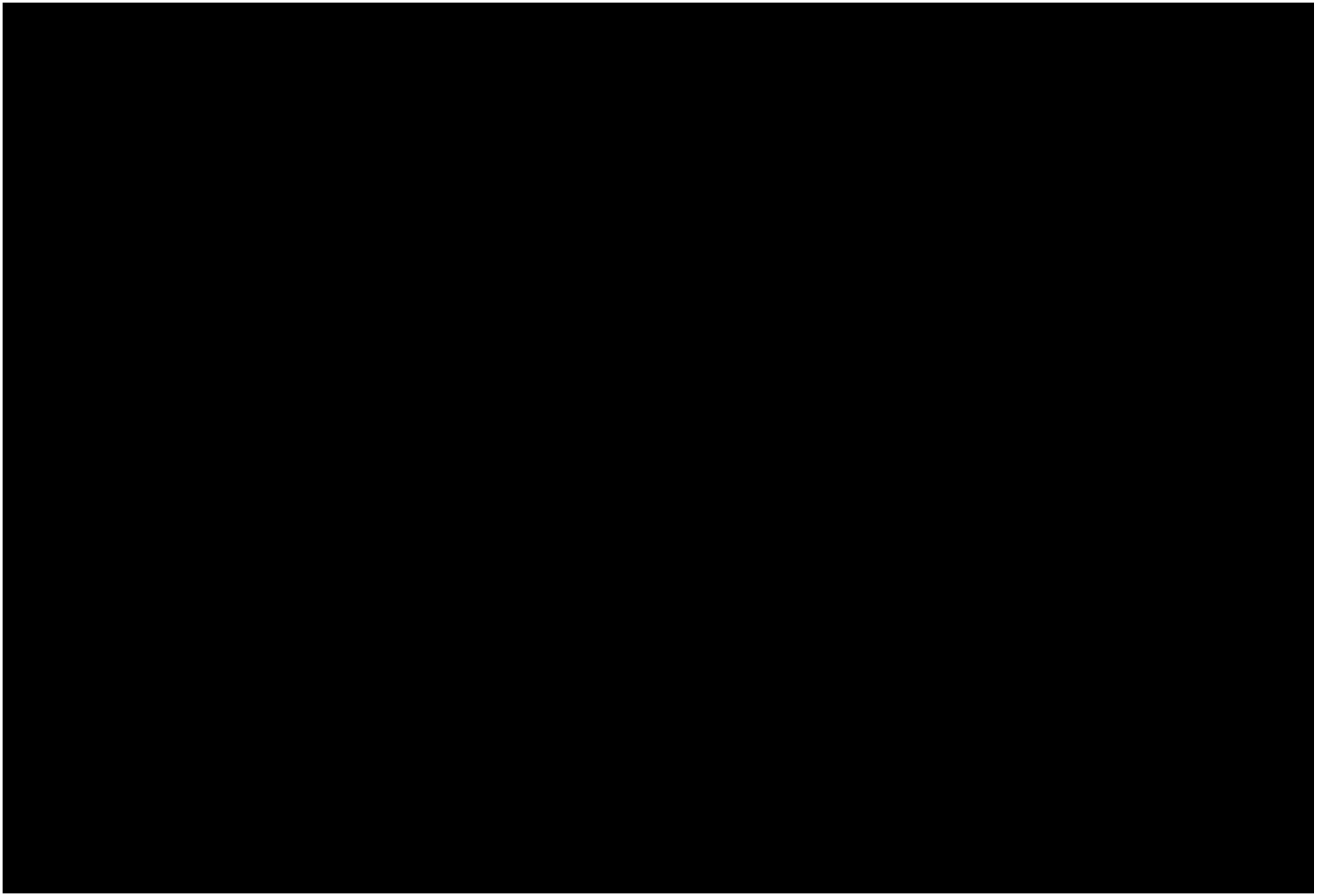
Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Wheatland Rural Electric Association, Inc.

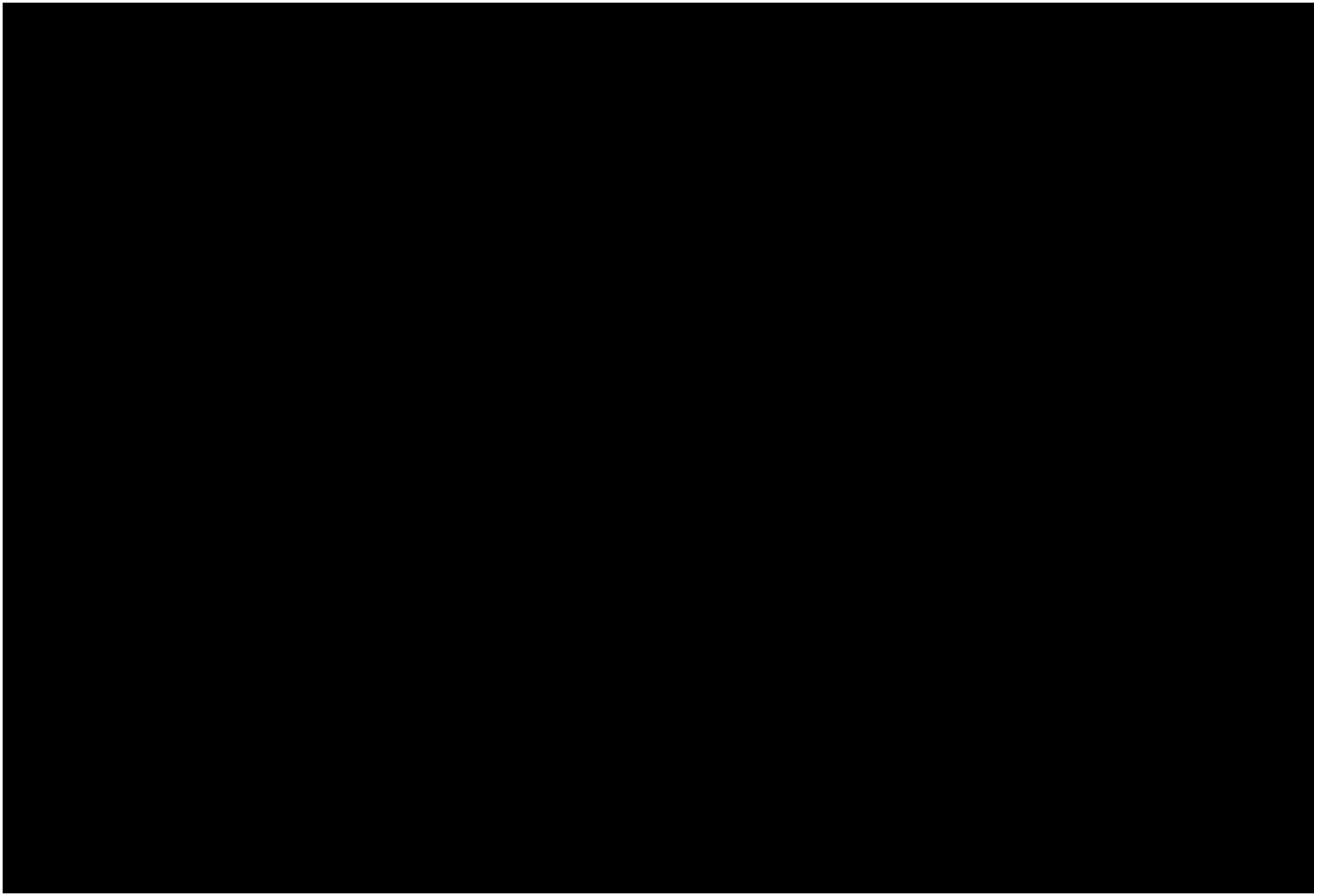
Date of On Peak Day - 06/11/2021



Member Forecasted On Peak Demand Day for July 2021

Wheatland Rural Electric Association, Inc.

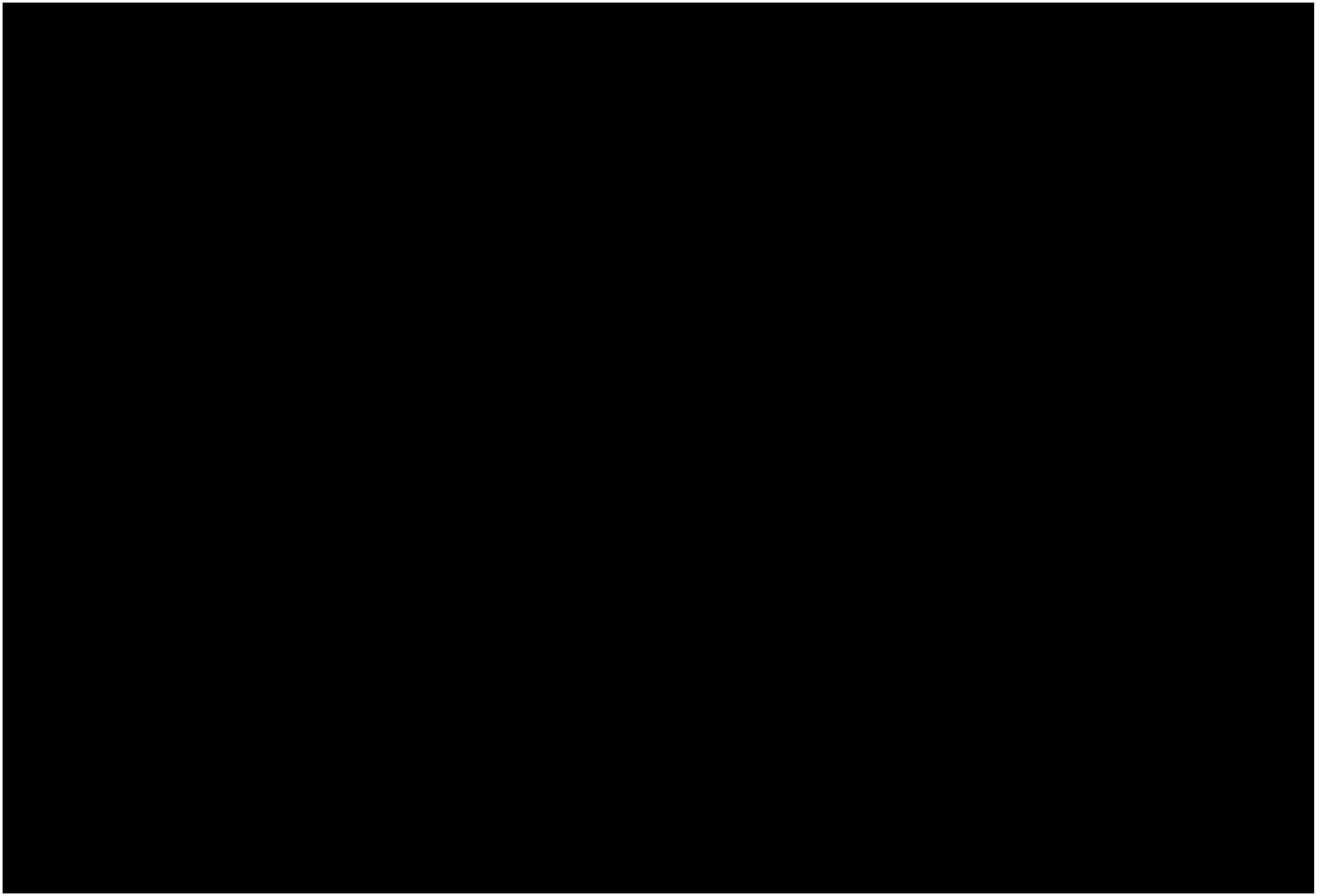
Date of On Peak Day - 07/25/2021



Member Forecasted On Peak Demand Day for August 2021

Wheatland Rural Electric Association, Inc.

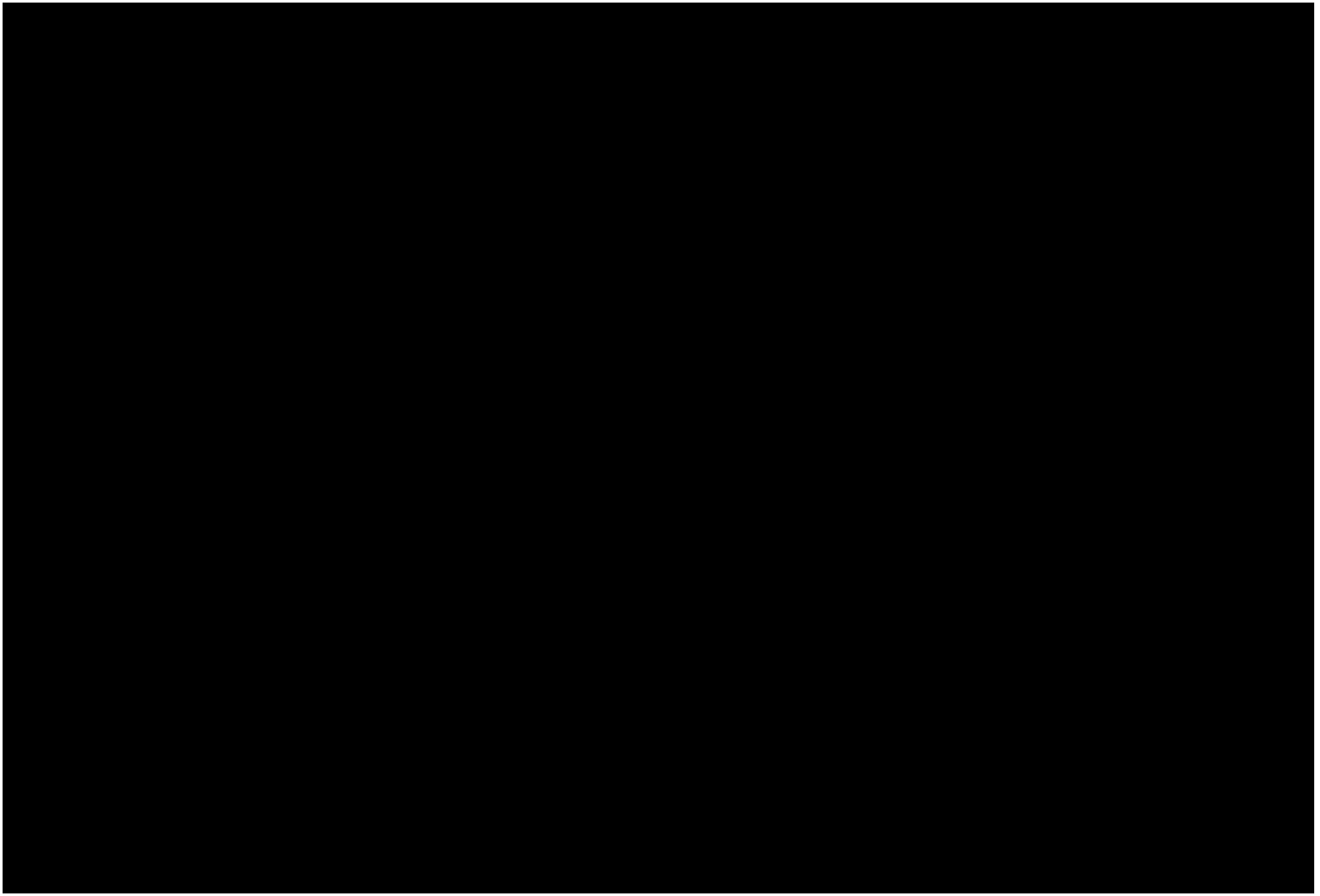
Date of On Peak Day - 08/31/2021



Member Forecasted On Peak Demand Day for September 2021

Wheatland Rural Electric Association, Inc.

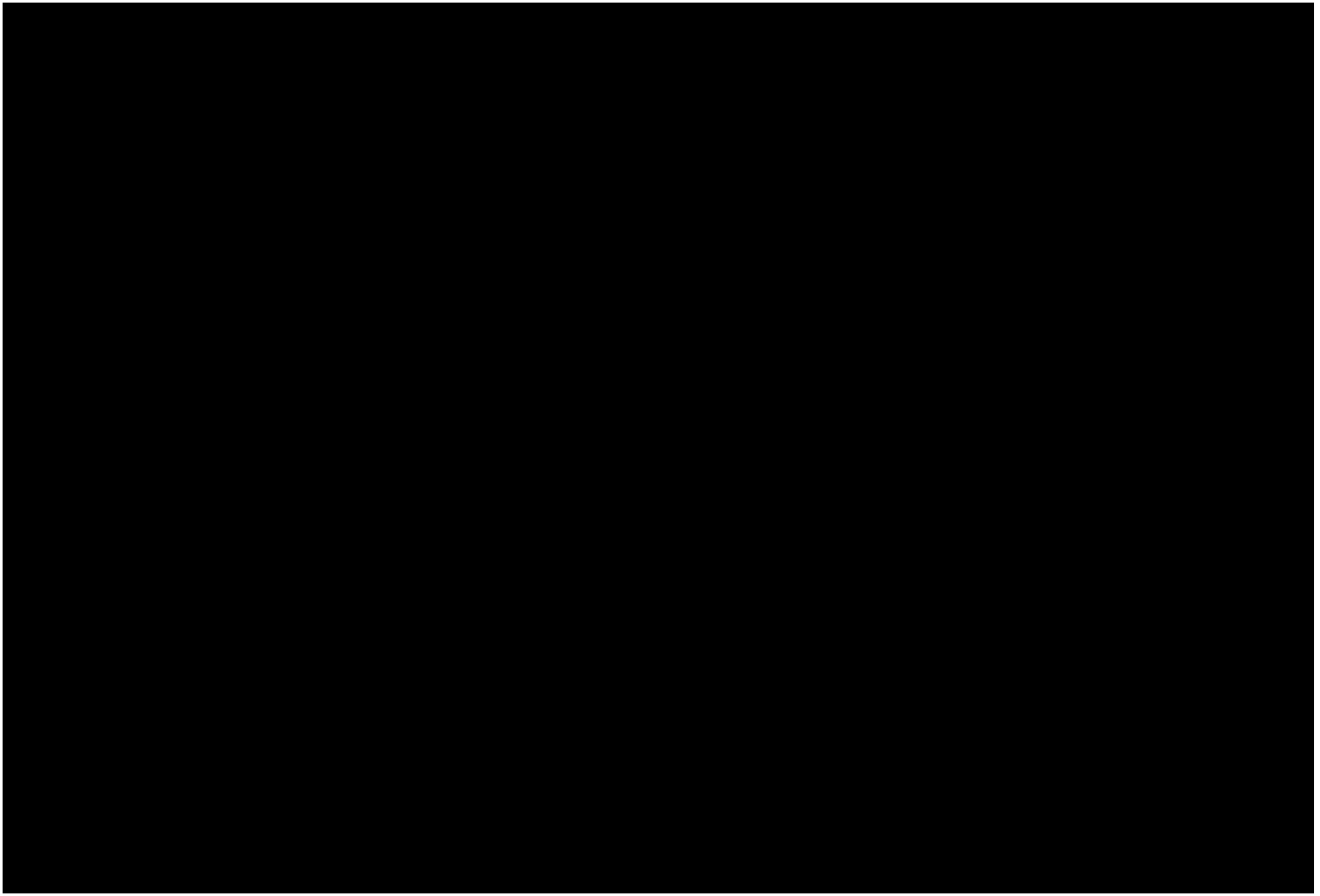
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Wheatland Rural Electric Association, Inc.

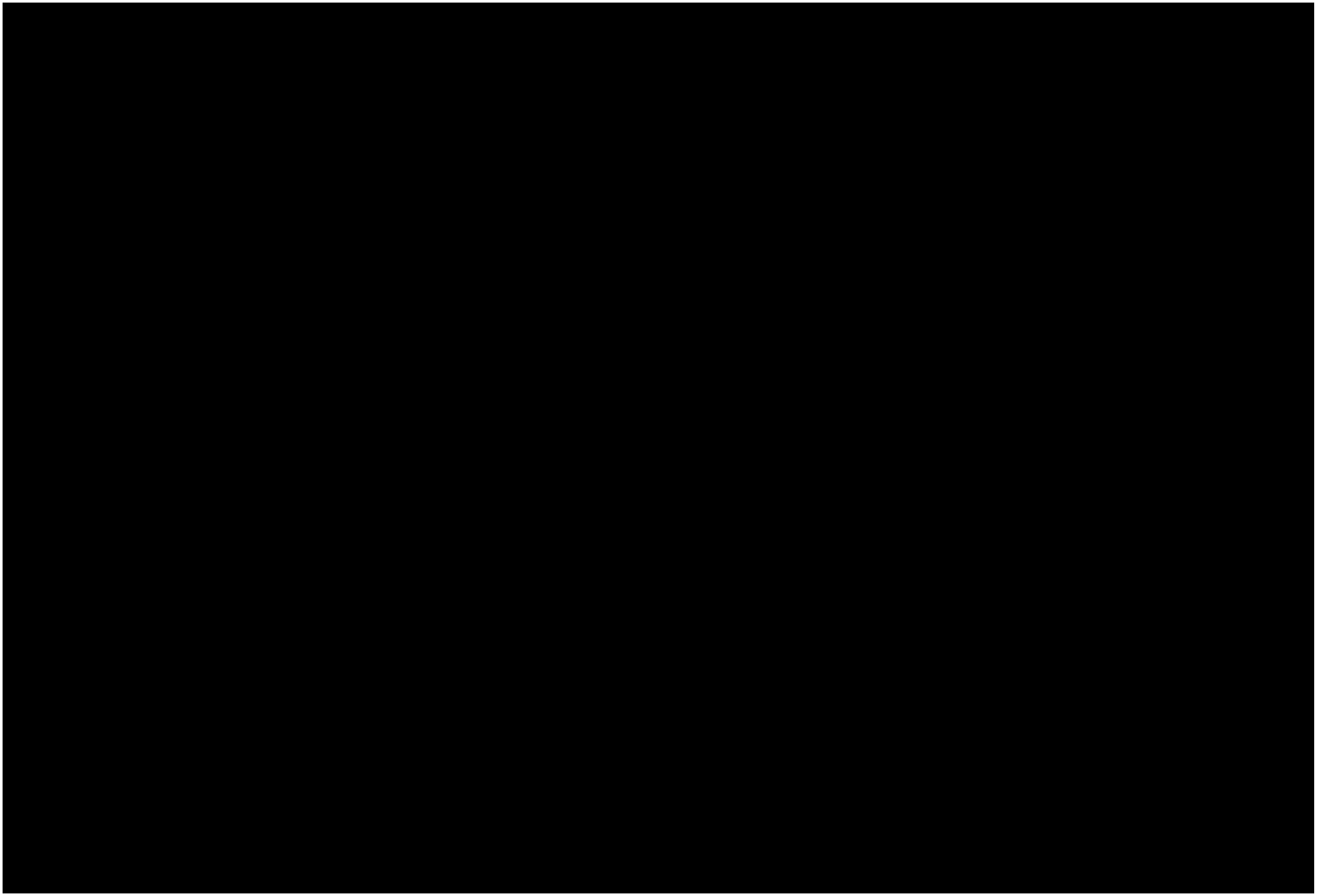
Date of On Peak Day - 10/14/2021



Member Forecasted On Peak Demand Day for November 2021

Wheatland Rural Electric Association, Inc.

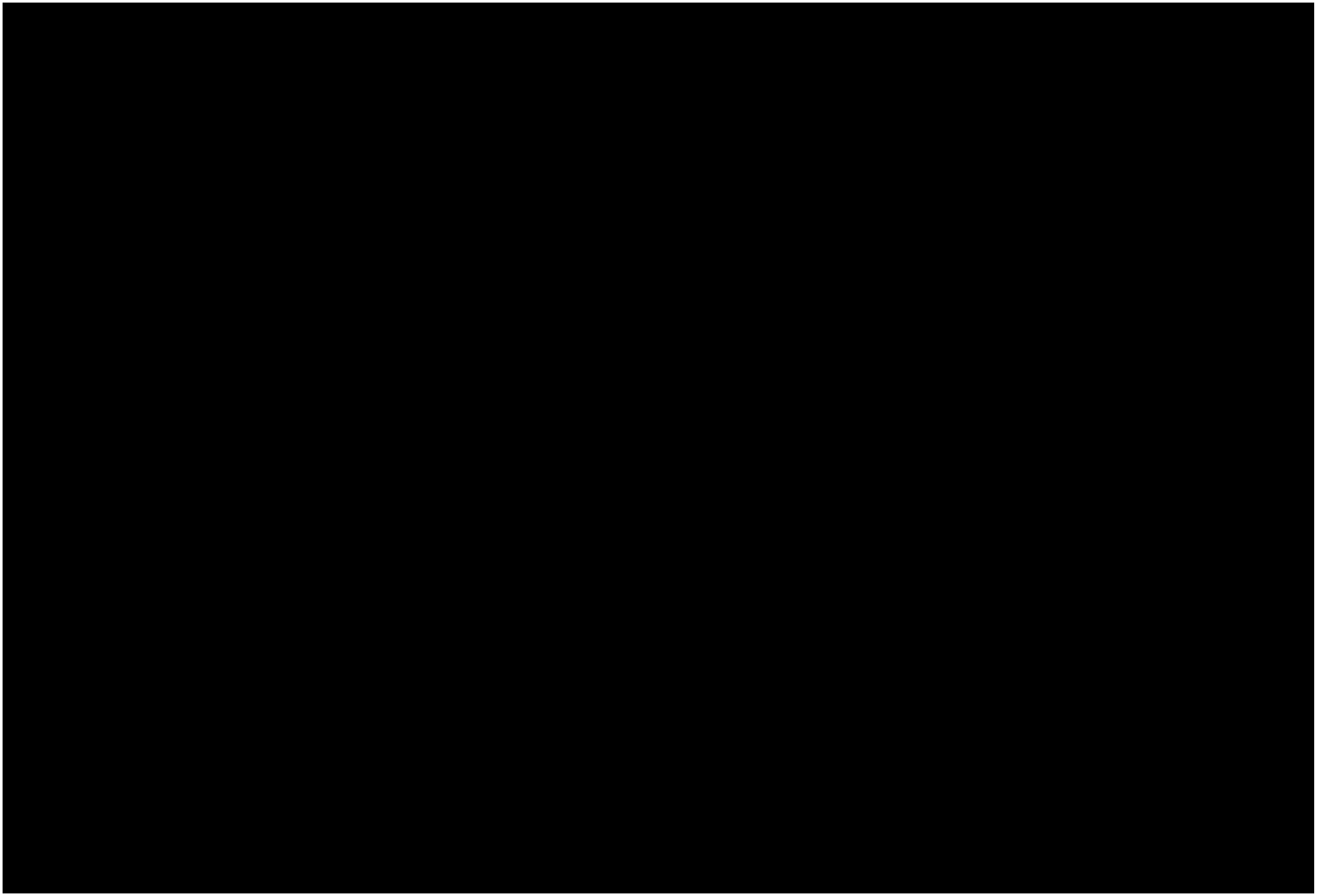
Date of On Peak Day - 11/28/2021



Member Forecasted On Peak Demand Day for December 2021

Wheatland Rural Electric Association, Inc.

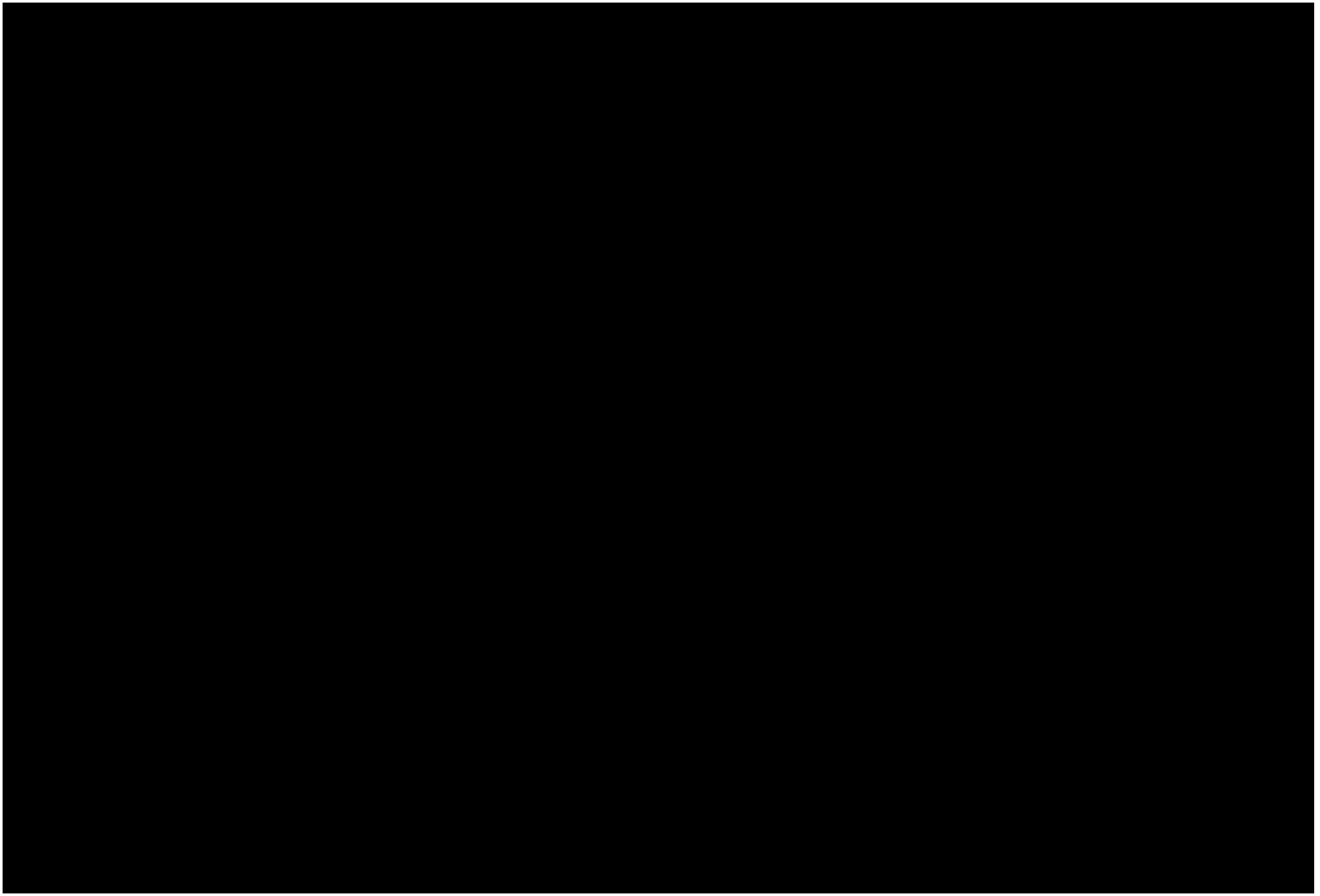
Date of On Peak Day - 12/02/2021



Member Forecasted On Peak Demand Day for January 2021

White River Electric Association, Inc.

Date of On Peak Day - 01/28/2021



Member Forecasted On Peak Demand Day for February 2021

White River Electric Association, Inc.

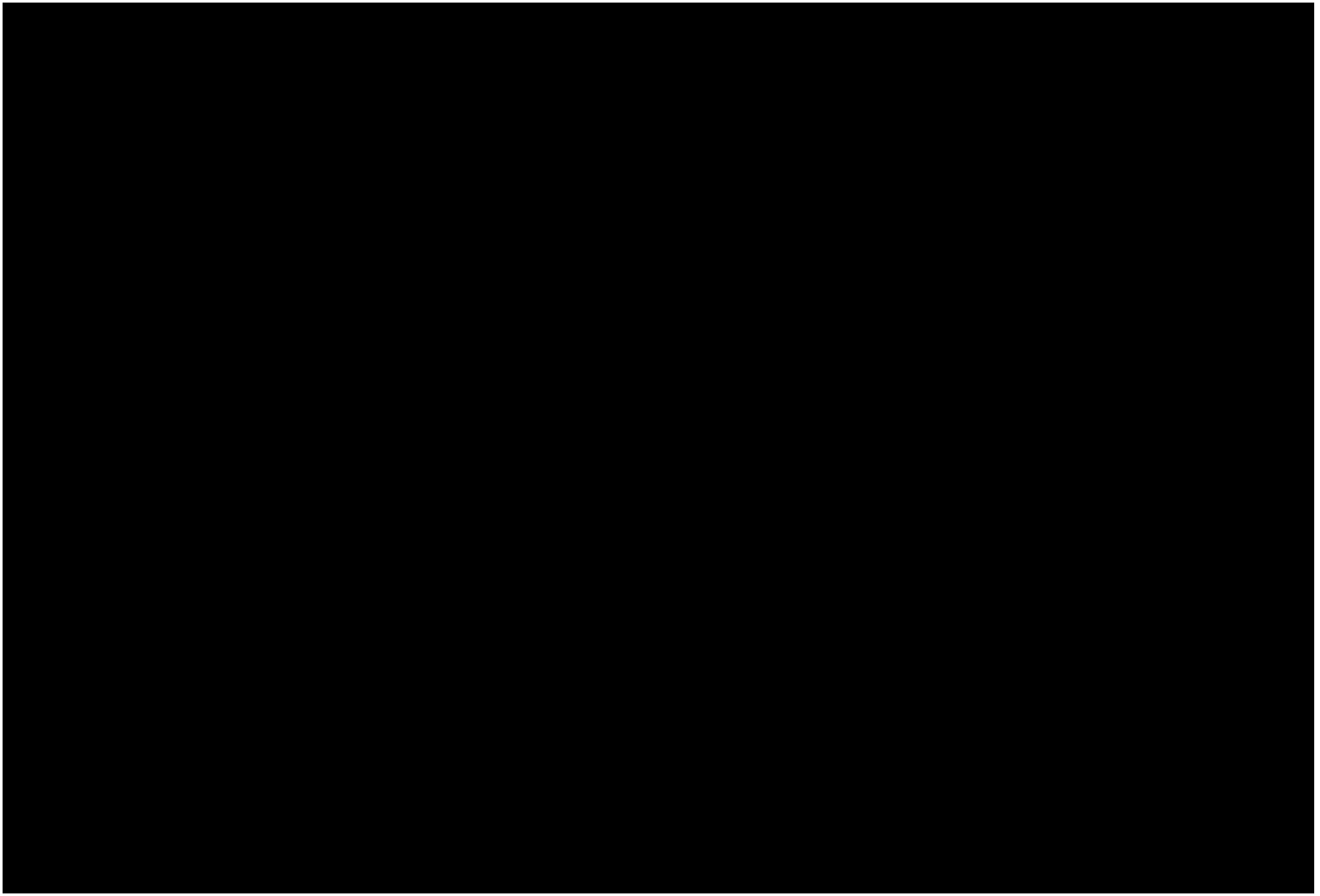
Date of On Peak Day - 02/02/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

White River Electric Association, Inc.

Date of On Peak Day - 03/30/2021



Member Forecasted On Peak Demand Day for April 2021

White River Electric Association, Inc.

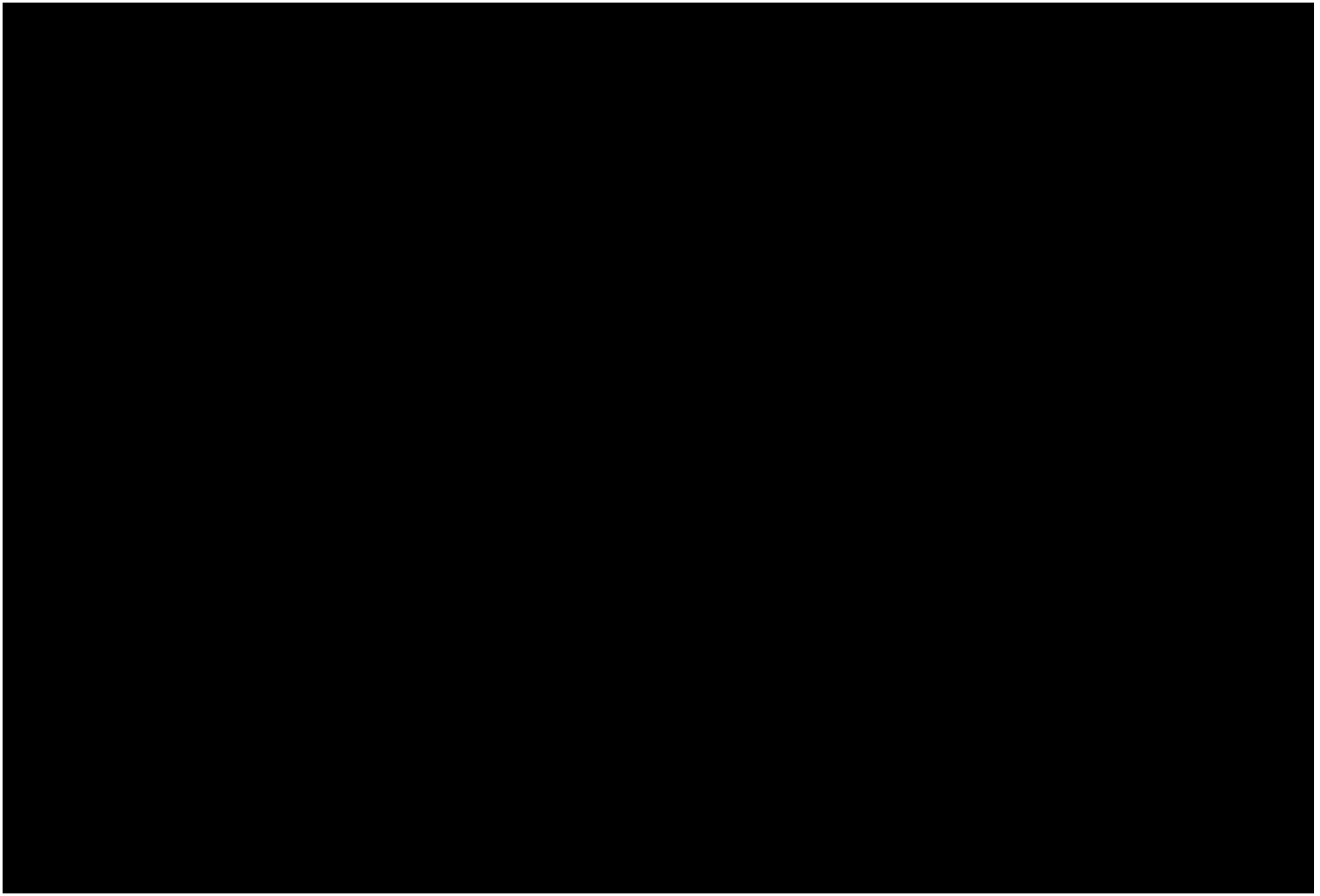
Date of On Peak Day - 04/01/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

White River Electric Association, Inc.

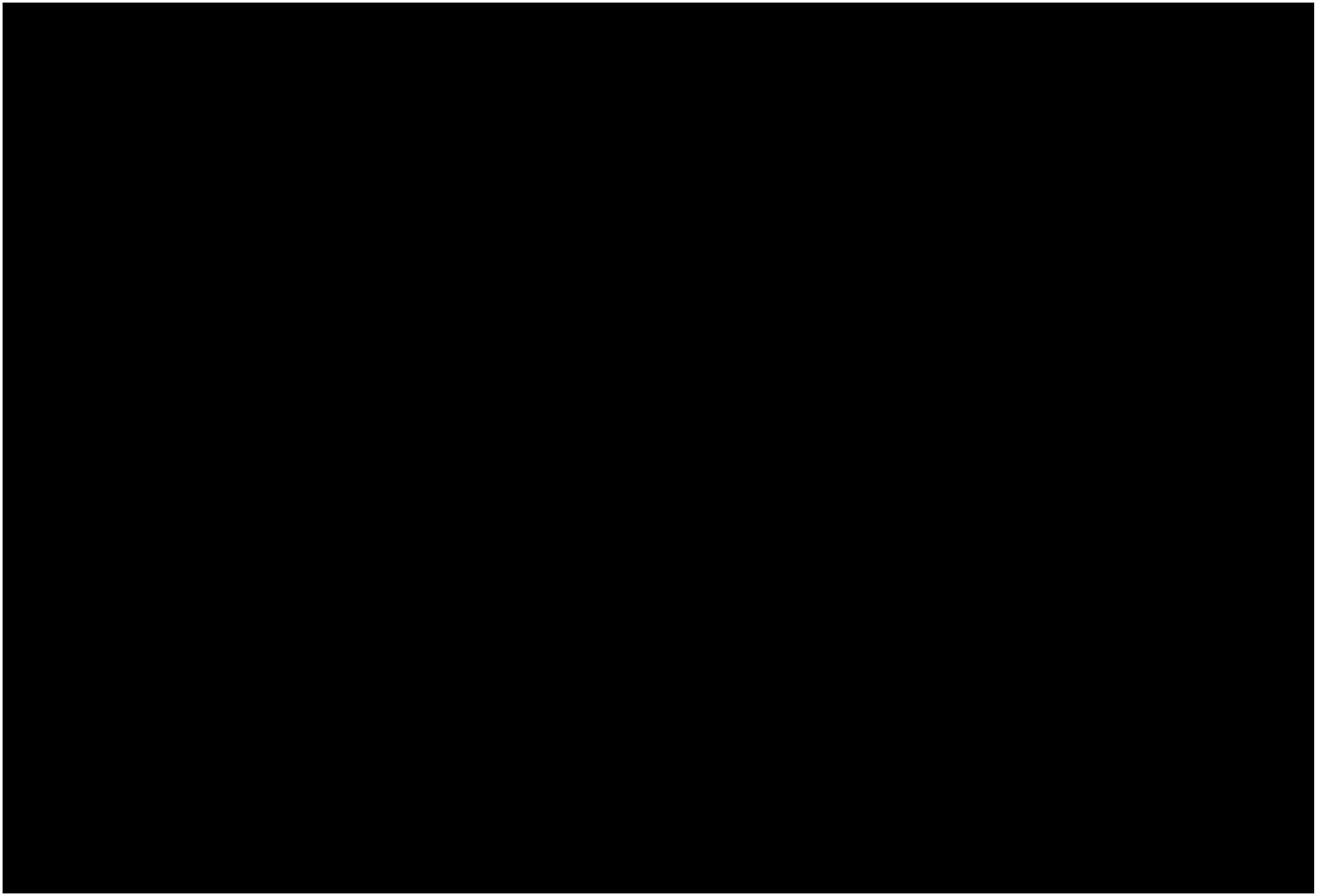
Date of On Peak Day - 05/03/2021



Member Forecasted On Peak Demand Day for June 2021

White River Electric Association, Inc.

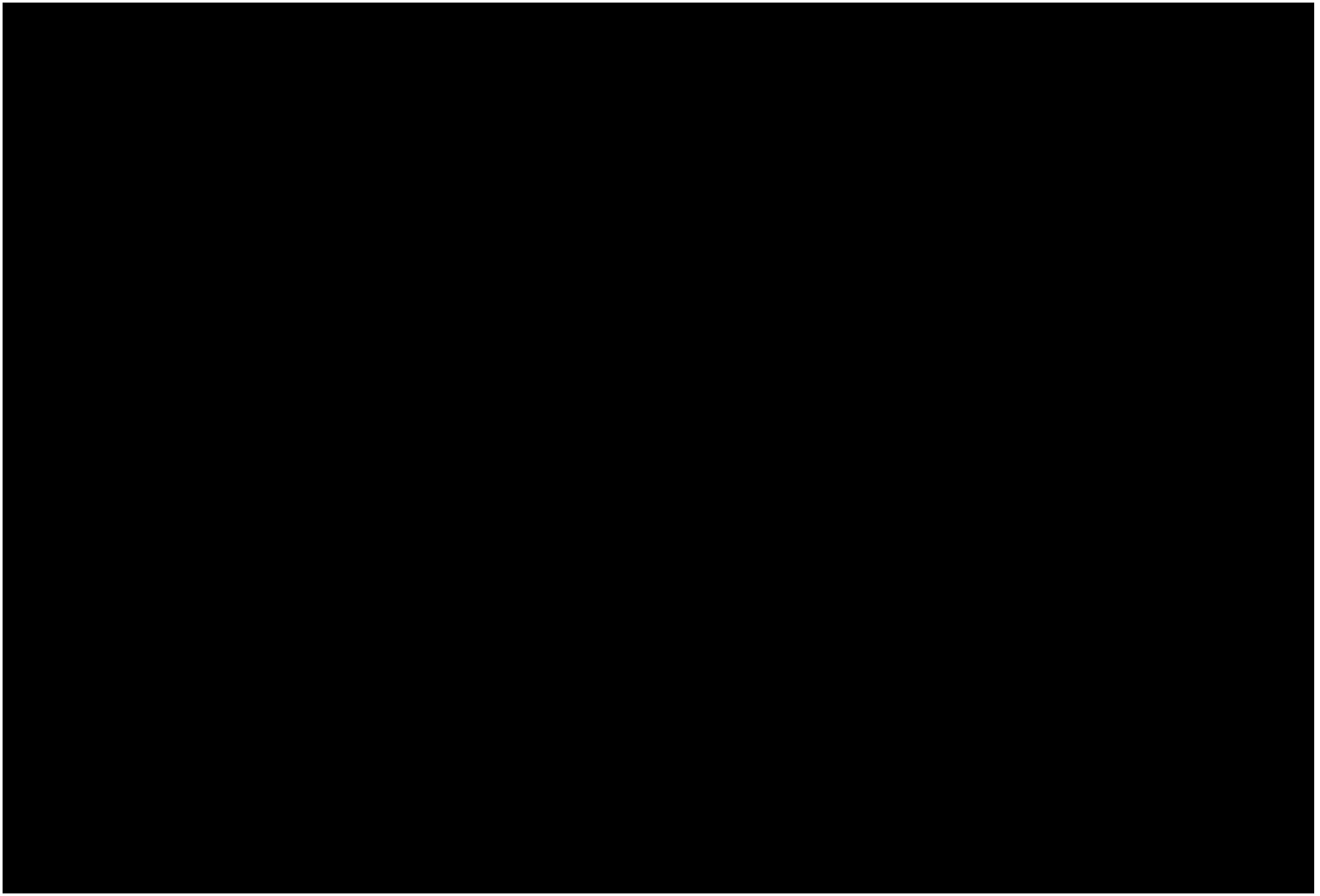
Date of On Peak Day - 06/03/2021



Member Forecasted On Peak Demand Day for July 2021

White River Electric Association, Inc.

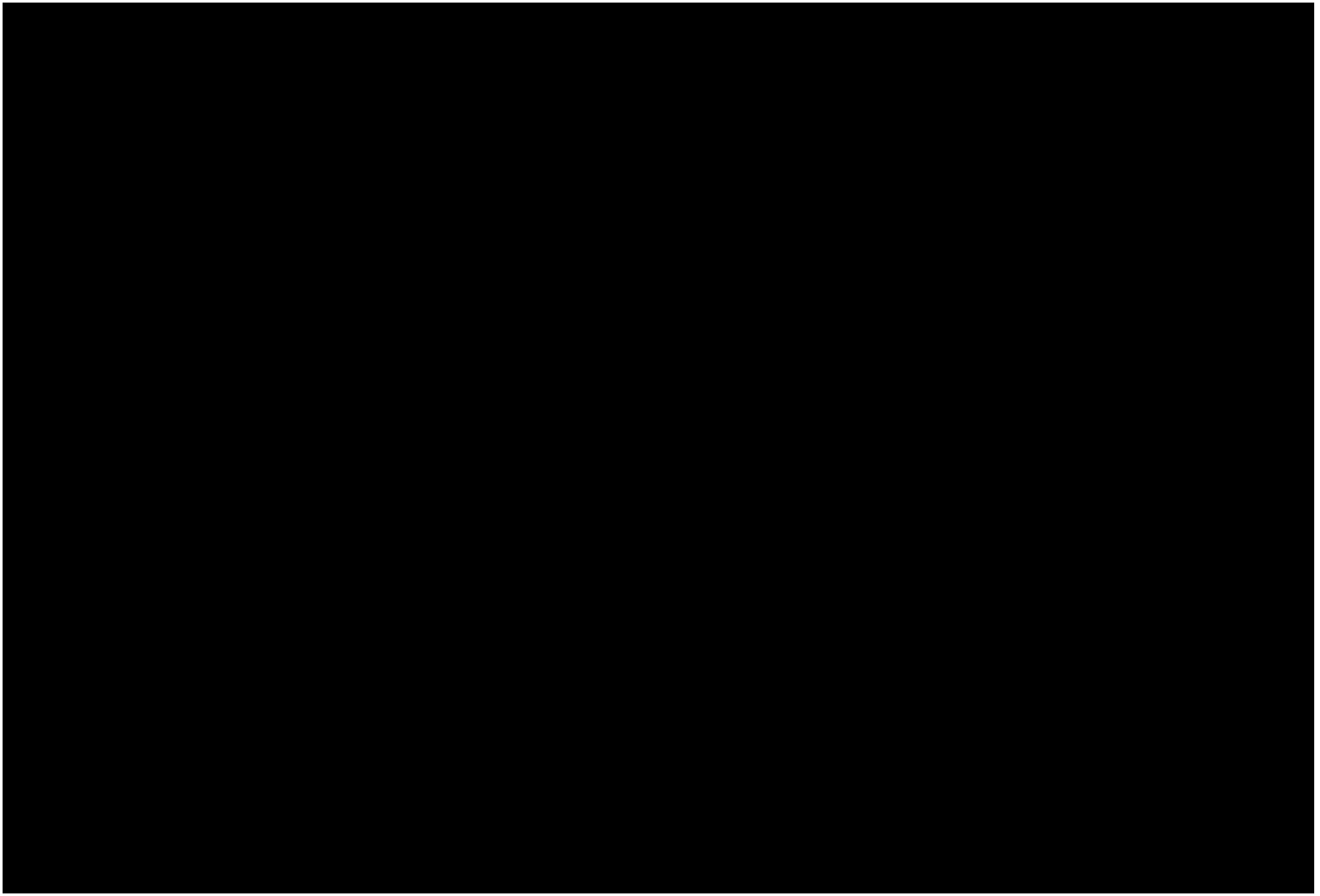
Date of On Peak Day - 07/06/2021



Member Forecasted On Peak Demand Day for August 2021

White River Electric Association, Inc.

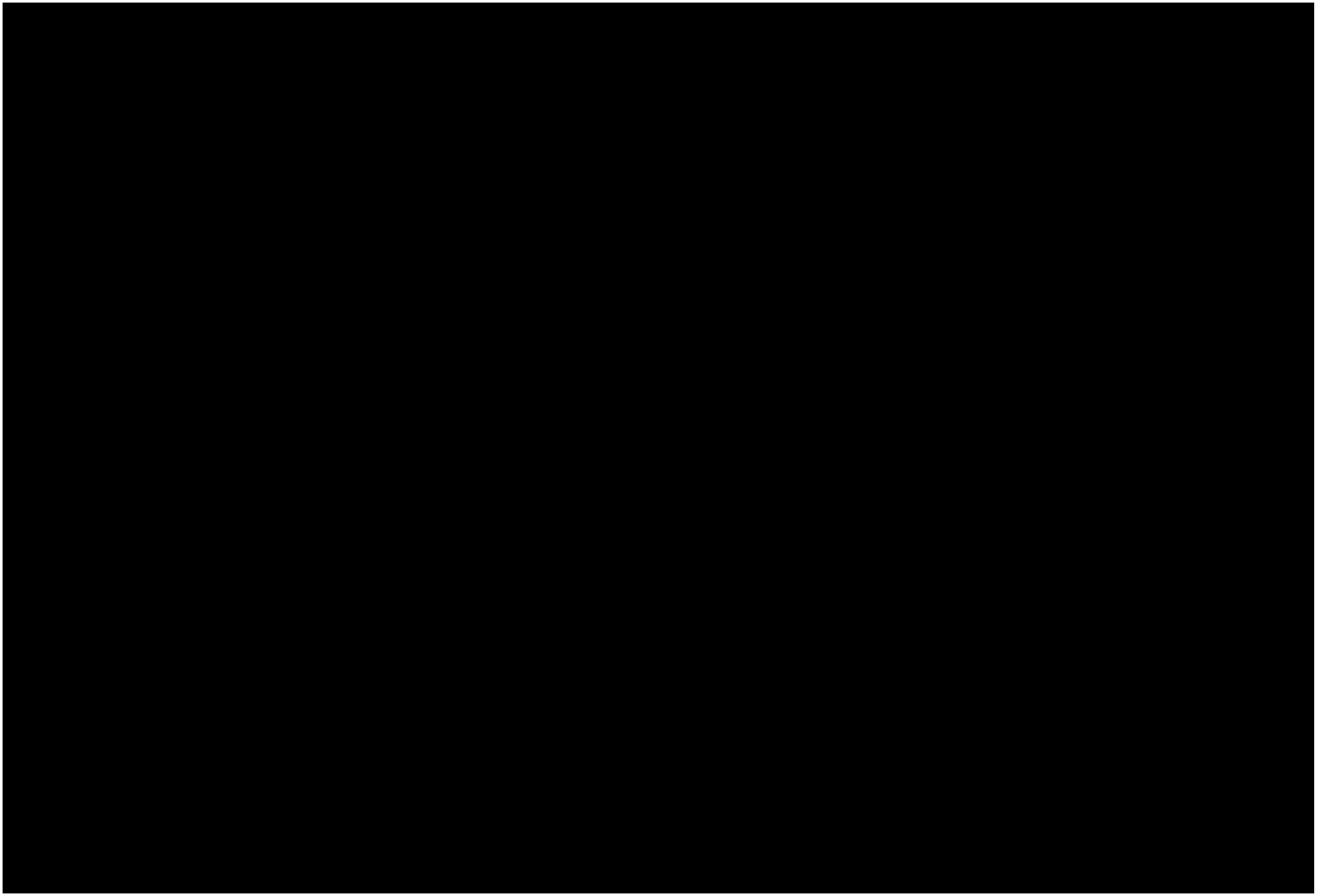
Date of On Peak Day - 08/30/2021



Member Forecasted On Peak Demand Day for September 2021

White River Electric Association, Inc.

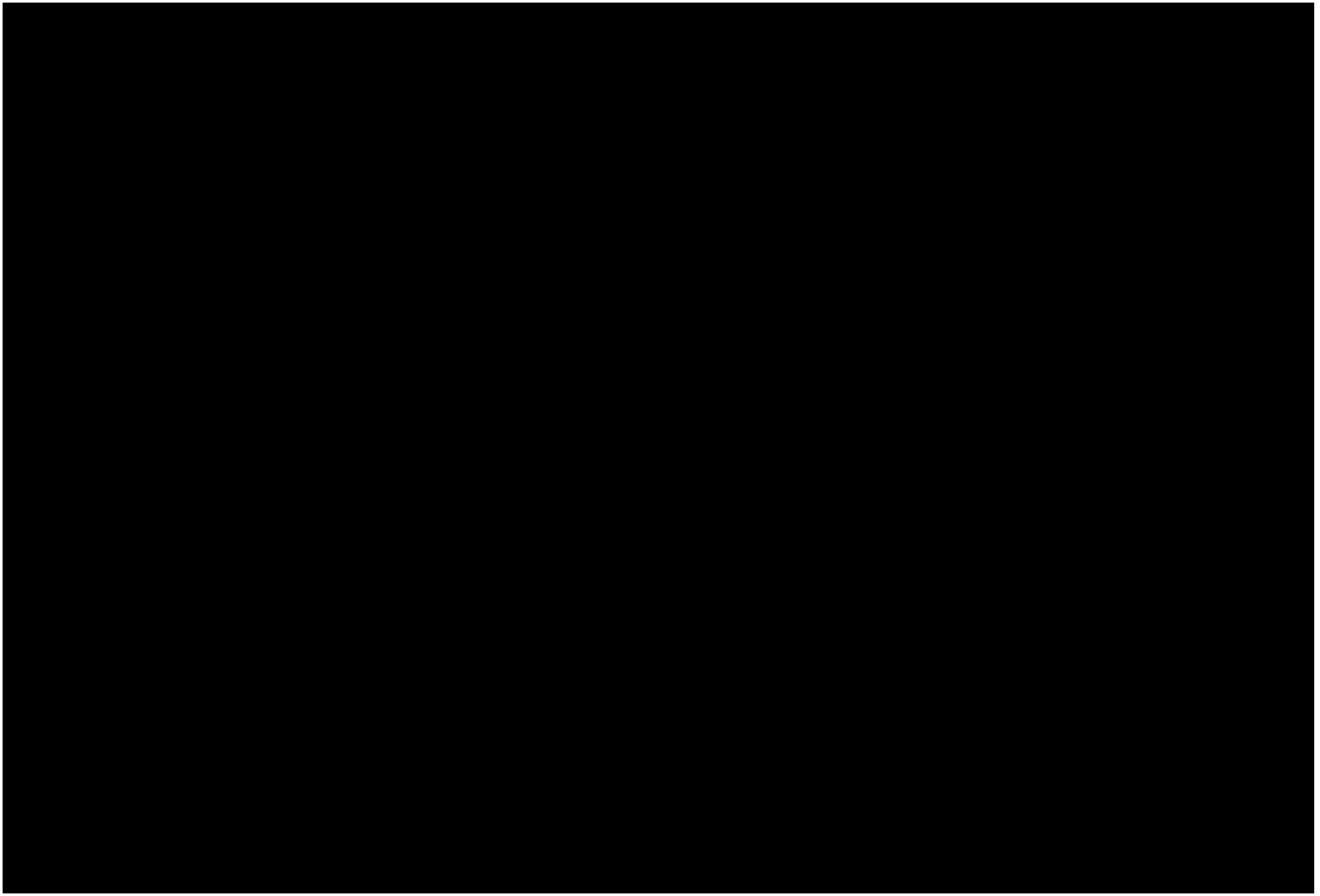
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

White River Electric Association, Inc.

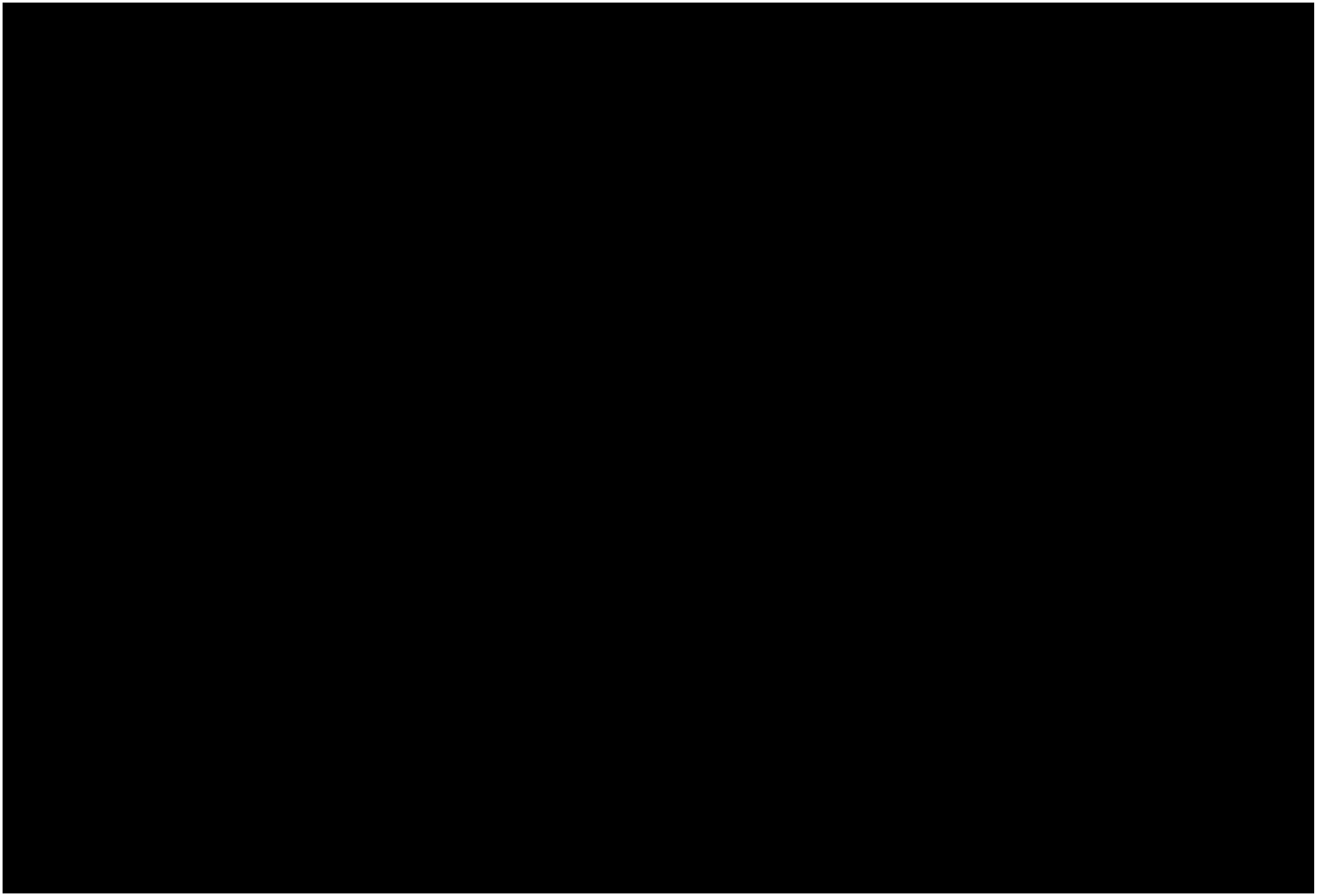
Date of On Peak Day - 10/28/2021



Member Forecasted On Peak Demand Day for November 2021

White River Electric Association, Inc.

Date of On Peak Day - 11/04/2021



Member Forecasted On Peak Demand Day for December 2021

White River Electric Association, Inc.

Date of On Peak Day - 12/30/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Wyrulec Company

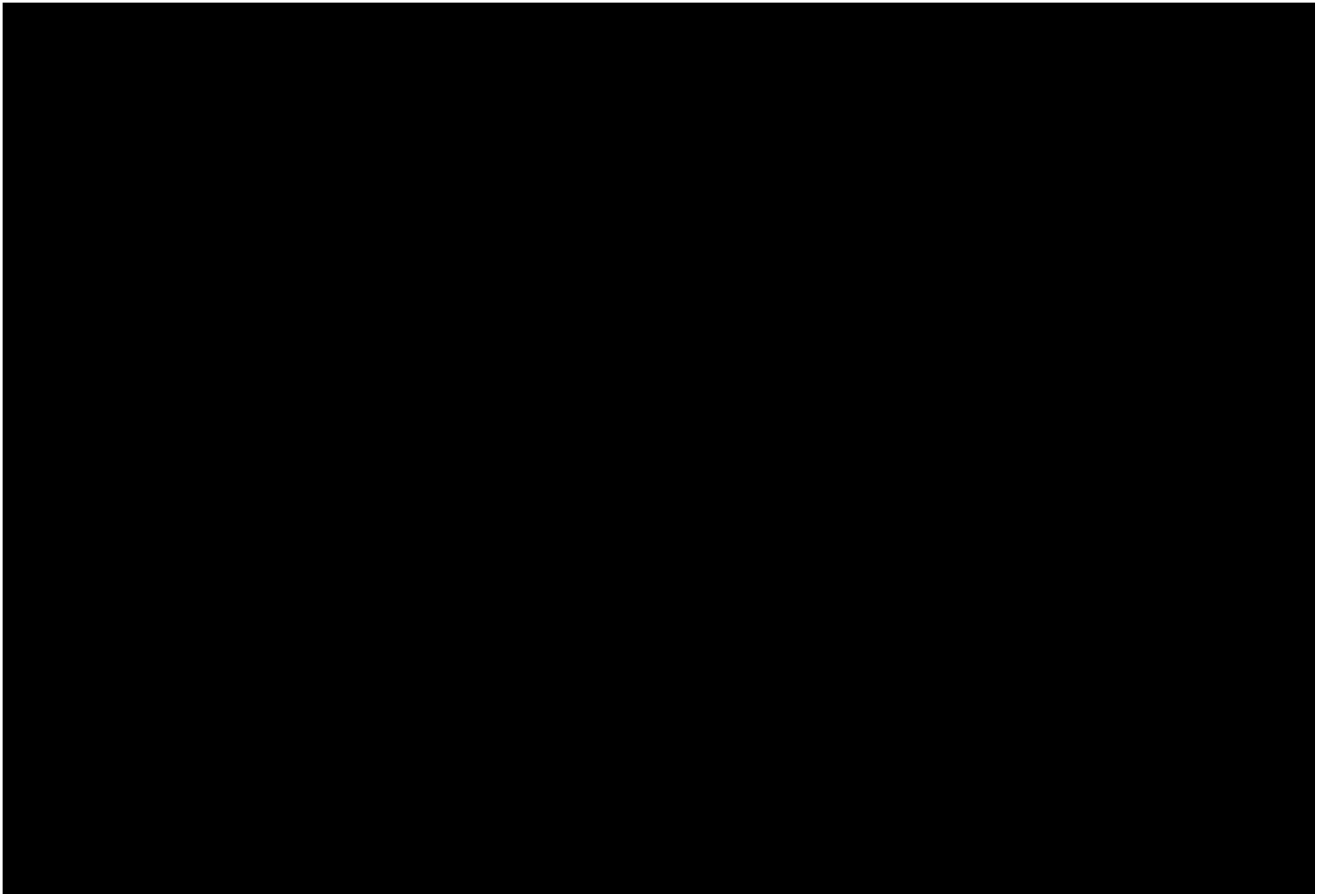
Date of On Peak Day - 01/25/2021

[redacted]

Member Forecasted On Peak Demand Day for February 2021

Wyrulec Company

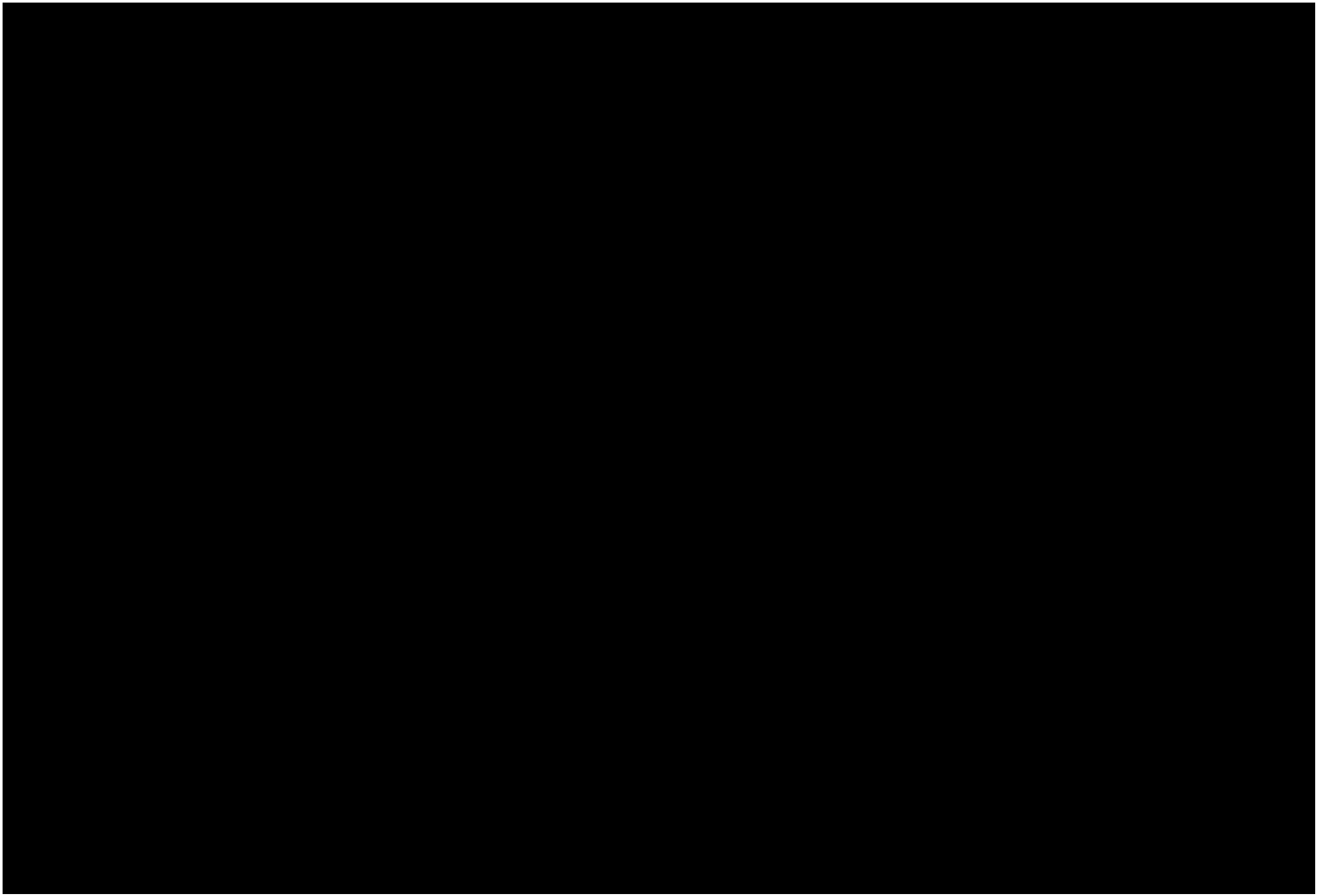
Date of On Peak Day - 02/24/2021



Member Forecasted On Peak Demand Day for March 2021

Wyrulec Company

Date of On Peak Day - 03/04/2021



Member Forecasted On Peak Demand Day for April 2021

Wyrulec Company

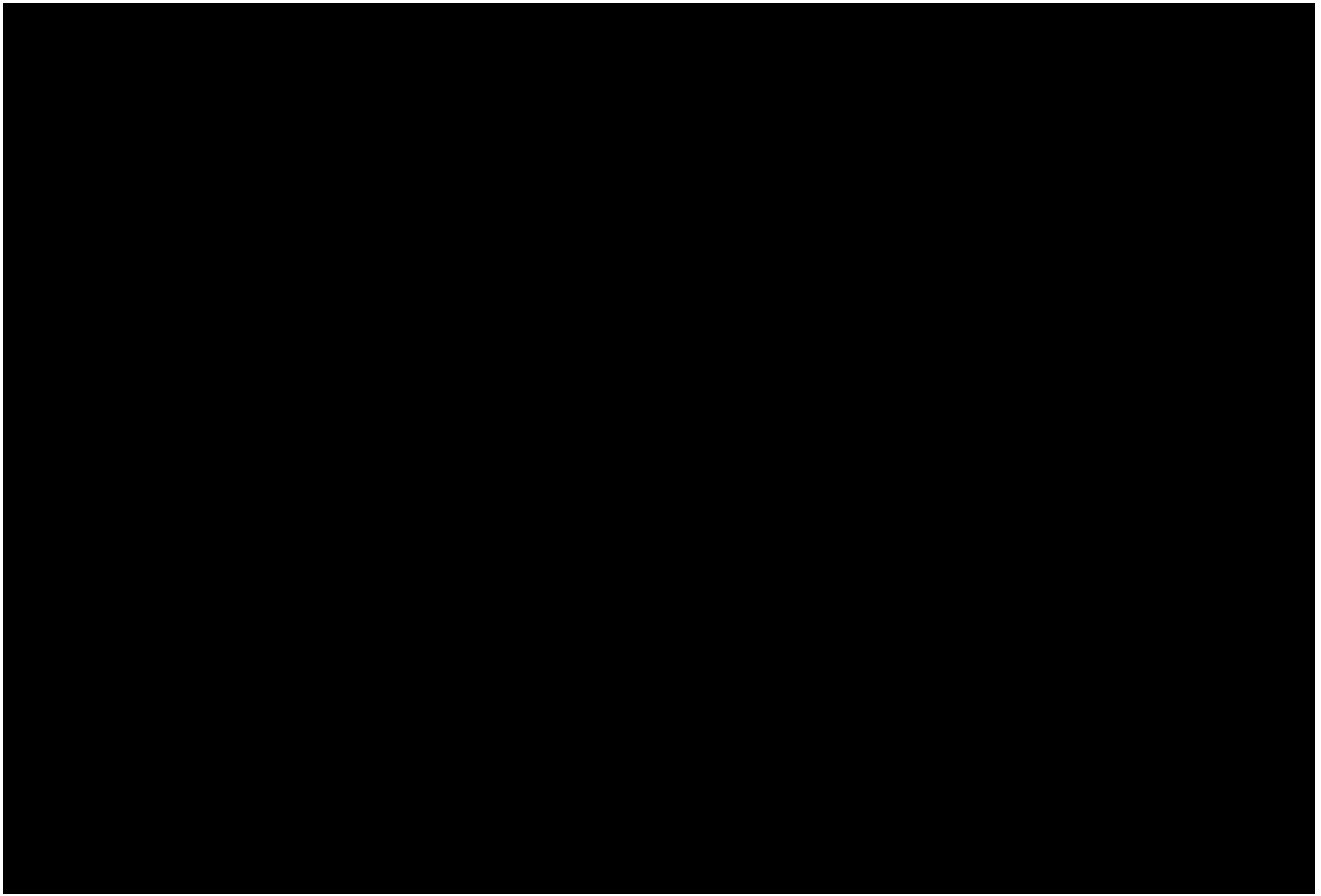
Date of On Peak Day - 04/04/2021

[redacted]

Member Forecasted On Peak Demand Day for May 2021

Wyrulec Company

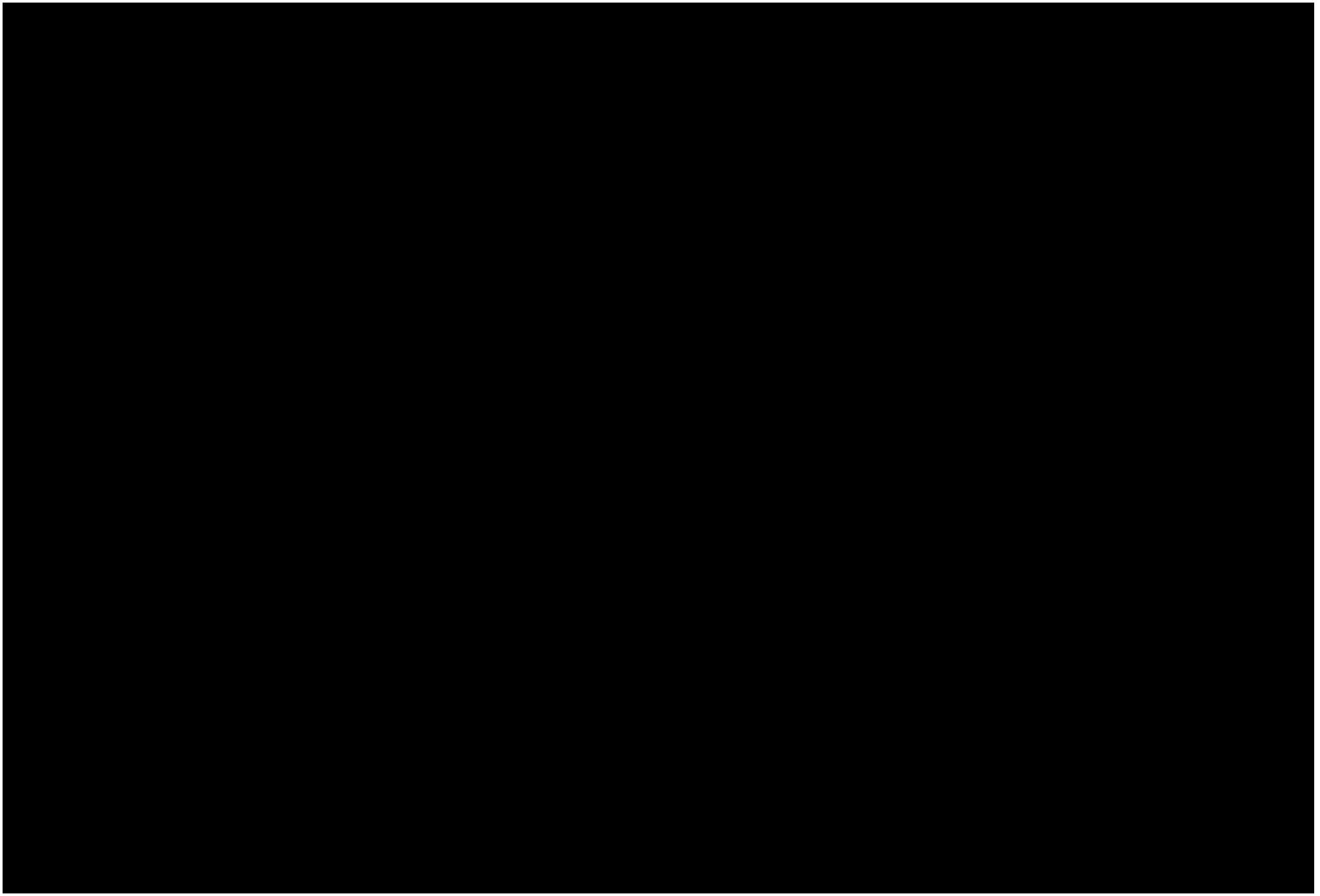
Date of On Peak Day - 05/13/2021



Member Forecasted On Peak Demand Day for June 2021

Wyrulec Company

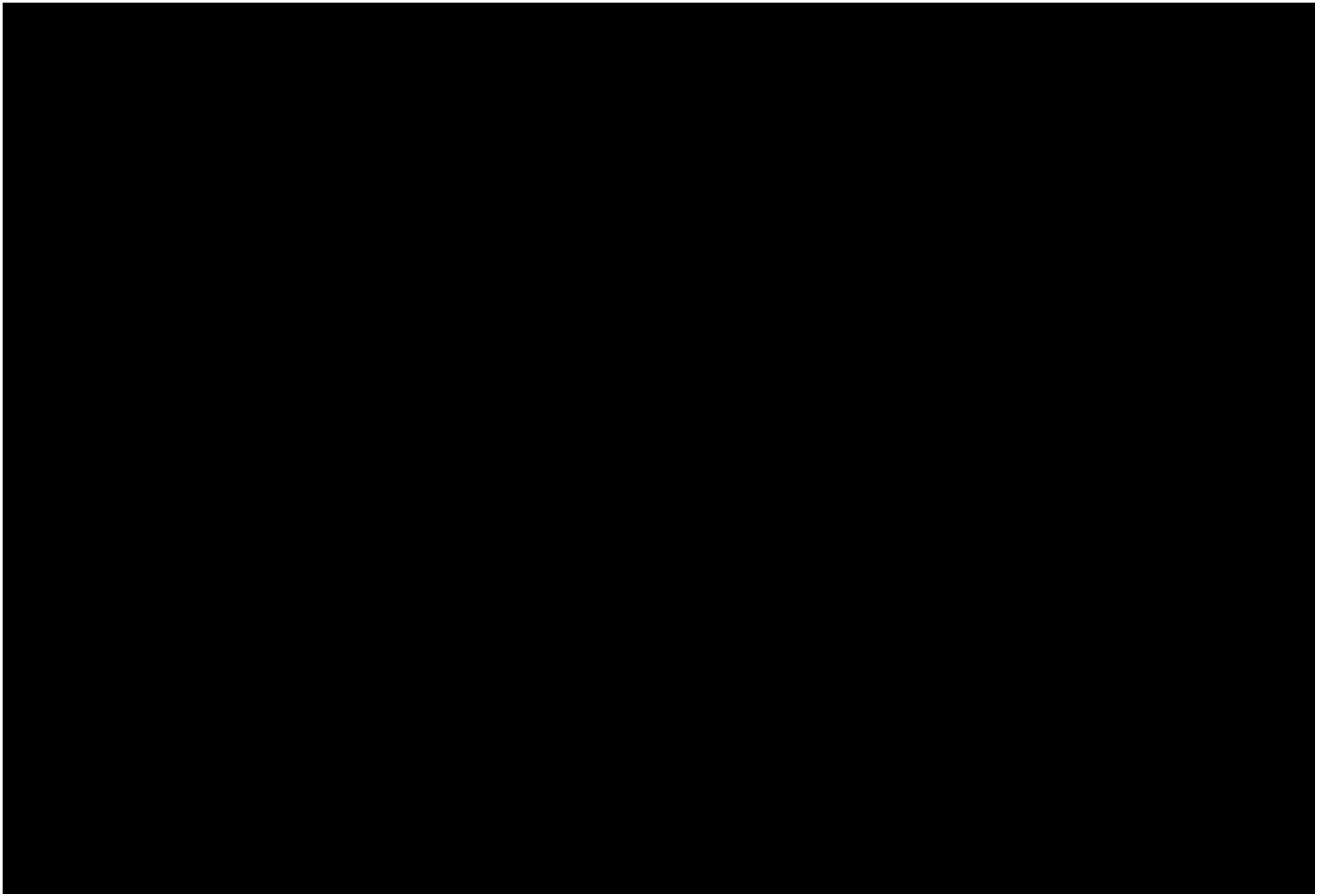
Date of On Peak Day - 06/28/2021



Member Forecasted On Peak Demand Day for July 2021

Wyrulec Company

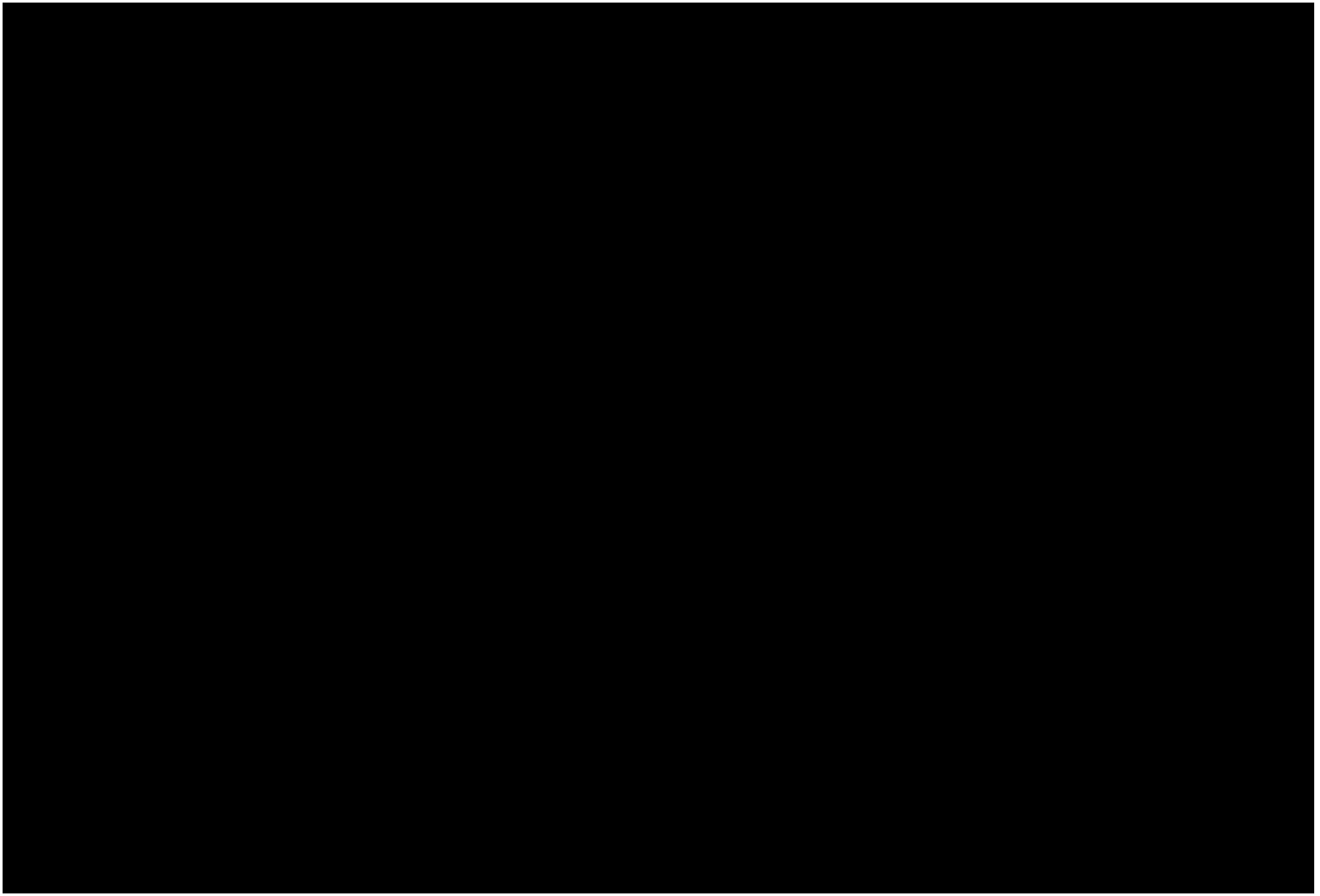
Date of On Peak Day - 07/22/2021



Member Forecasted On Peak Demand Day for August 2021

Wyrulec Company

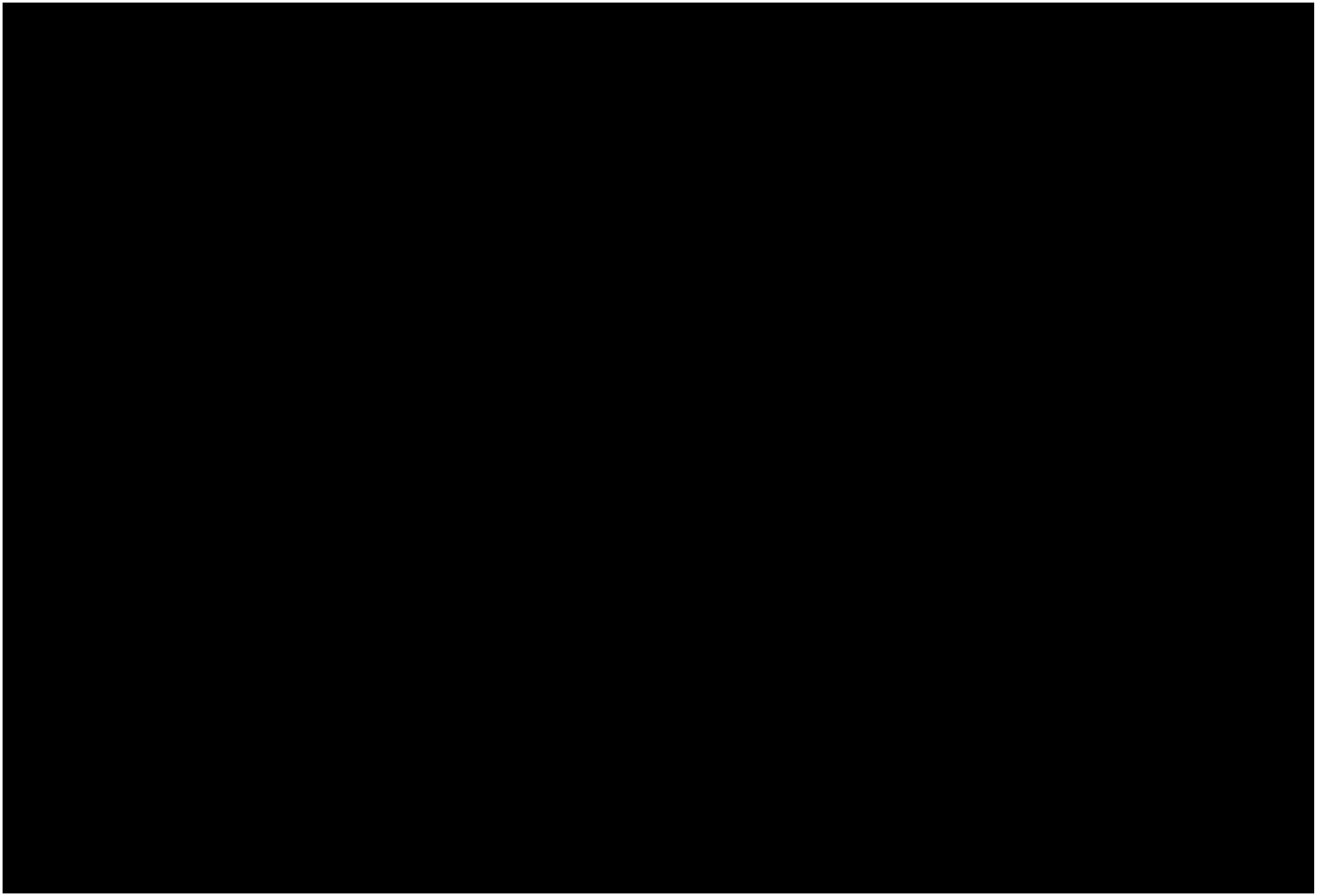
Date of On Peak Day - 08/01/2021



Member Forecasted On Peak Demand Day for September 2021

Wyrulec Company

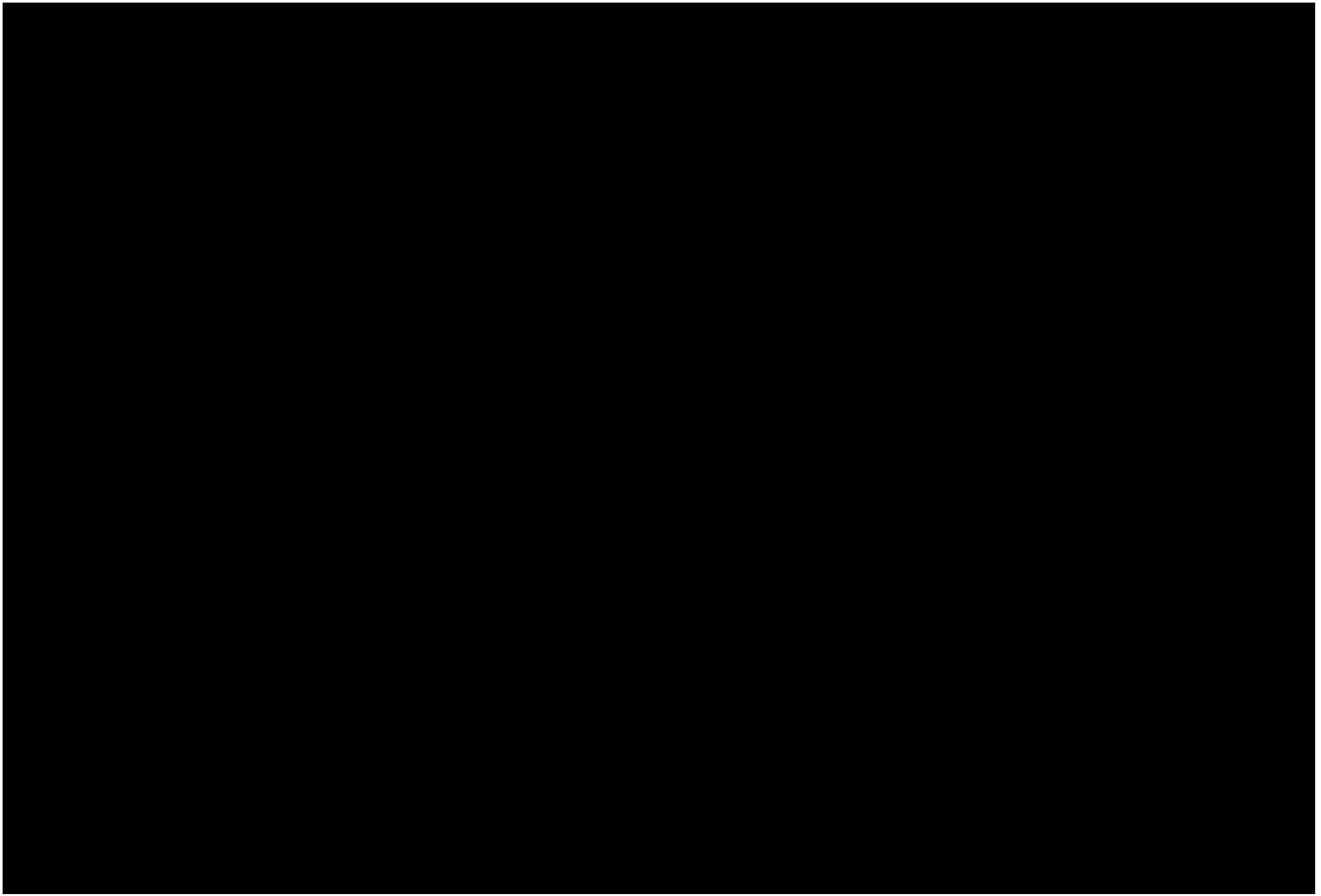
Date of On Peak Day - 09/02/2021



Member Forecasted On Peak Demand Day for October 2021

Wyrulec Company

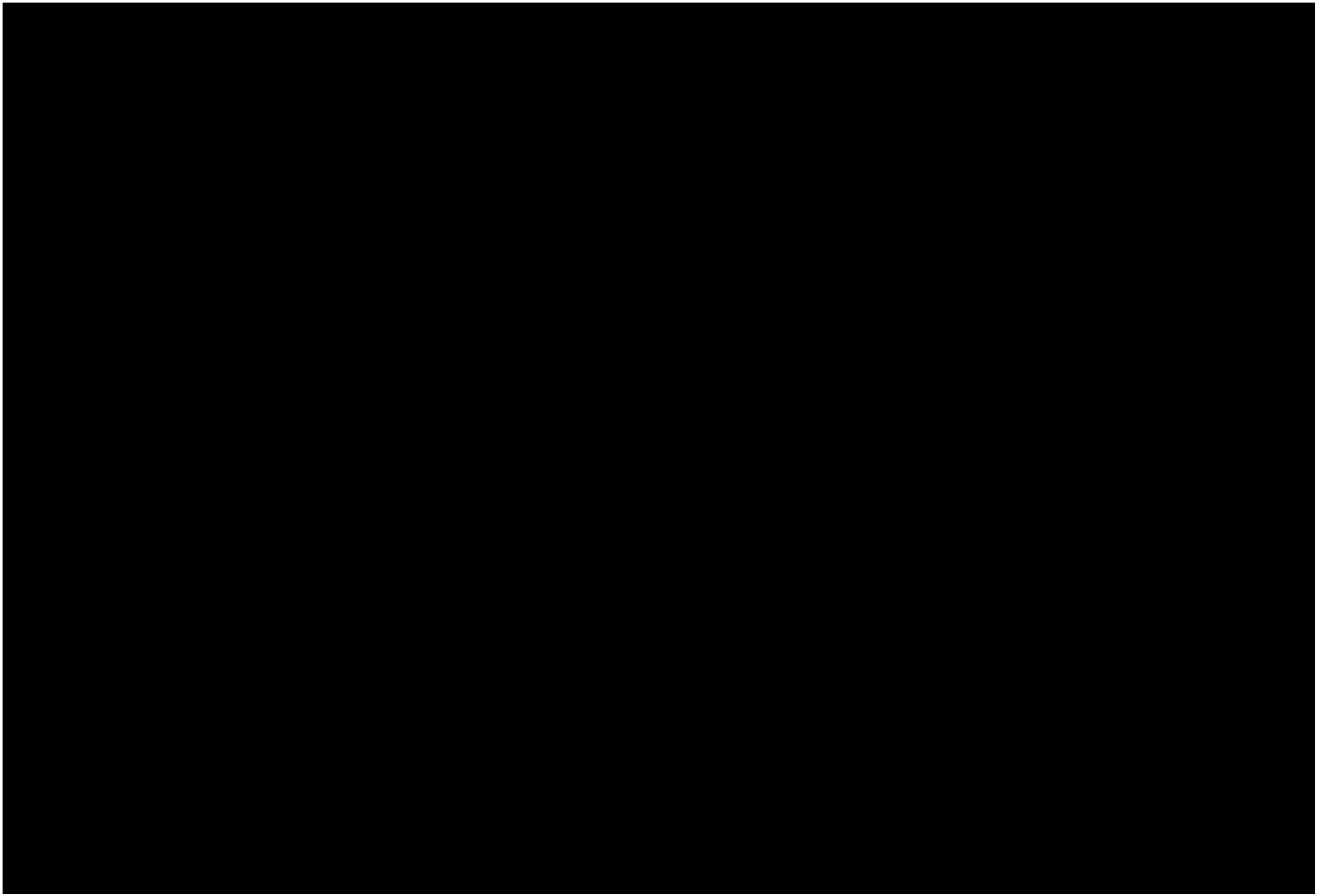
Date of On Peak Day - 10/27/2021



Member Forecasted On Peak Demand Day for November 2021

Wyrulec Company

Date of On Peak Day - 11/22/2021



Member Forecasted On Peak Demand Day for December 2021

Wyrulec Company

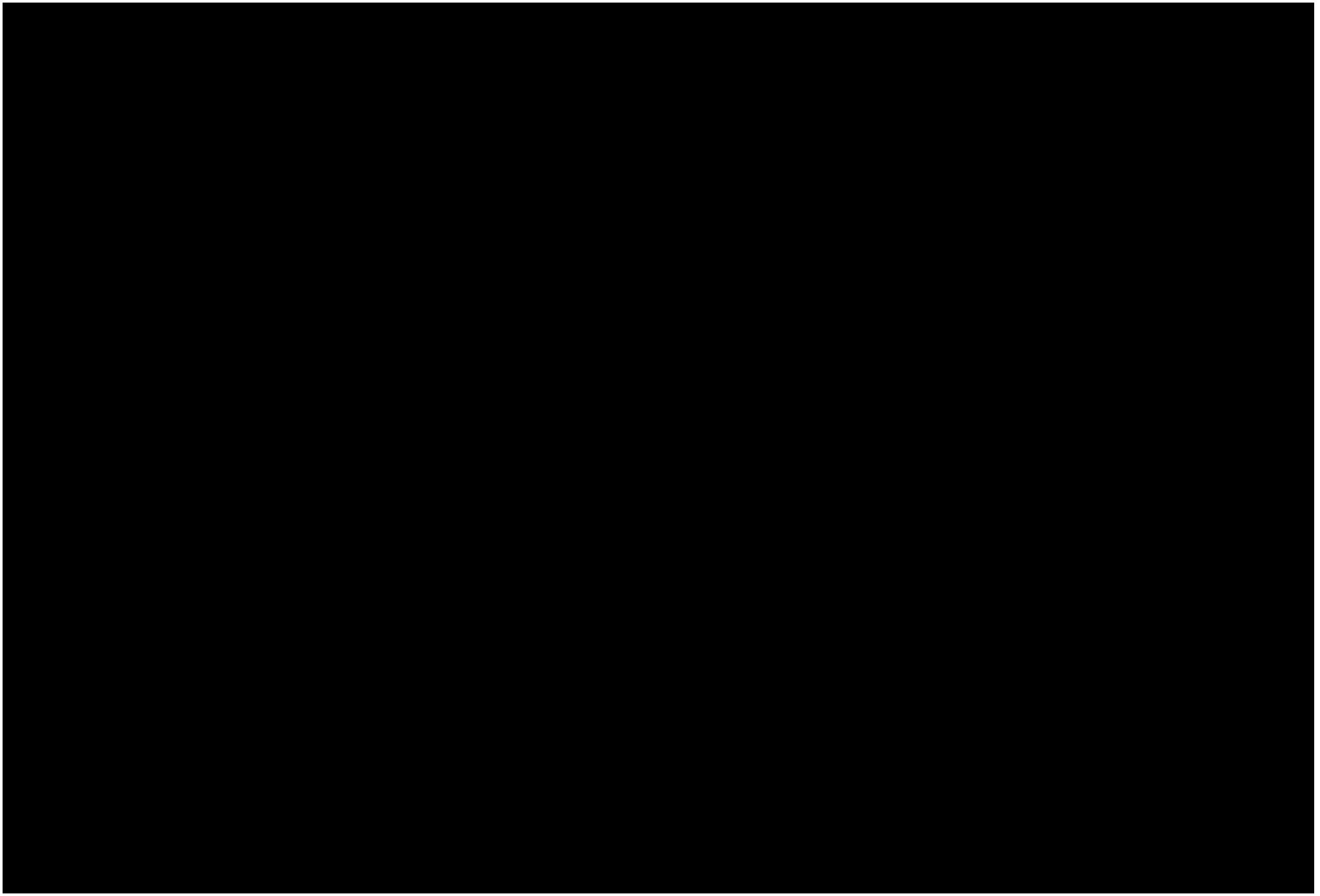
Date of On Peak Day - 12/27/2021

[redacted]

Member Forecasted On Peak Demand Day for January 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 01/07/2021



Member Forecasted On Peak Demand Day for February 2021

Y-W Electric Association, Inc.

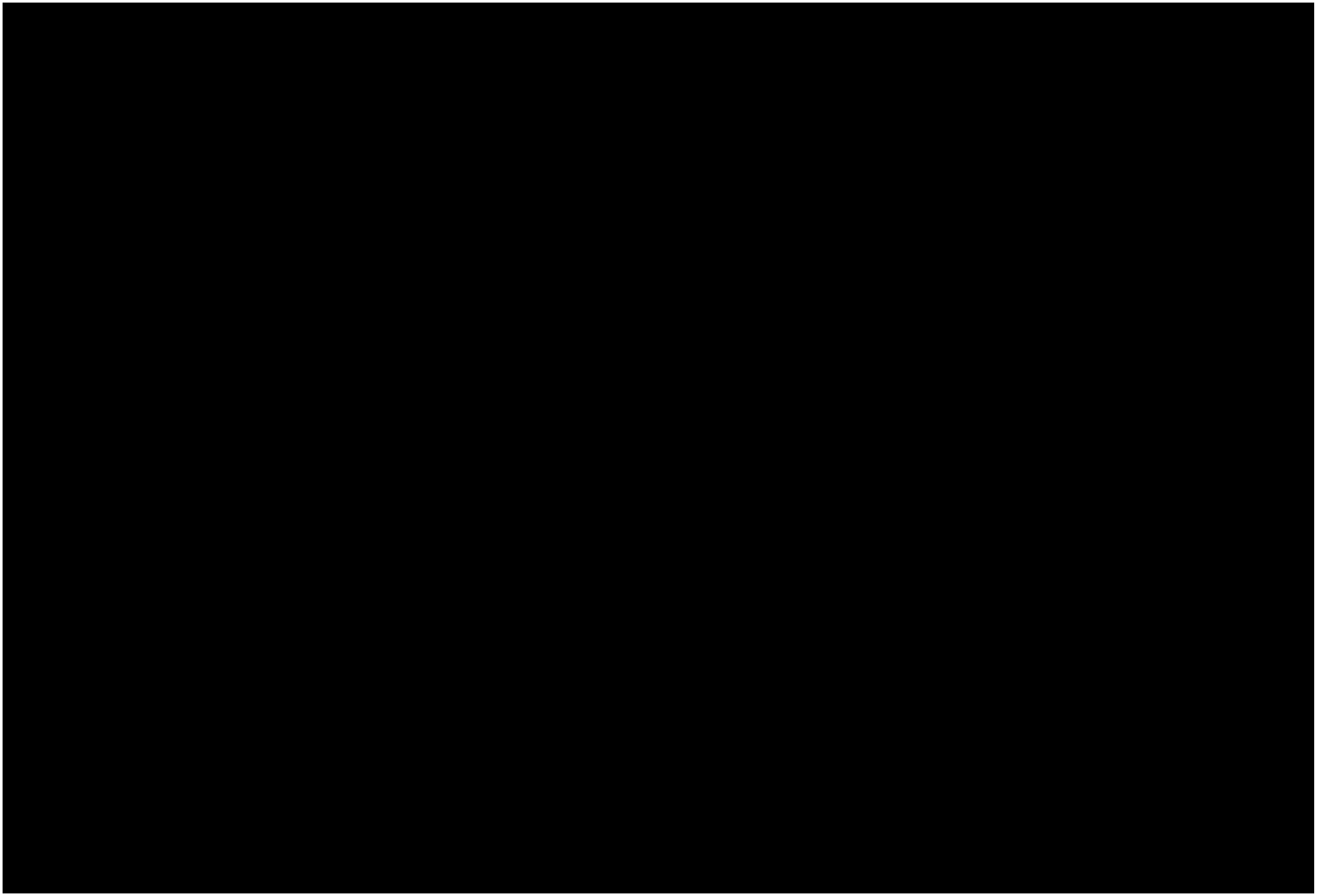
Date of On Peak Day - 02/25/2021

[redacted]

Member Forecasted On Peak Demand Day for March 2021

Y-W Electric Association, Inc.

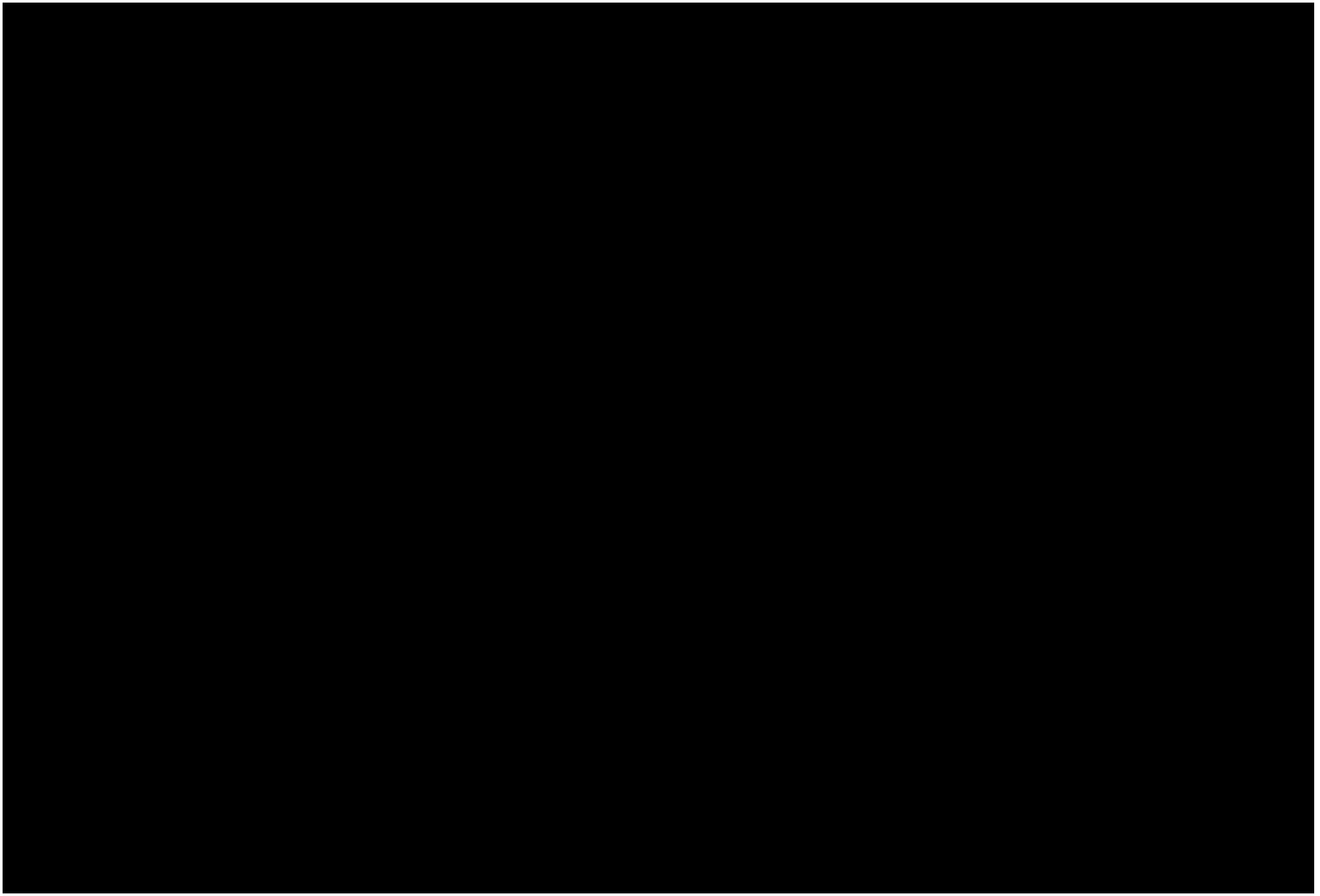
Date of On Peak Day - 03/18/2021



Member Forecasted On Peak Demand Day for April 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 04/12/2021



Member Forecasted On Peak Demand Day for May 2021

Y-W Electric Association, Inc.

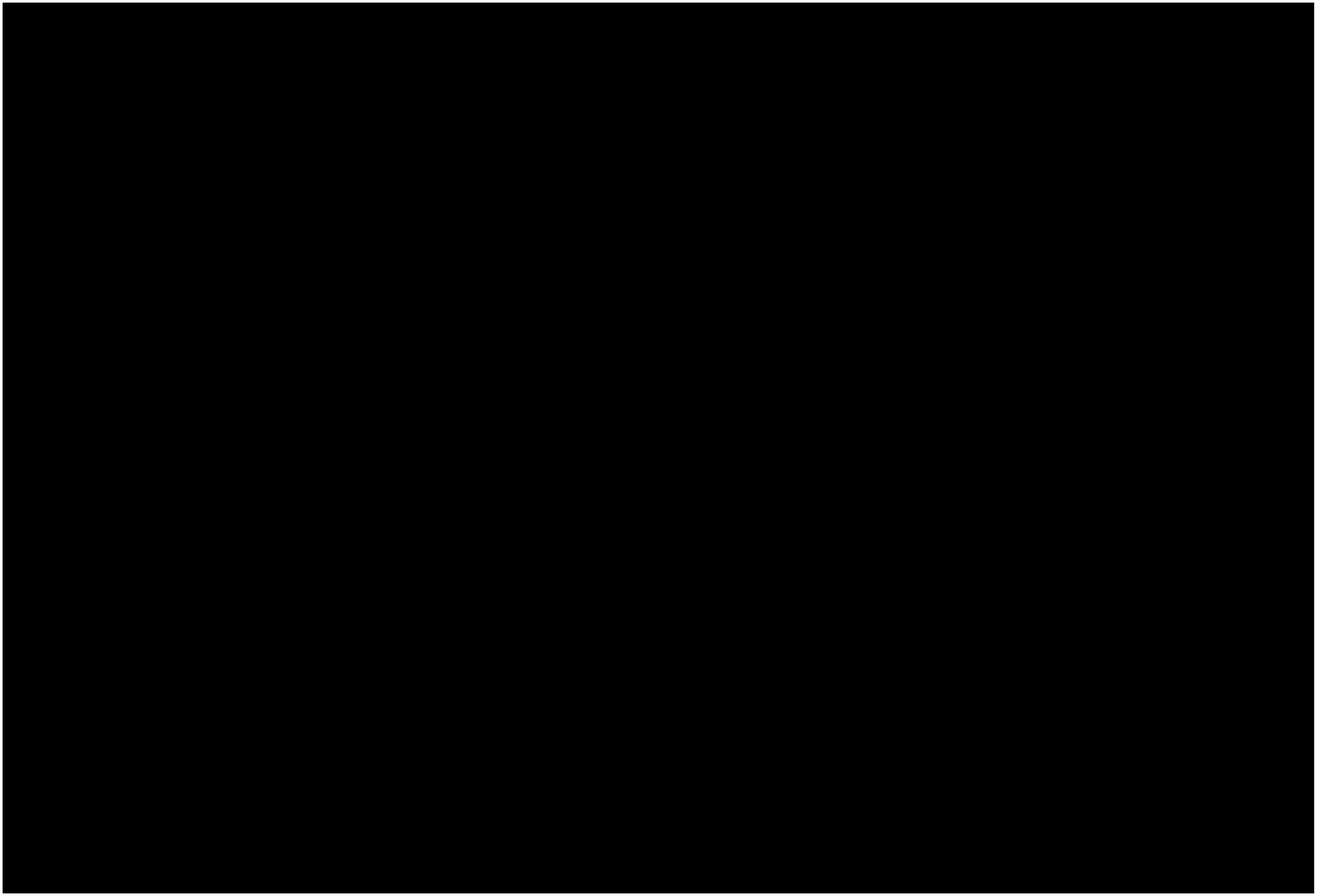
Date of On Peak Day - 05/31/2021

[redacted]

Member Forecasted On Peak Demand Day for June 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 06/11/2021



Member Forecasted On Peak Demand Day for July 2021

Y-W Electric Association, Inc.

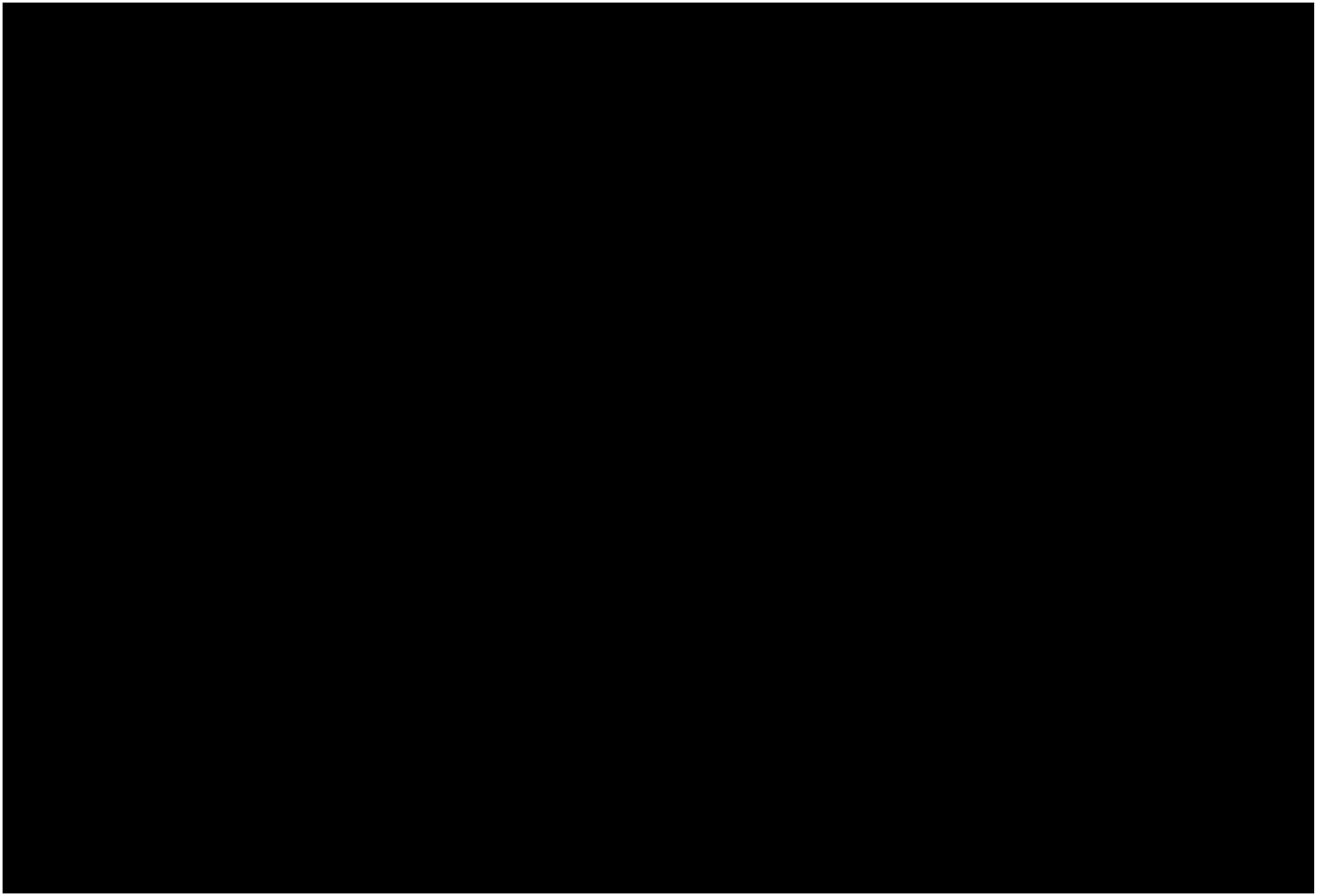
Date of On Peak Day - 07/21/2021

[redacted]

Member Forecasted On Peak Demand Day for August 2021

Y-W Electric Association, Inc.

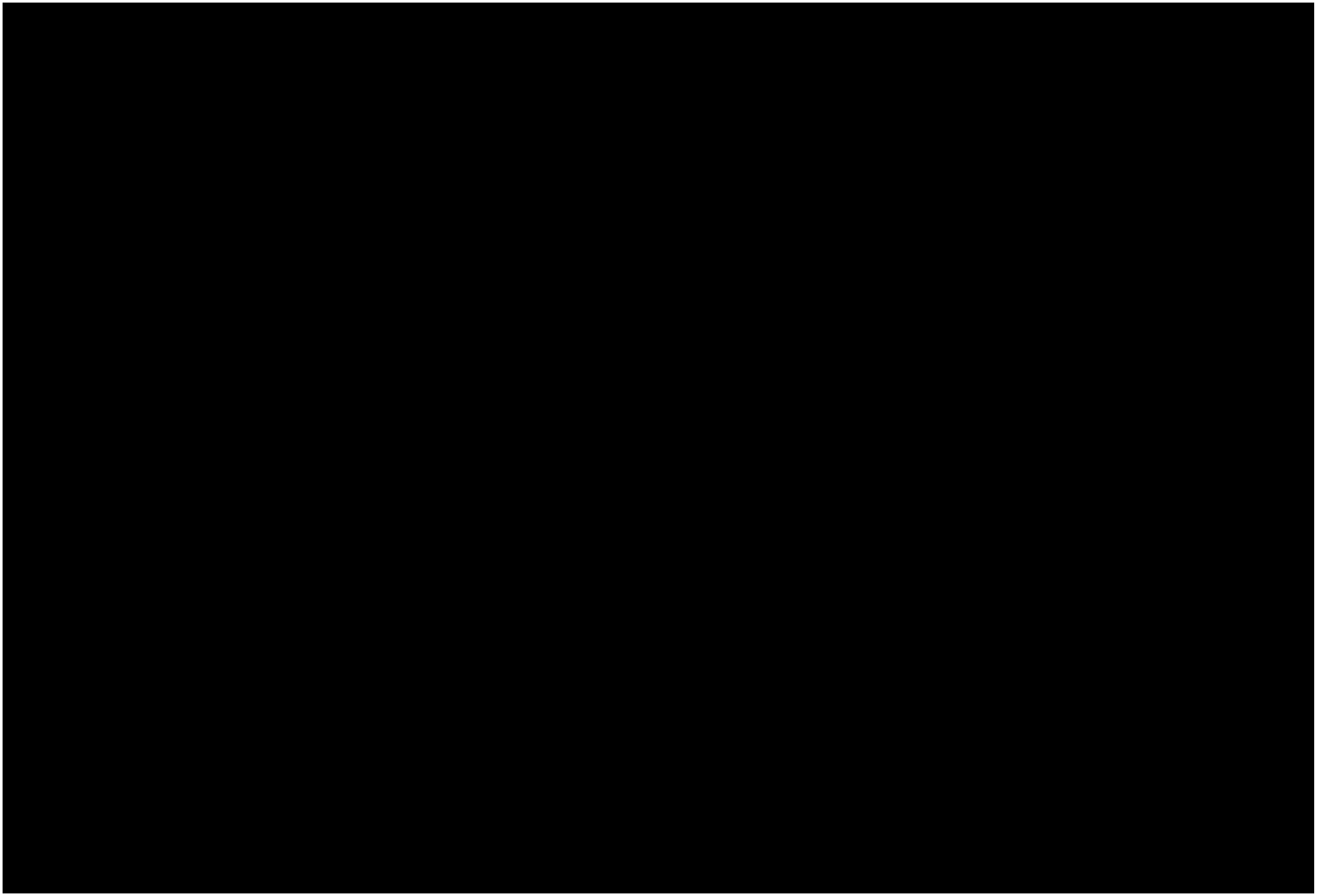
Date of On Peak Day - 08/28/2021



Member Forecasted On Peak Demand Day for September 2021

Y-W Electric Association, Inc.

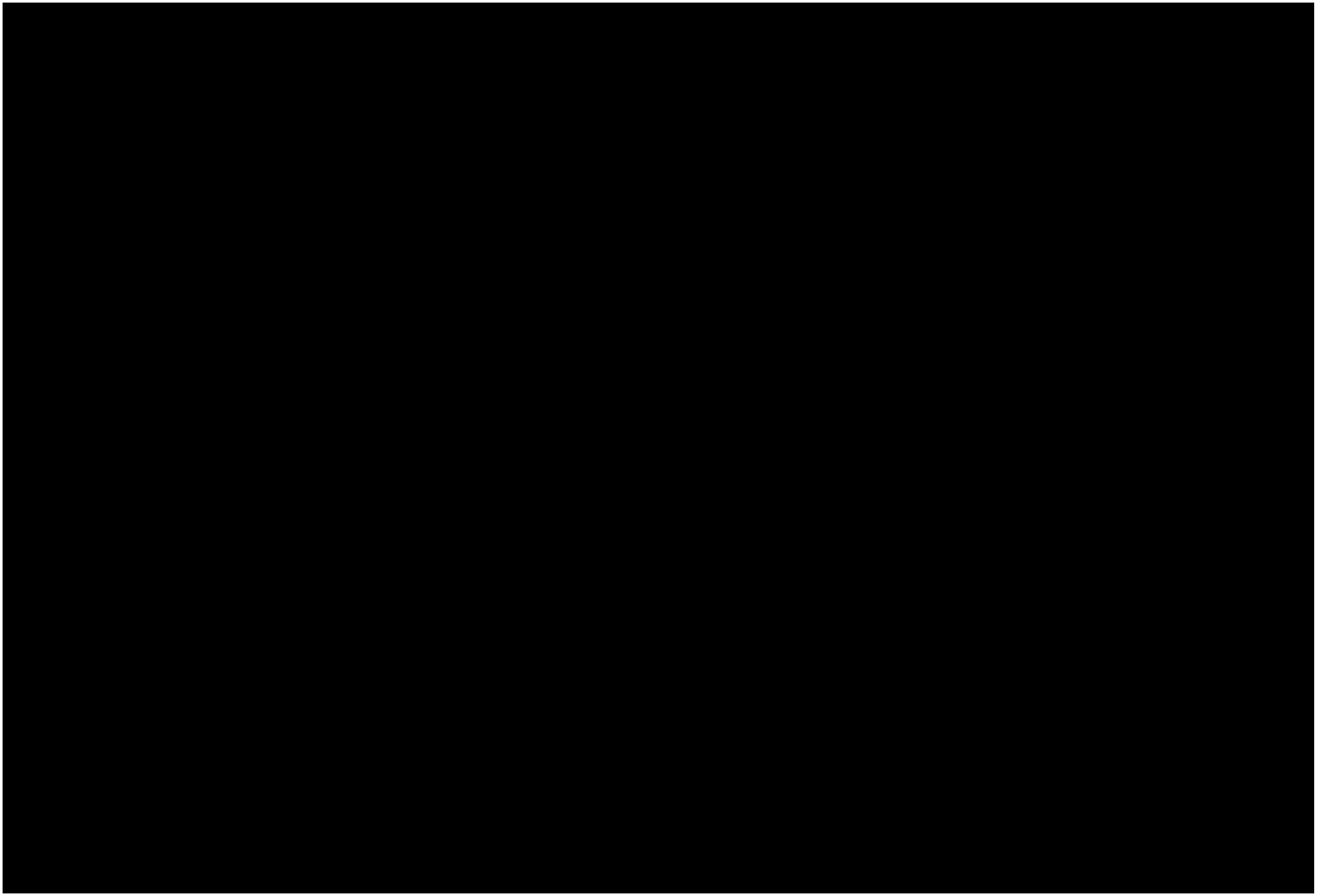
Date of On Peak Day - 09/03/2021



Member Forecasted On Peak Demand Day for October 2021

Y-W Electric Association, Inc.

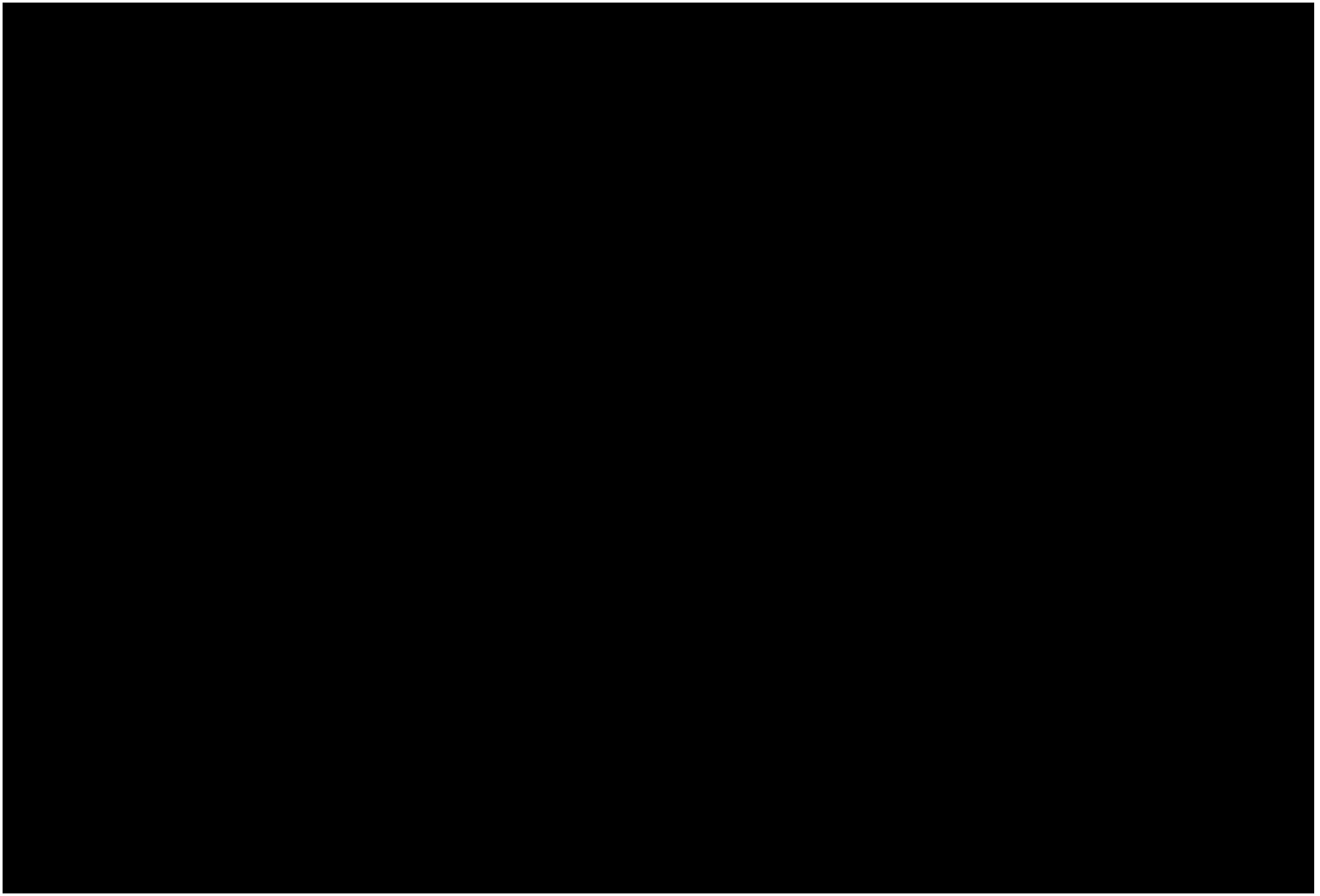
Date of On Peak Day - 10/11/2021



Member Forecasted On Peak Demand Day for November 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 11/17/2021



Member Forecasted On Peak Demand Day for December 2021

Y-W Electric Association, Inc.

Date of On Peak Day - 12/29/2021

[redacted]

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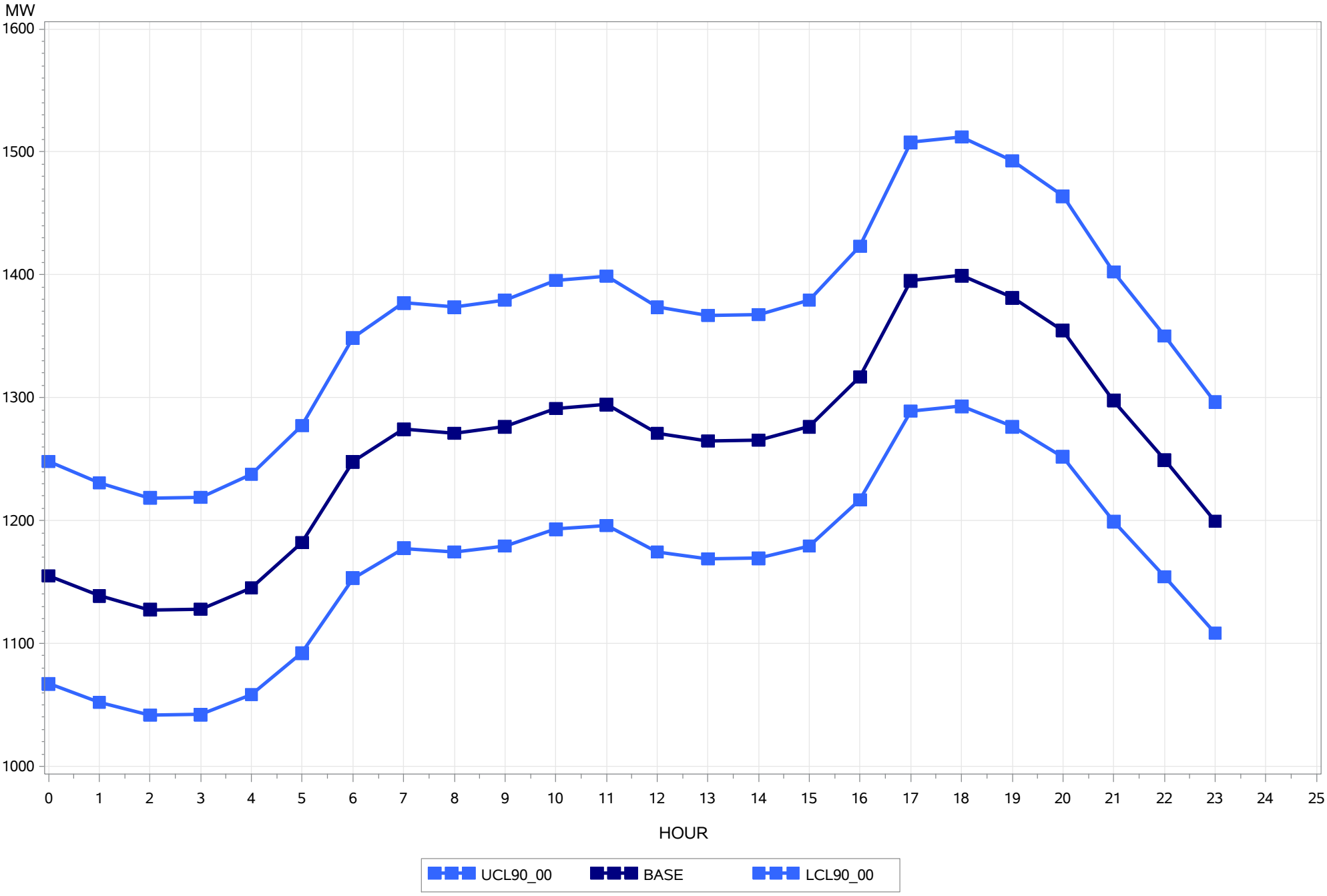
Member Forecasted Off Peak Demand Day for January 2021

STATE OF COLORADO

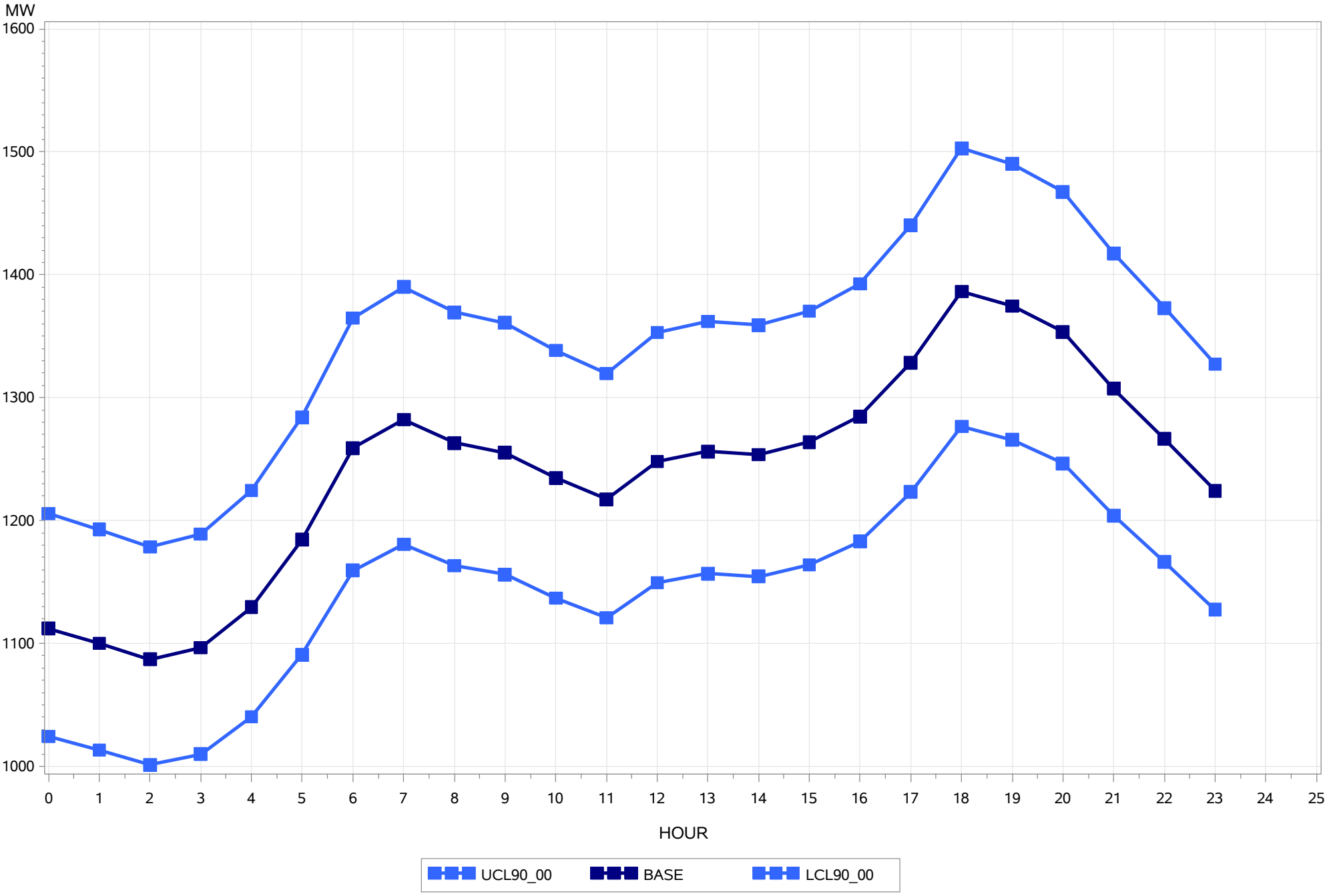
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF COLORADO

Date of Off Peak Day - 02/11/2021



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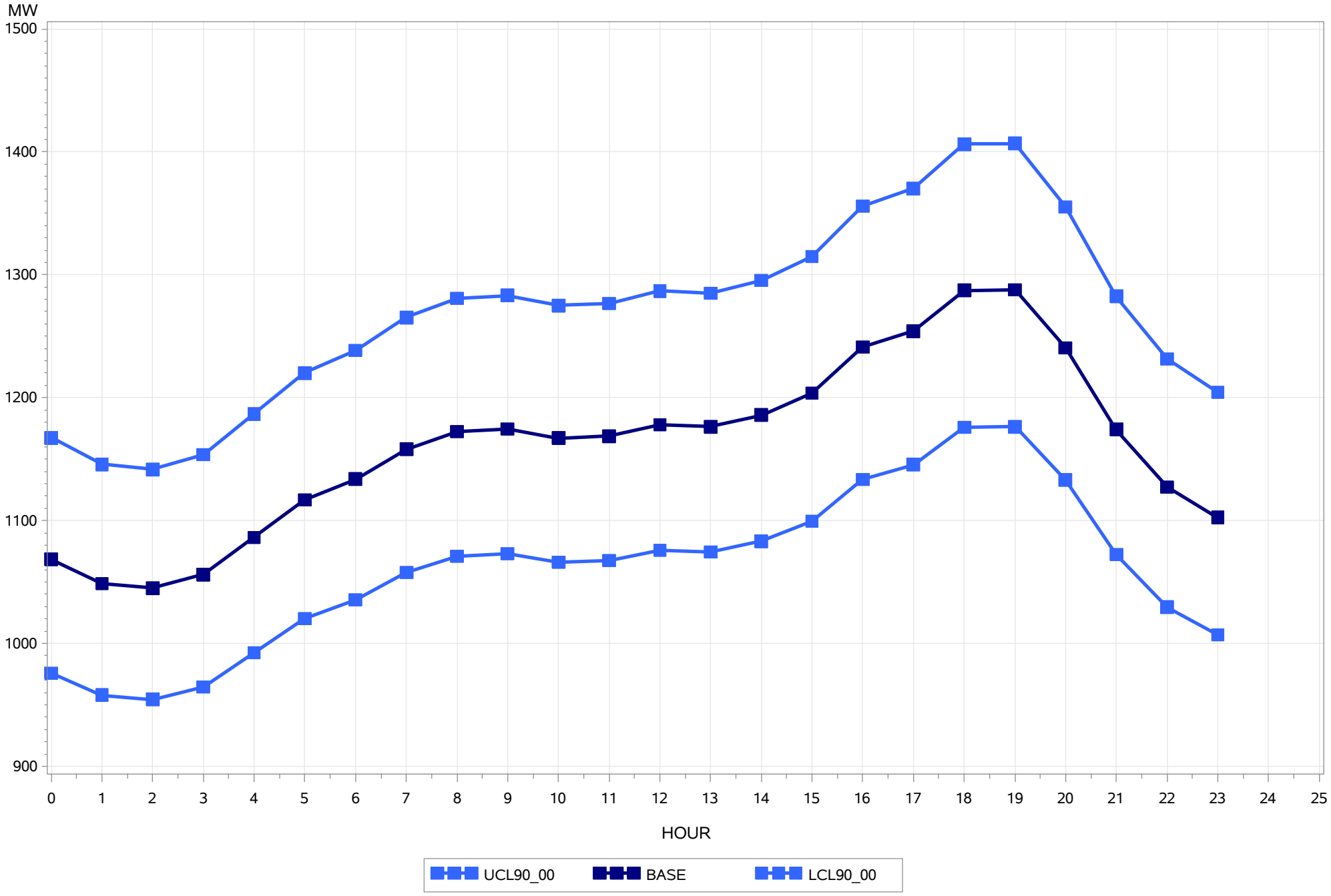
Member Forecasted Off Peak Demand Day for March 2021

STATE OF COLORADO

Date of Off Peak Day - 03/21/2021



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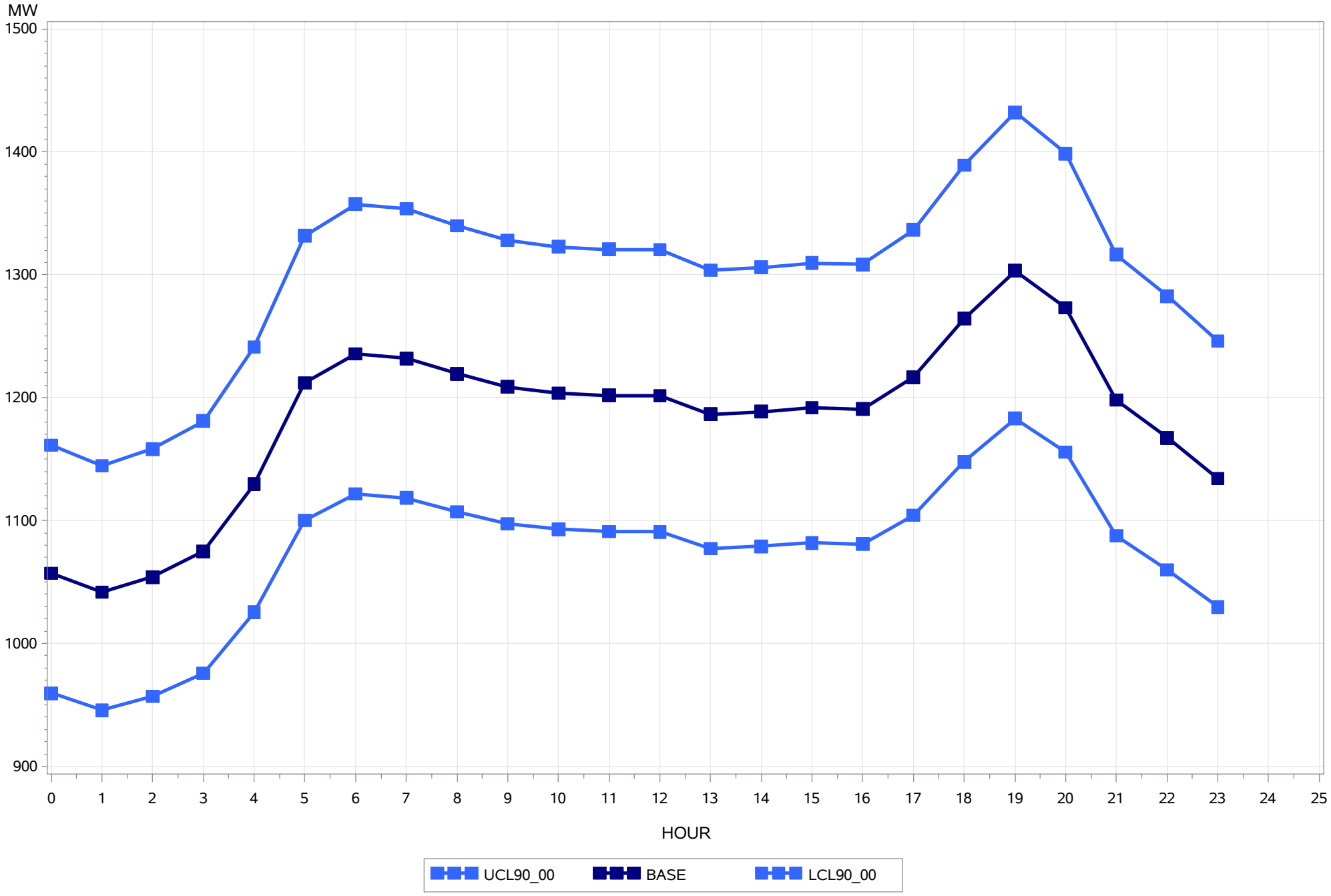
Member Forecasted Off Peak Demand Day for April 2021

STATE OF COLORADO

Date of Off Peak Day - 04/07/2021



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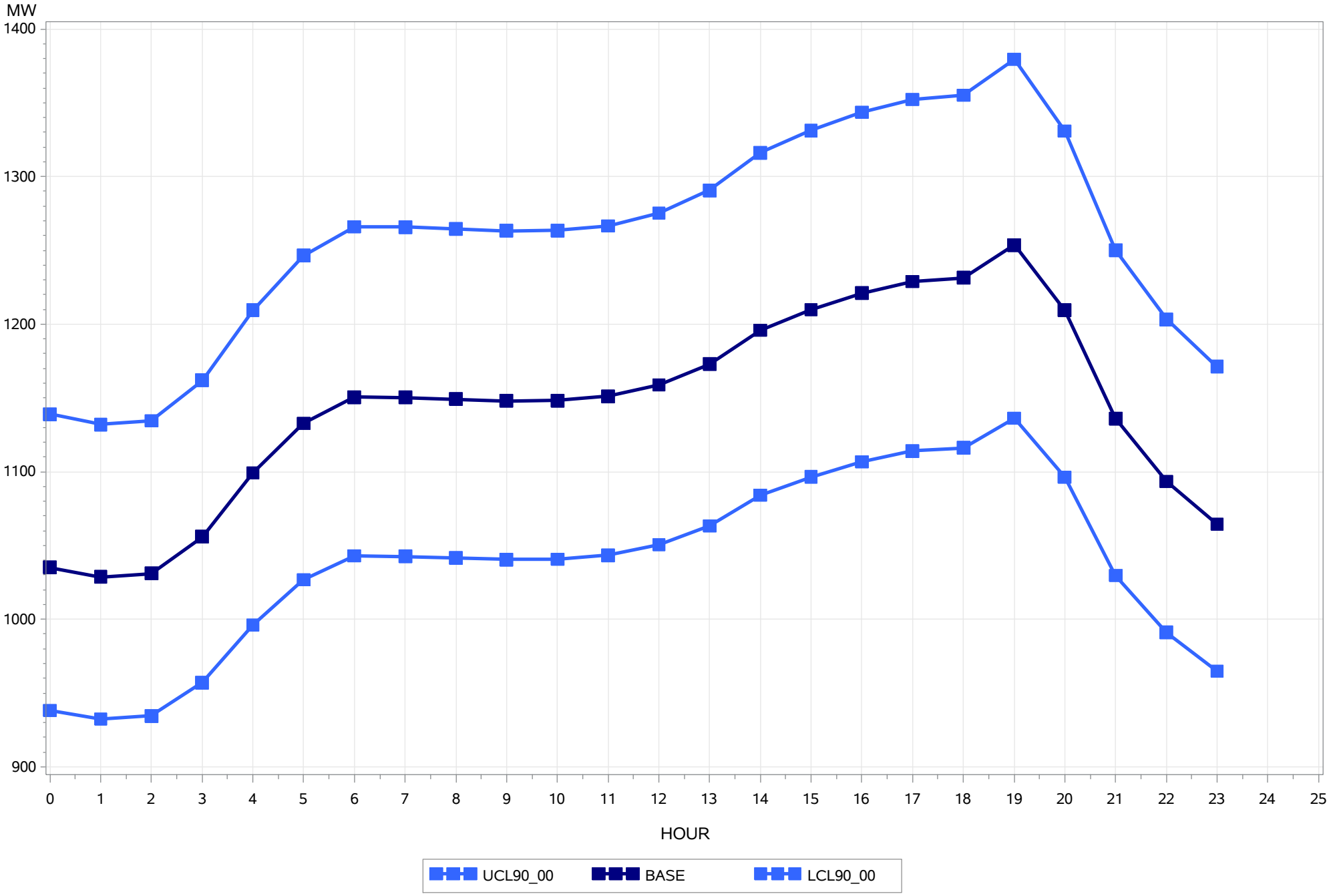
Member Forecasted Off Peak Demand Day for May 2021

STATE OF COLORADO

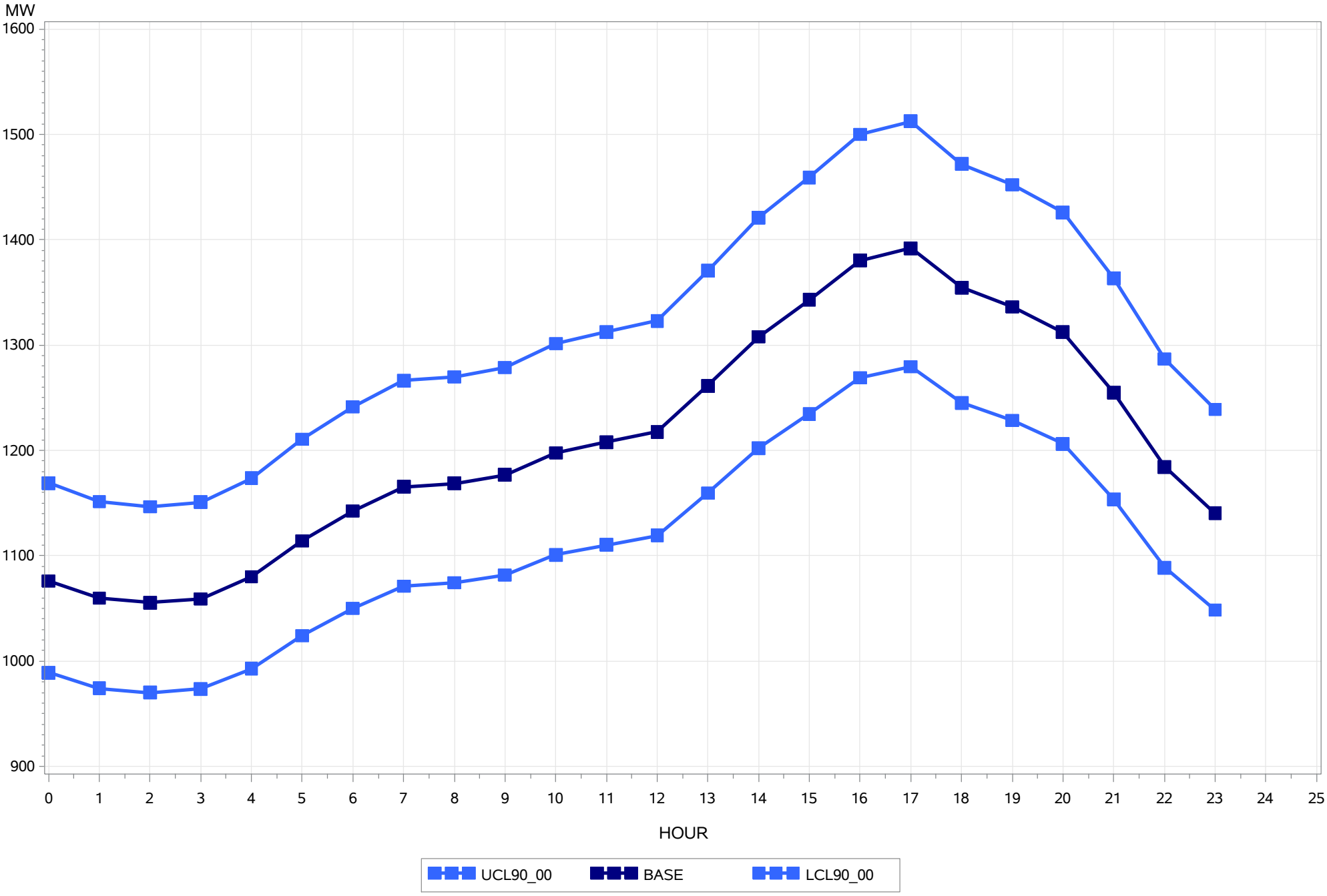
Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

STATE OF COLORADO

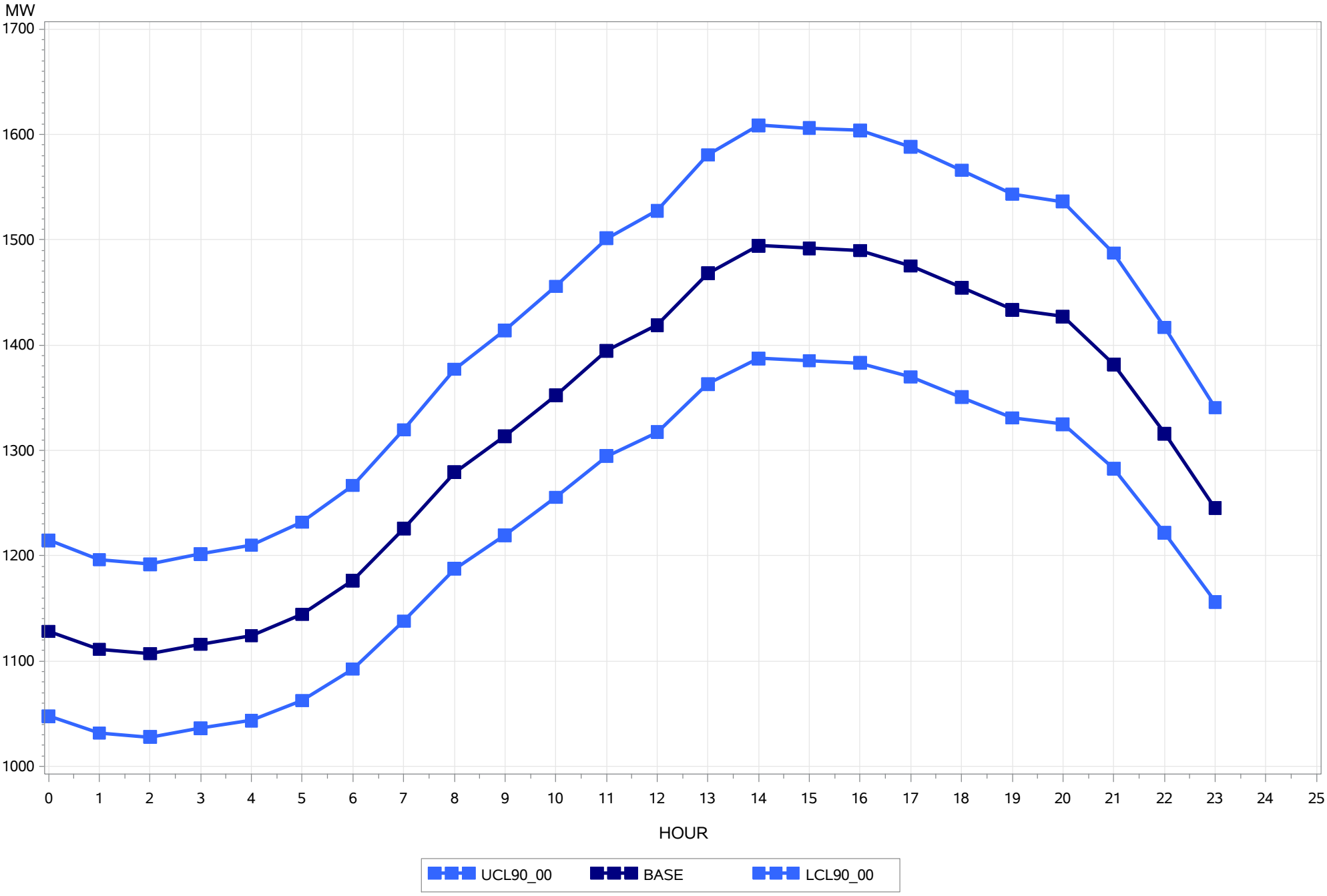
Date of Off Peak Day - 06/02/2021



Member Forecasted Off Peak Demand Day for July 2021

STATE OF COLORADO

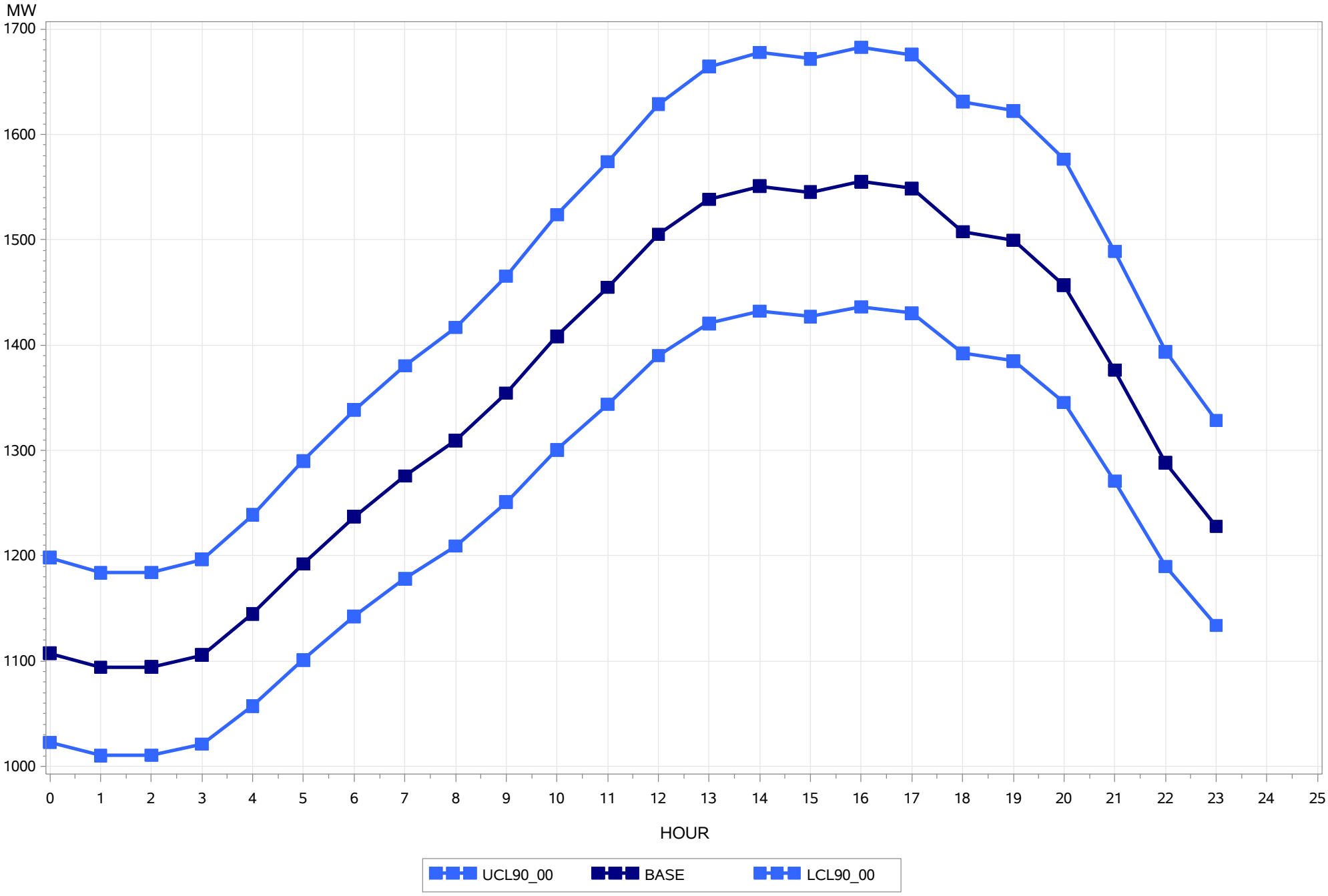
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

STATE OF COLORADO

Date of Off Peak Day - 08/13/2021



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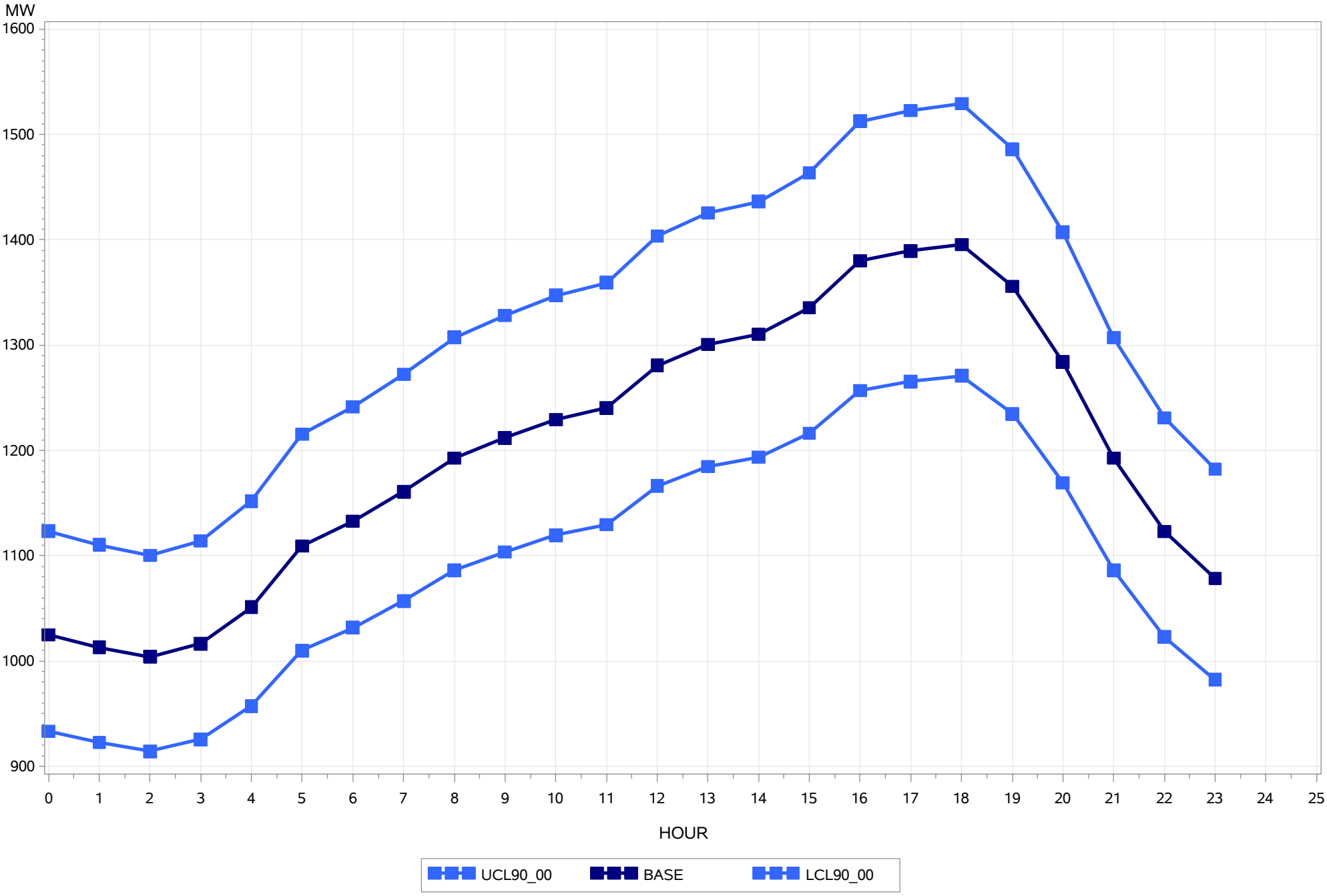
Member Forecasted Off Peak Demand Day for September 2021

STATE OF COLORADO

Date of Off Peak Day - 09/20/2021



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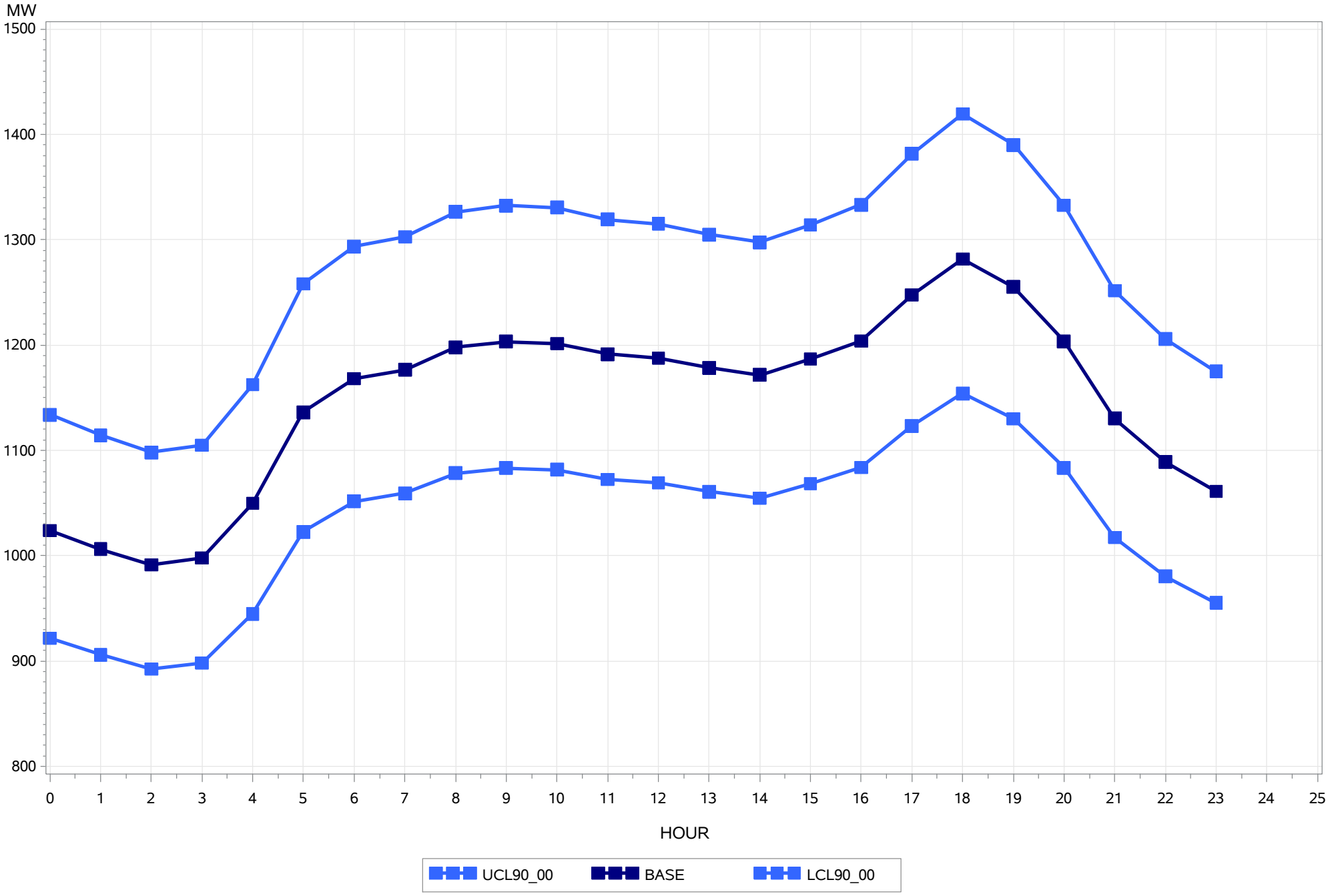
Member Forecasted Off Peak Demand Day for October 2021

STATE OF COLORADO

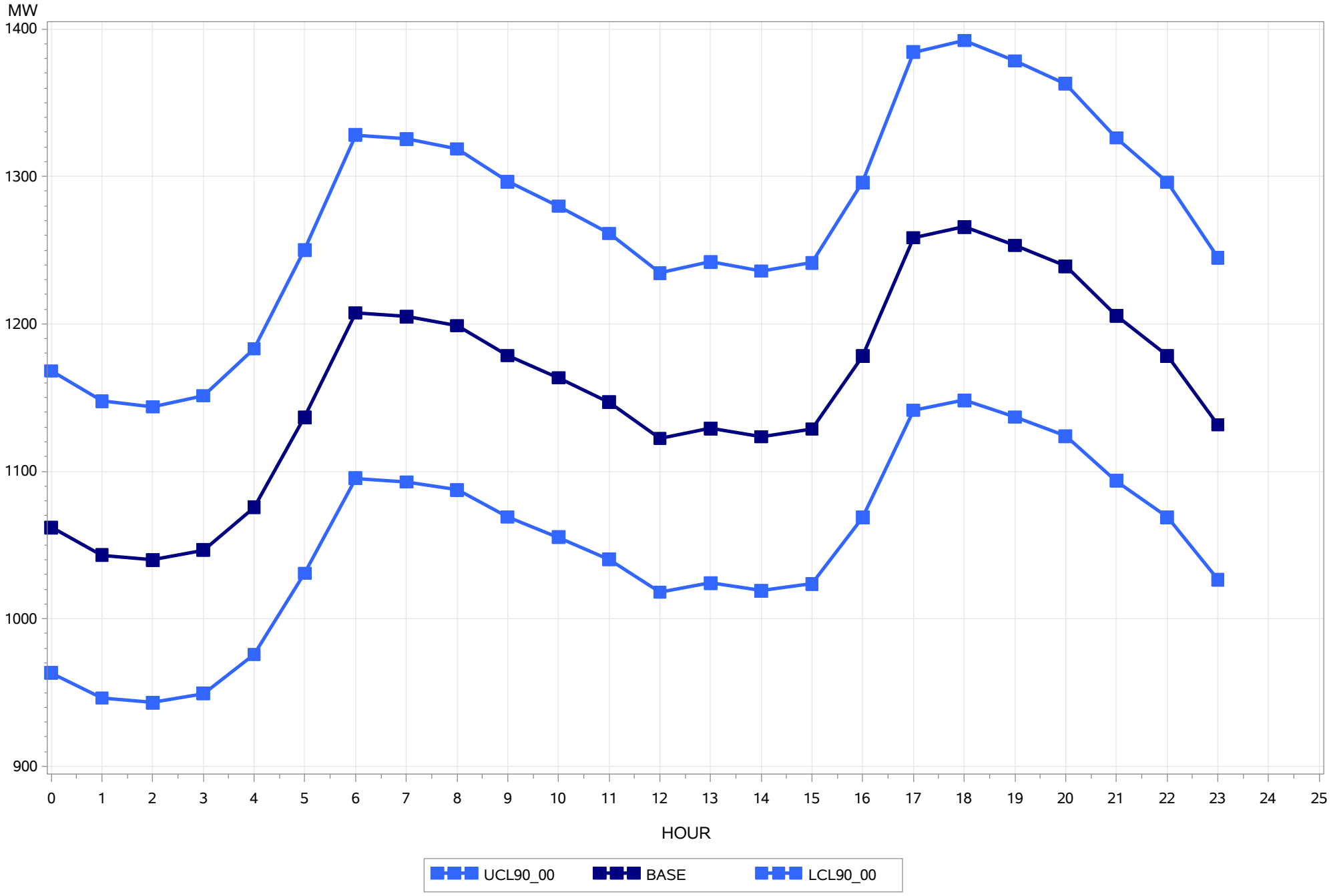
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF COLORADO

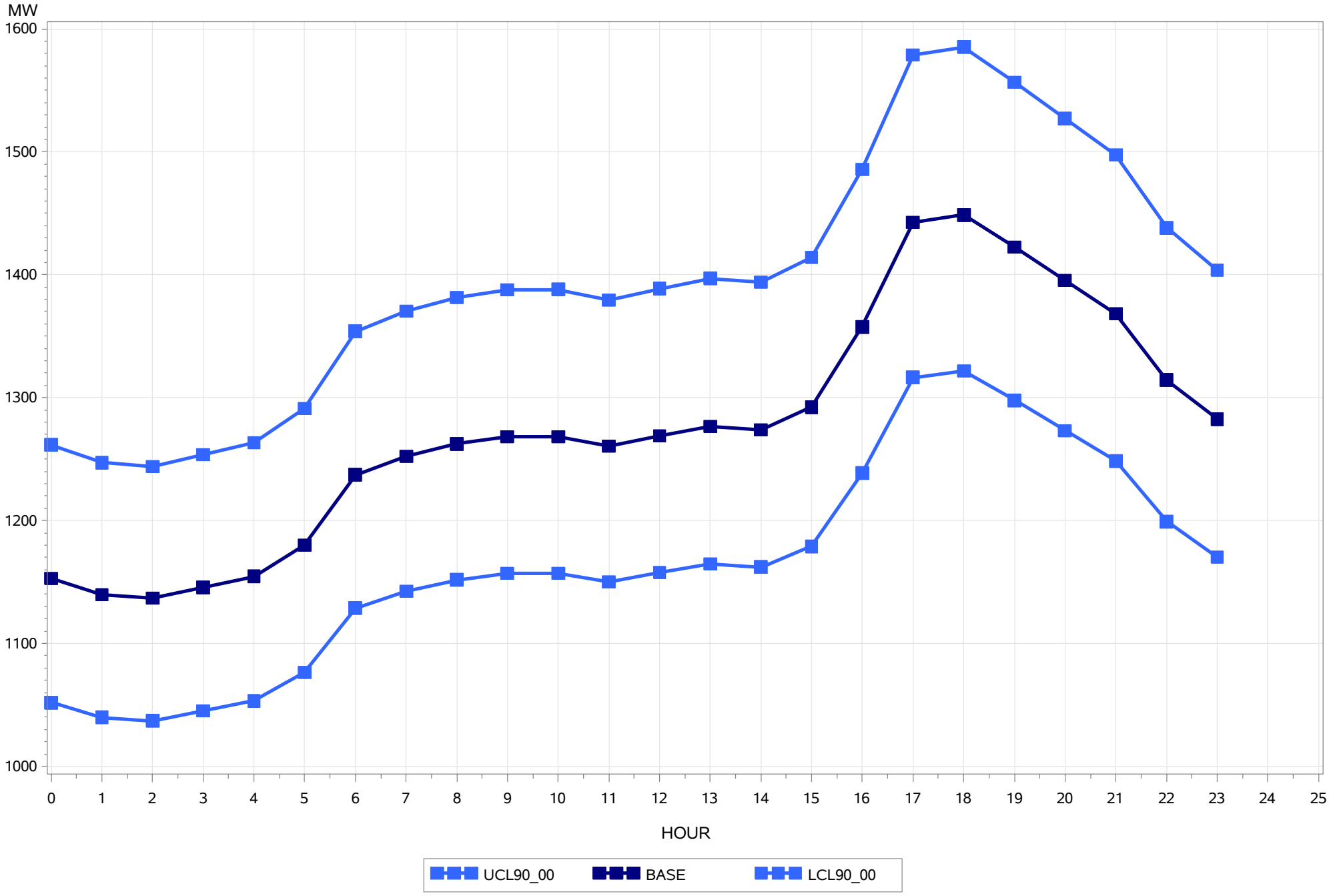
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF COLORADO

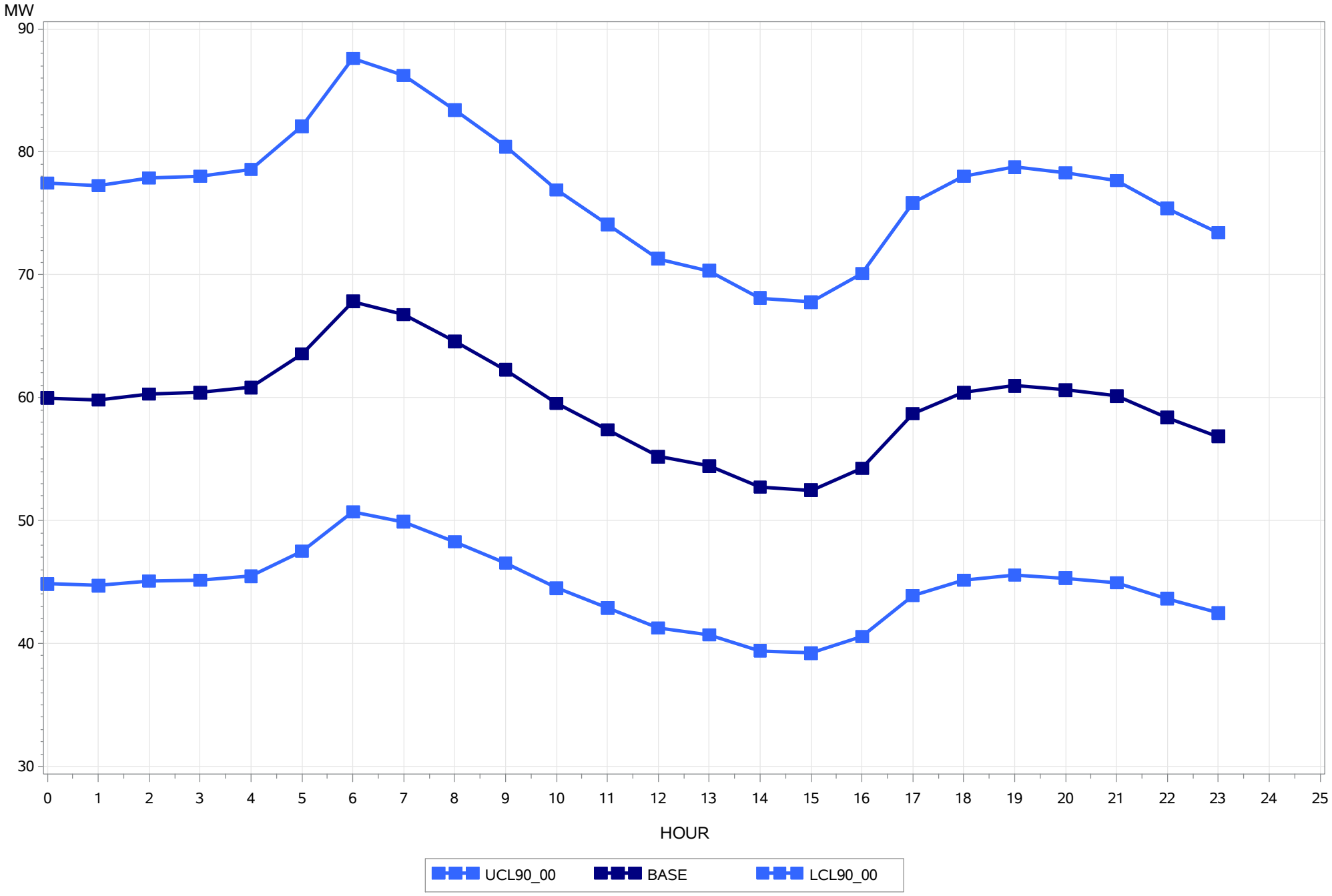
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

STATE OF NEBRASKA

Date of Off Peak Day - 01/18/2021



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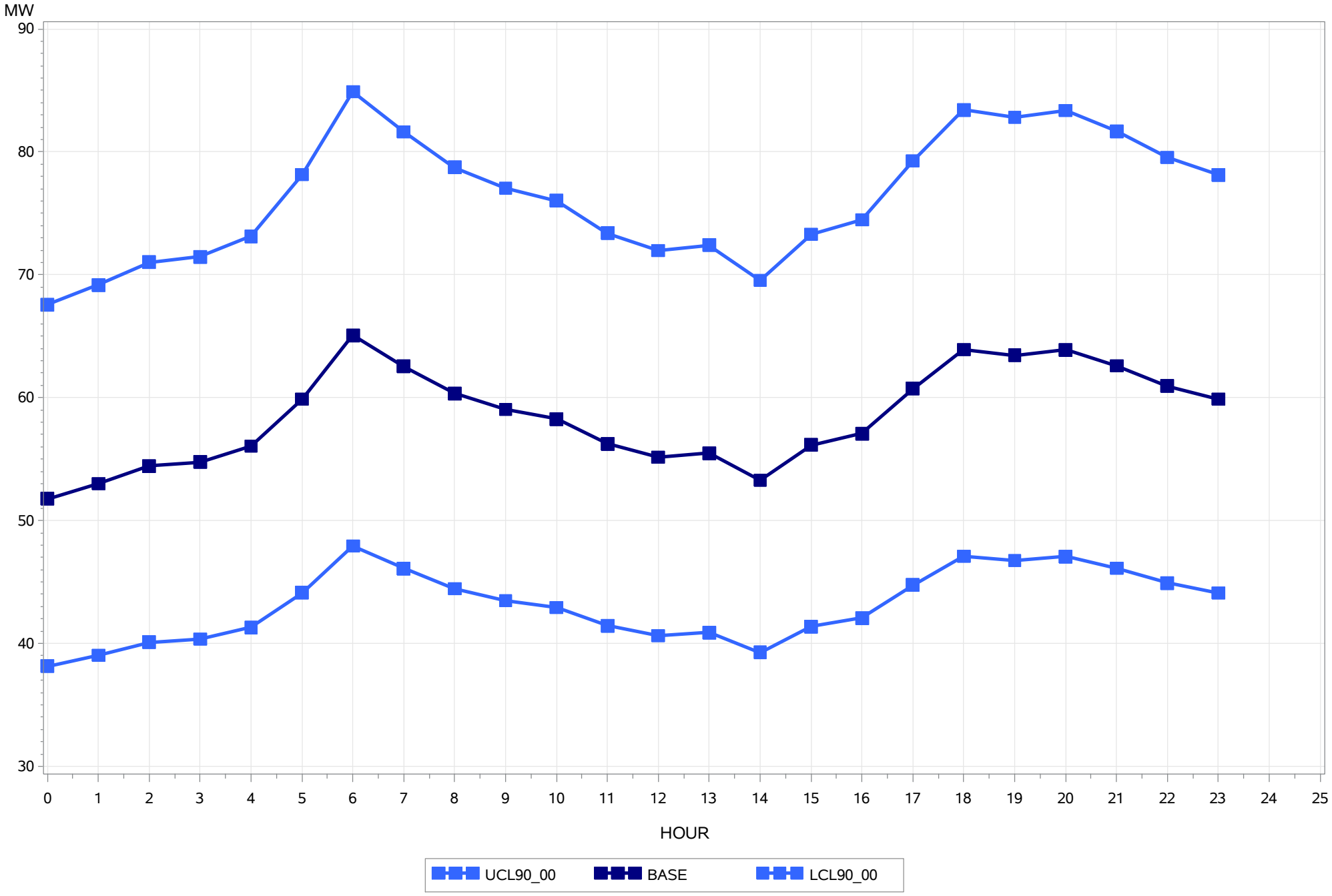
Member Forecasted Off Peak Demand Day for February 2021

STATE OF NEBRASKA

Date of Off Peak Day - 02/22/2021



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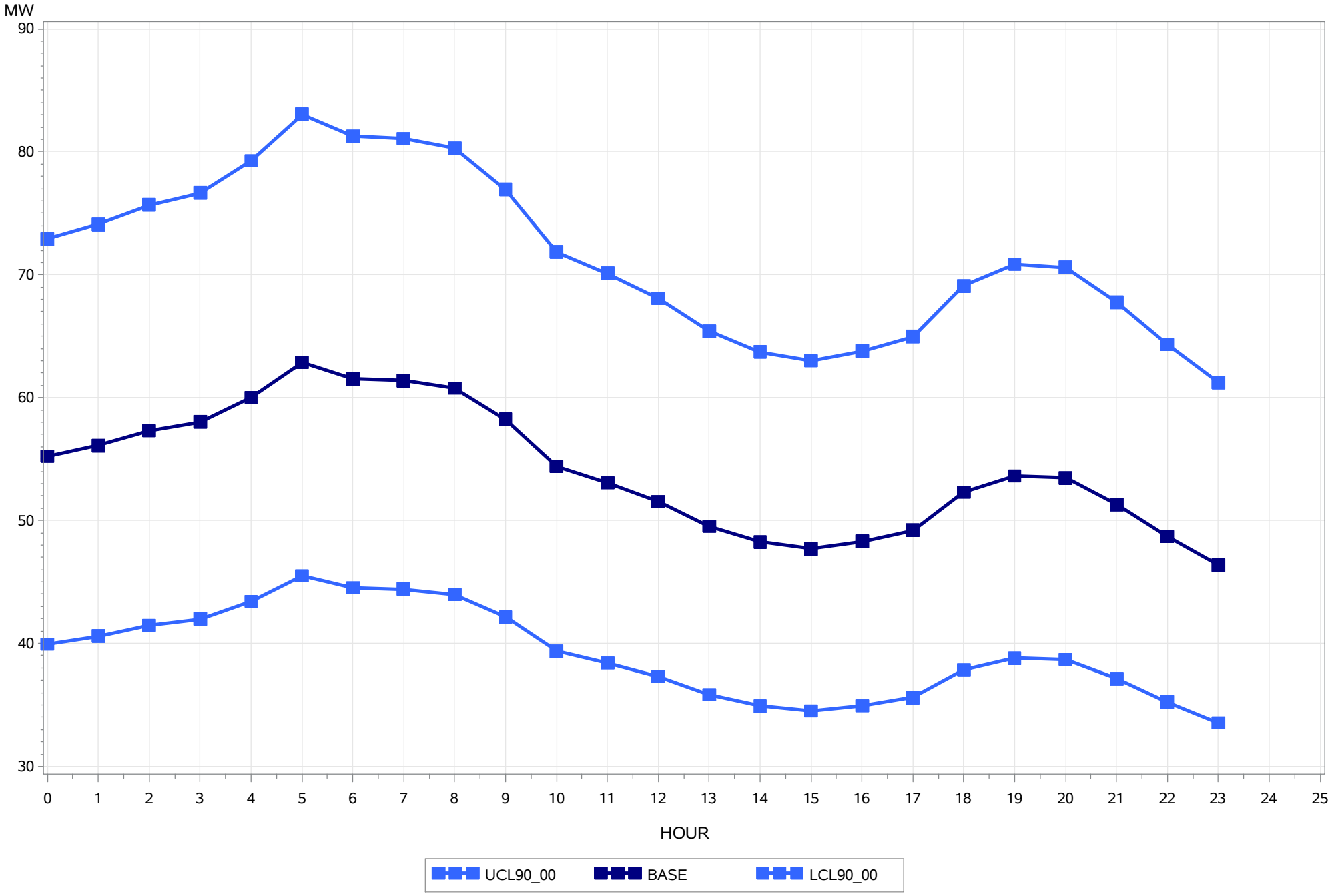
Member Forecasted Off Peak Demand Day for March 2021

STATE OF NEBRASKA

Date of Off Peak Day - 03/27/2021



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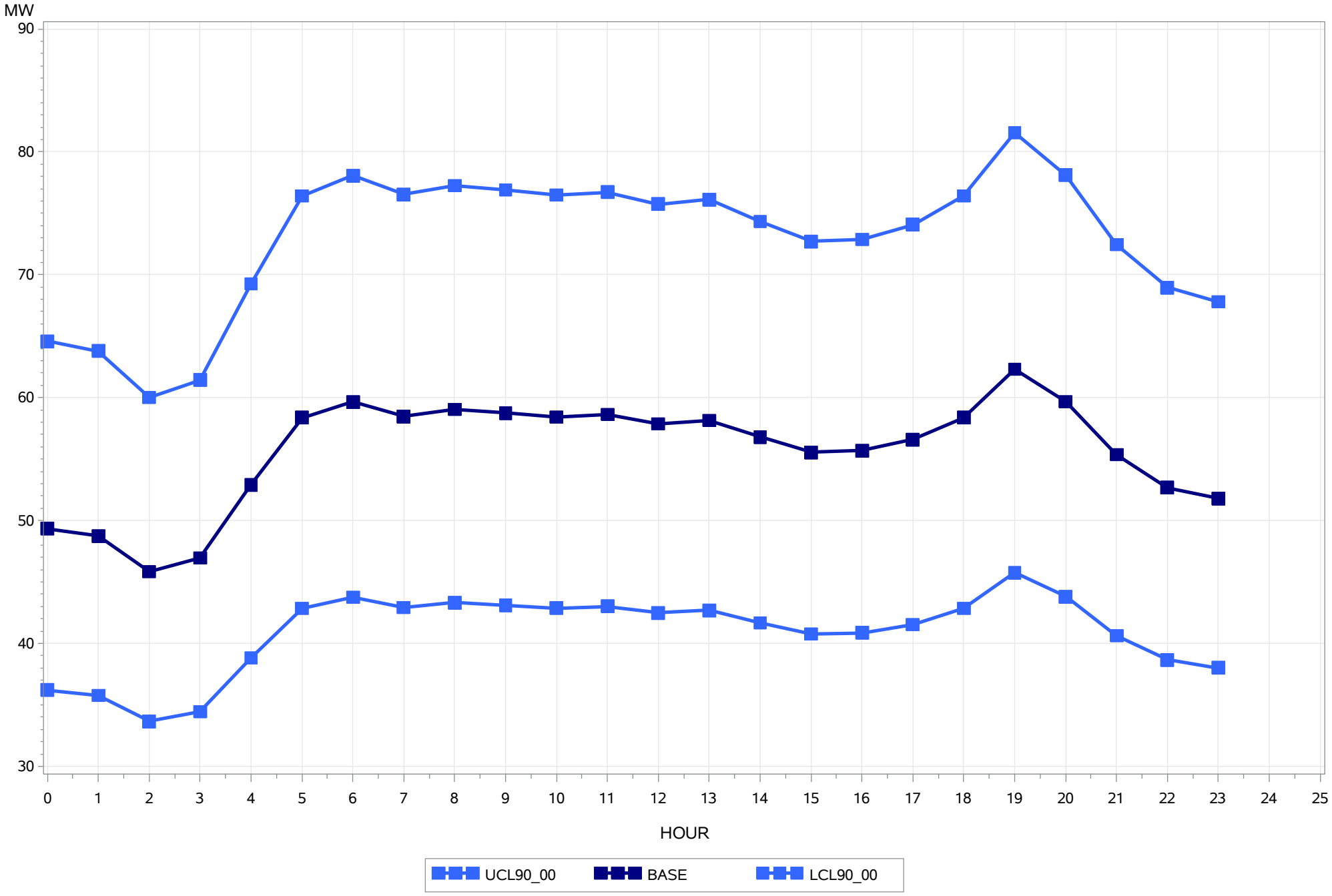
Member Forecasted Off Peak Demand Day for April 2021

STATE OF NEBRASKA

Date of Off Peak Day - 04/29/2021



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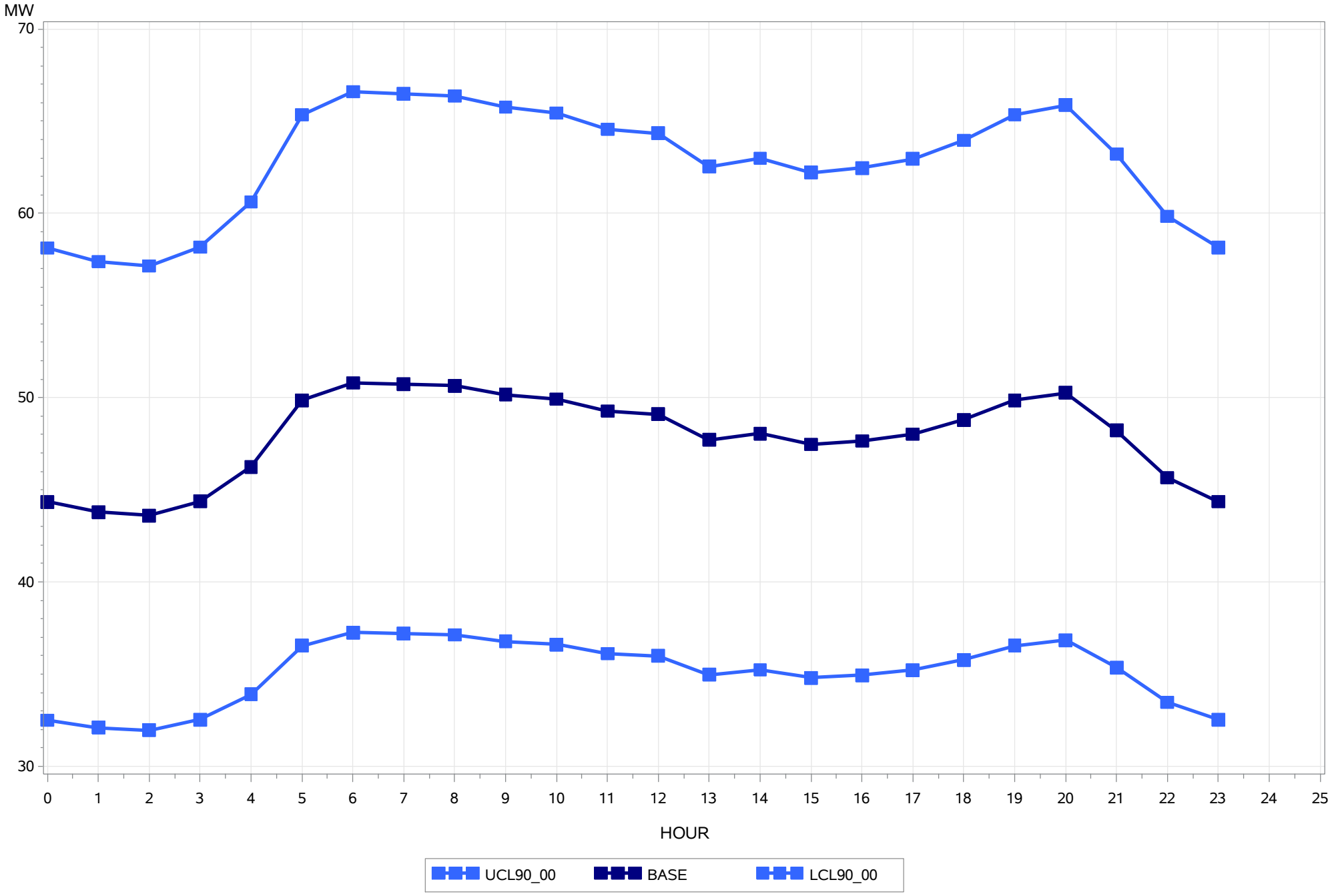
Member Forecasted Off Peak Demand Day for May 2021

STATE OF NEBRASKA

Date of Off Peak Day - 05/27/2021



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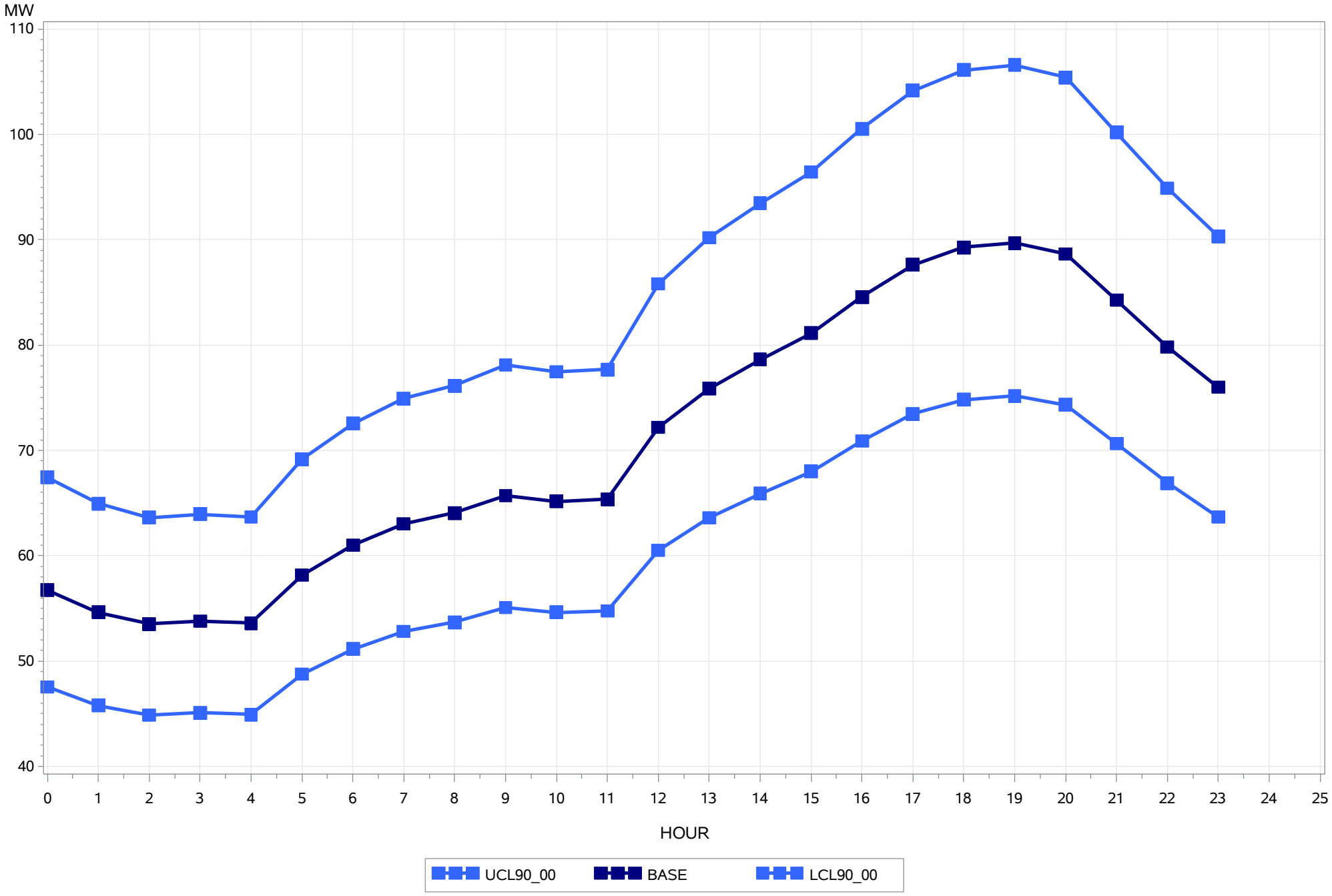
Member Forecasted Off Peak Demand Day for June 2021

STATE OF NEBRASKA

Date of Off Peak Day - 06/21/2021



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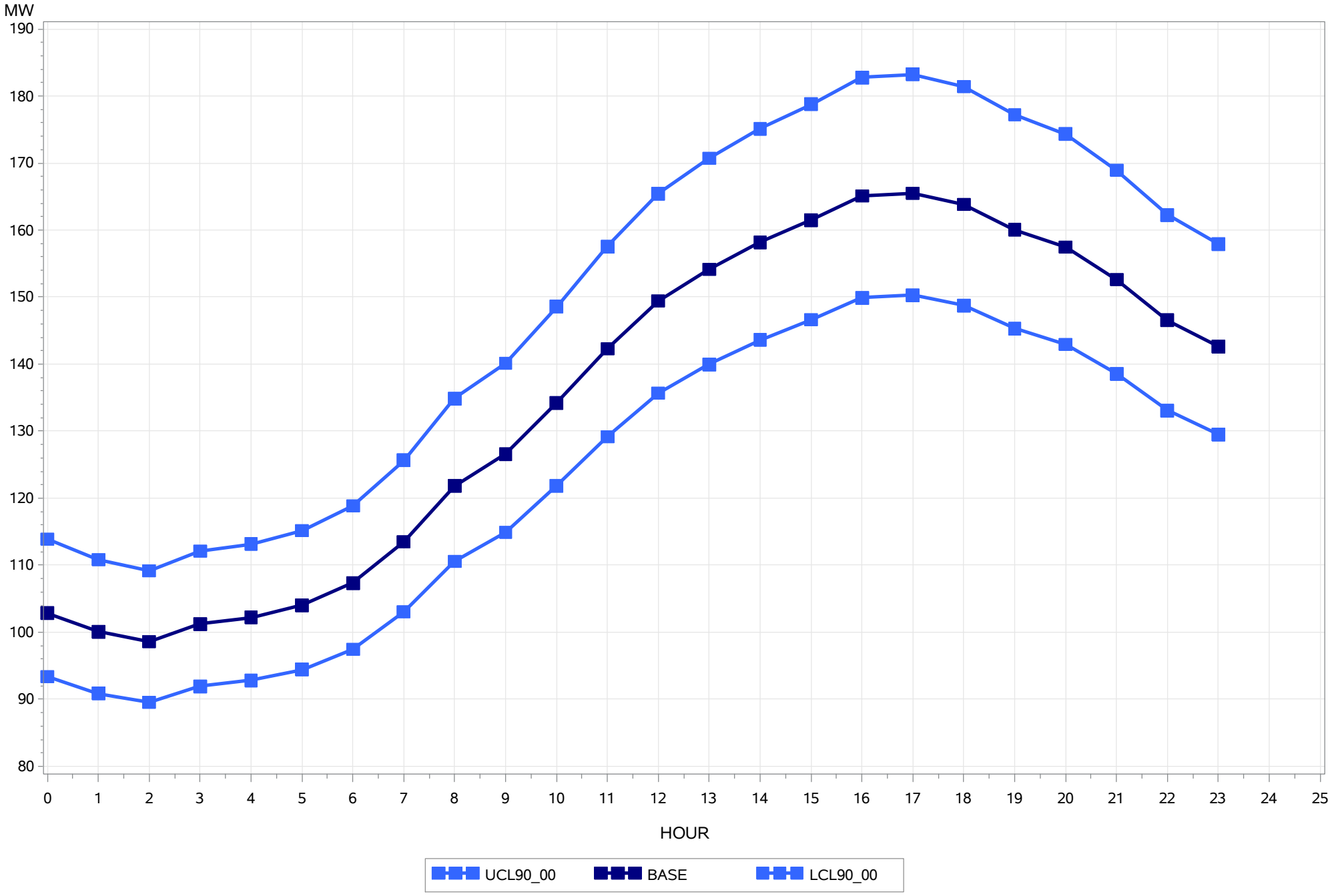
Member Forecasted Off Peak Demand Day for July 2021

STATE OF NEBRASKA

Date of Off Peak Day - 07/03/2021



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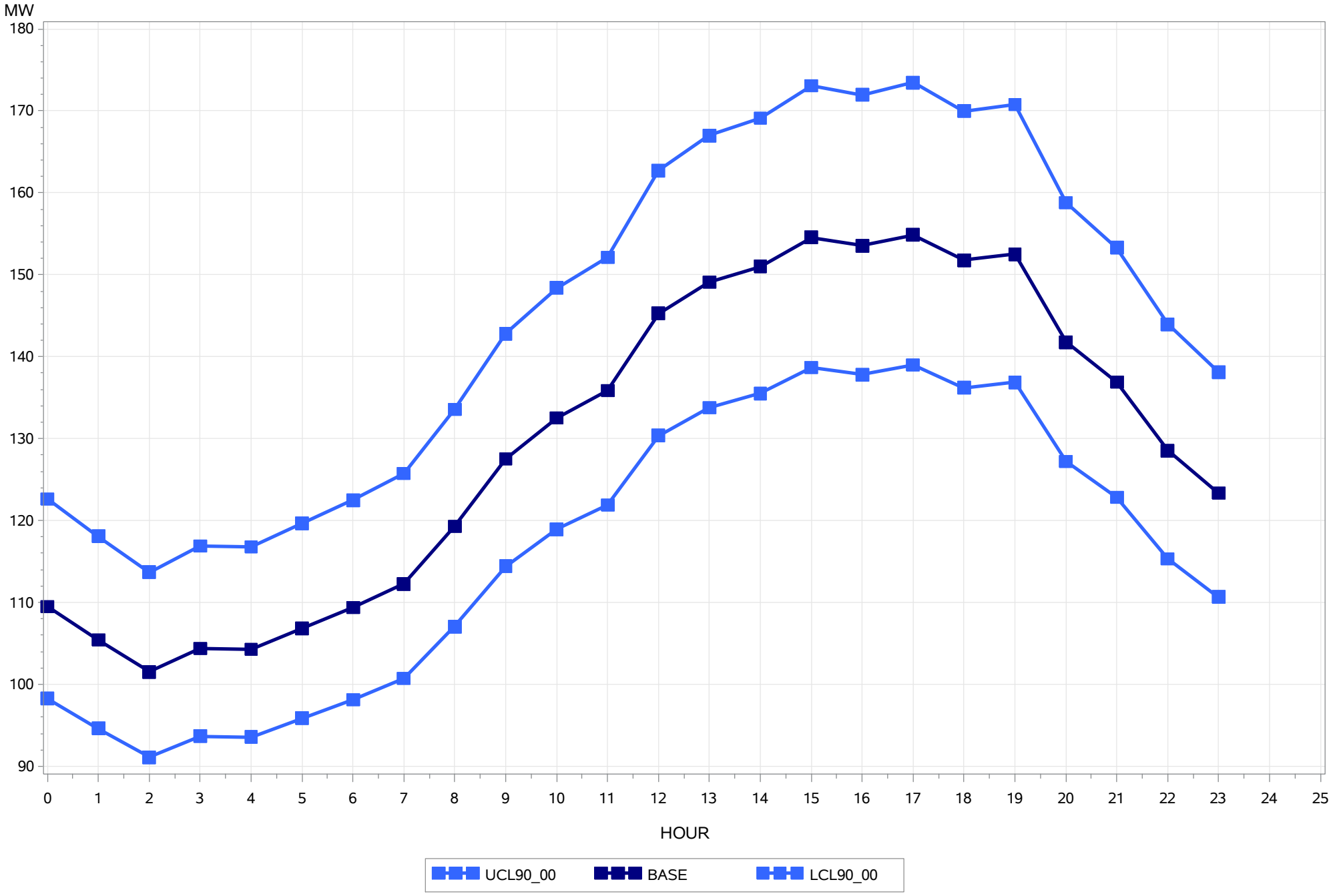
Member Forecasted Off Peak Demand Day for August 2021

STATE OF NEBRASKA

Date of Off Peak Day - 08/13/2021



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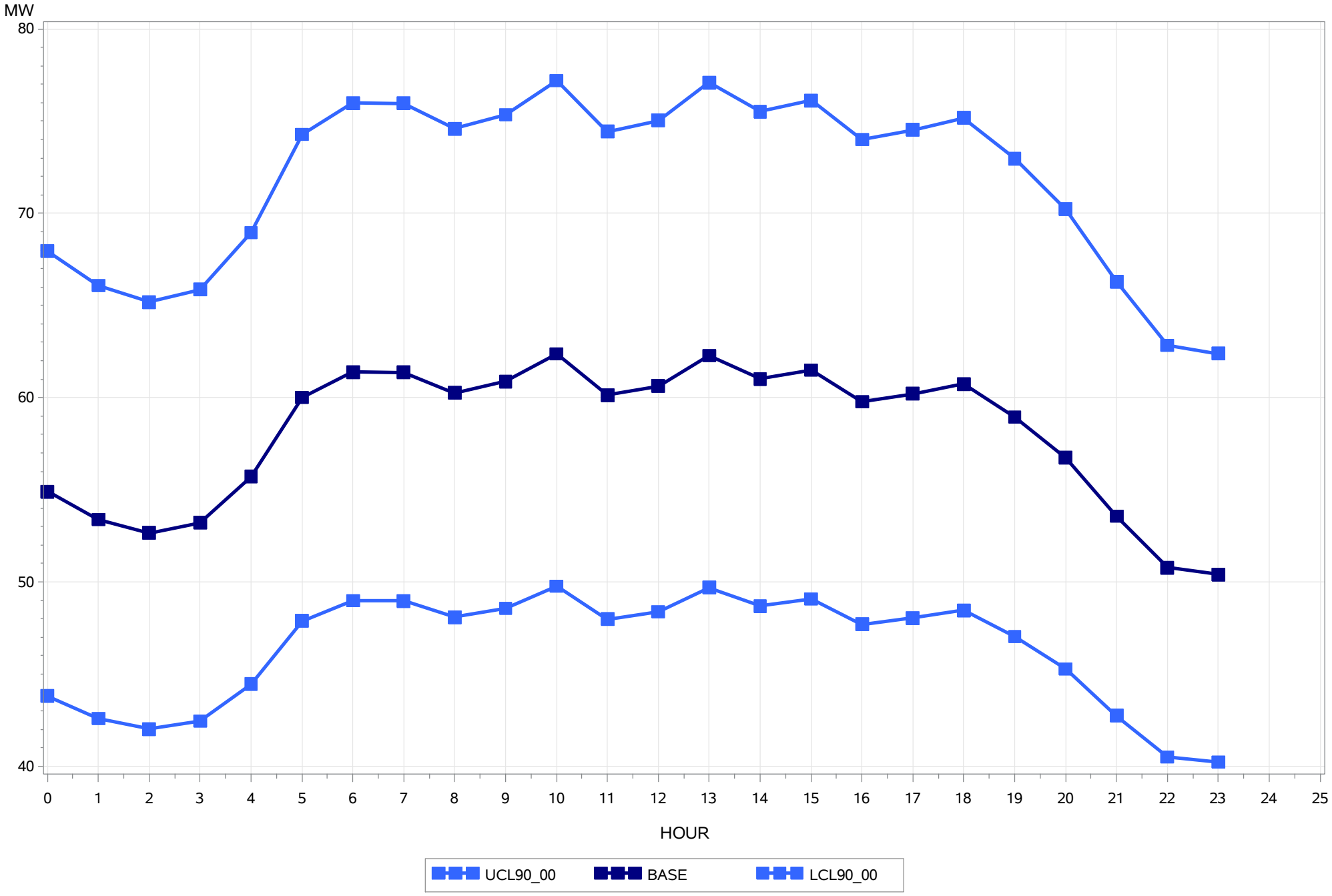
Member Forecasted Off Peak Demand Day for September 2021

STATE OF NEBRASKA

Date of Off Peak Day - 09/30/2021



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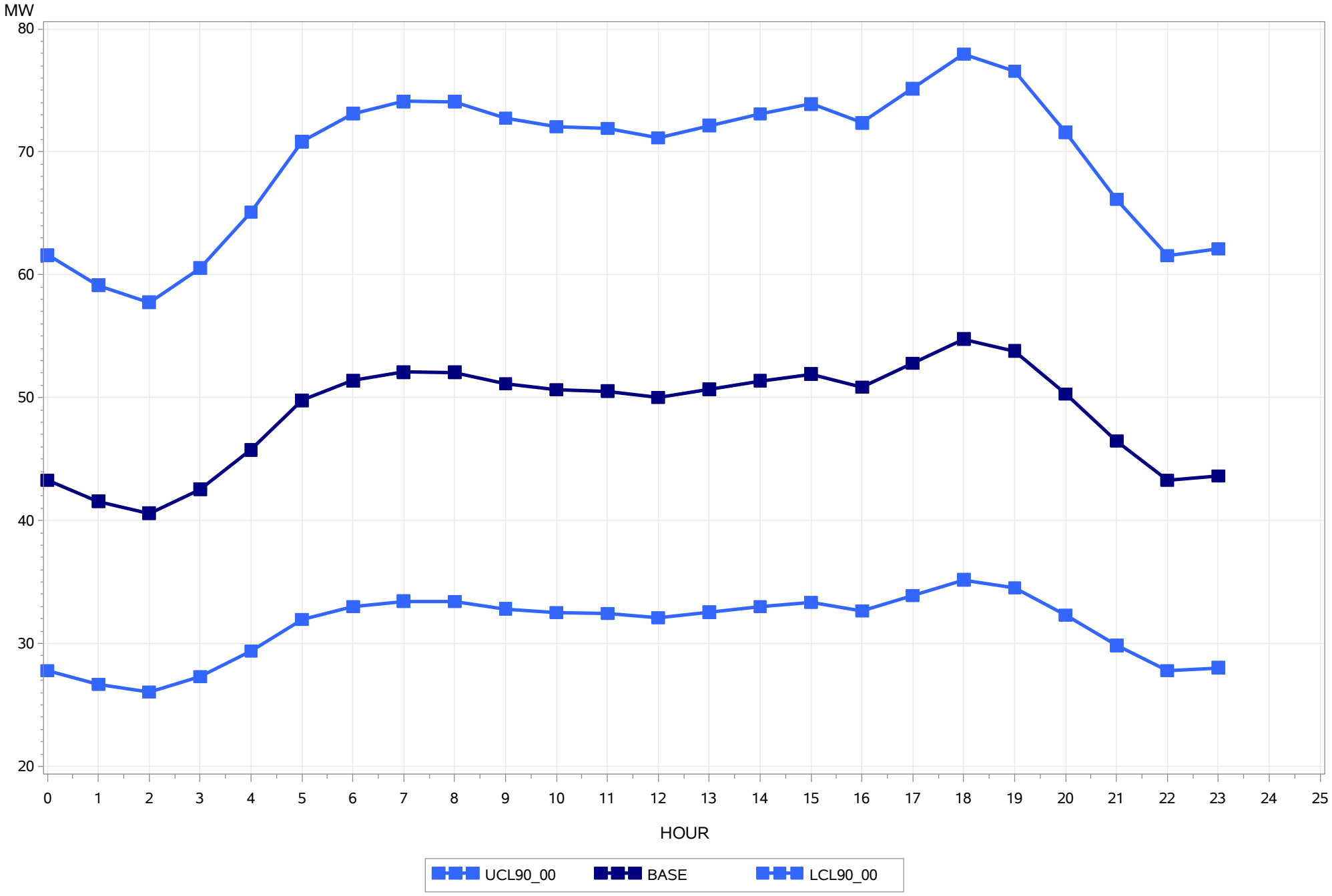
Member Forecasted Off Peak Demand Day for October 2021

STATE OF NEBRASKA

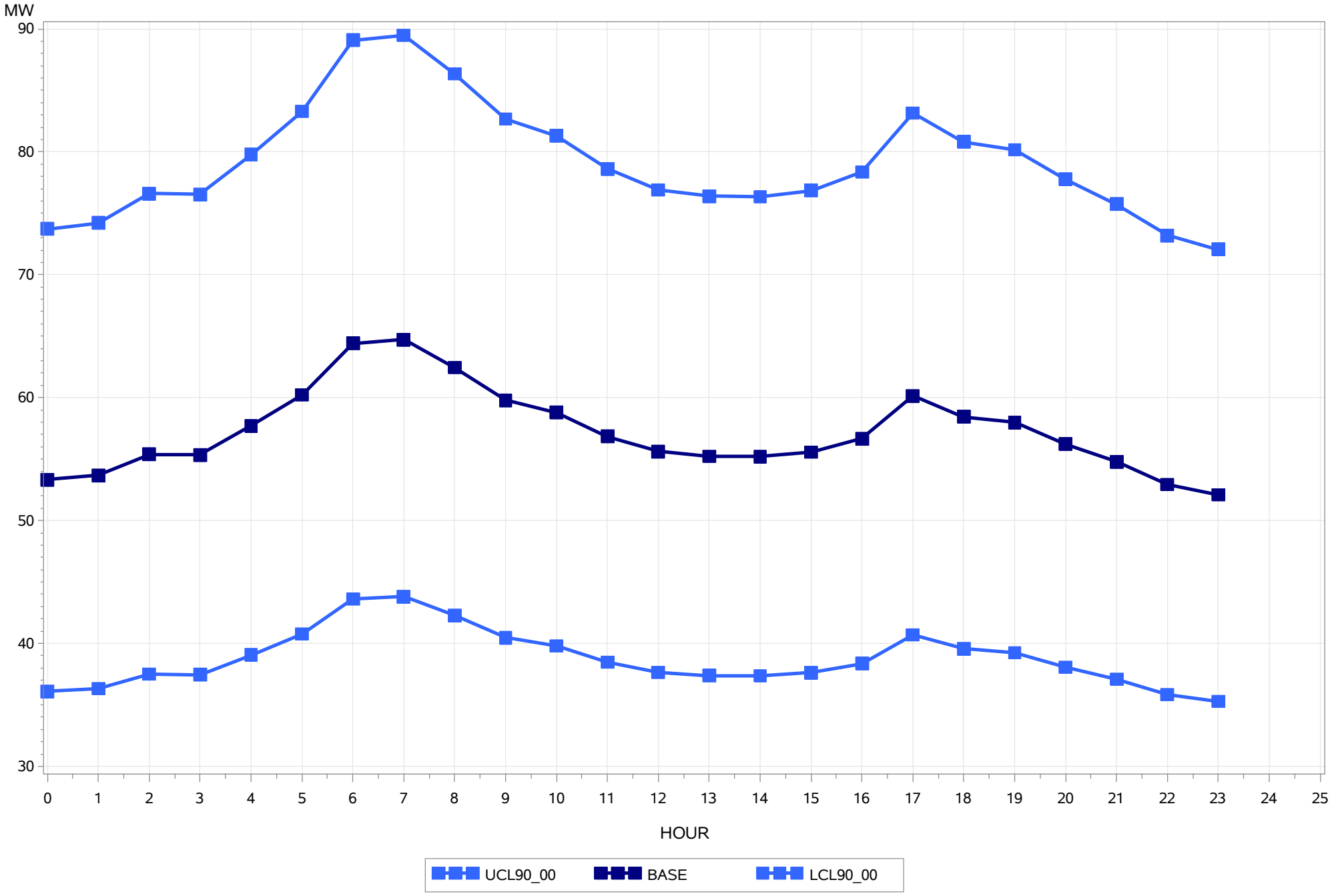
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF NEBRASKA

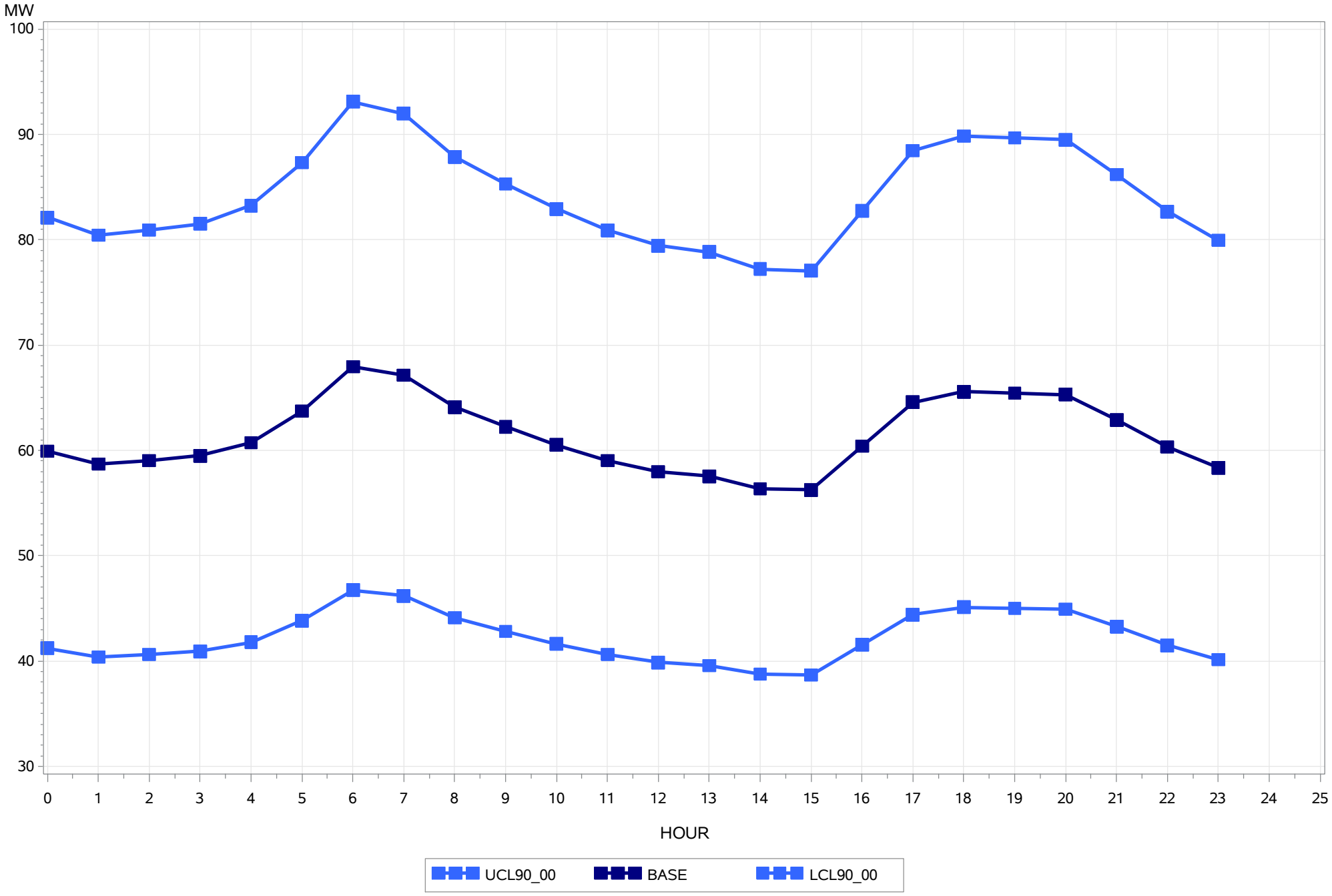
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF NEBRASKA

Date of Off Peak Day - 12/08/2021



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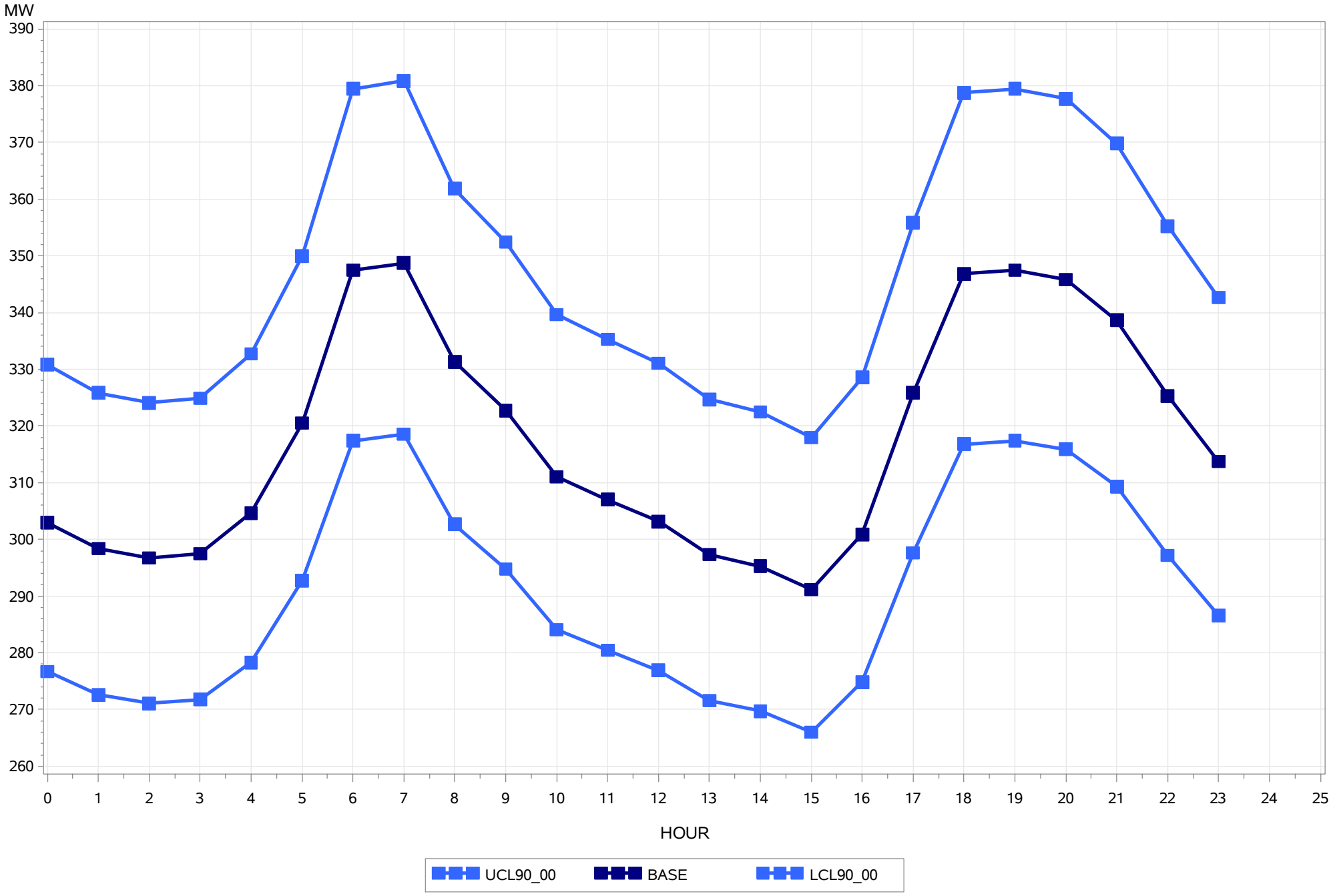
Member Forecasted Off Peak Demand Day for January 2021

STATE OF NEW MEXICO

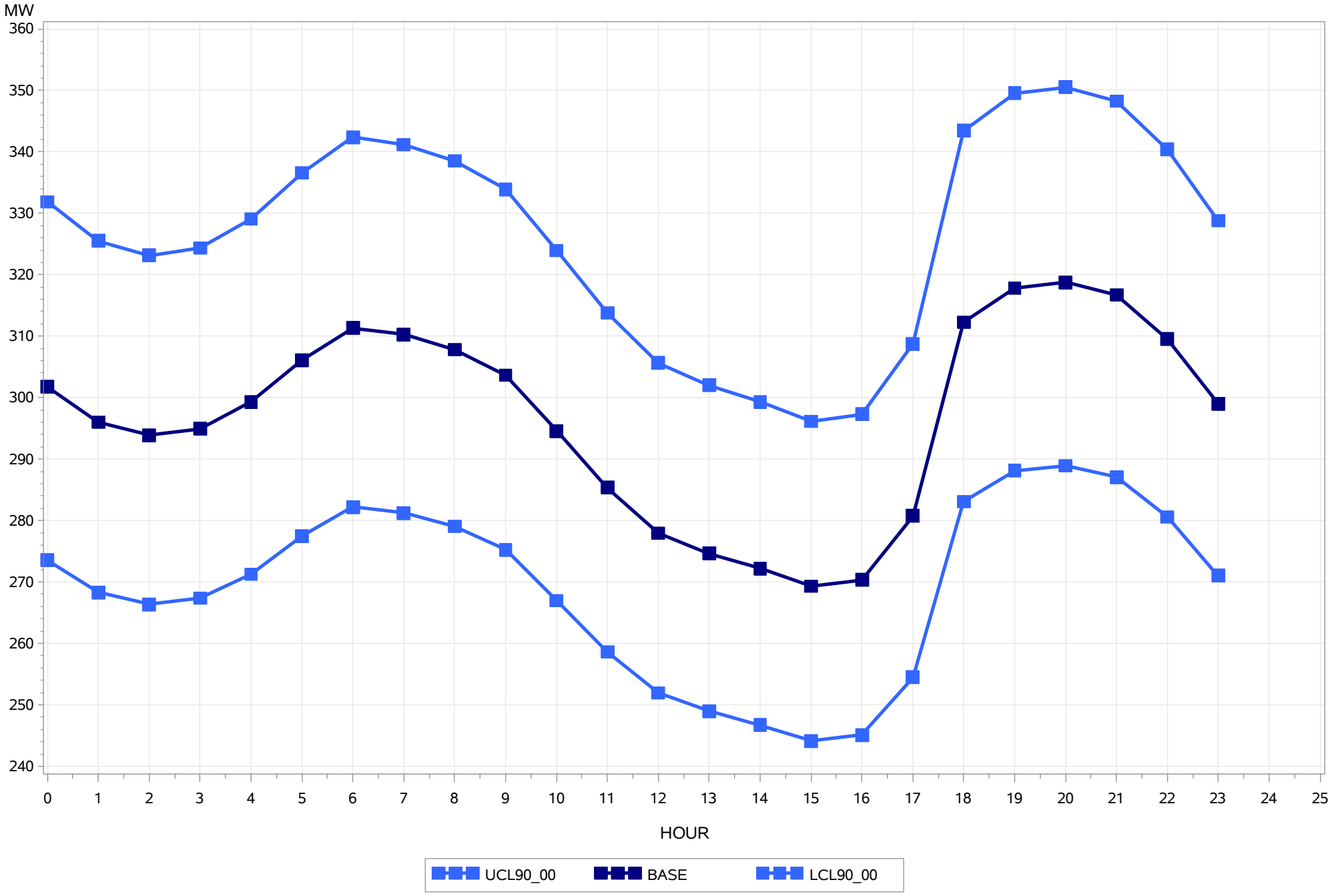
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF NEW MEXICO

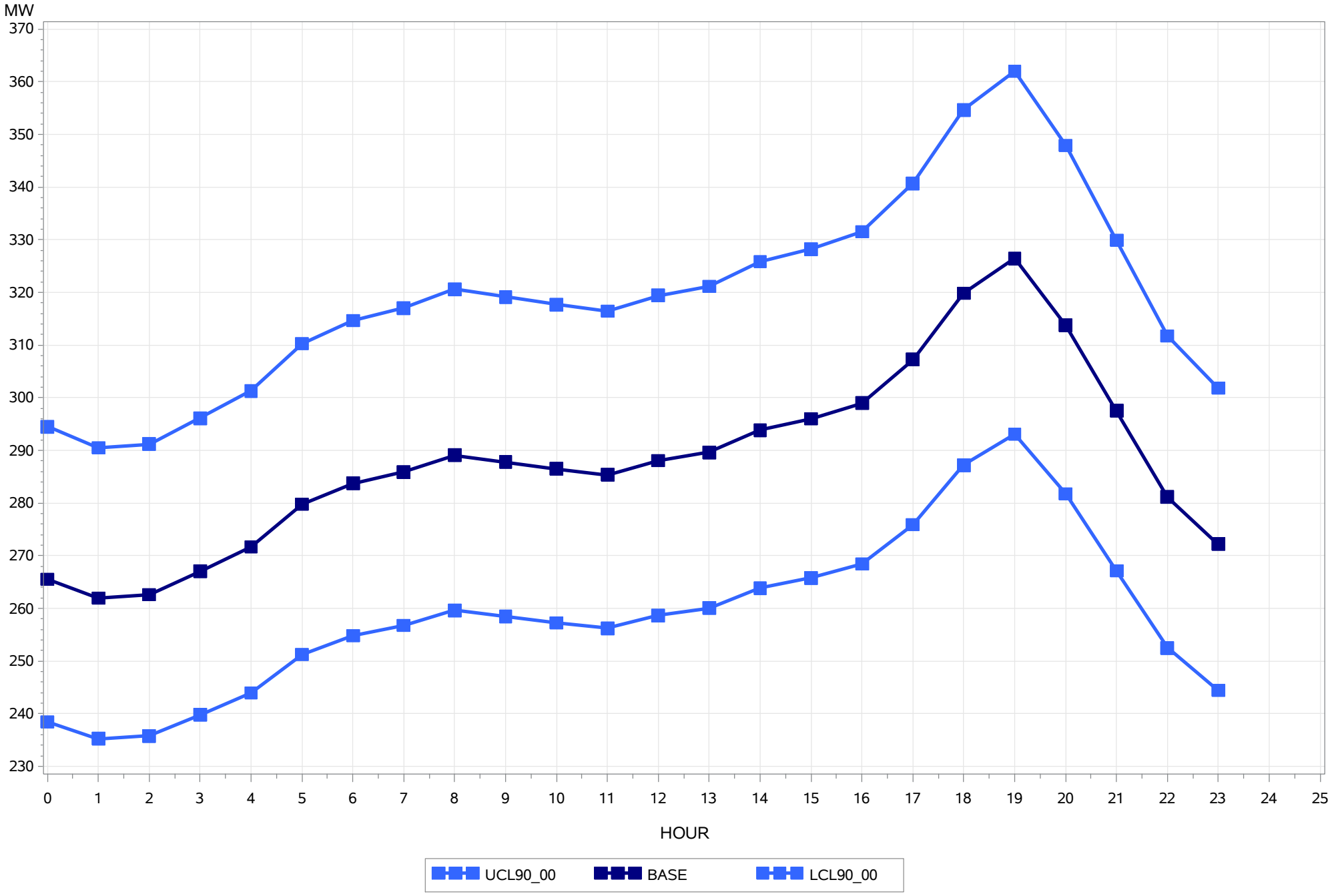
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 03/21/2021



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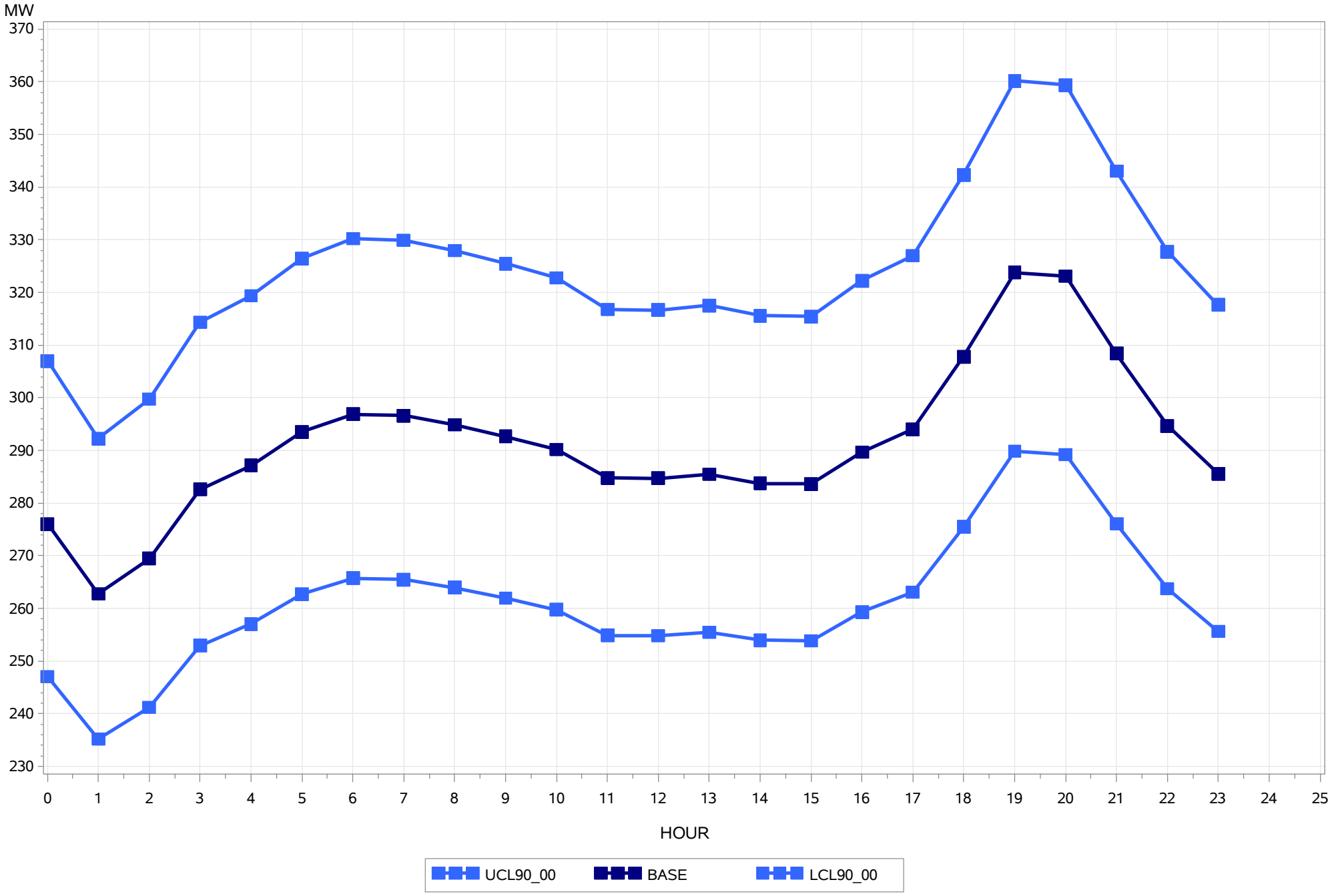
Member Forecasted Off Peak Demand Day for April 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 04/03/2021



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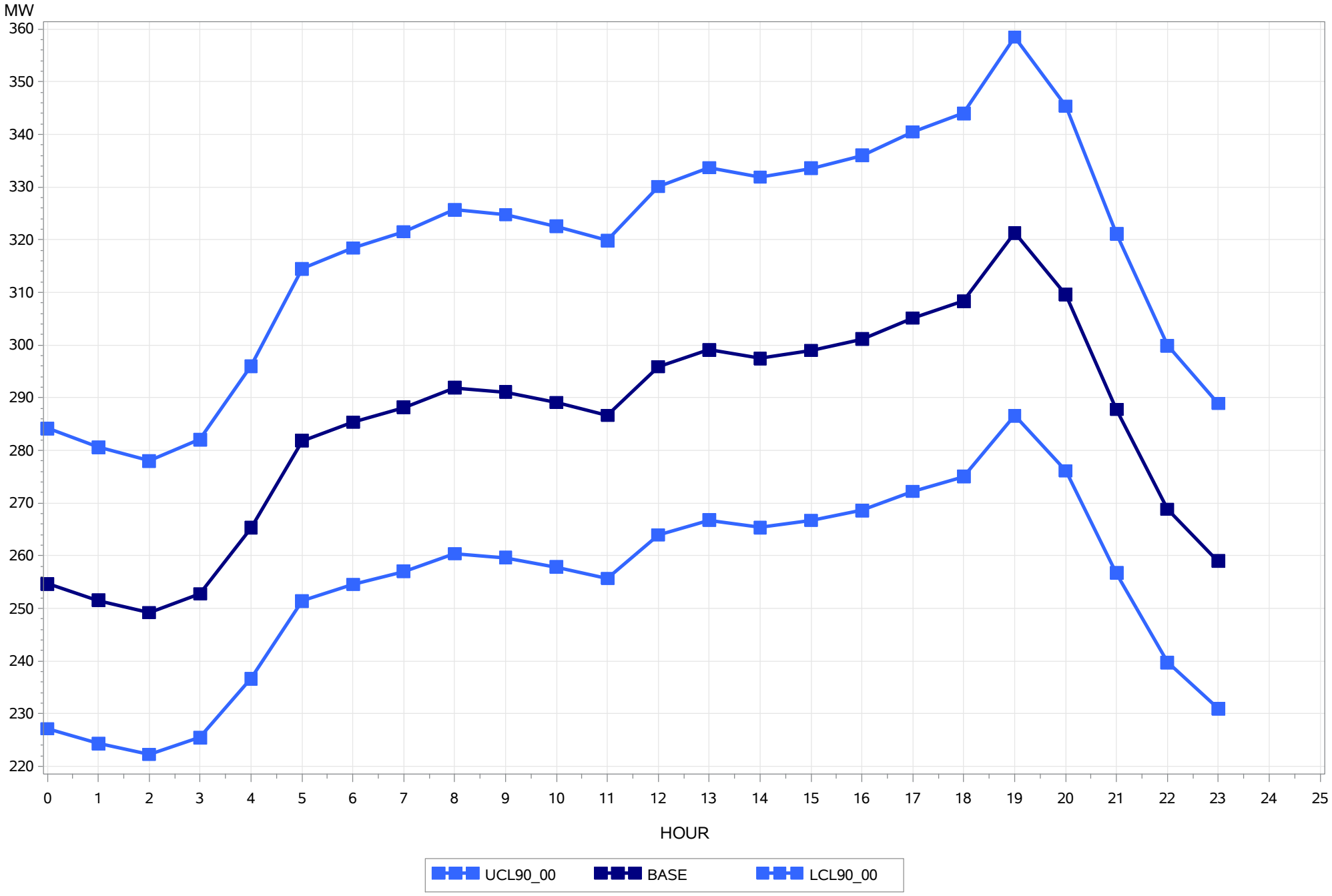
Member Forecasted Off Peak Demand Day for May 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 05/03/2021



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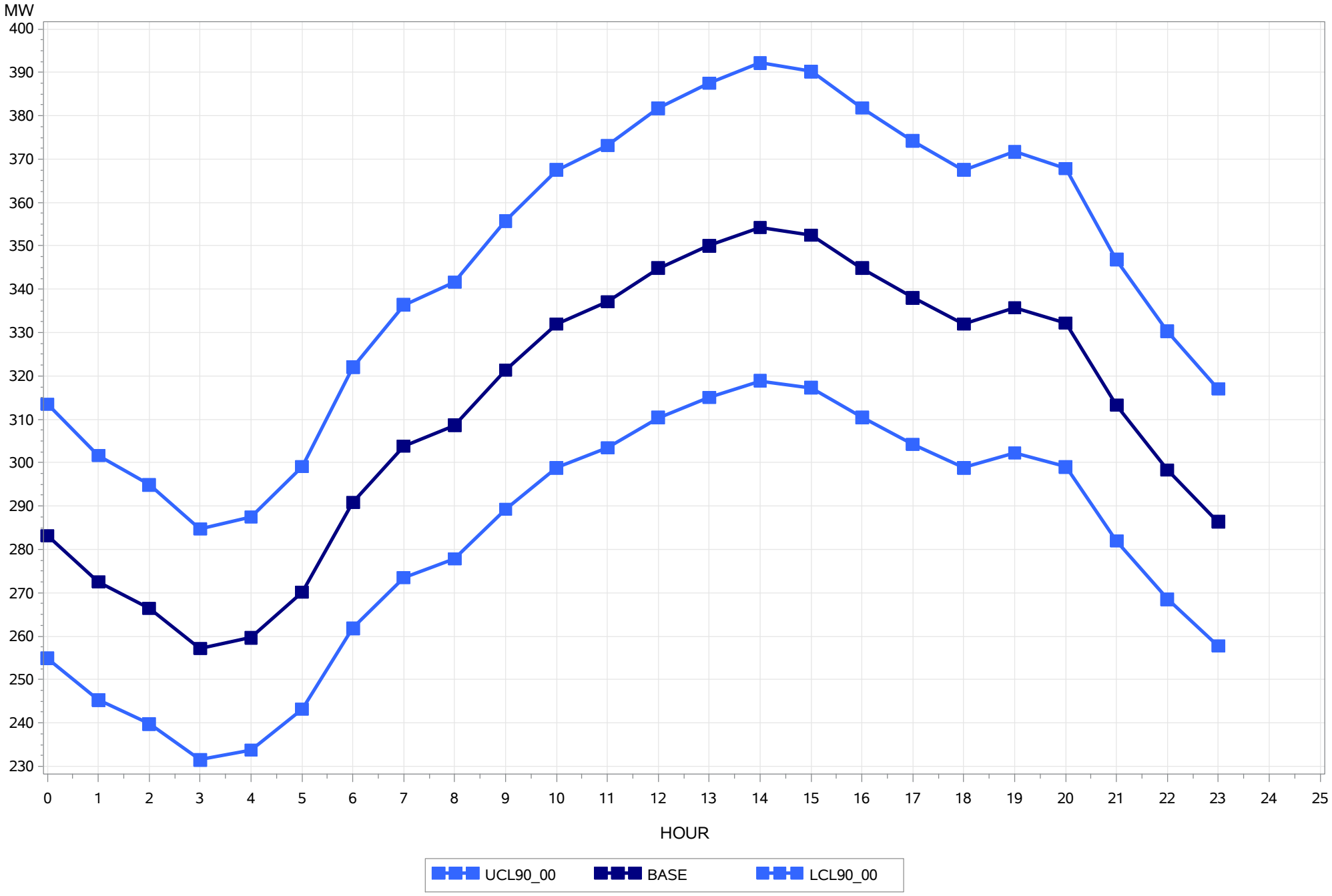
Member Forecasted Off Peak Demand Day for June 2021

STATE OF NEW MEXICO

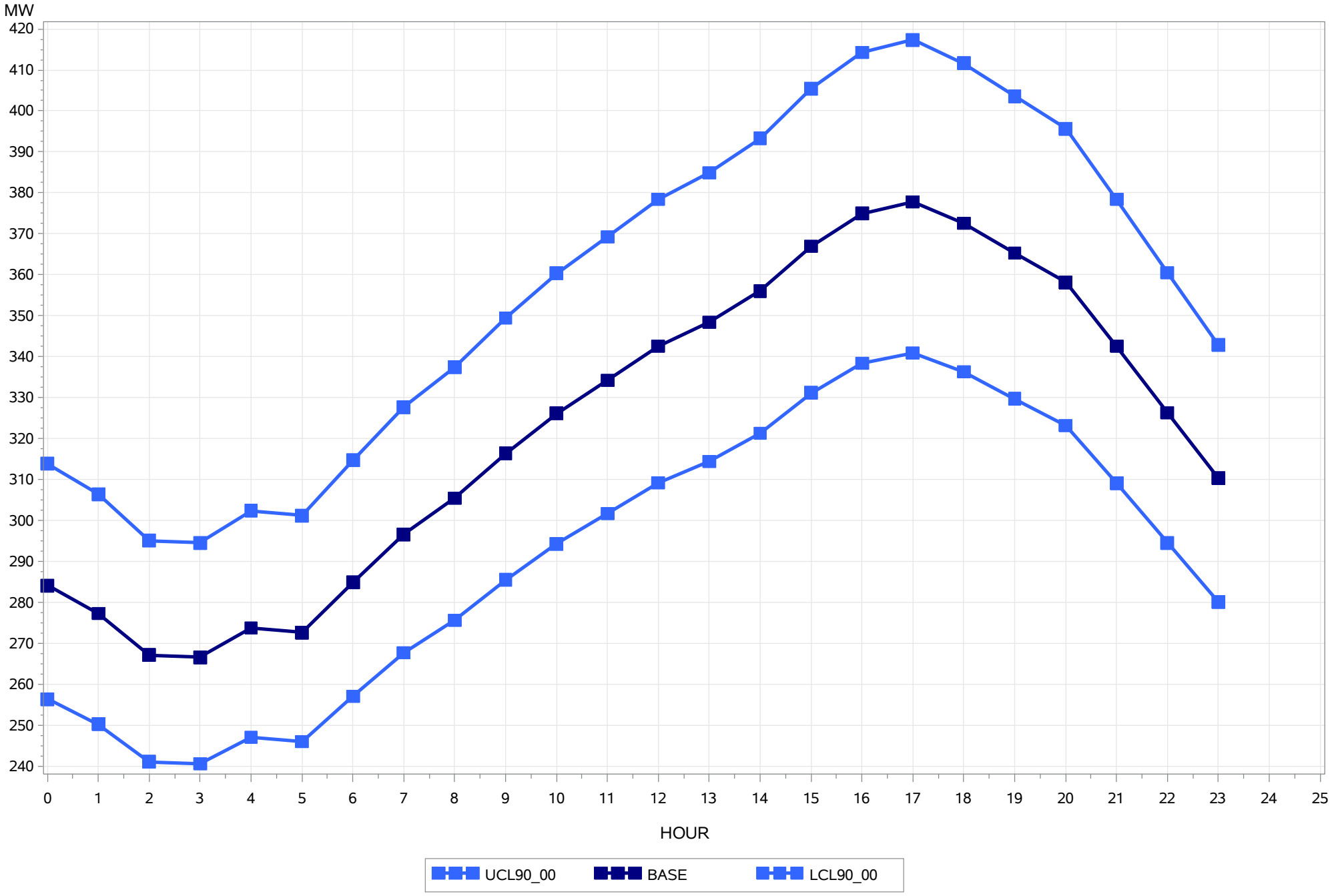
Date of Off Peak Day - 06/03/2021



Member Forecasted Off Peak Demand Day for July 2021

STATE OF NEW MEXICO

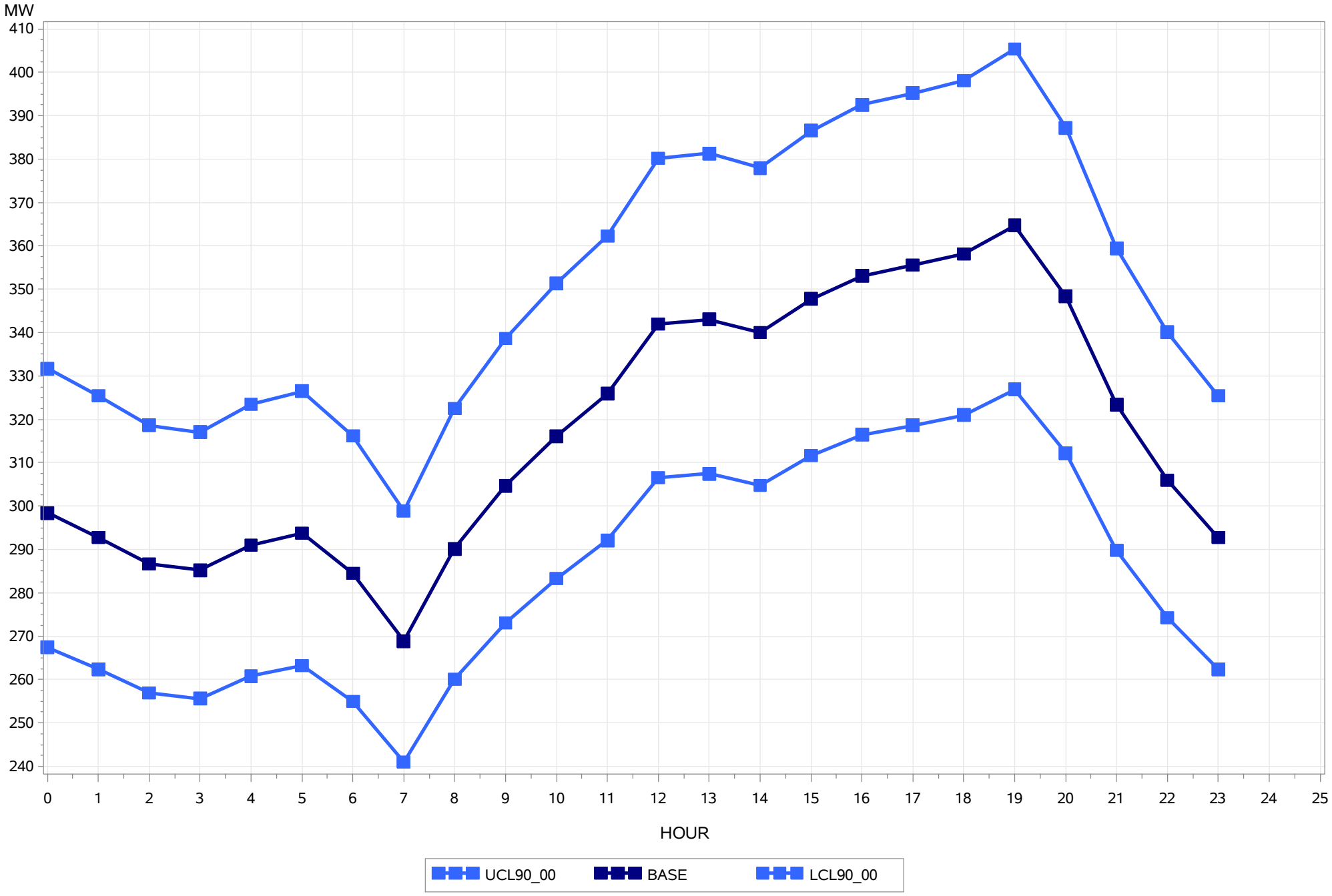
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

STATE OF NEW MEXICO

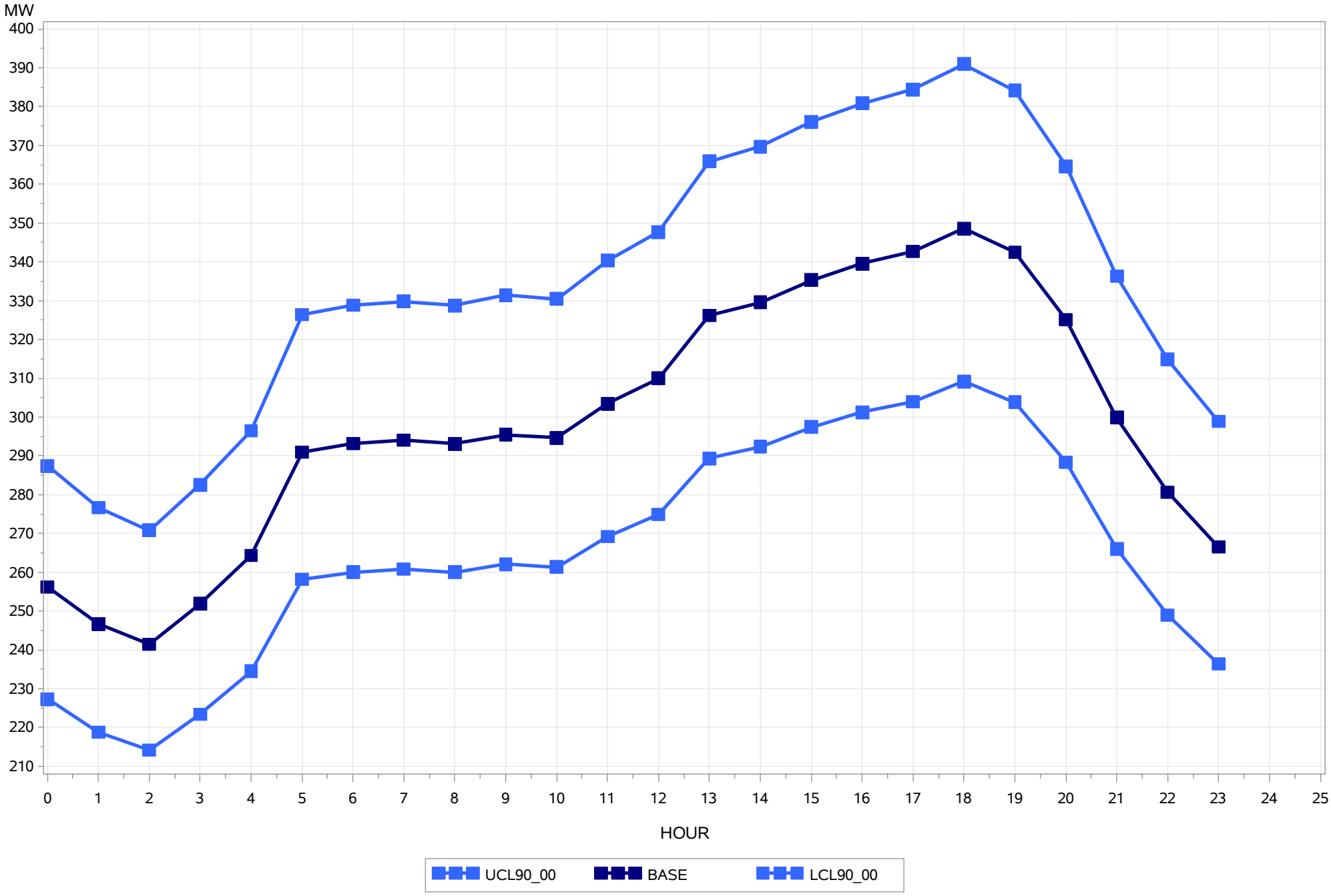
Date of Off Peak Day - 08/29/2021



Member Forecasted Off Peak Demand Day for September 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 09/28/2021



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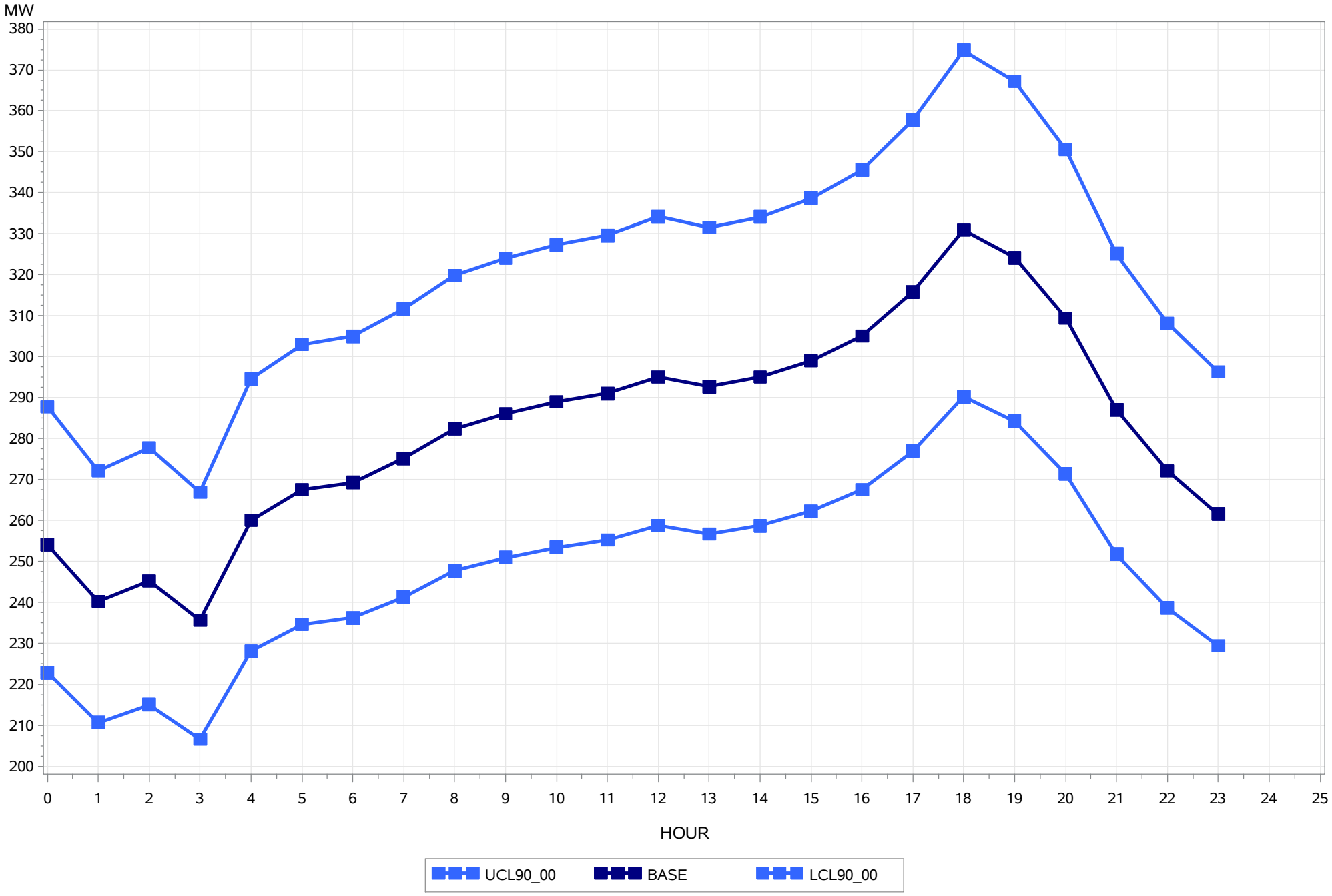
Member Forecasted Off Peak Demand Day for October 2021

STATE OF NEW MEXICO

Date of Off Peak Day - 10/03/2021



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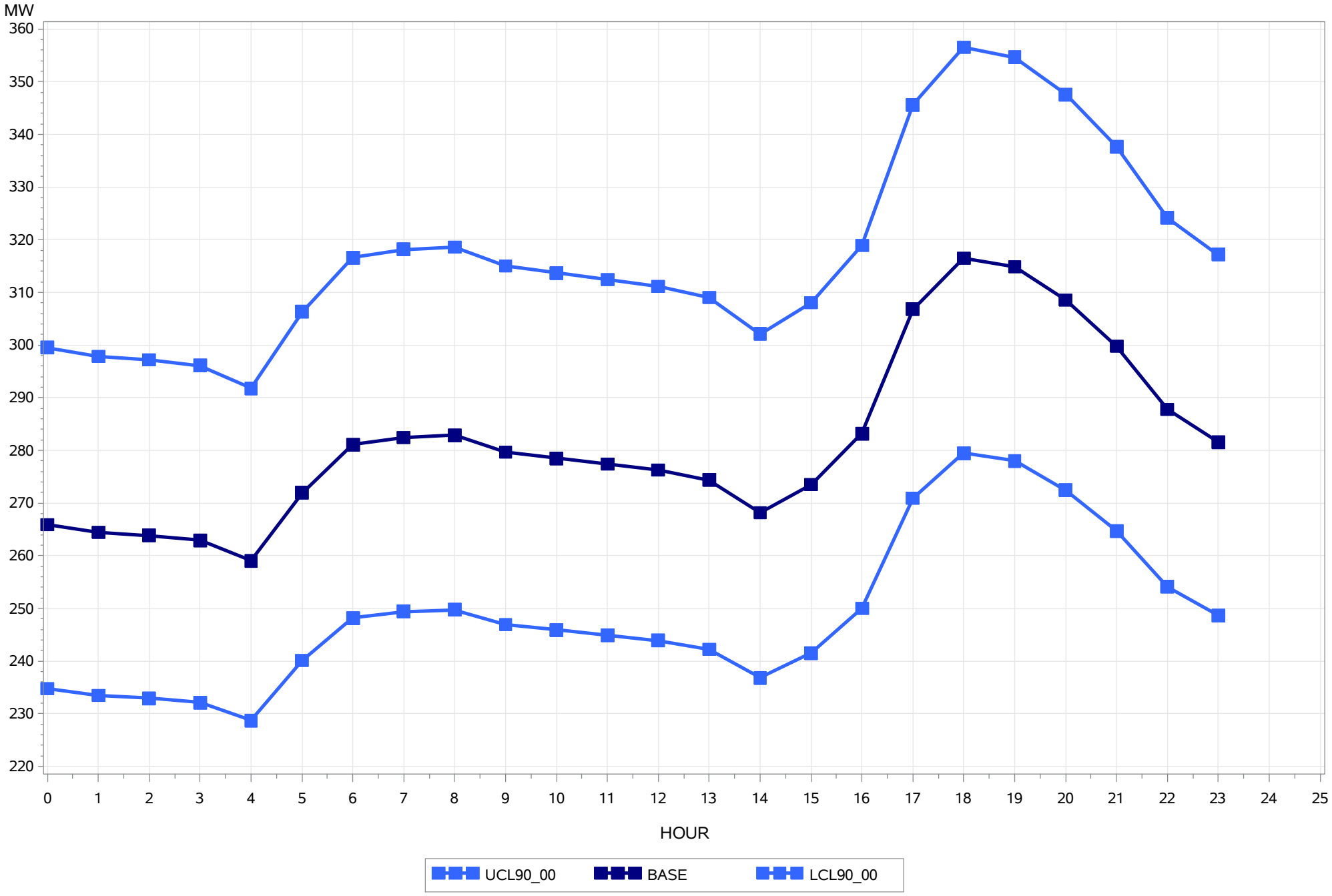
Member Forecasted Off Peak Demand Day for November 2021

STATE OF NEW MEXICO

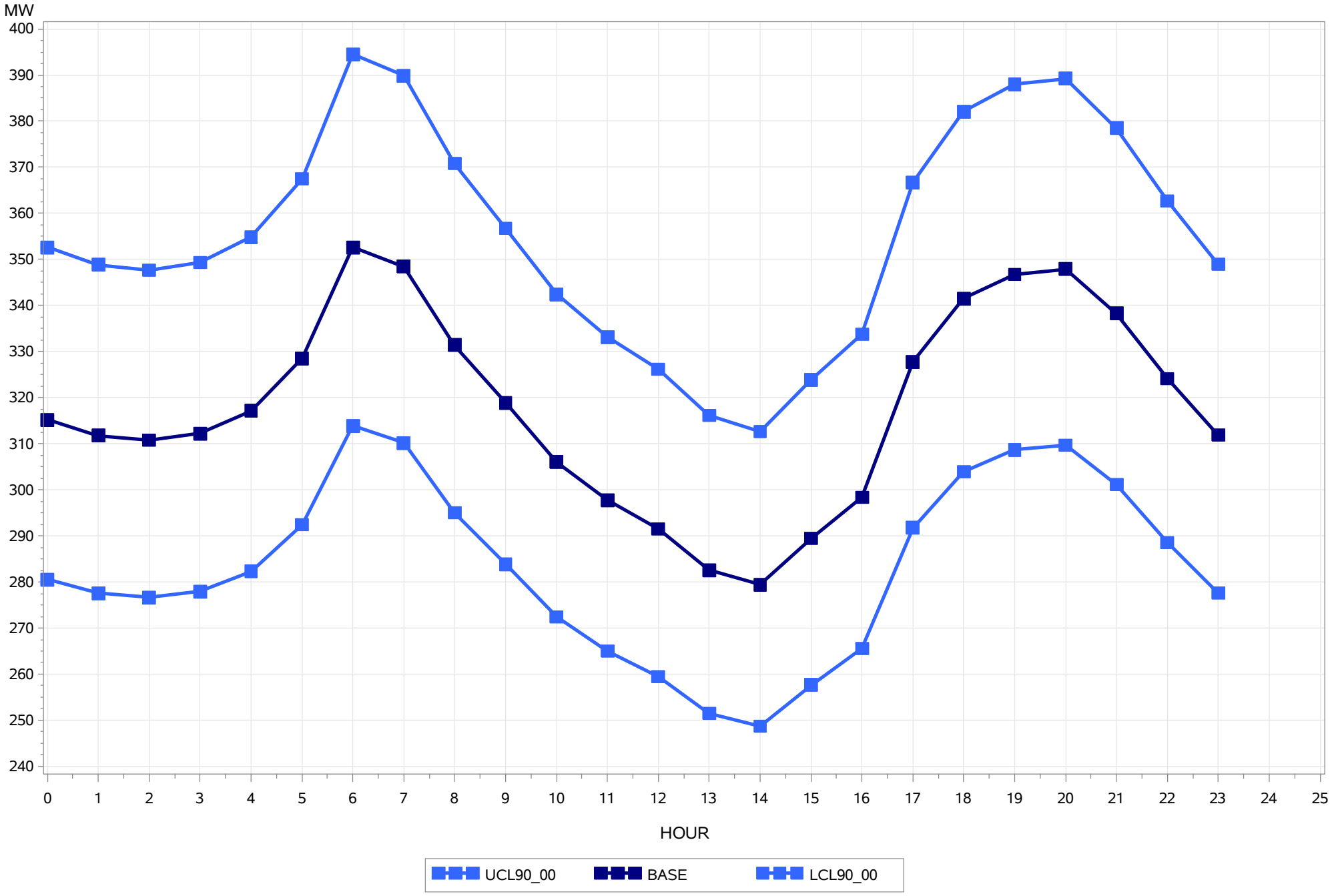
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

STATE OF NEW MEXICO

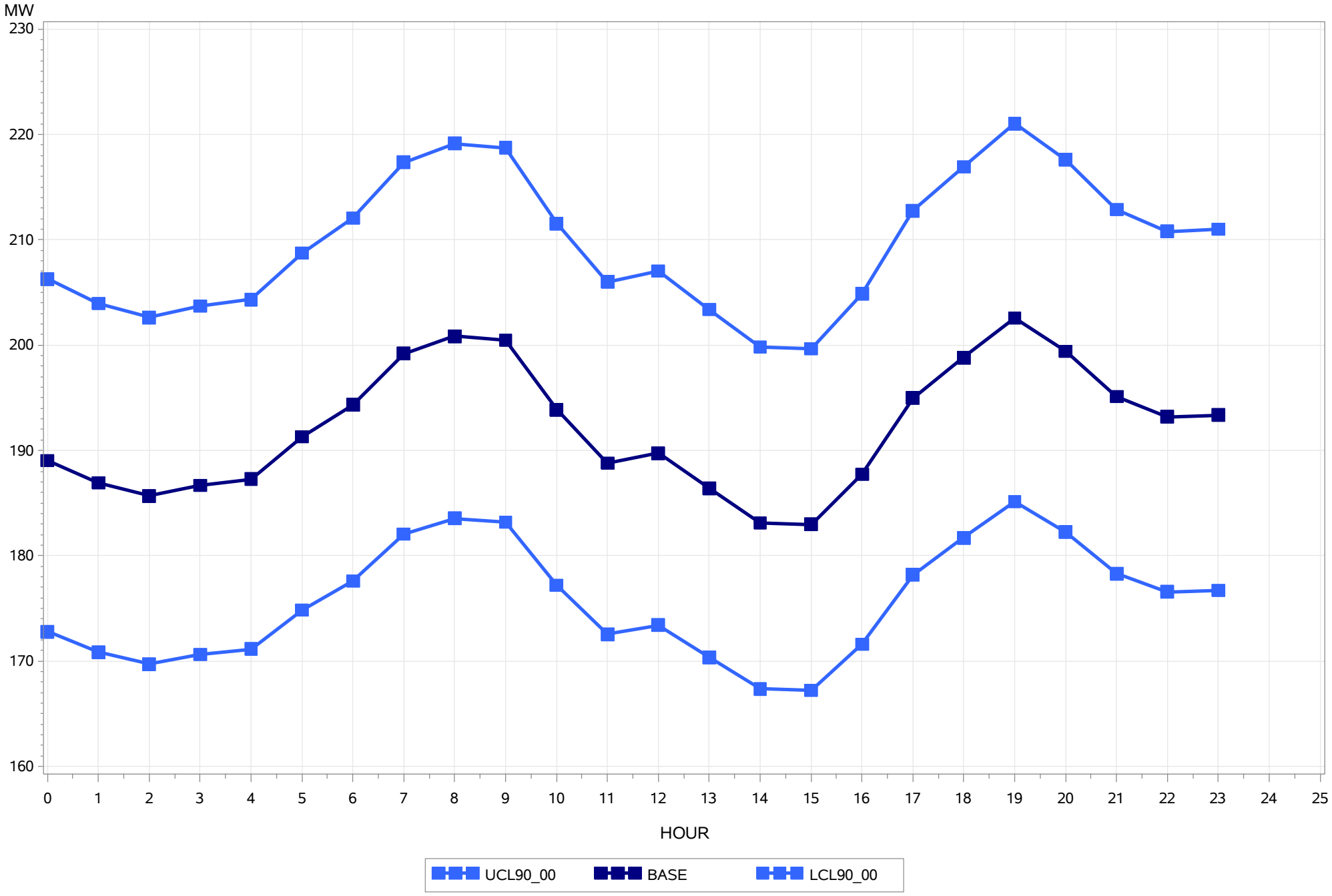
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

STATE OF WYOMING

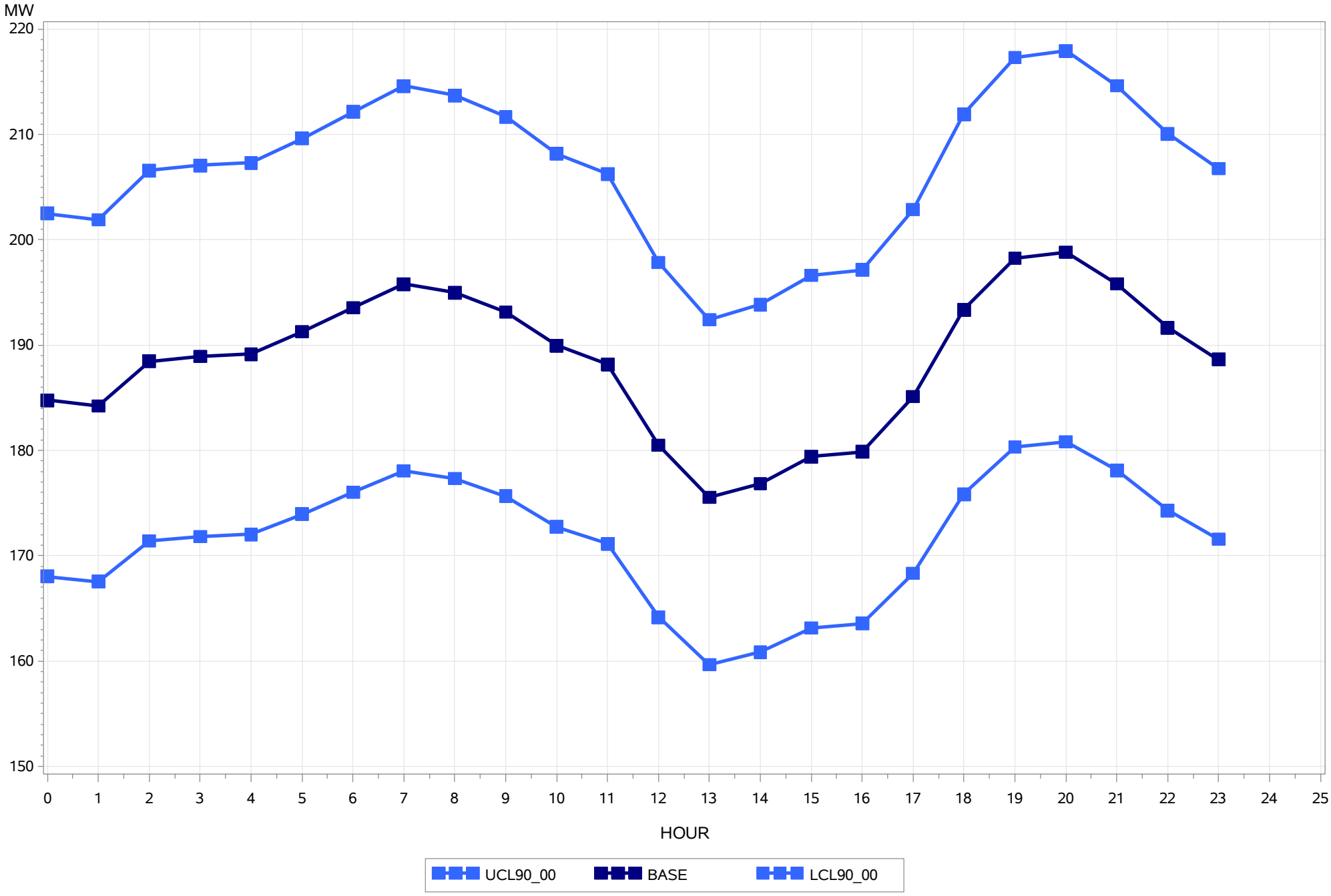
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

STATE OF WYOMING

Date of Off Peak Day - 02/21/2021



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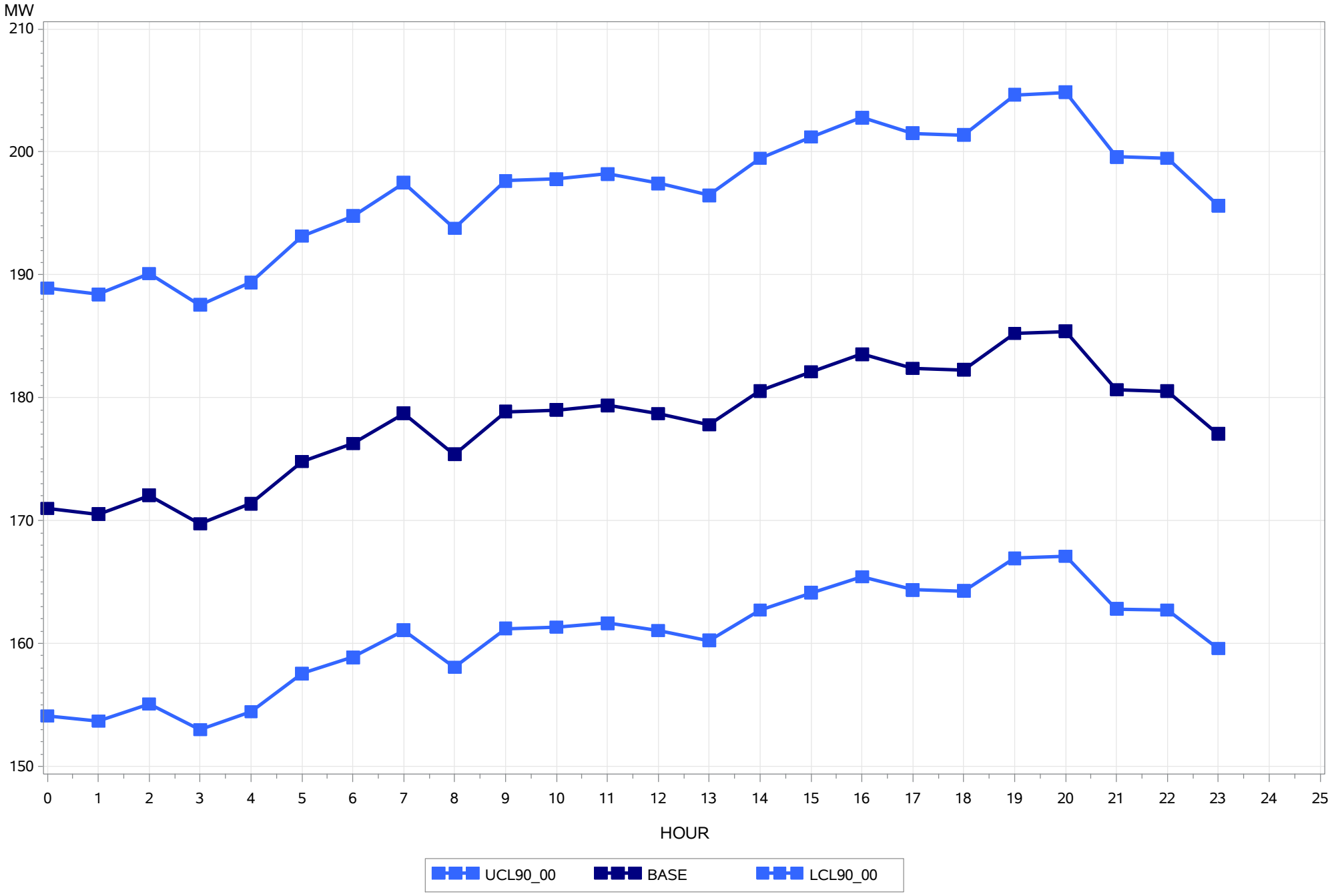
Member Forecasted Off Peak Demand Day for March 2021

STATE OF WYOMING

Date of Off Peak Day - 03/21/2021



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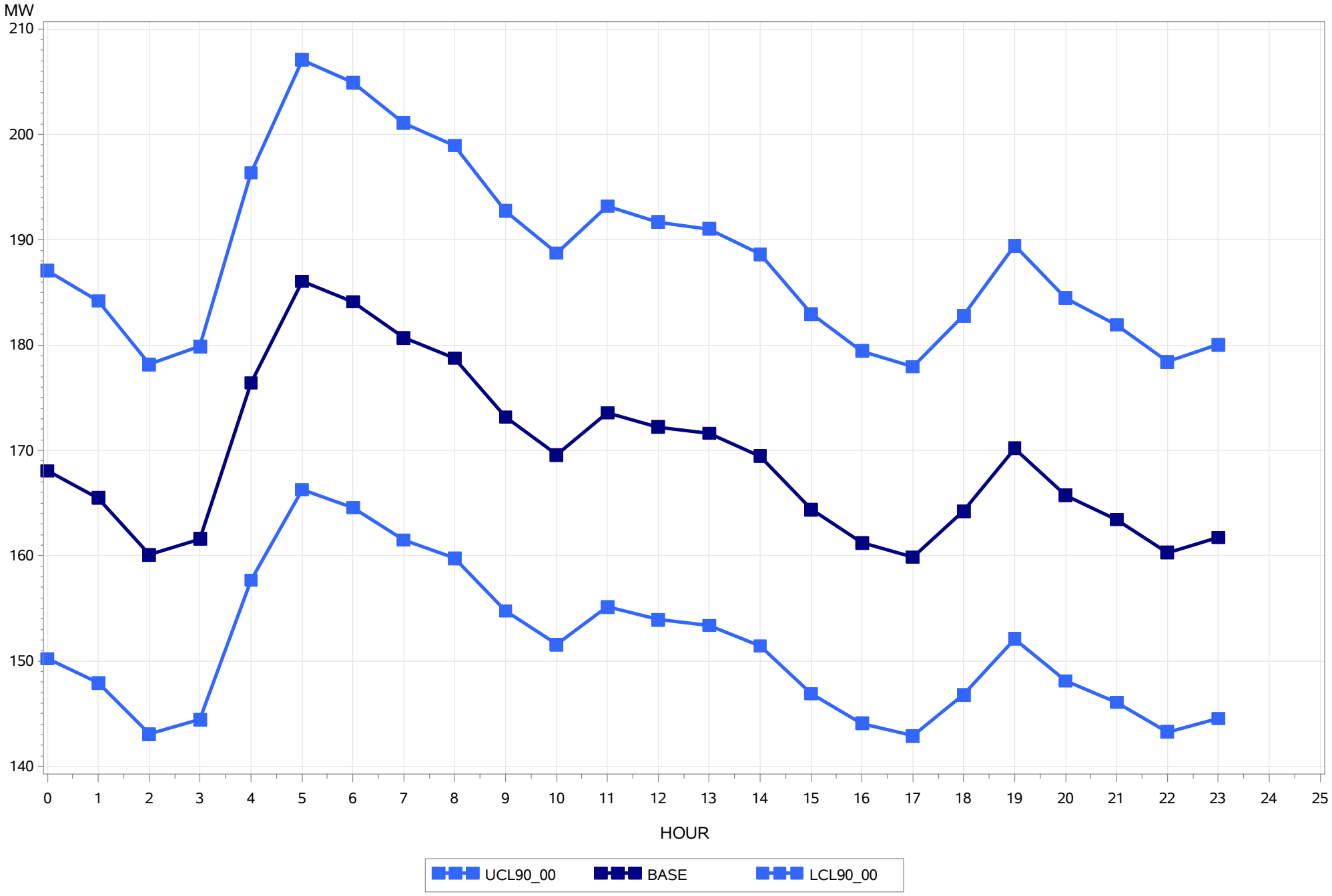
Member Forecasted Off Peak Demand Day for April 2021

STATE OF WYOMING

Date of Off Peak Day - 04/29/2021



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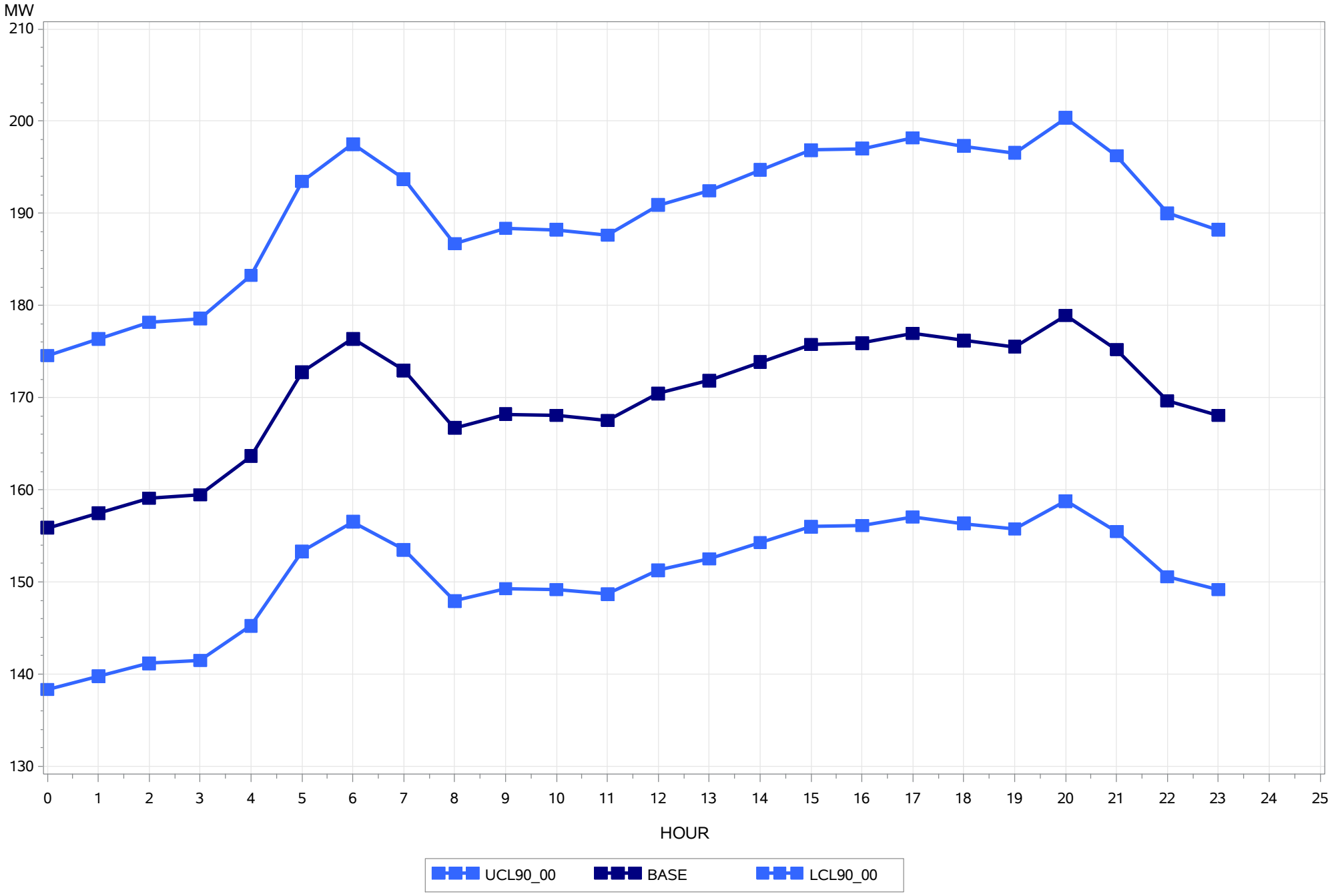
Member Forecasted Off Peak Demand Day for May 2021

STATE OF WYOMING

Date of Off Peak Day - 05/12/2021



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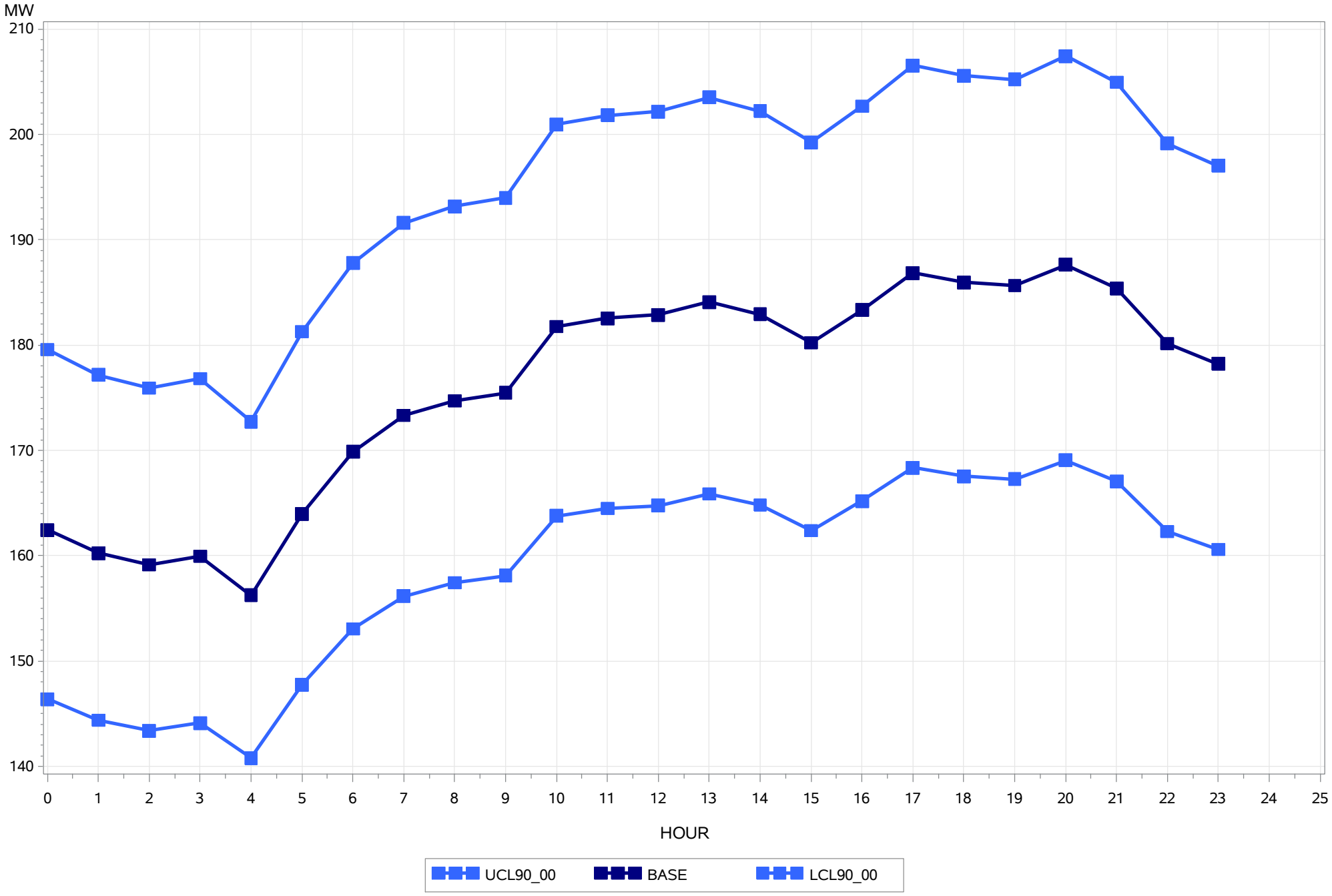
Member Forecasted Off Peak Demand Day for June 2021

STATE OF WYOMING

Date of Off Peak Day - 06/01/2021



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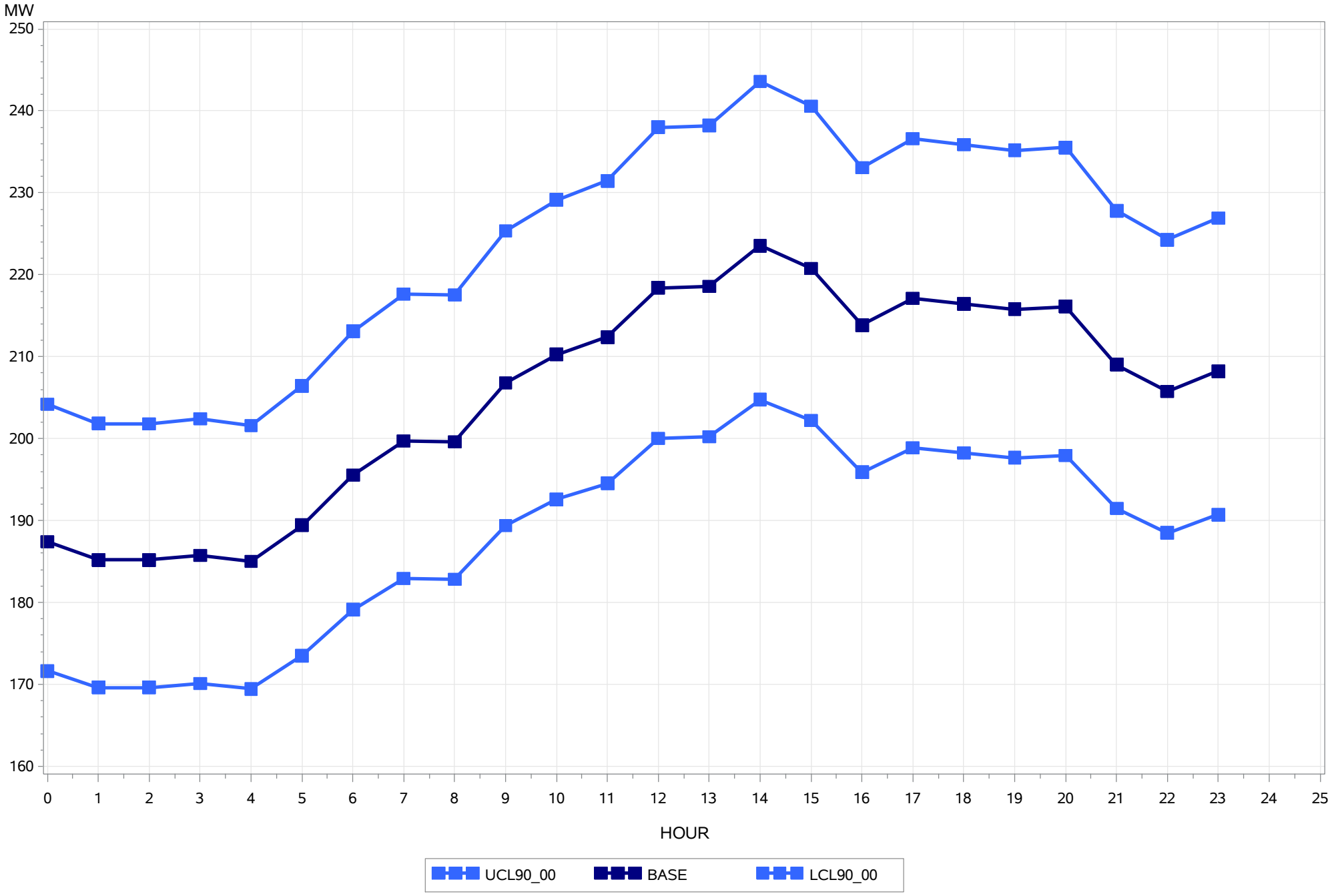
Member Forecasted Off Peak Demand Day for July 2021

STATE OF WYOMING

Date of Off Peak Day - 07/01/2021



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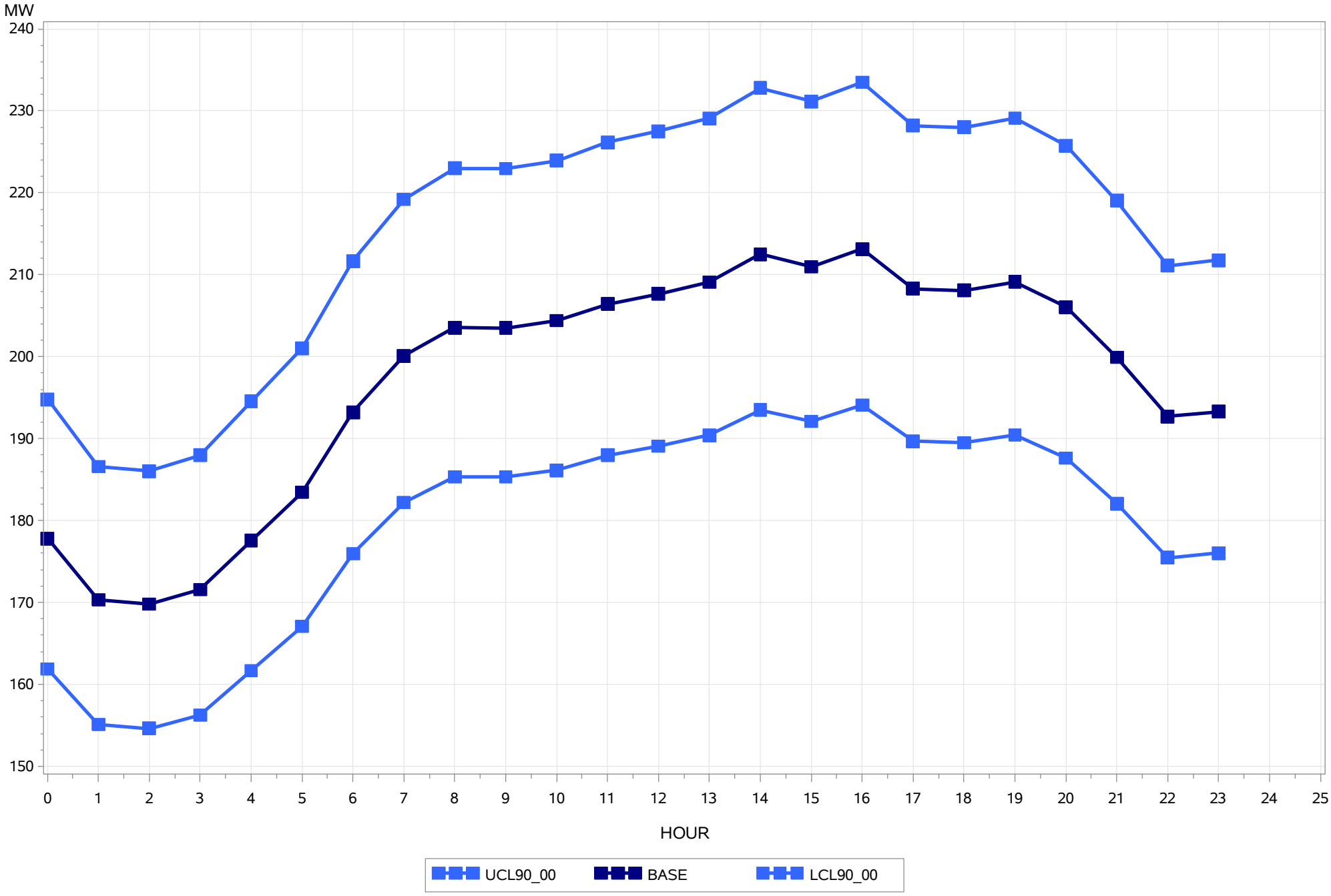
Member Forecasted Off Peak Demand Day for August 2021

STATE OF WYOMING

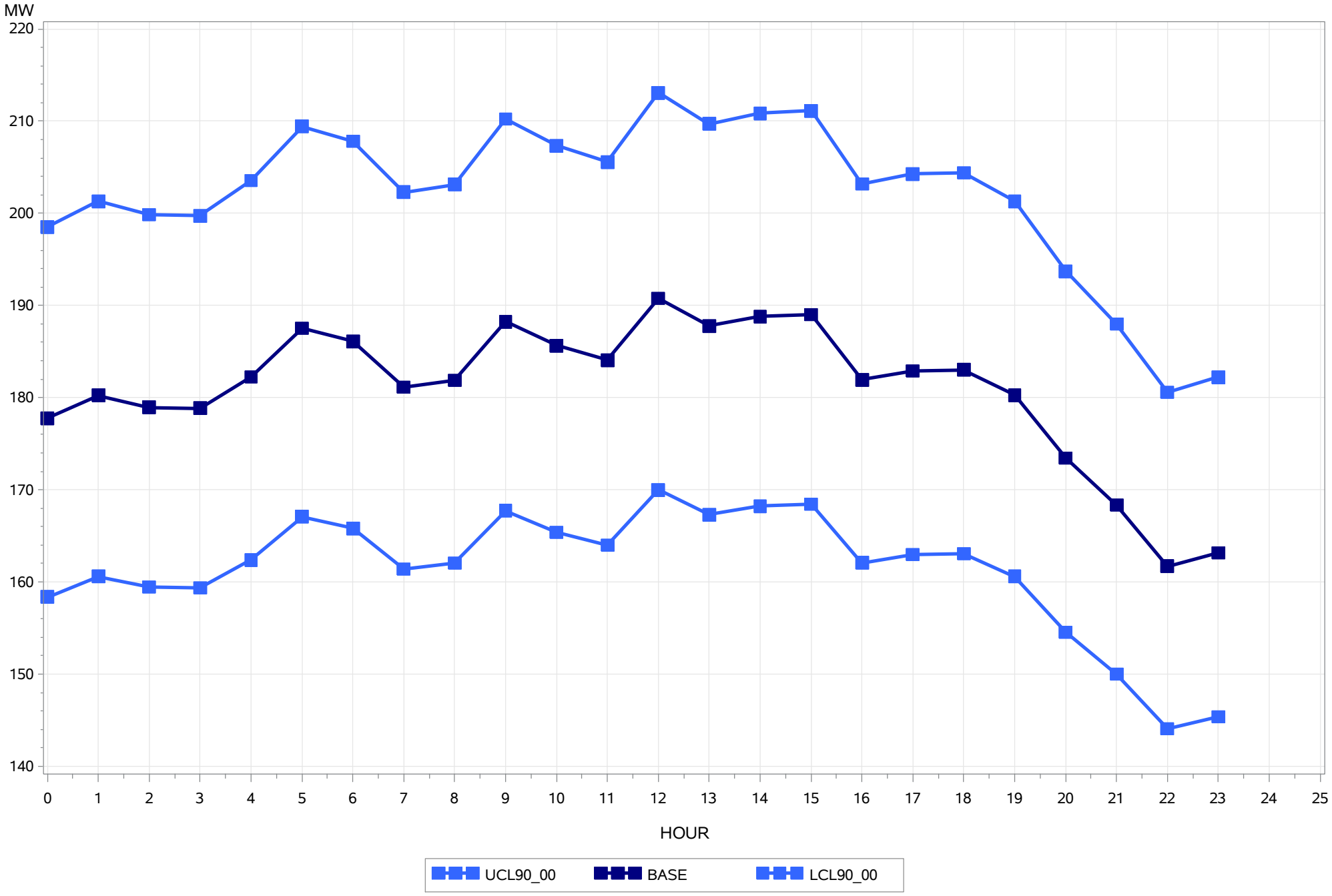
Date of Off Peak Day - 08/16/2021



Member Forecasted Off Peak Demand Day for September 2021

STATE OF WYOMING

Date of Off Peak Day - 09/30/2021



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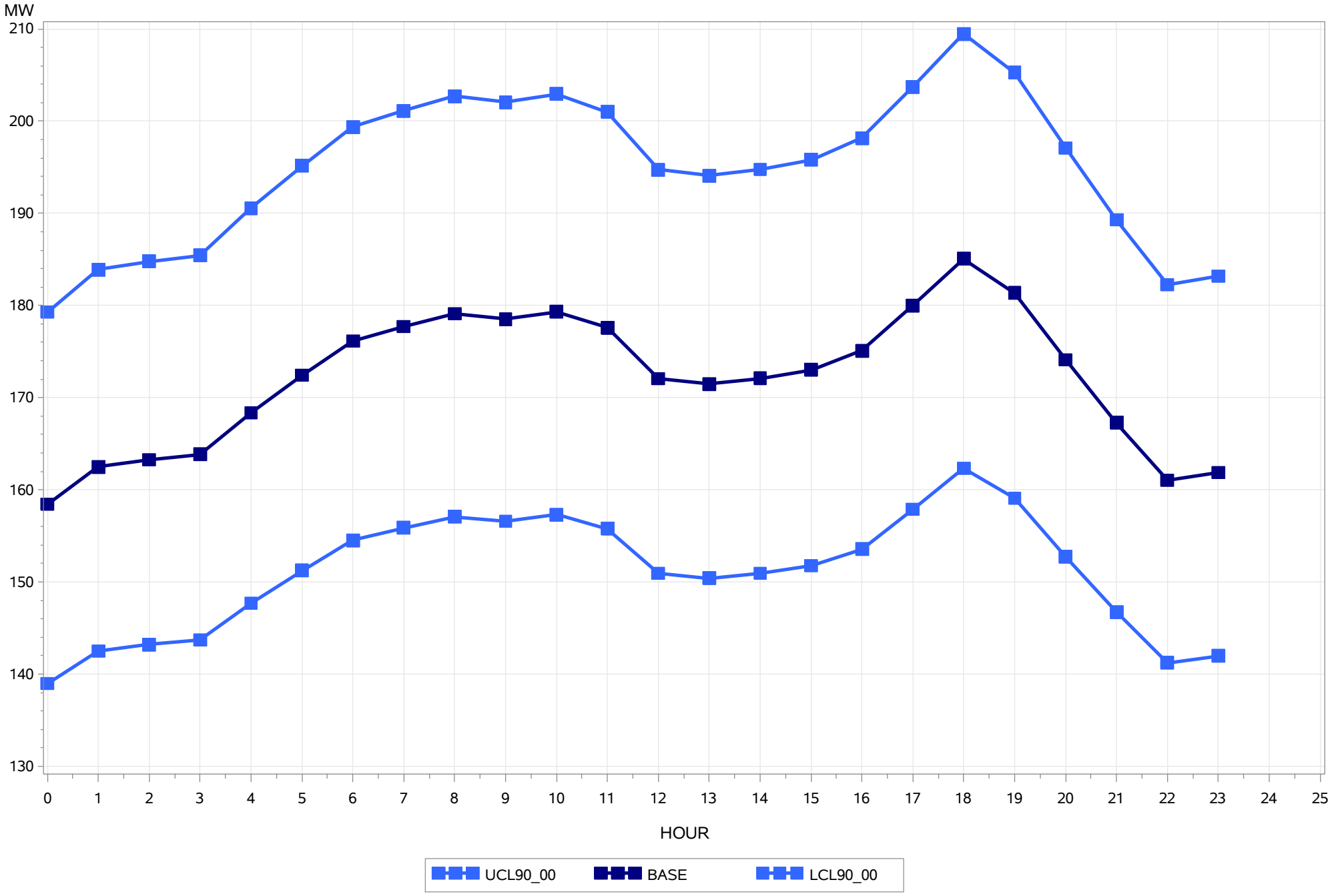
Member Forecasted Off Peak Demand Day for October 2021

STATE OF WYOMING

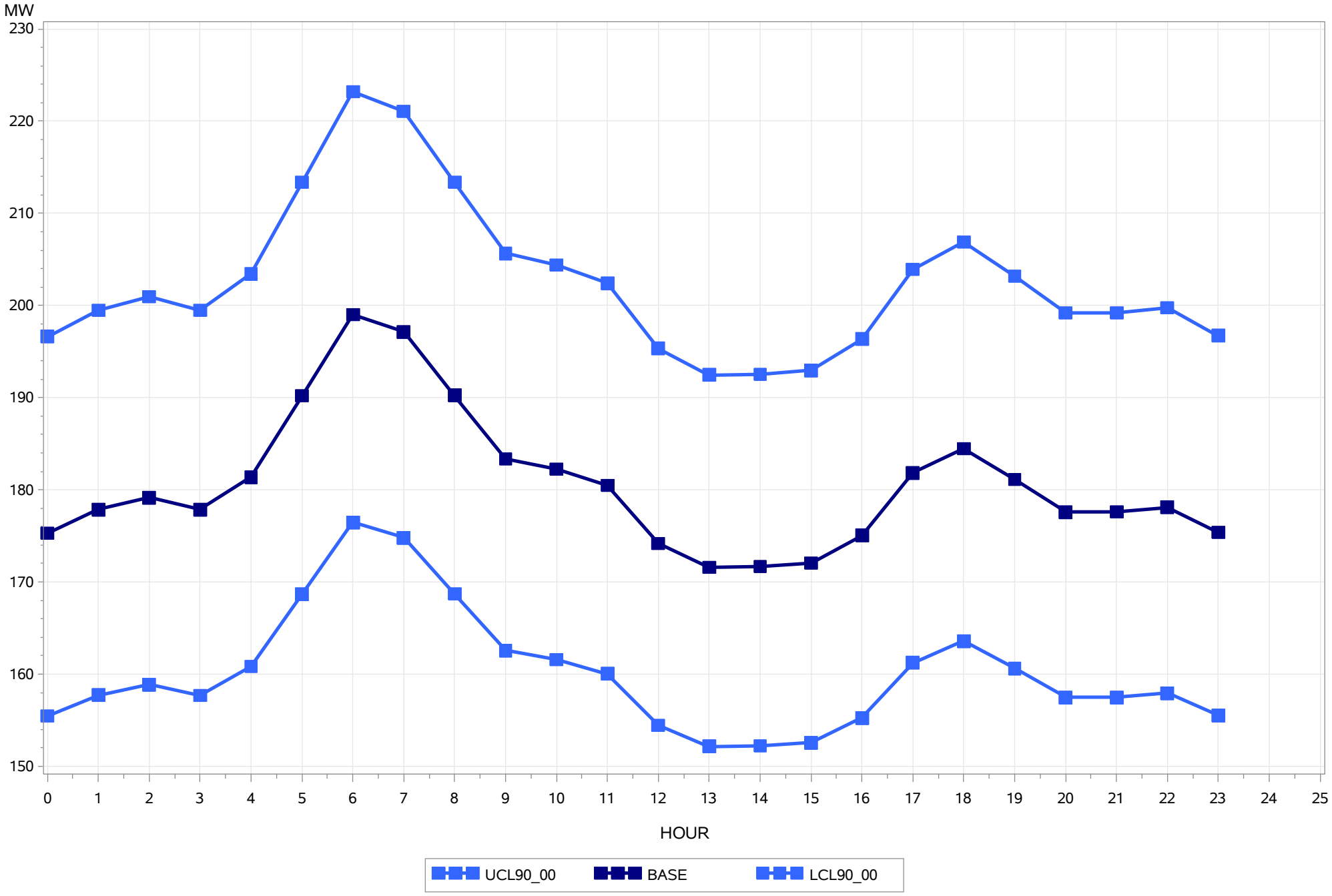
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

STATE OF WYOMING

Date of Off Peak Day - 11/03/2021



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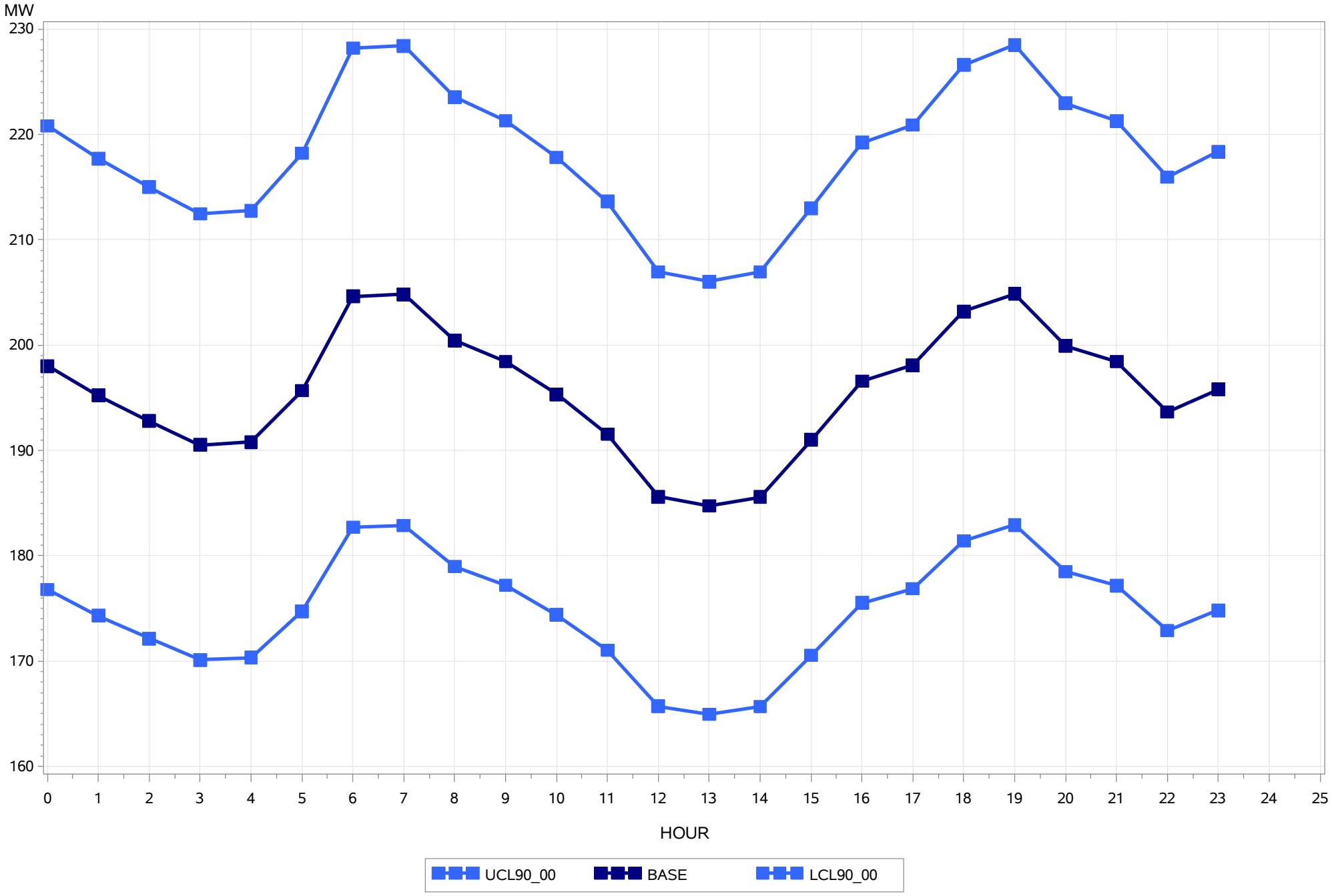
Member Forecasted Off Peak Demand Day for December 2021

STATE OF WYOMING

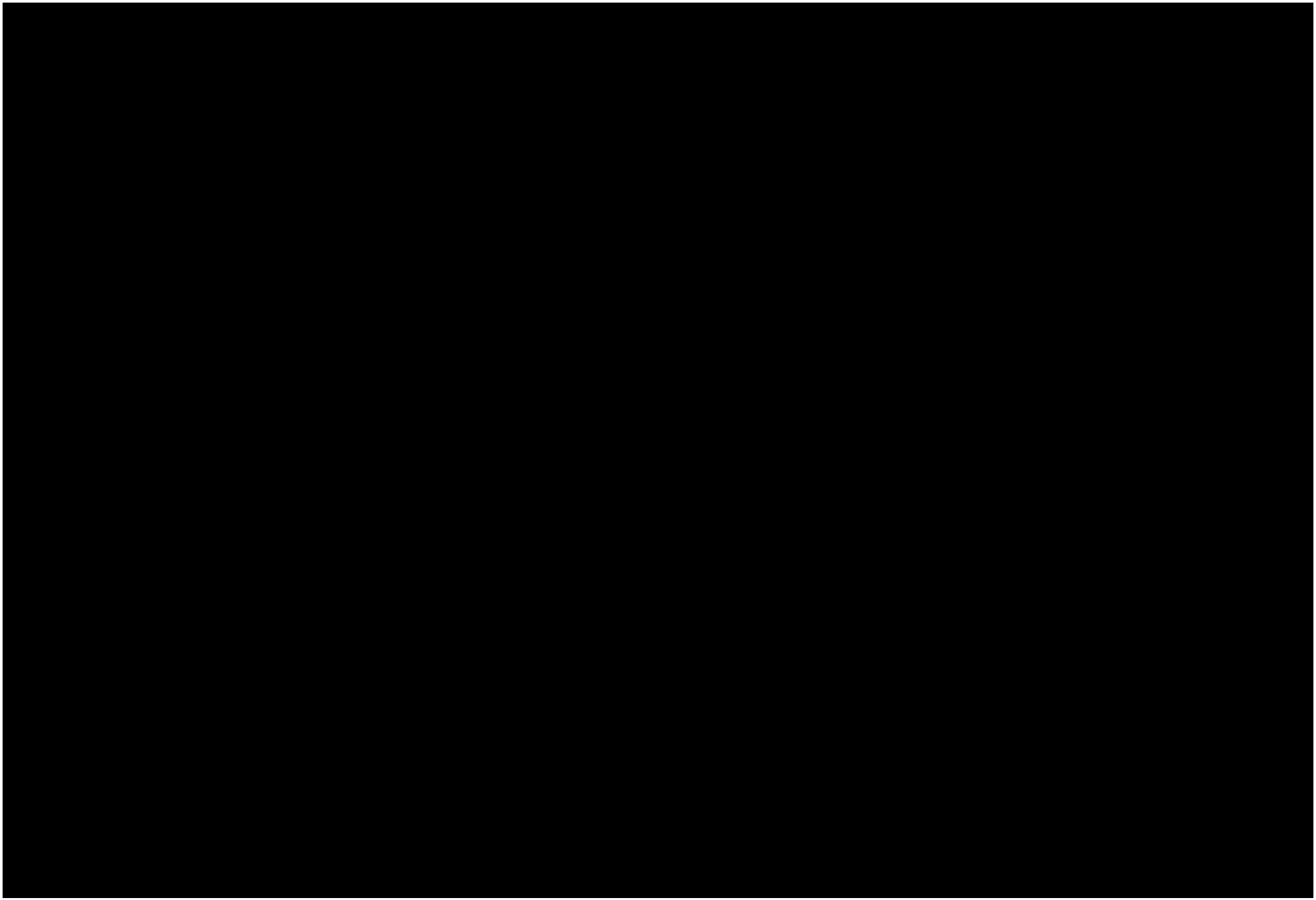
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Big Horn Rural Electric Company

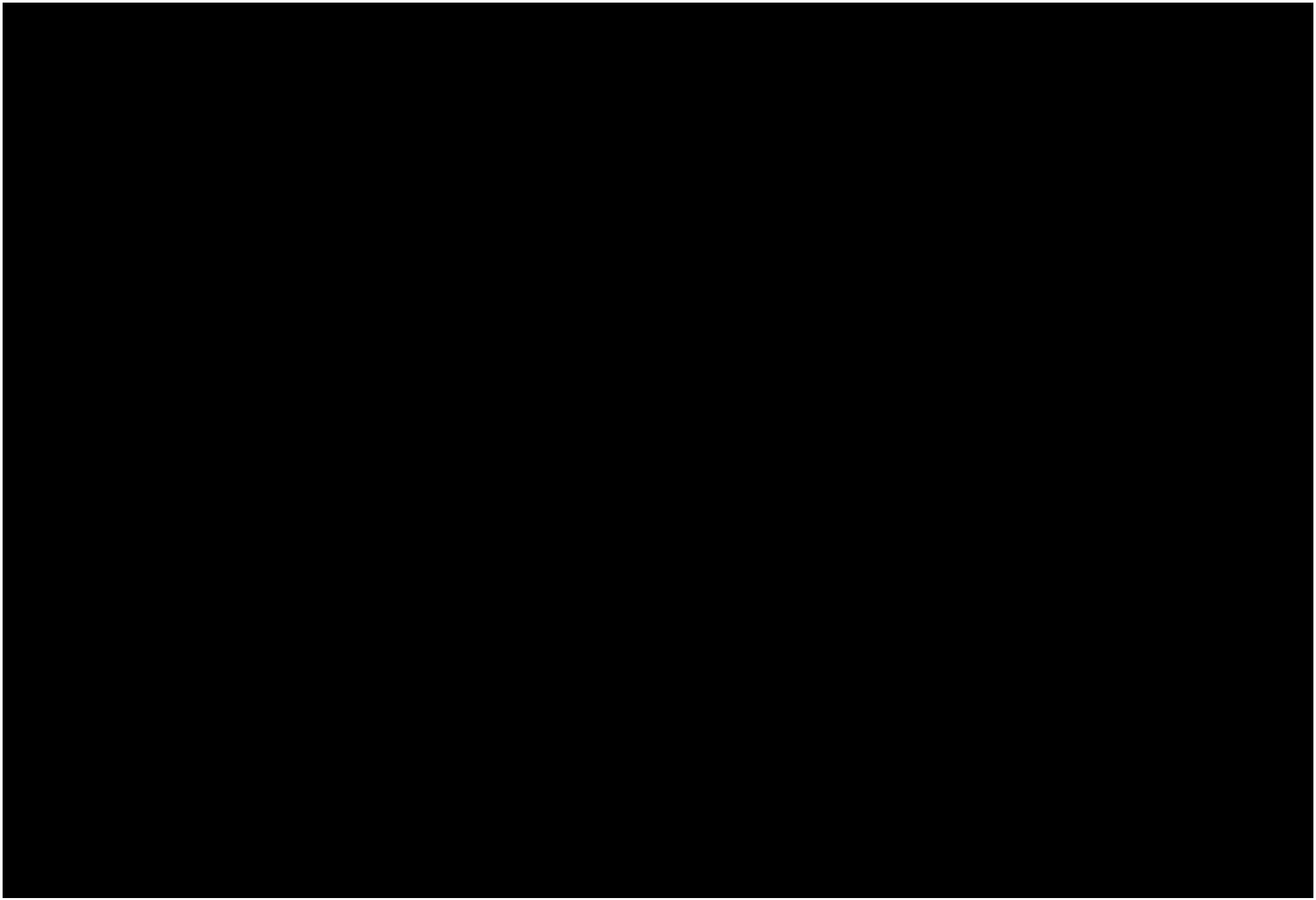
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Big Horn Rural Electric Company

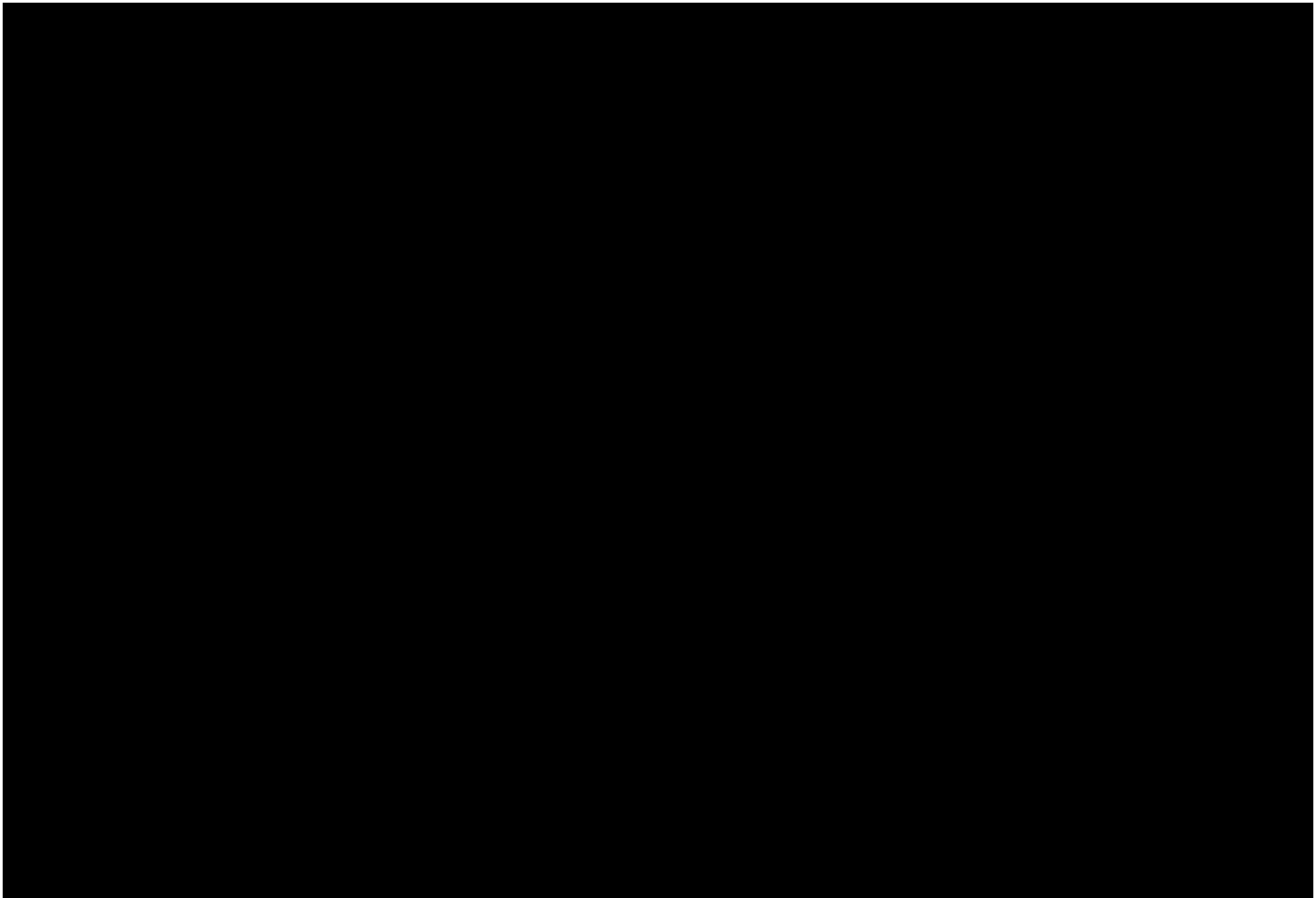
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Big Horn Rural Electric Company

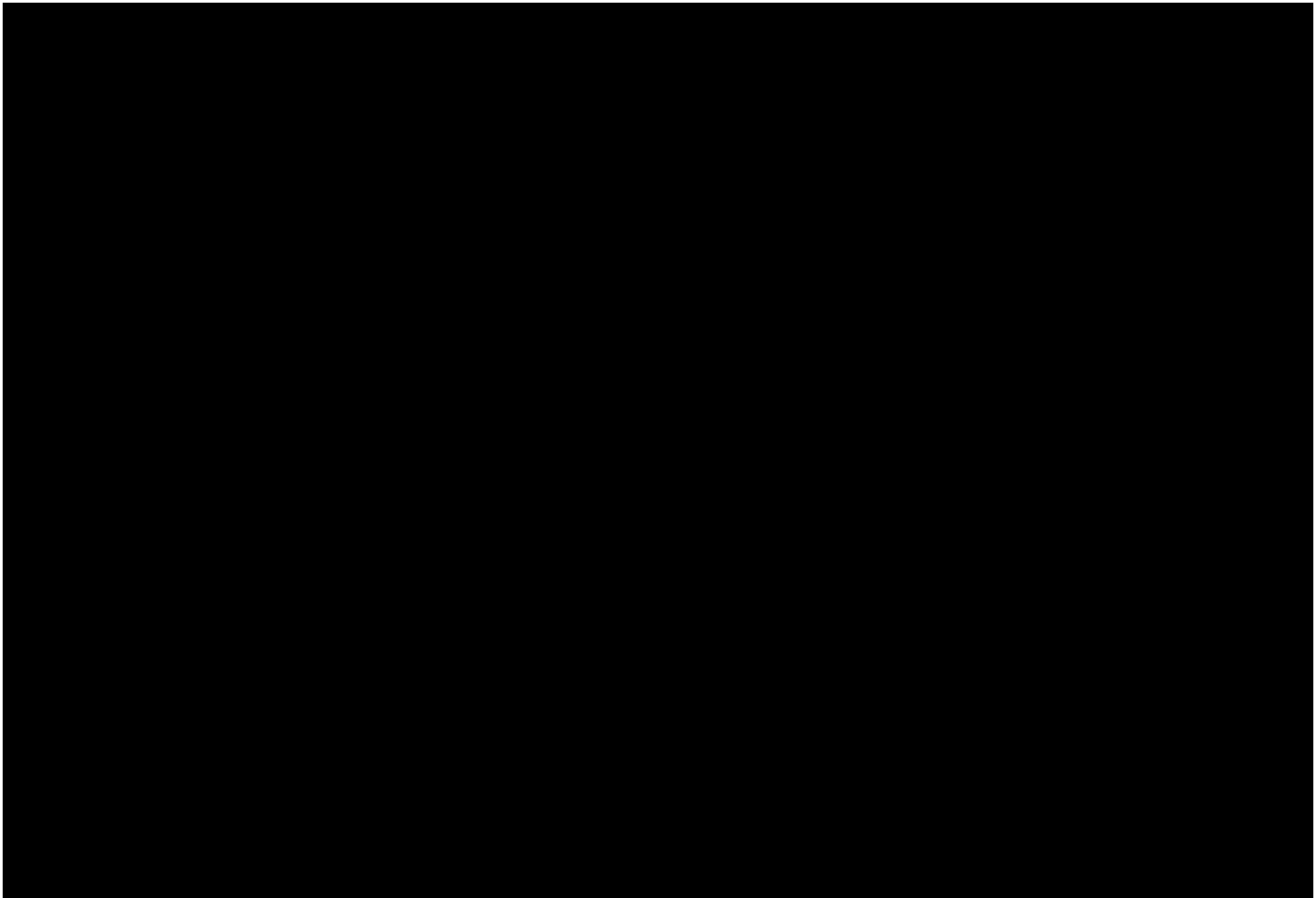
Date of Off Peak Day - 03/27/2021



Member Forecasted Off Peak Demand Day for April 2021

Big Horn Rural Electric Company

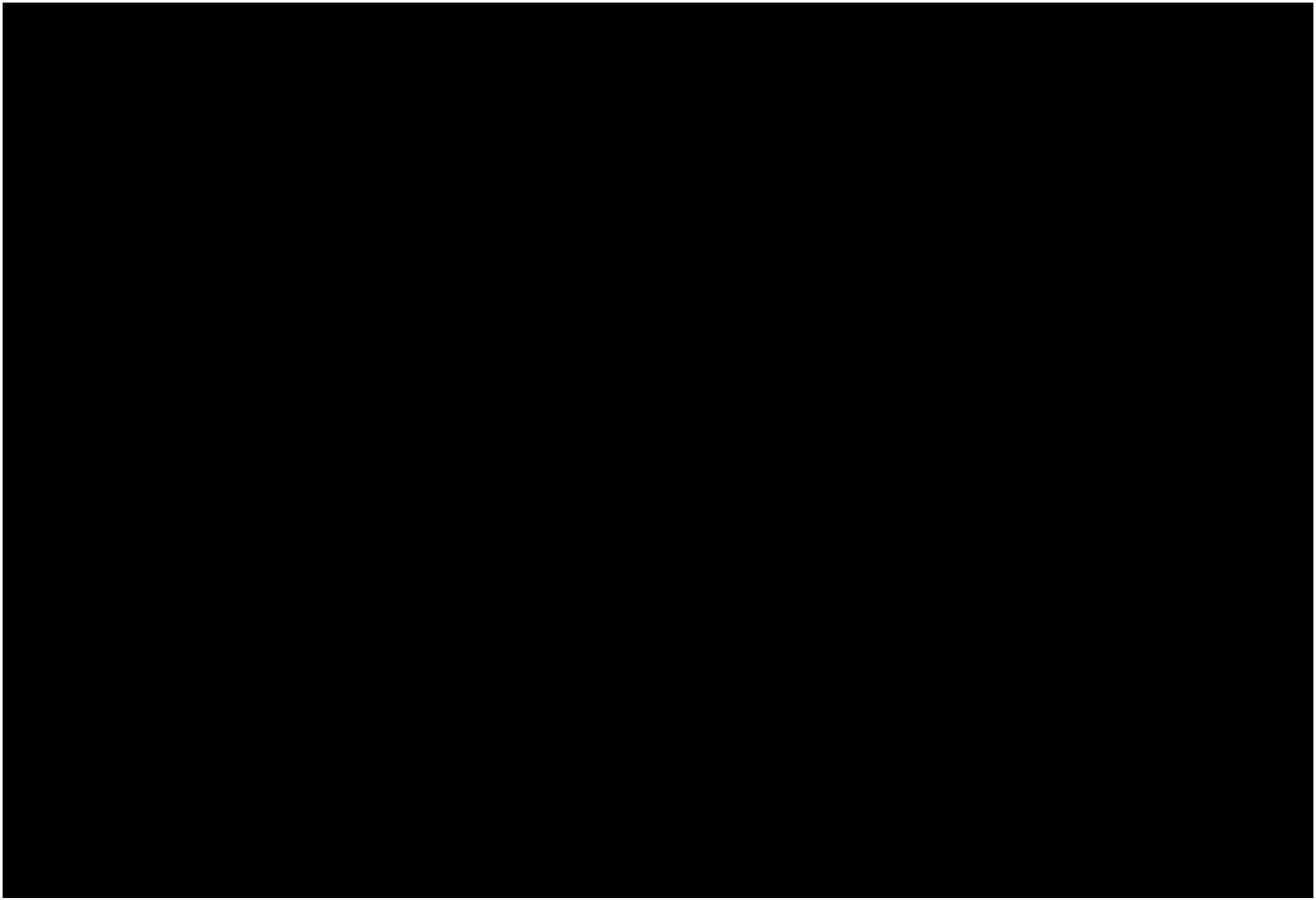
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Big Horn Rural Electric Company

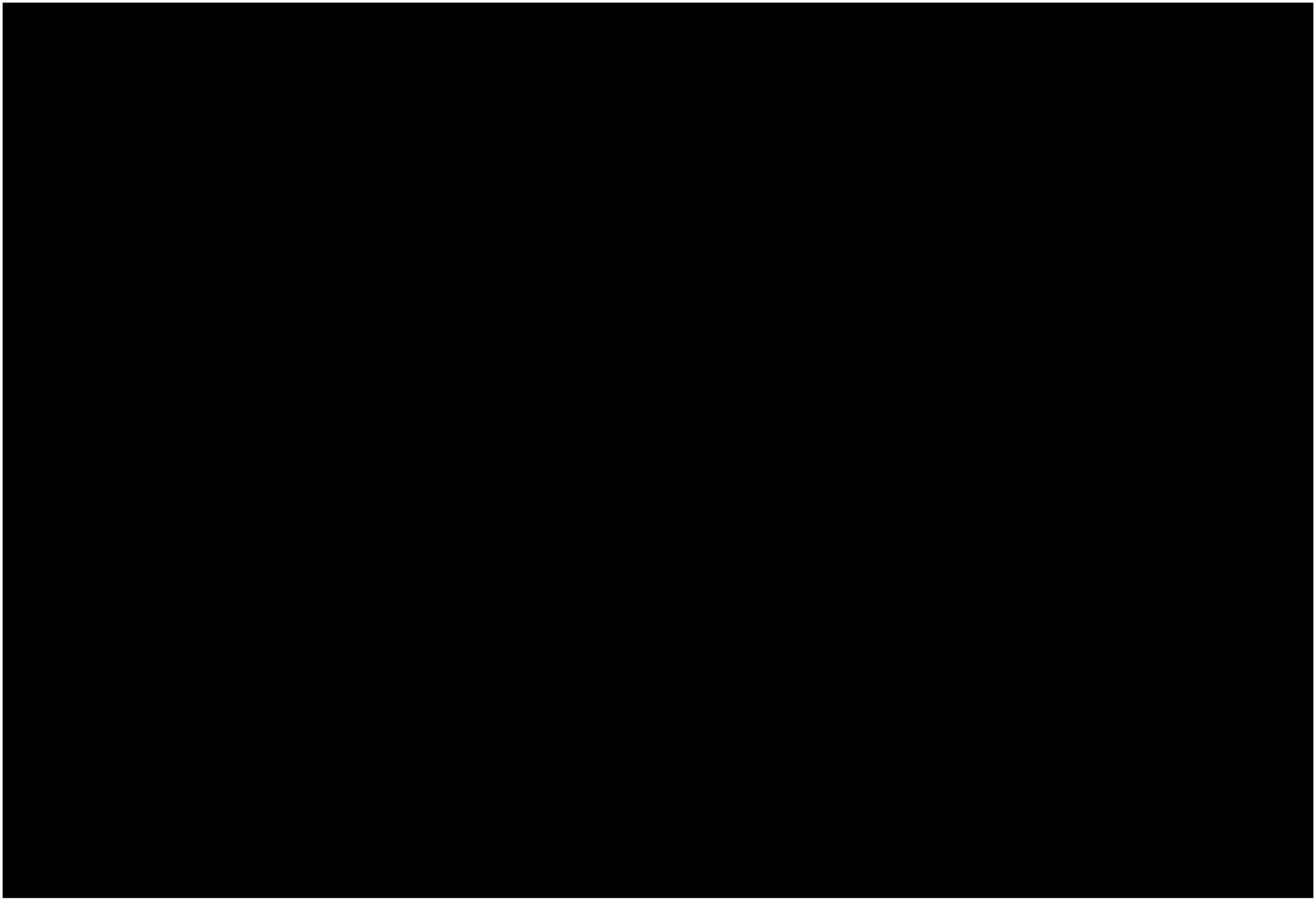
Date of Off Peak Day - 05/23/2021



Member Forecasted Off Peak Demand Day for June 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 06/02/2021



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Member Forecasted Off Peak Demand Day for July 2021

Big Horn Rural Electric Company

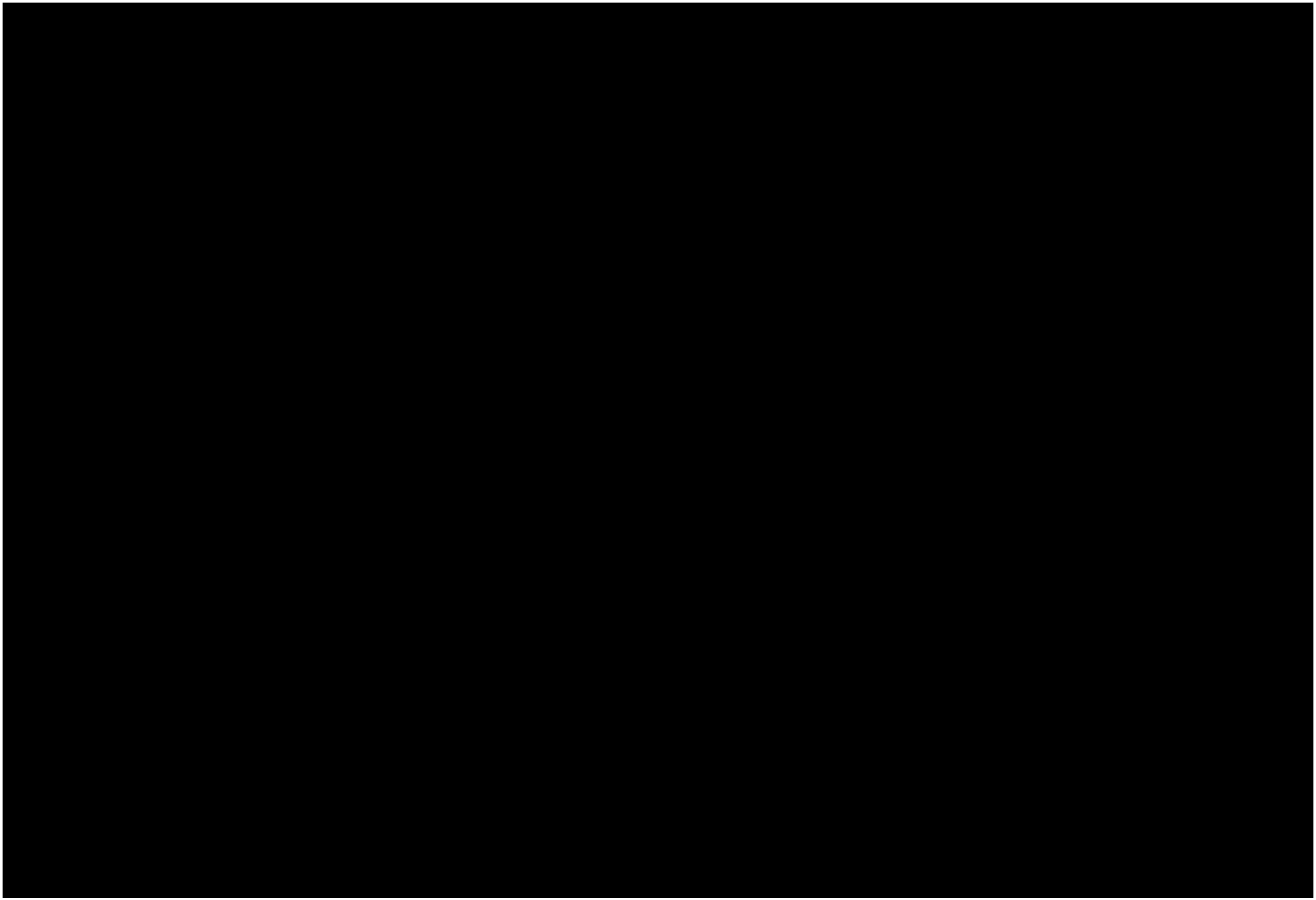
Date of Off Peak Day - 07/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Big Horn Rural Electric Company

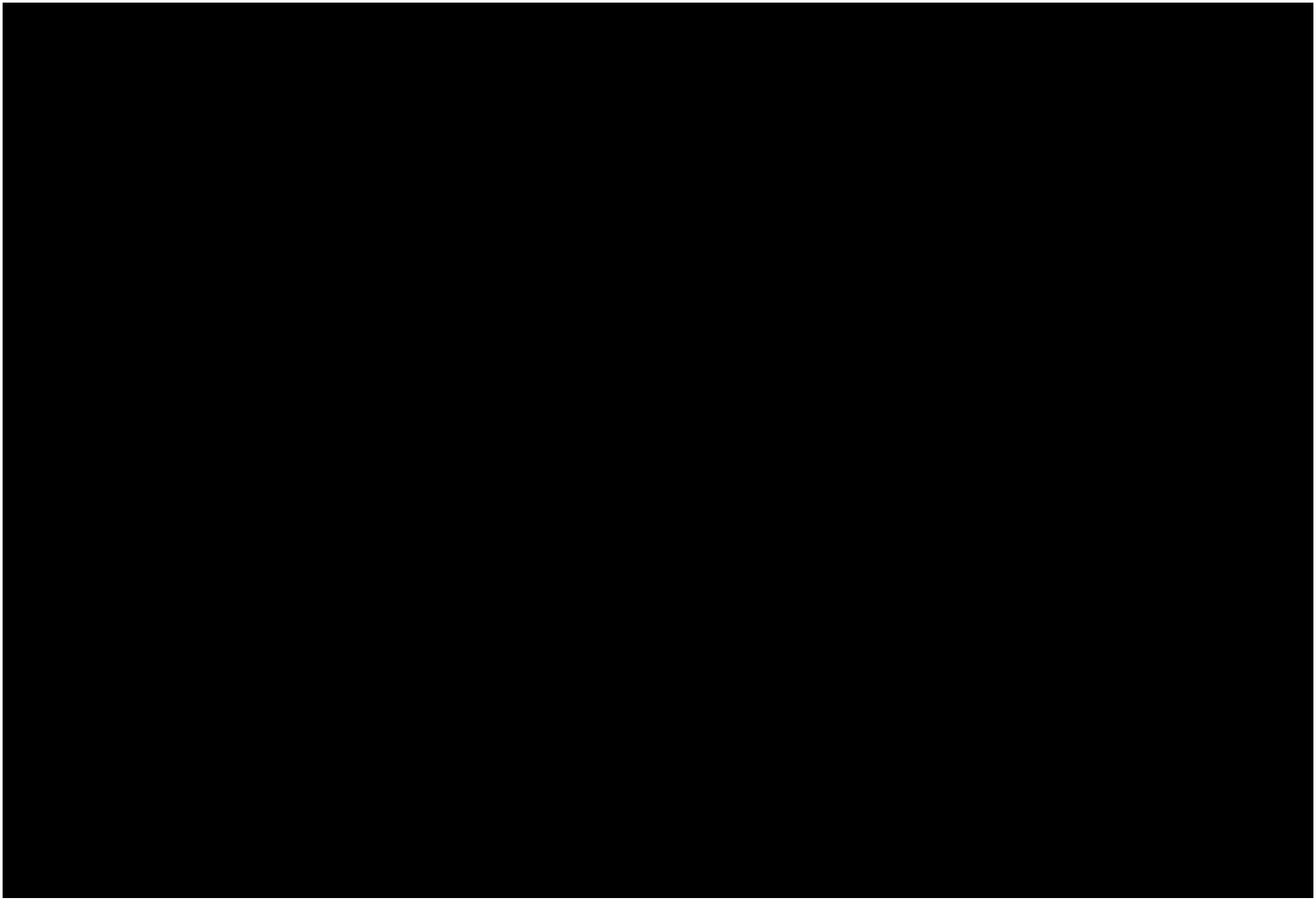
Date of Off Peak Day - 08/18/2021



Member Forecasted Off Peak Demand Day for September 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 09/17/2021



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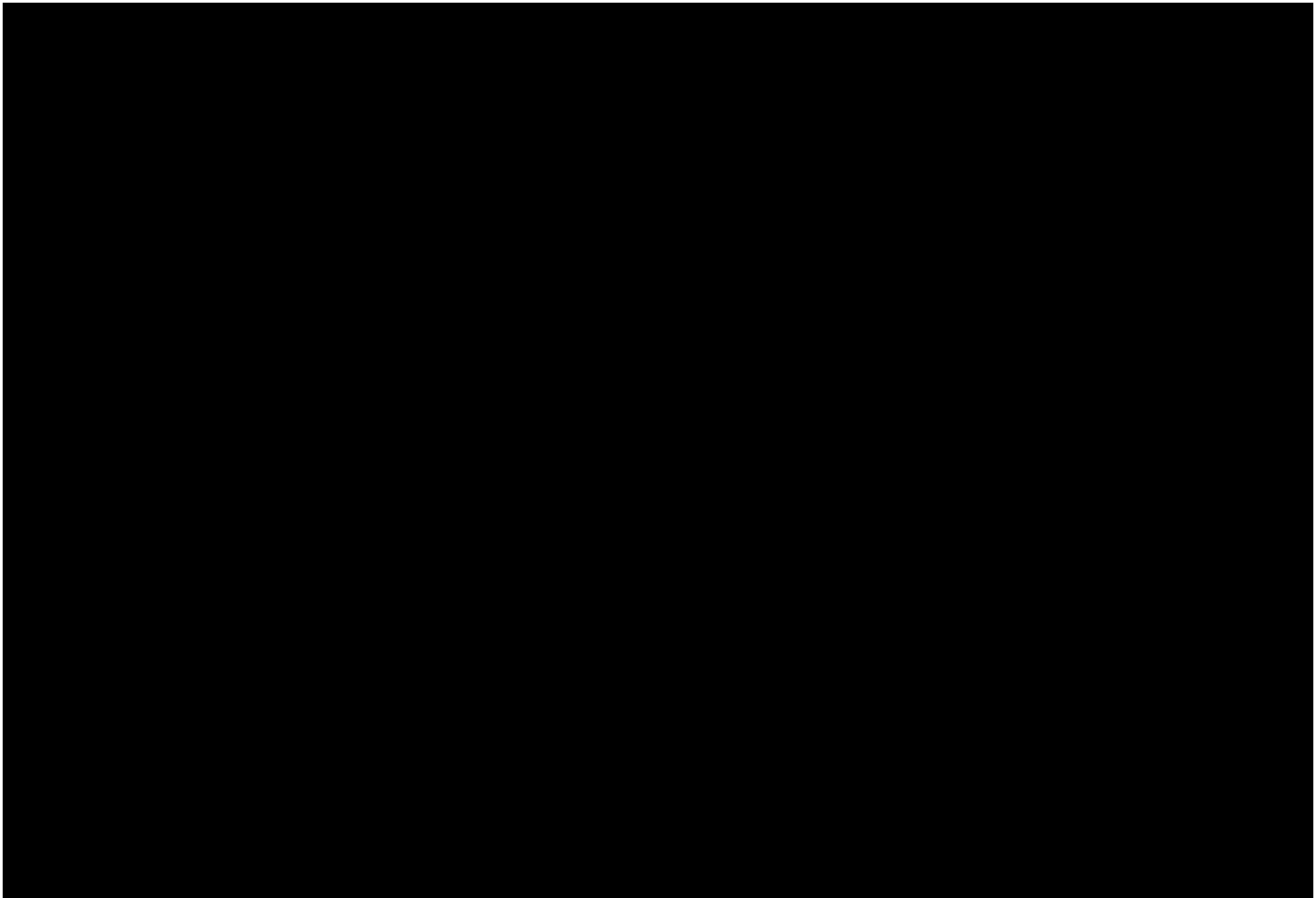
Member Forecasted Off Peak Demand Day for October 2021

Big Horn Rural Electric Company

Date of Off Peak Day - 10/07/2021



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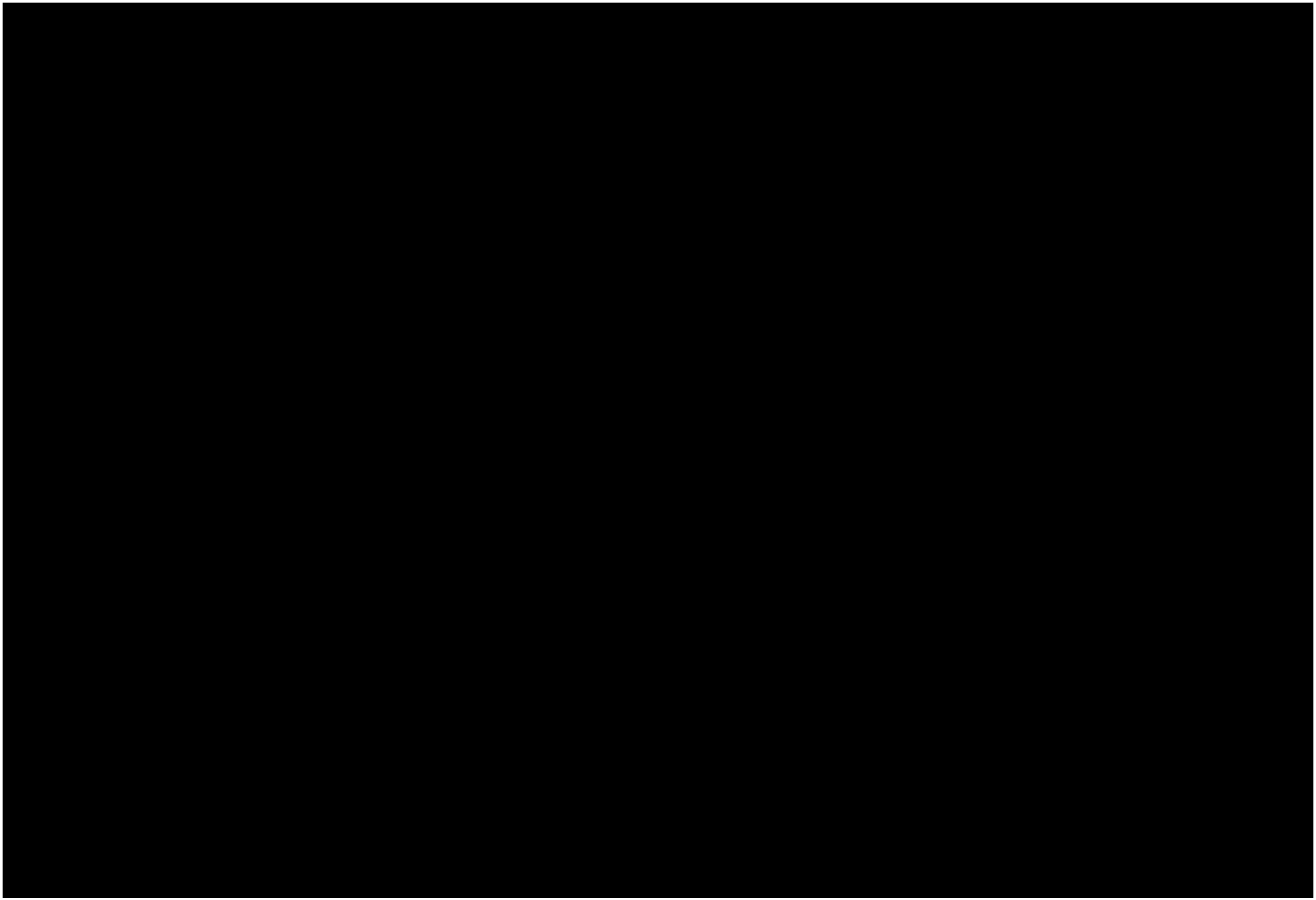
Member Forecasted Off Peak Demand Day for November 2021

Big Horn Rural Electric Company

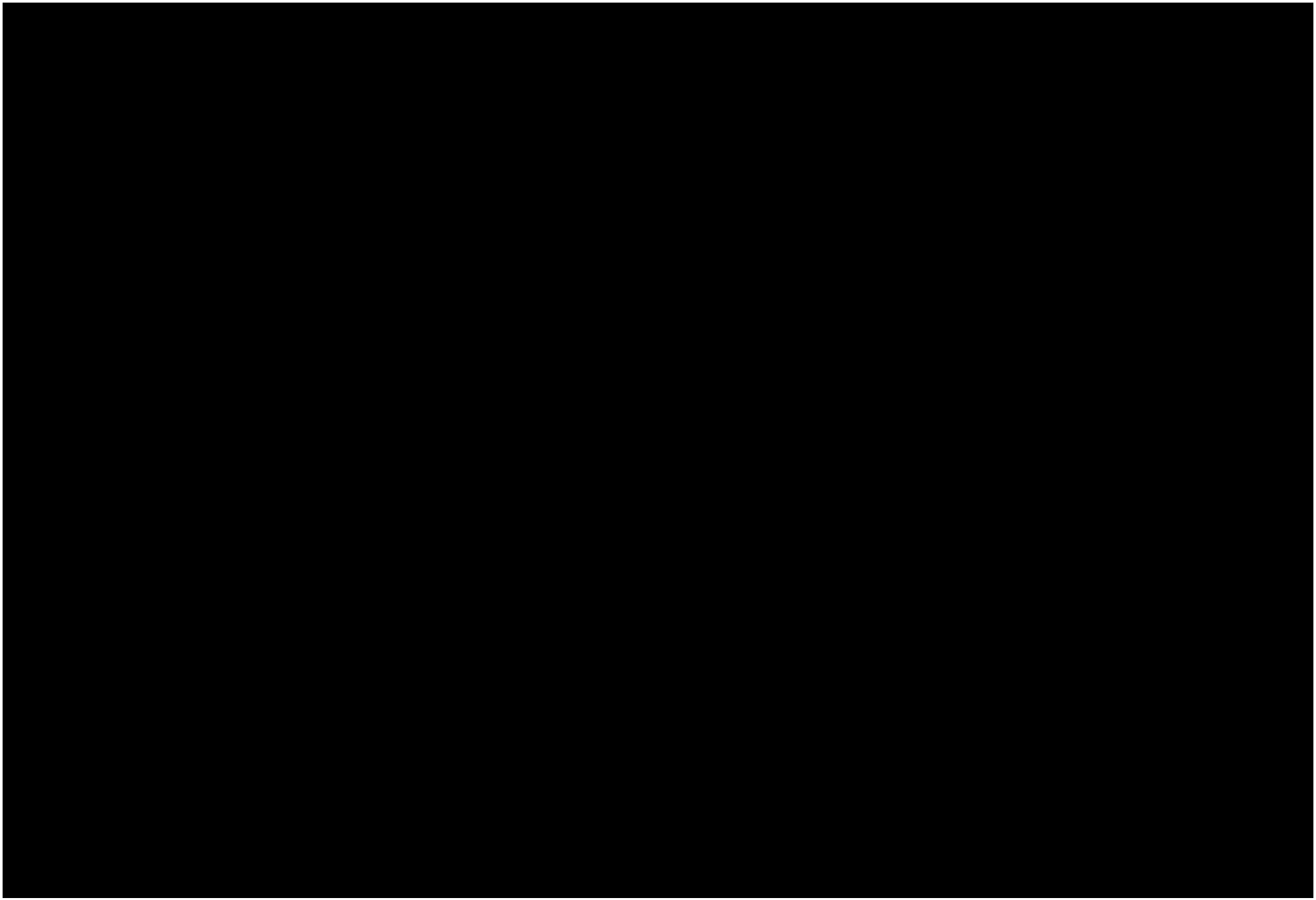
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Big Horn Rural Electric Company

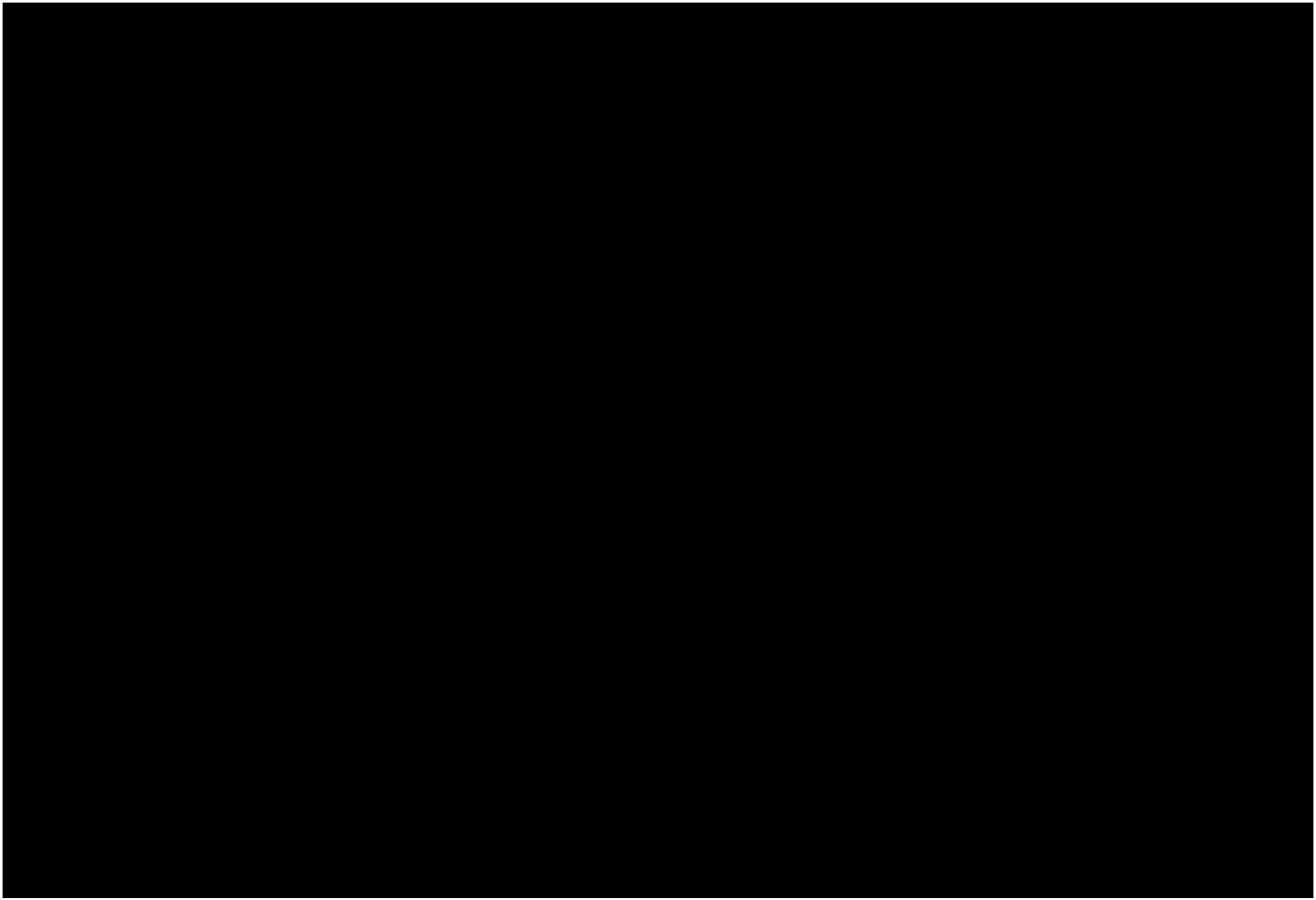
Date of Off Peak Day - 12/04/2021



Member Forecasted Off Peak Demand Day for January 2021

Carbon Power and Light, Inc.

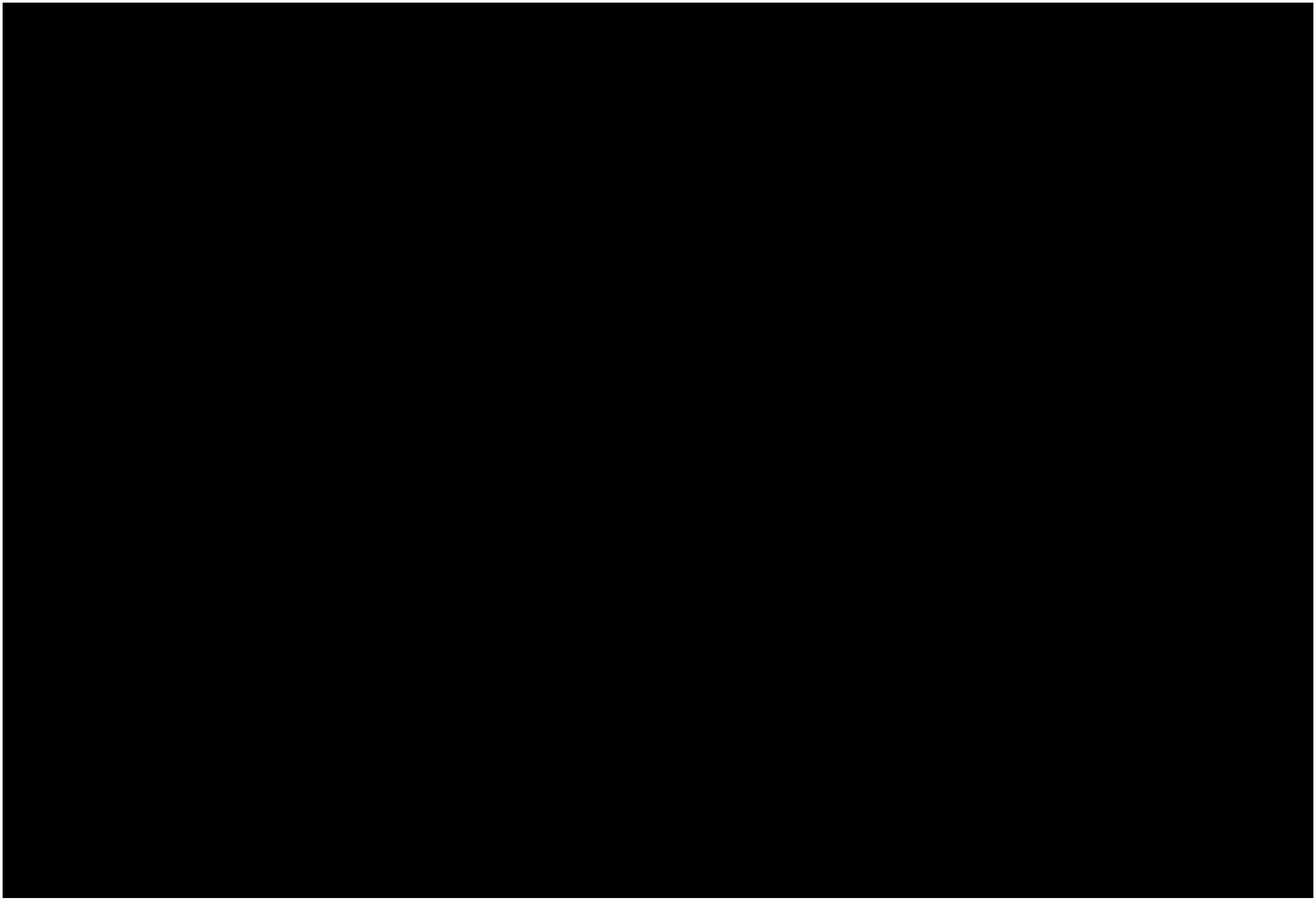
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Carbon Power and Light, Inc.

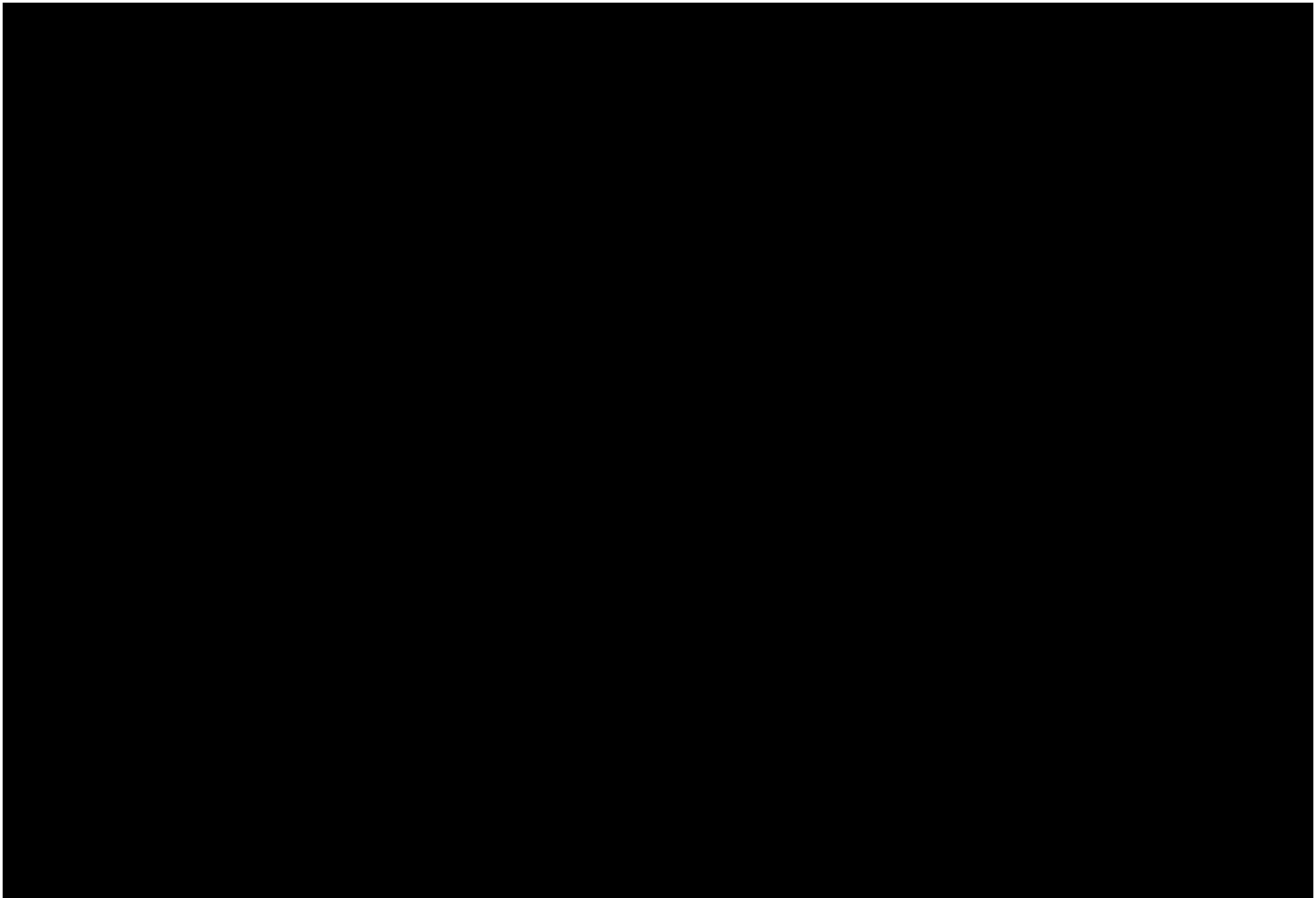
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Carbon Power and Light, Inc.

Date of Off Peak Day - 03/21/2021



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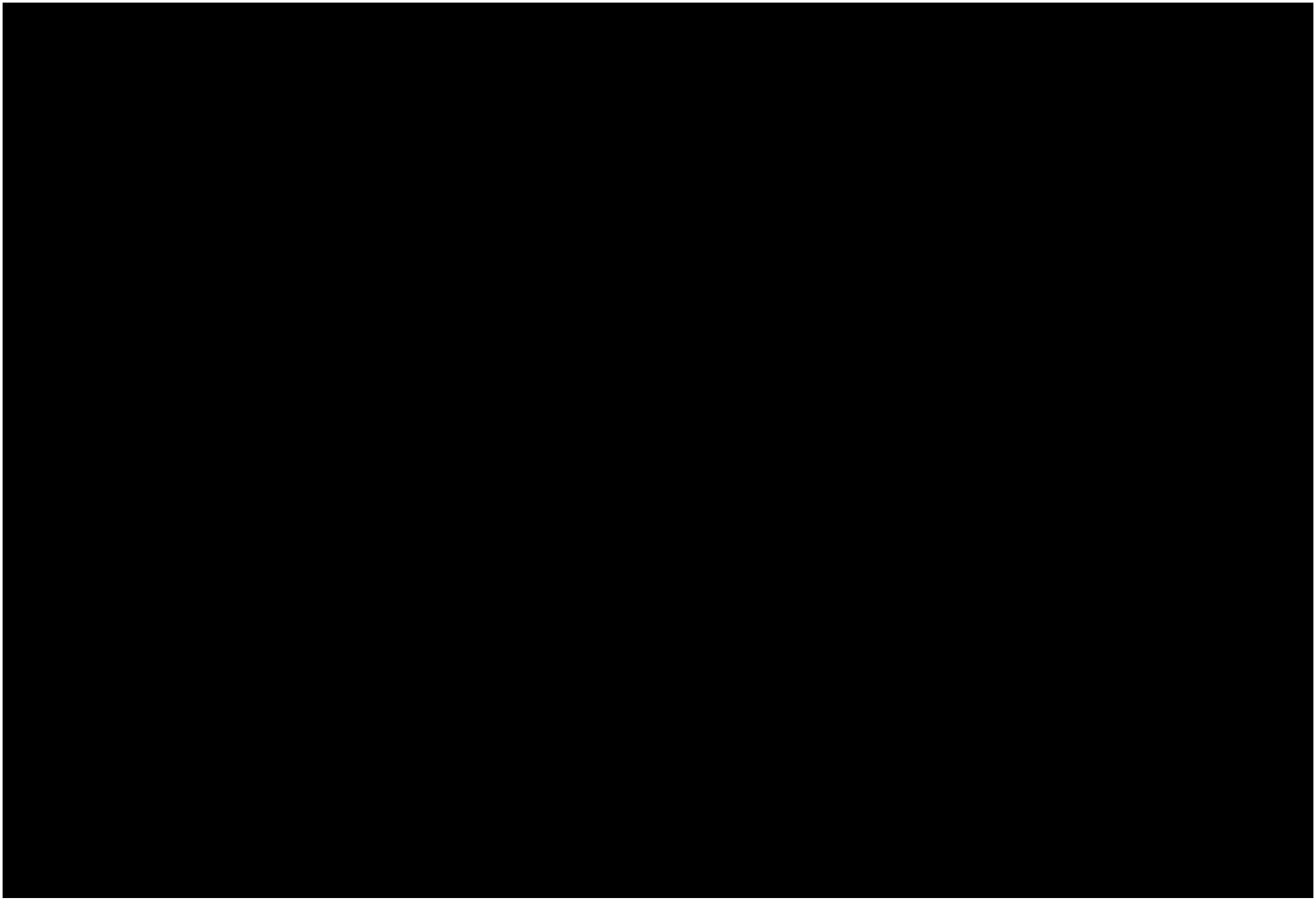
Member Forecasted Off Peak Demand Day for April 2021

Carbon Power and Light, Inc.

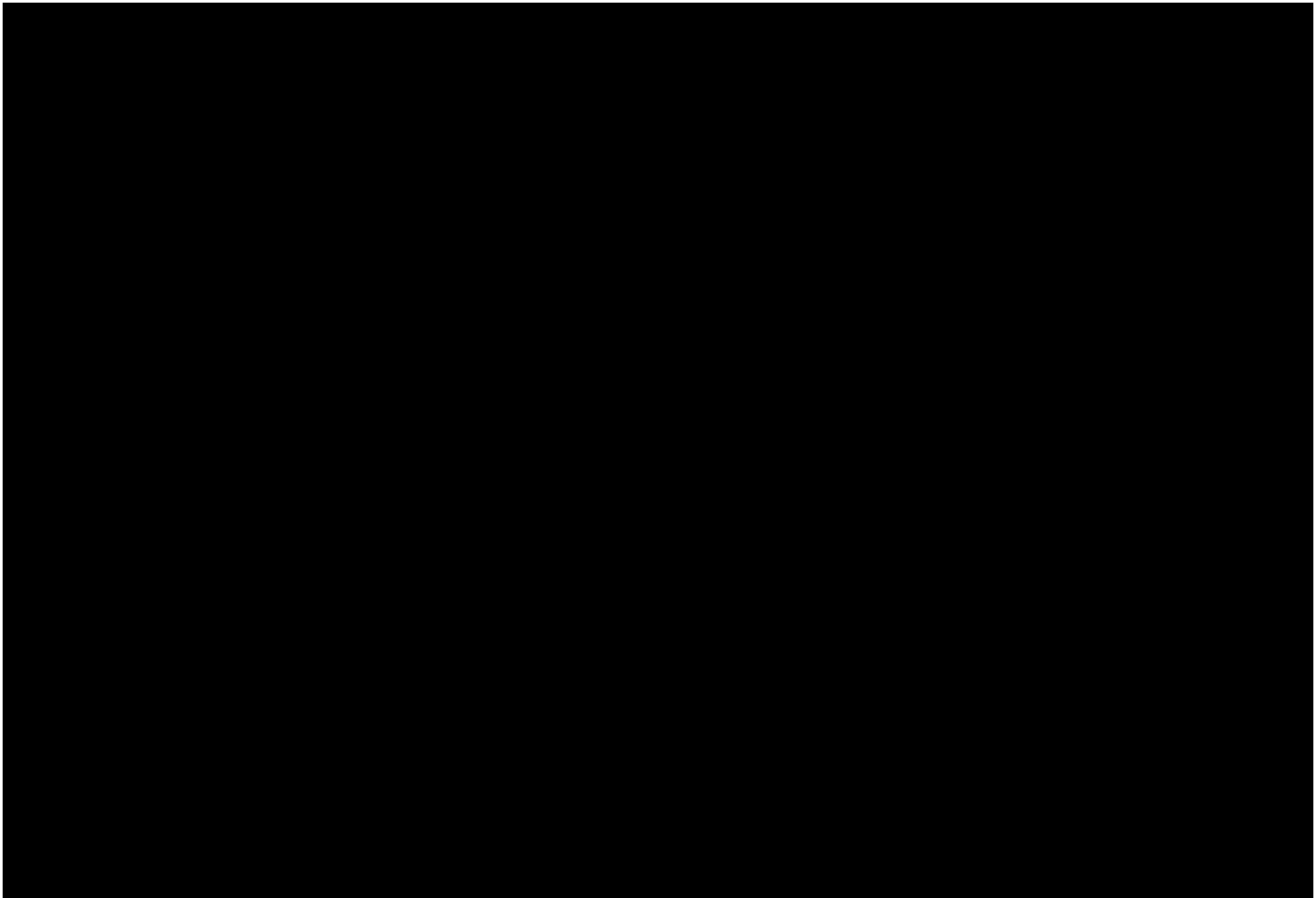
Date of Off Peak Day - 04/28/2021



Member Forecasted Off Peak Demand Day for May 2021

Carbon Power and Light, Inc.

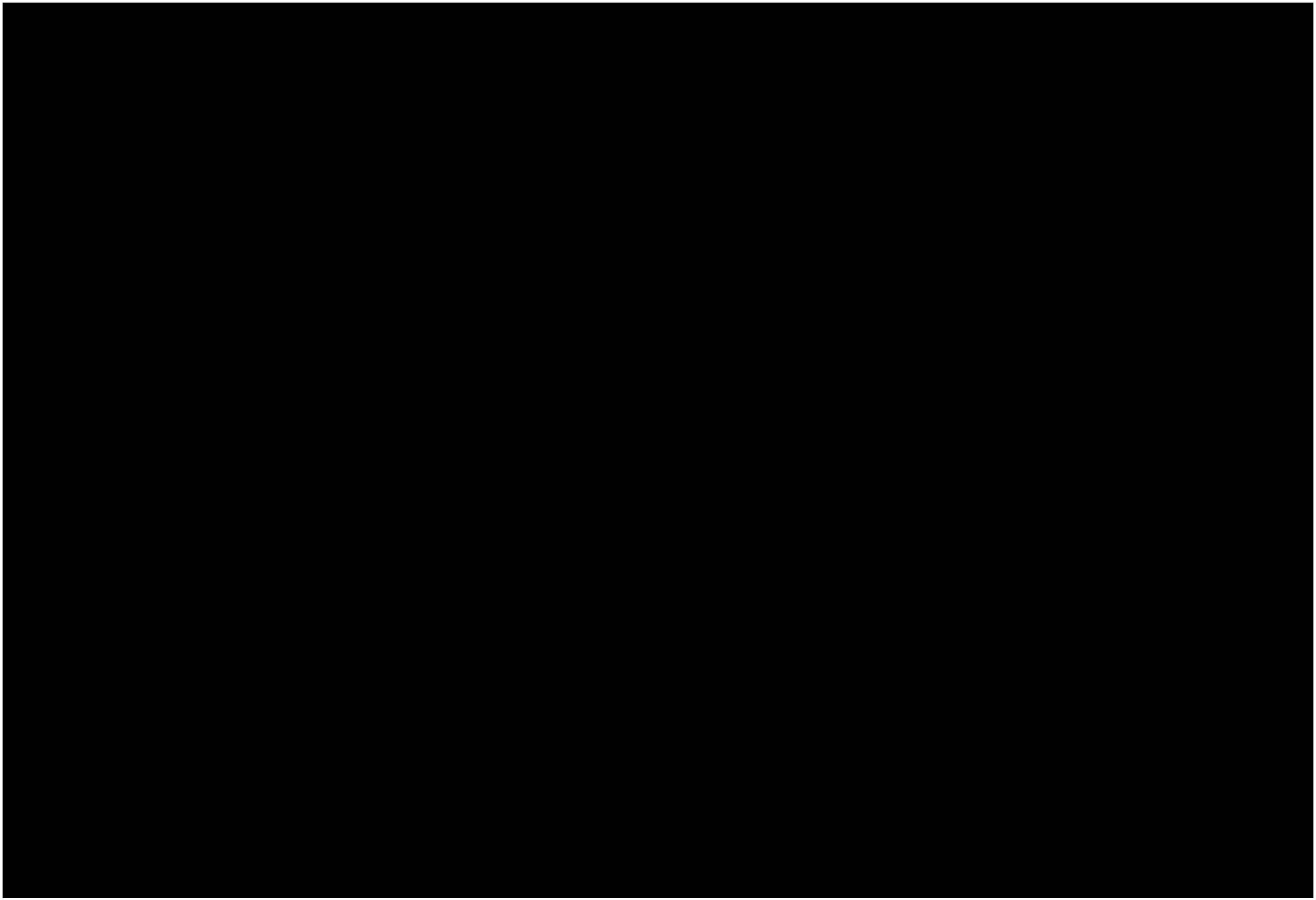
Date of Off Peak Day - 05/04/2021



Member Forecasted Off Peak Demand Day for June 2021

Carbon Power and Light, Inc.

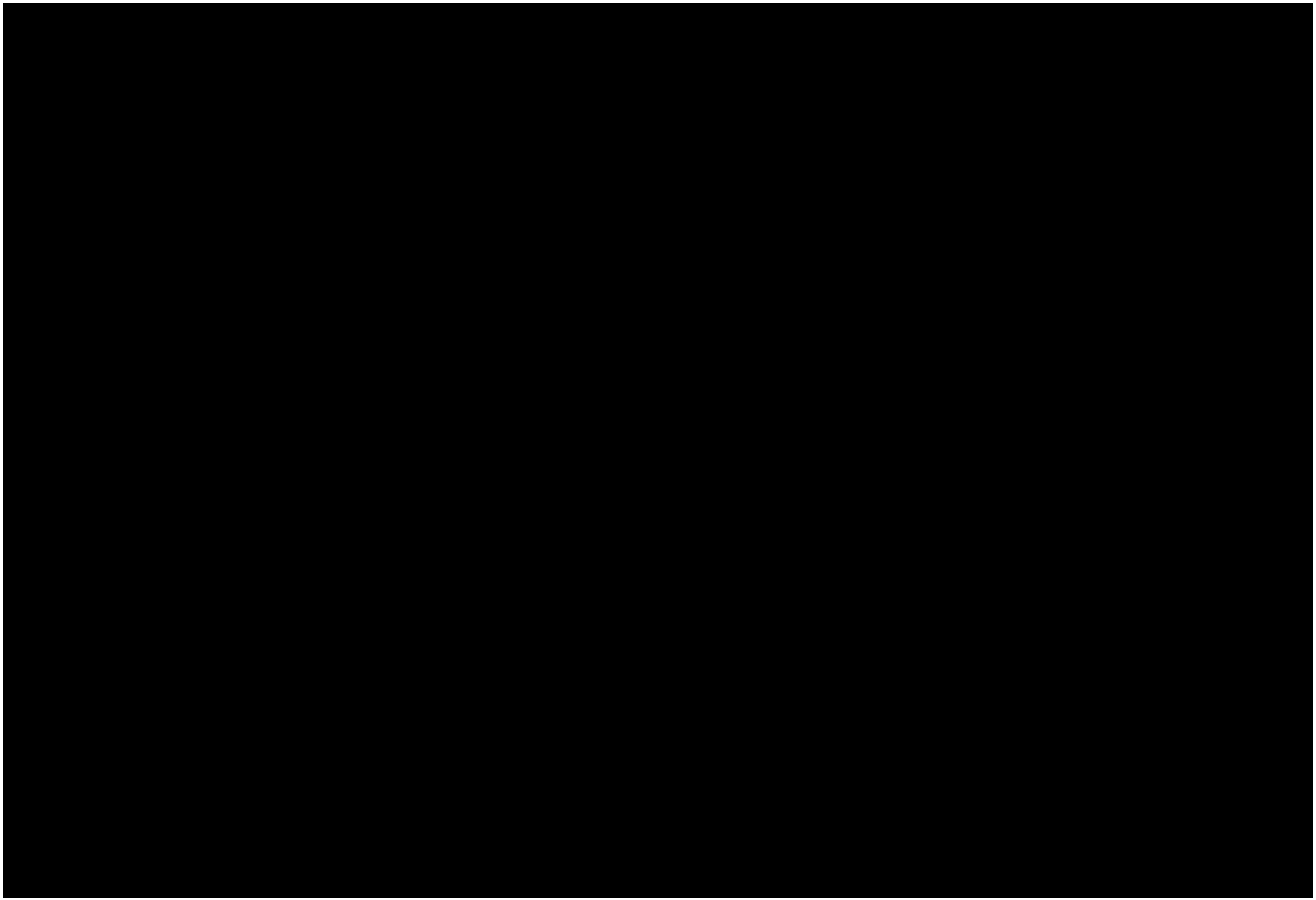
Date of Off Peak Day - 06/07/2021



Member Forecasted Off Peak Demand Day for July 2021

Carbon Power and Light, Inc.

Date of Off Peak Day - 07/04/2021



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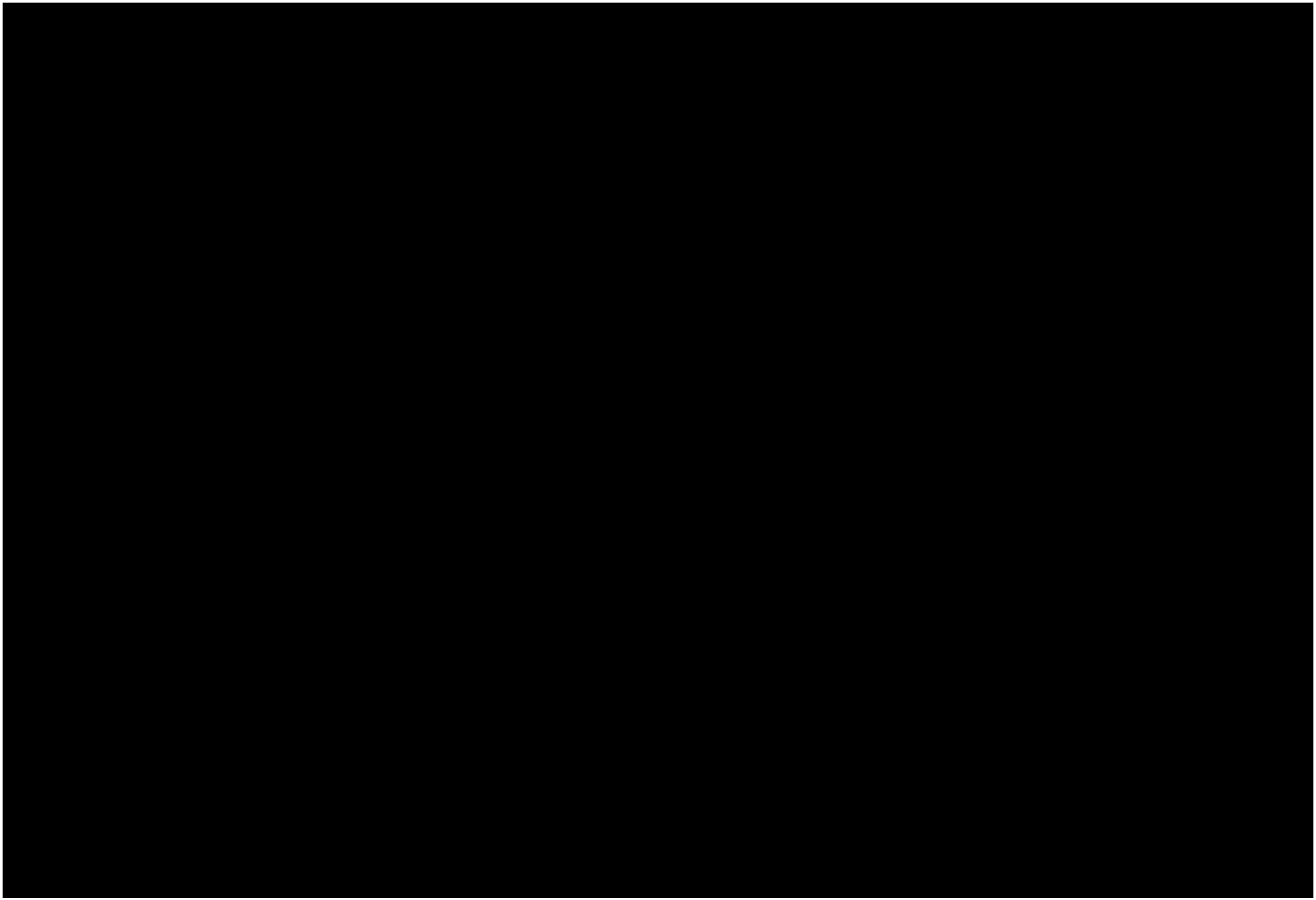
Member Forecasted Off Peak Demand Day for August 2021

Carbon Power and Light, Inc.

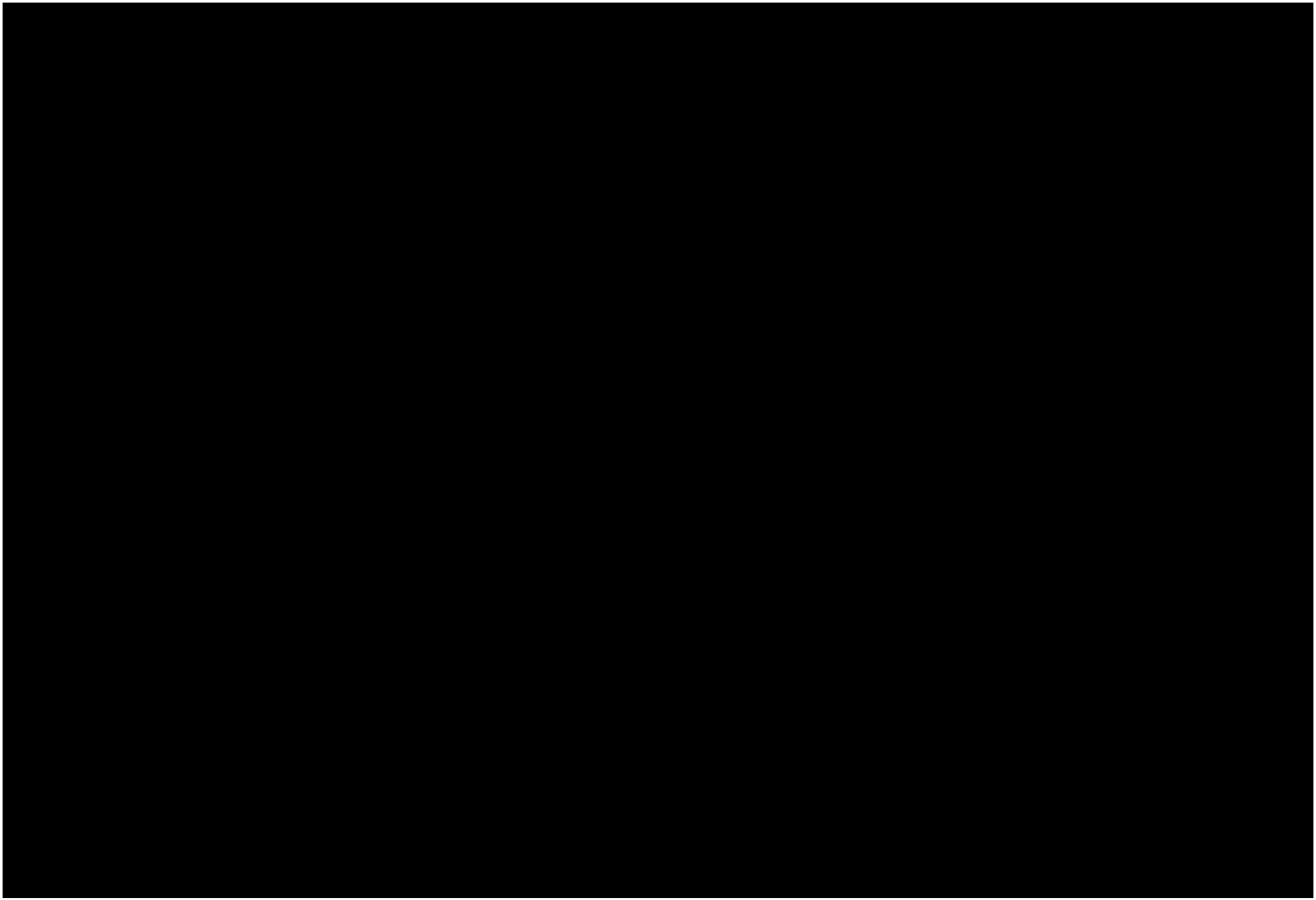
Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Carbon Power and Light, Inc.

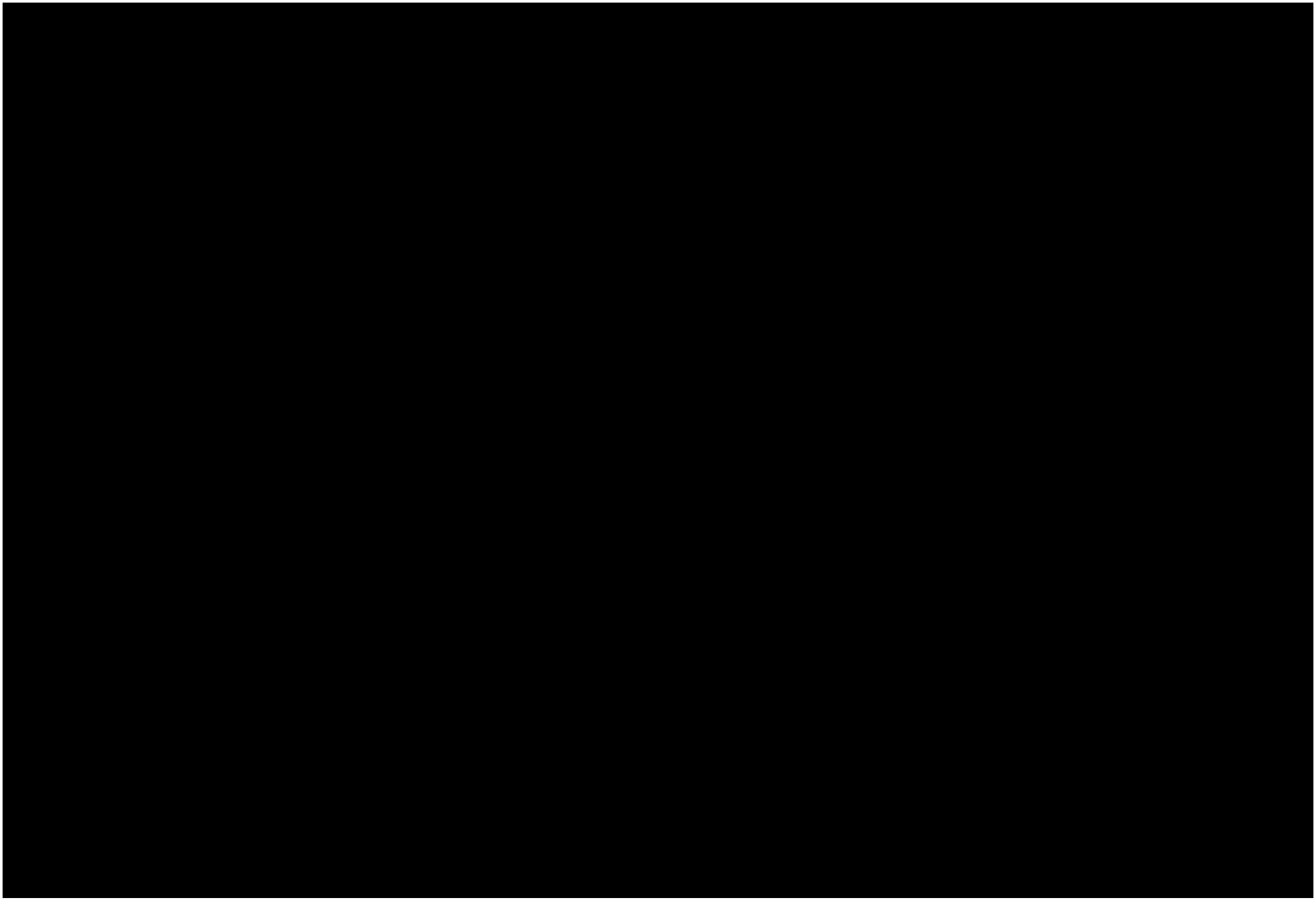
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Carbon Power and Light, Inc.

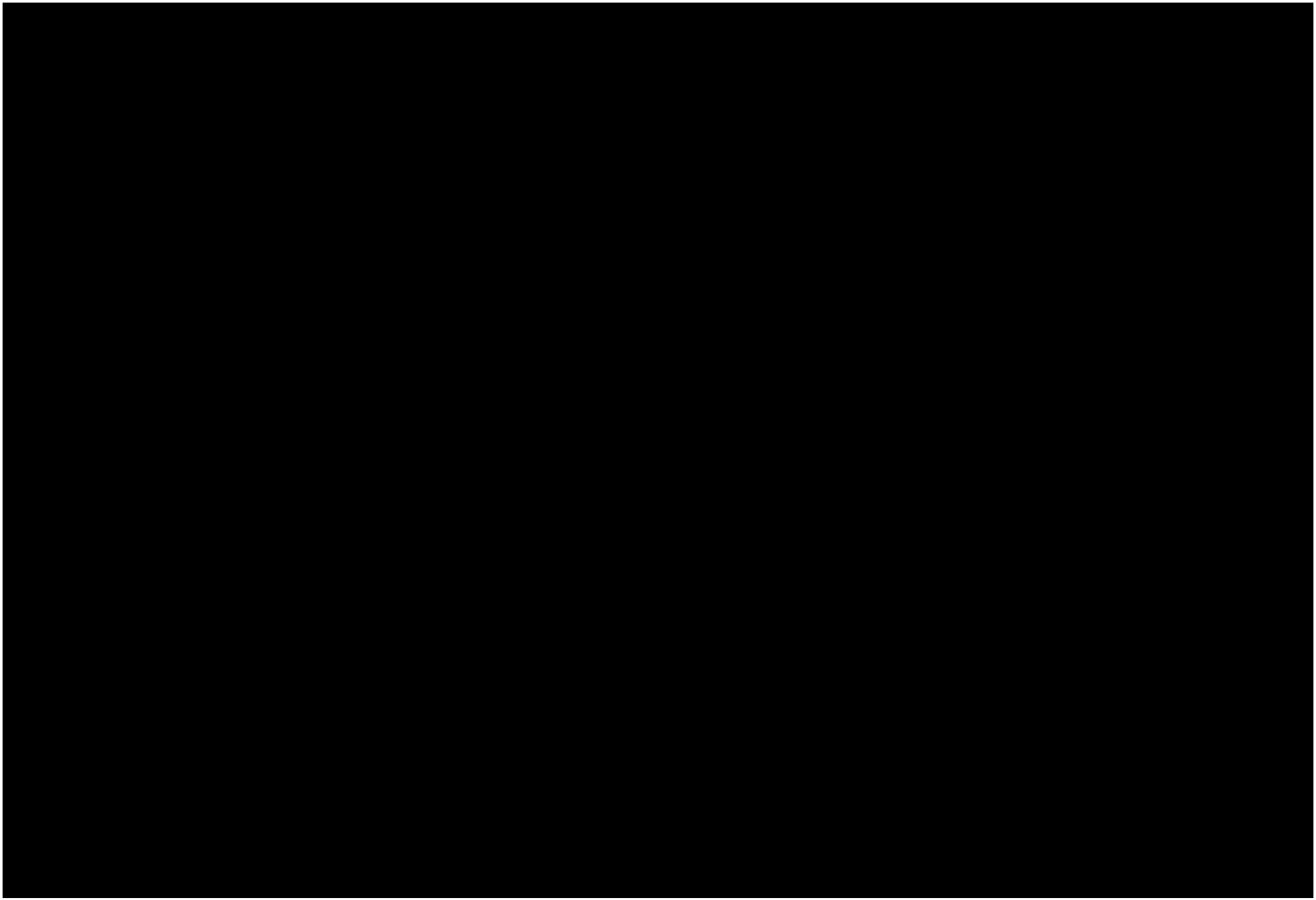
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Carbon Power and Light, Inc.

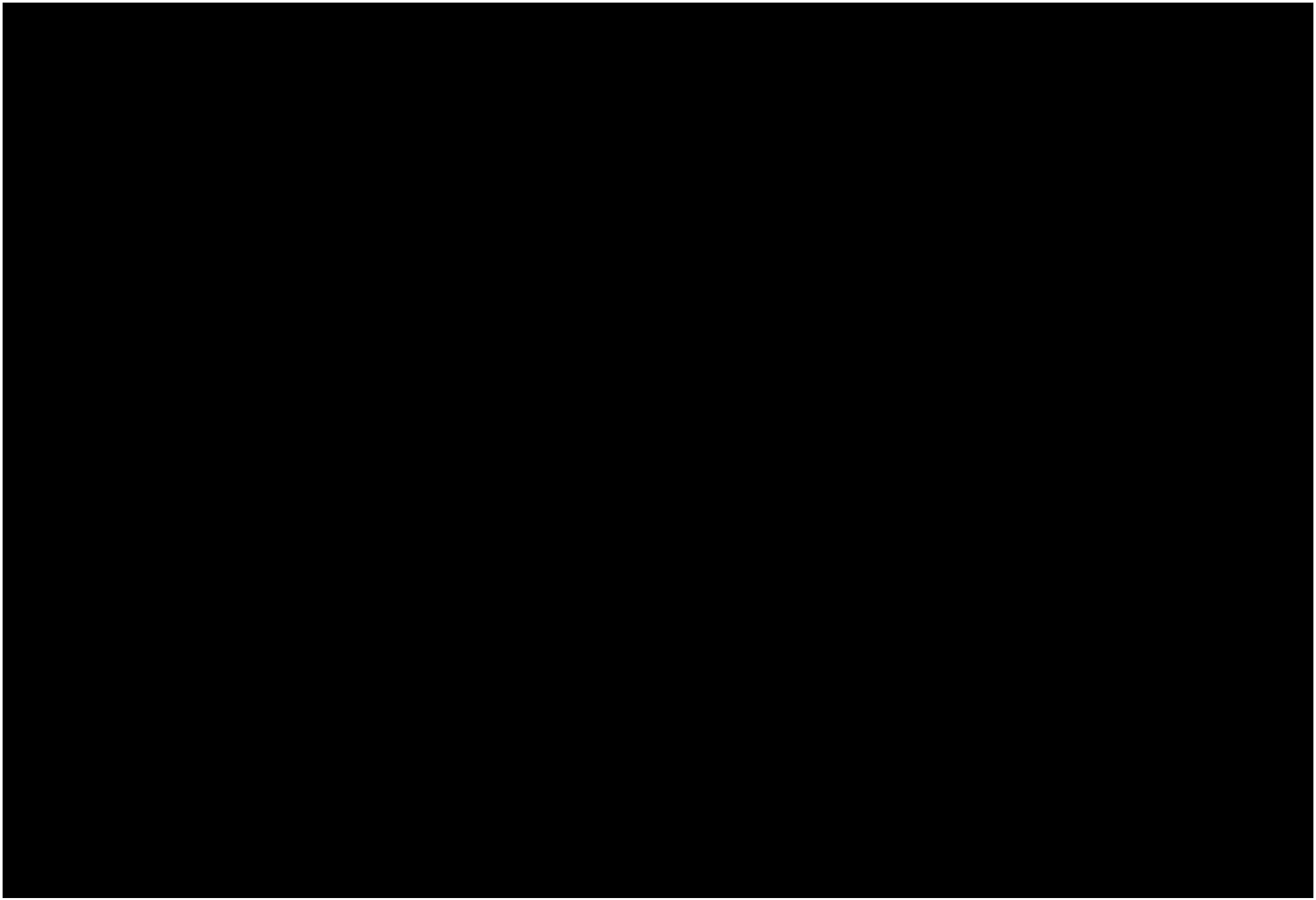
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Carbon Power and Light, Inc.

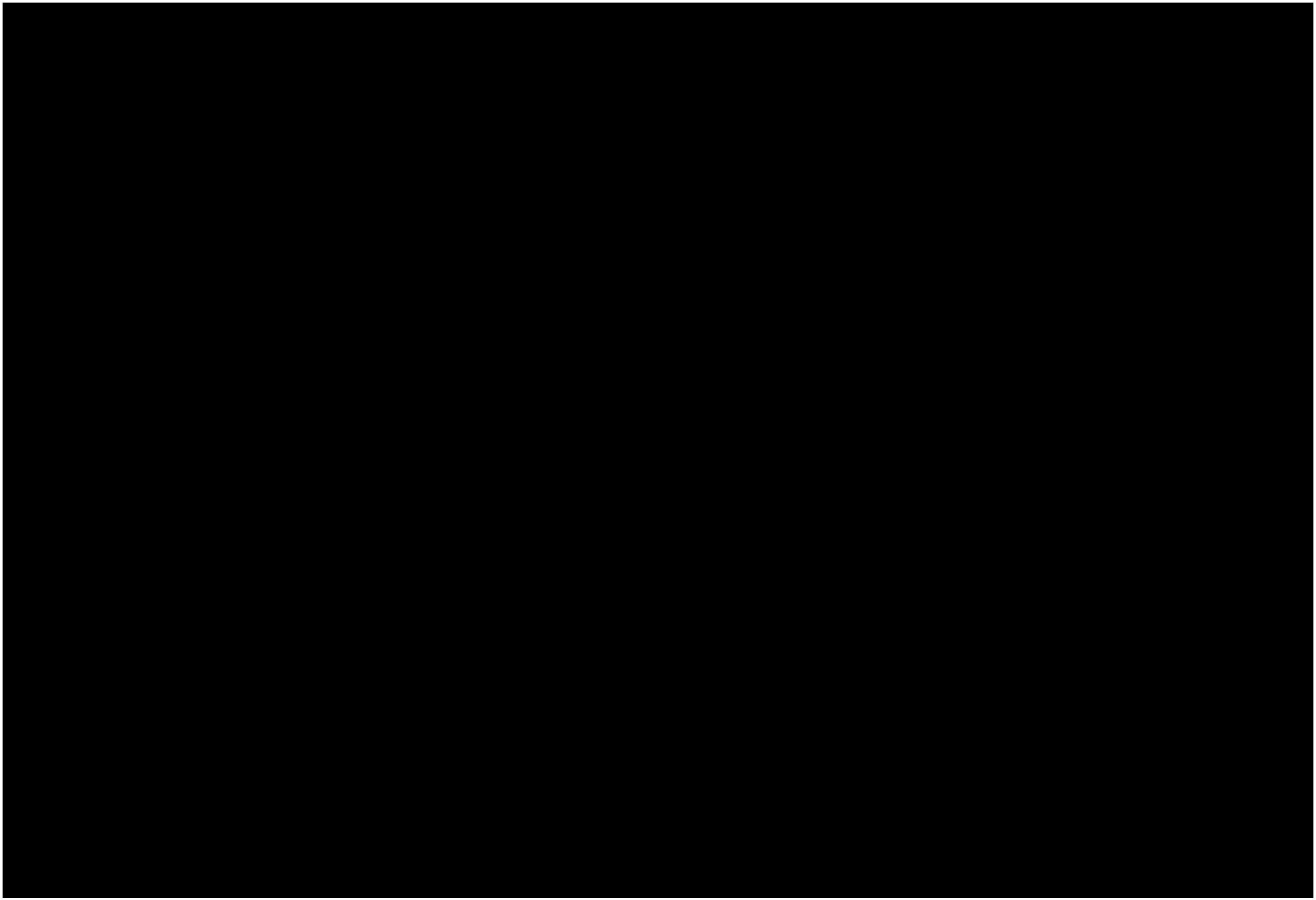
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Continental Divide Electric Cooperative, Inc.

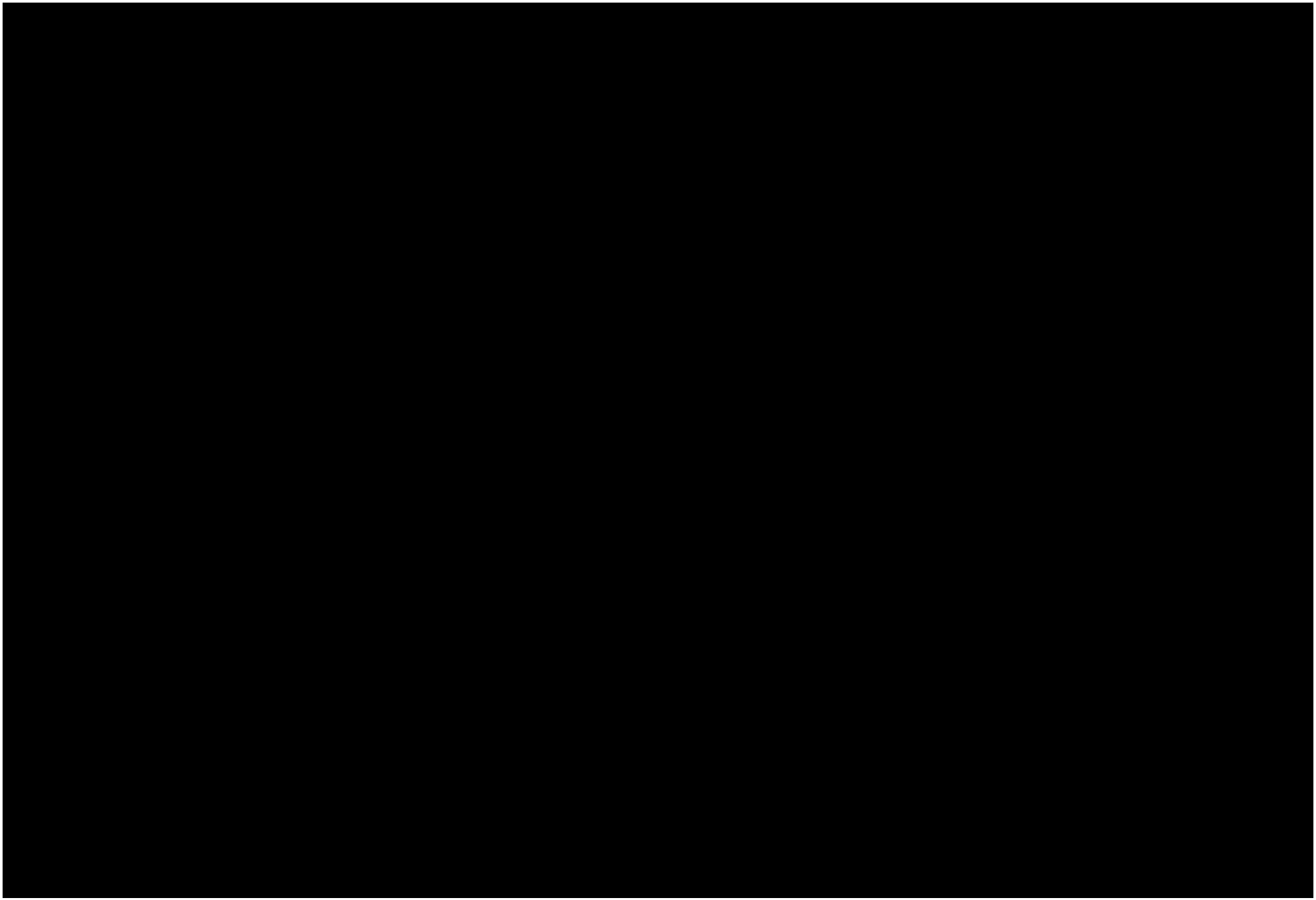
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Continental Divide Electric Cooperative, Inc.

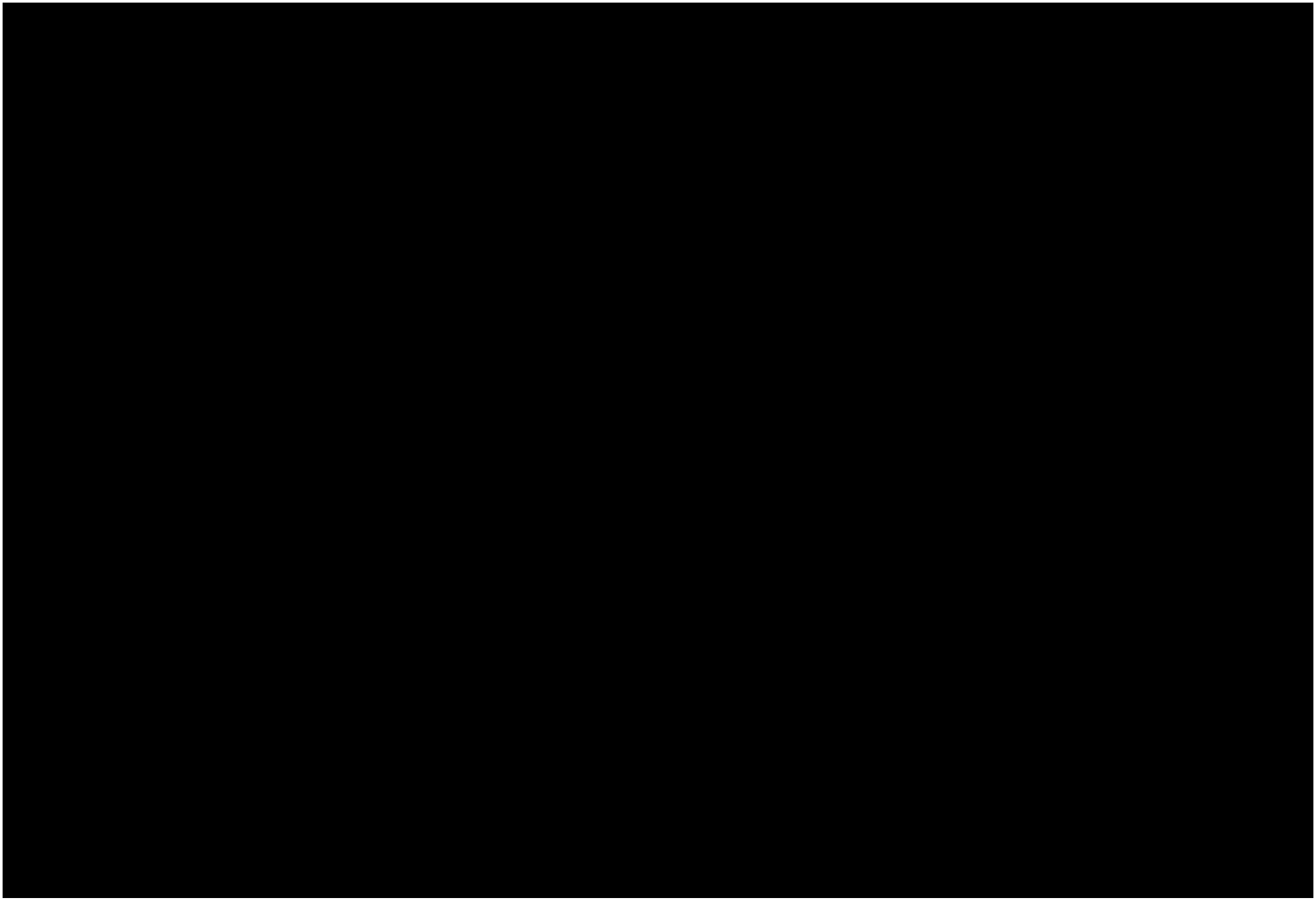
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Continental Divide Electric Cooperative, Inc.

Date of Off Peak Day - 03/31/2021



Member Forecasted Off Peak Demand Day for April 2021

Continental Divide Electric Cooperative, Inc.

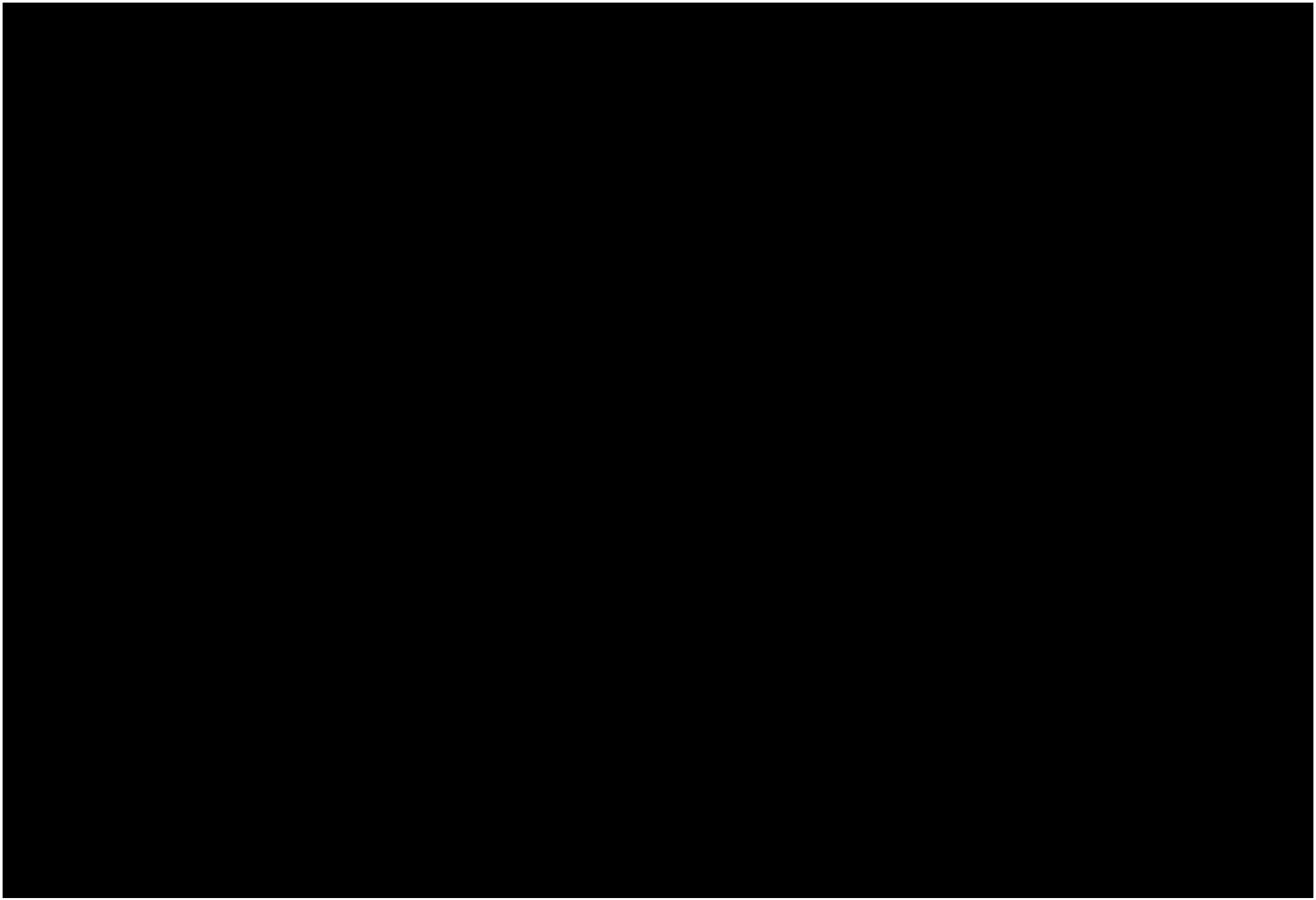
Date of Off Peak Day - 04/10/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Continental Divide Electric Cooperative, Inc.

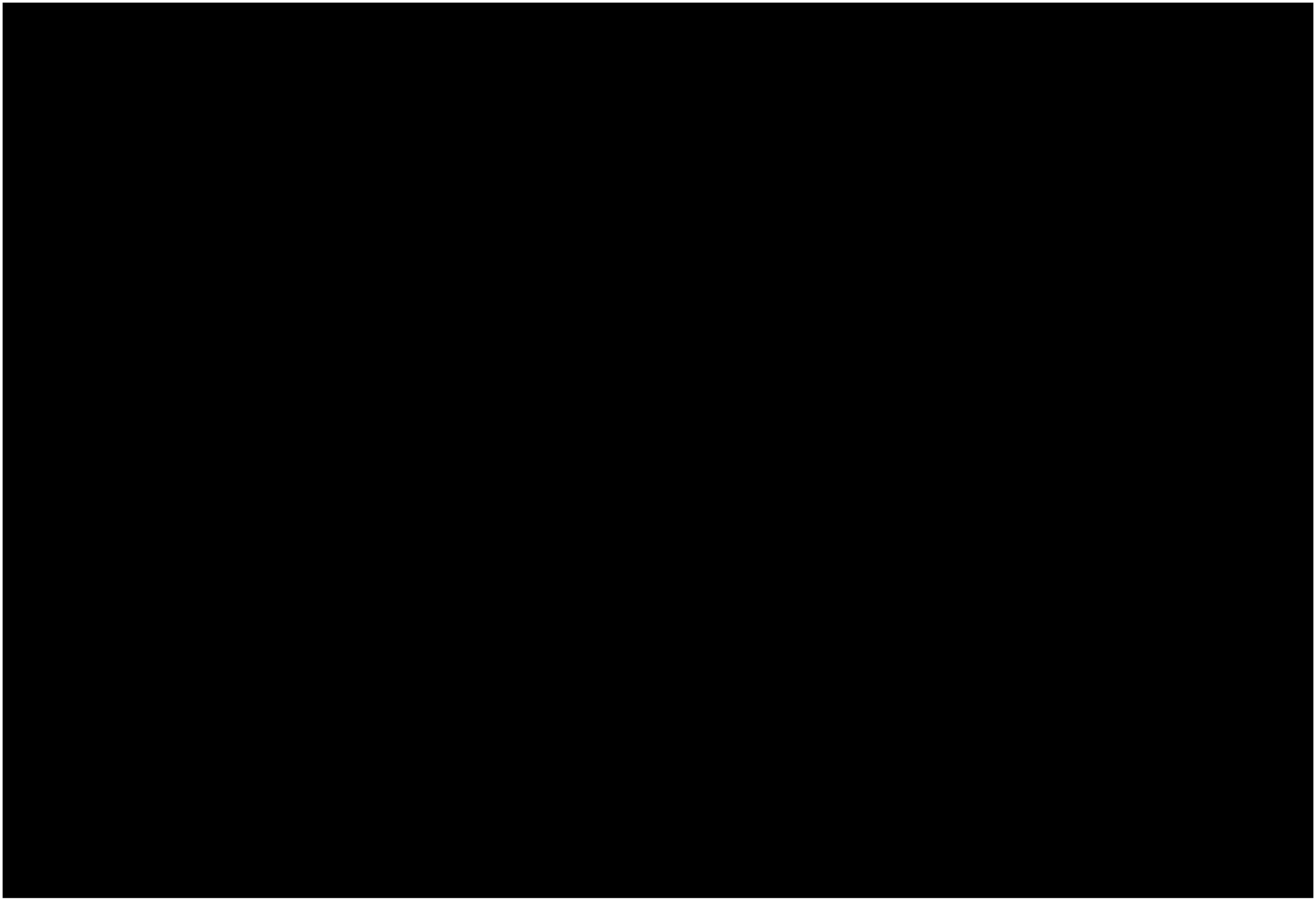
Date of Off Peak Day - 05/23/2021



Member Forecasted Off Peak Demand Day for June 2021

Continental Divide Electric Cooperative, Inc.

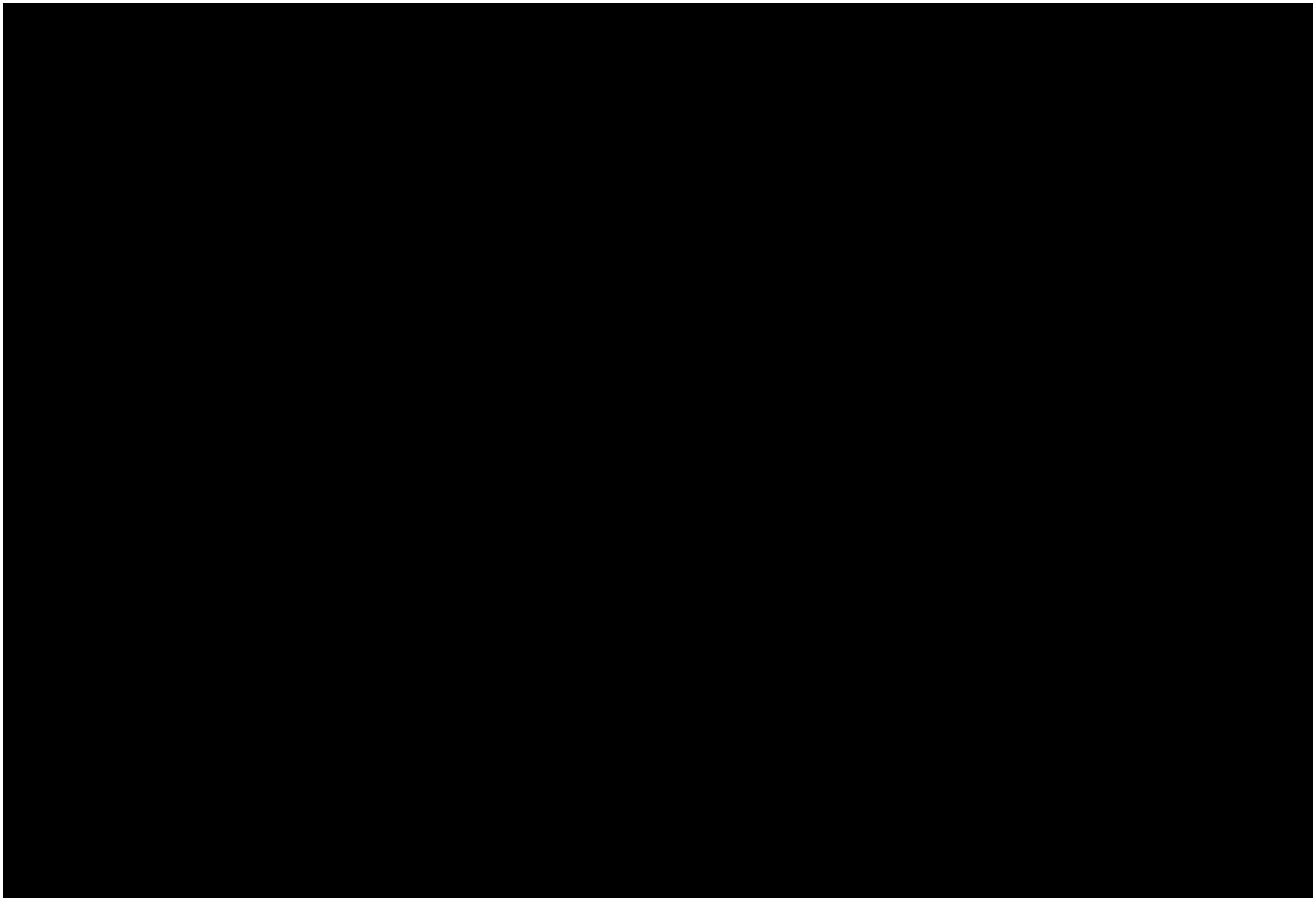
Date of Off Peak Day - 06/13/2021



Member Forecasted Off Peak Demand Day for July 2021

Continental Divide Electric Cooperative, Inc.

Date of Off Peak Day - 07/31/2021



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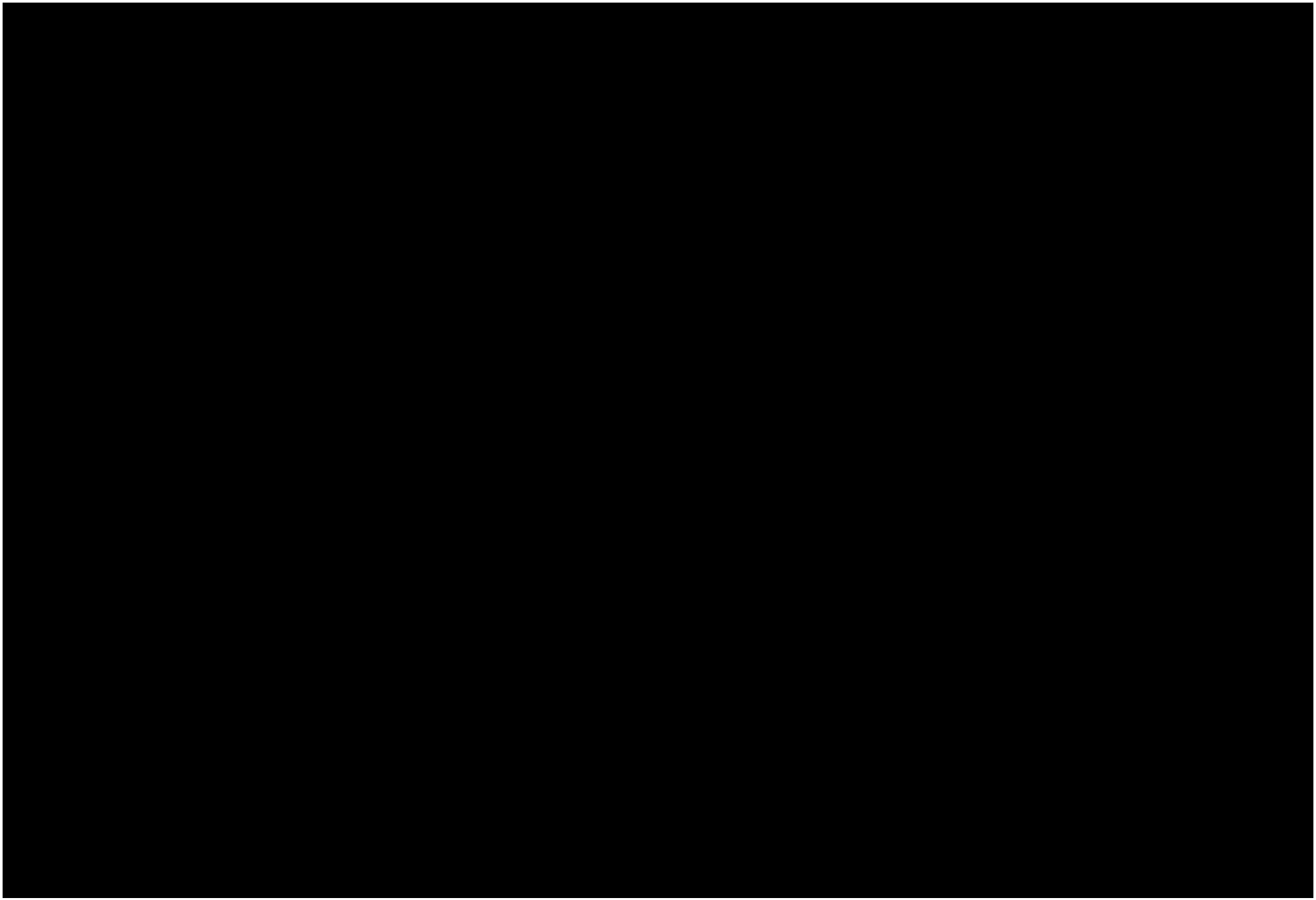
Member Forecasted Off Peak Demand Day for August 2021

Continental Divide Electric Cooperative, Inc.

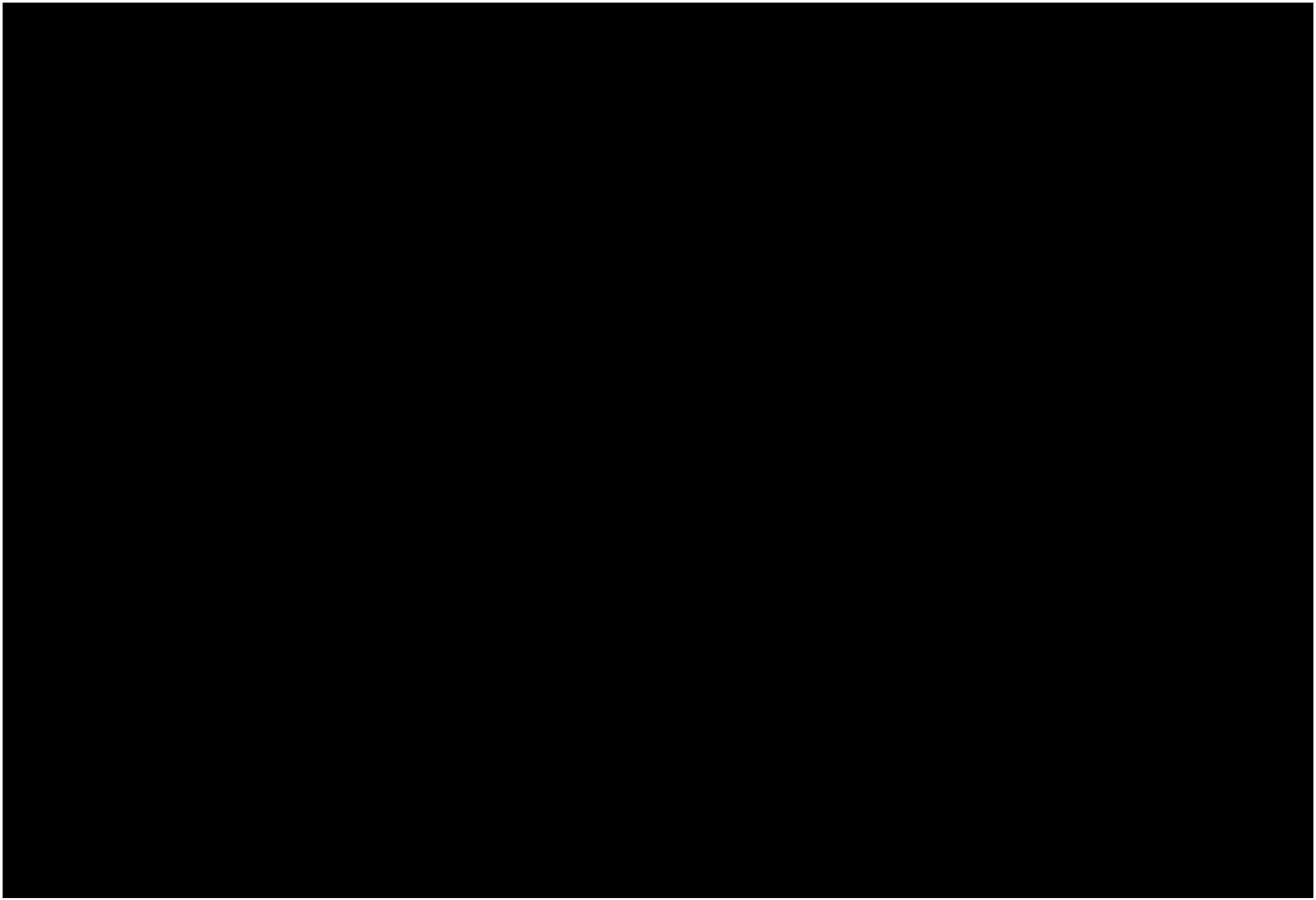
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

Continental Divide Electric Cooperative, Inc.

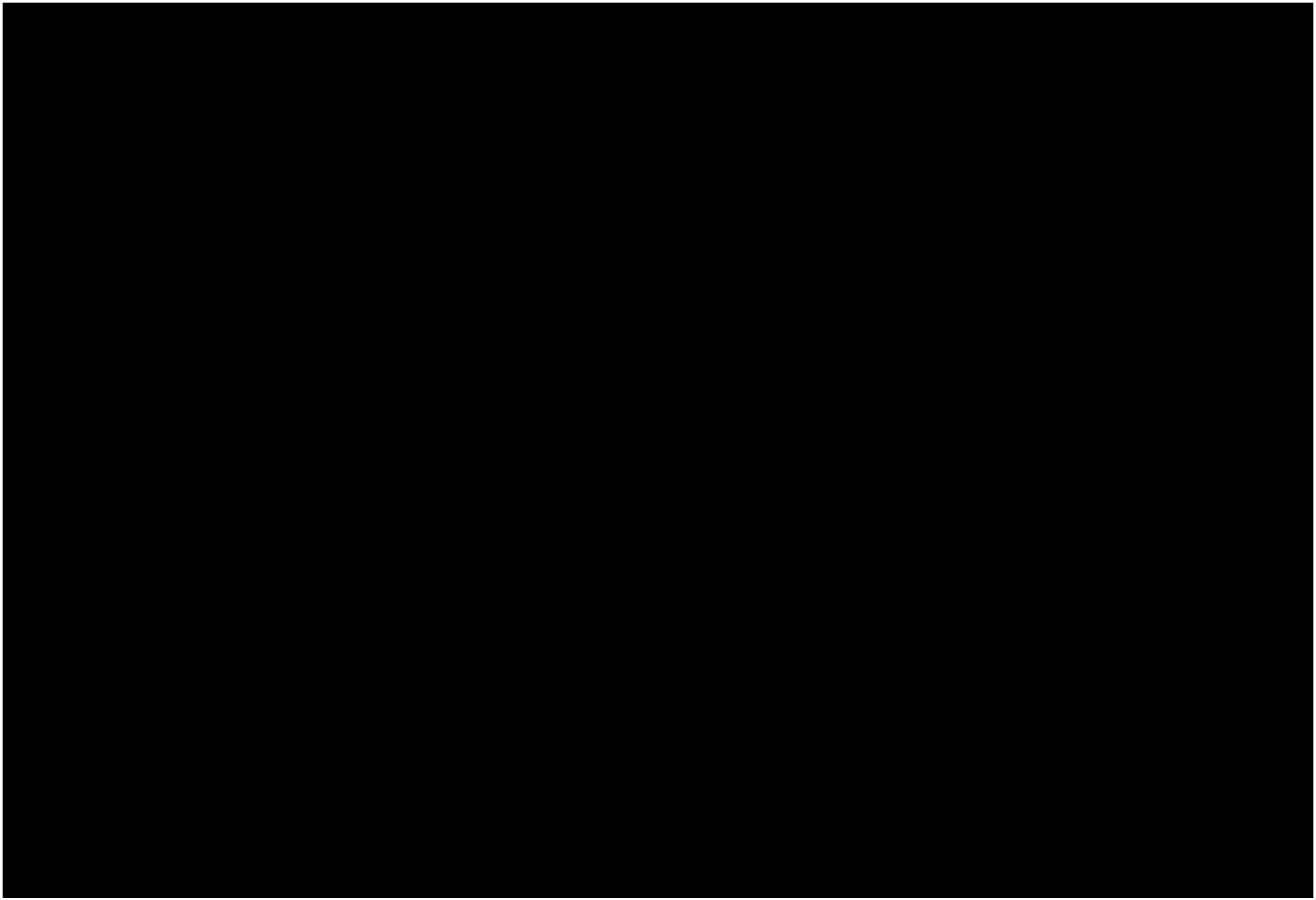
Date of Off Peak Day - 09/22/2021



Member Forecasted Off Peak Demand Day for October 2021

Continental Divide Electric Cooperative, Inc.

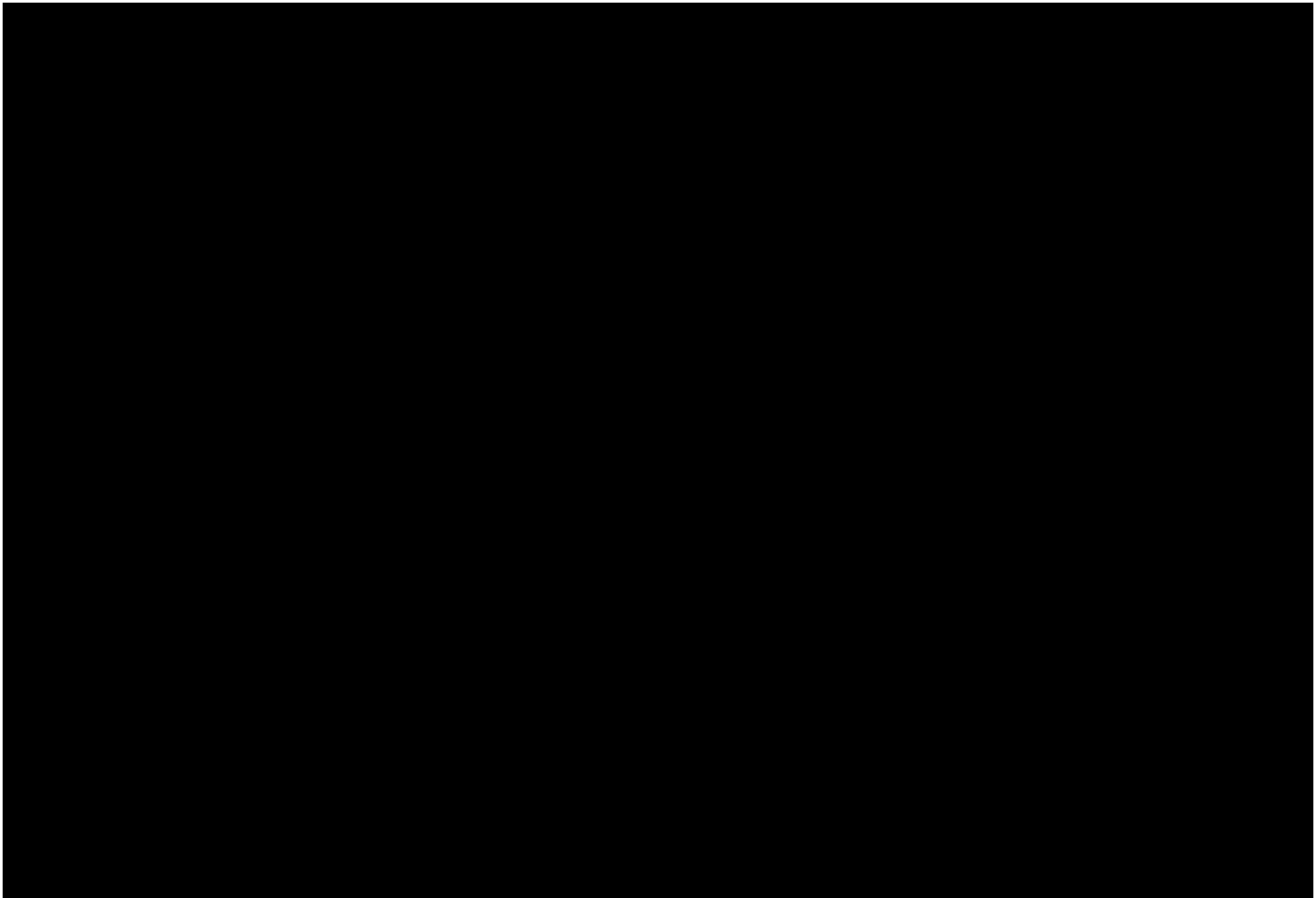
Date of Off Peak Day - 10/21/2021



Member Forecasted Off Peak Demand Day for November 2021

Continental Divide Electric Cooperative, Inc.

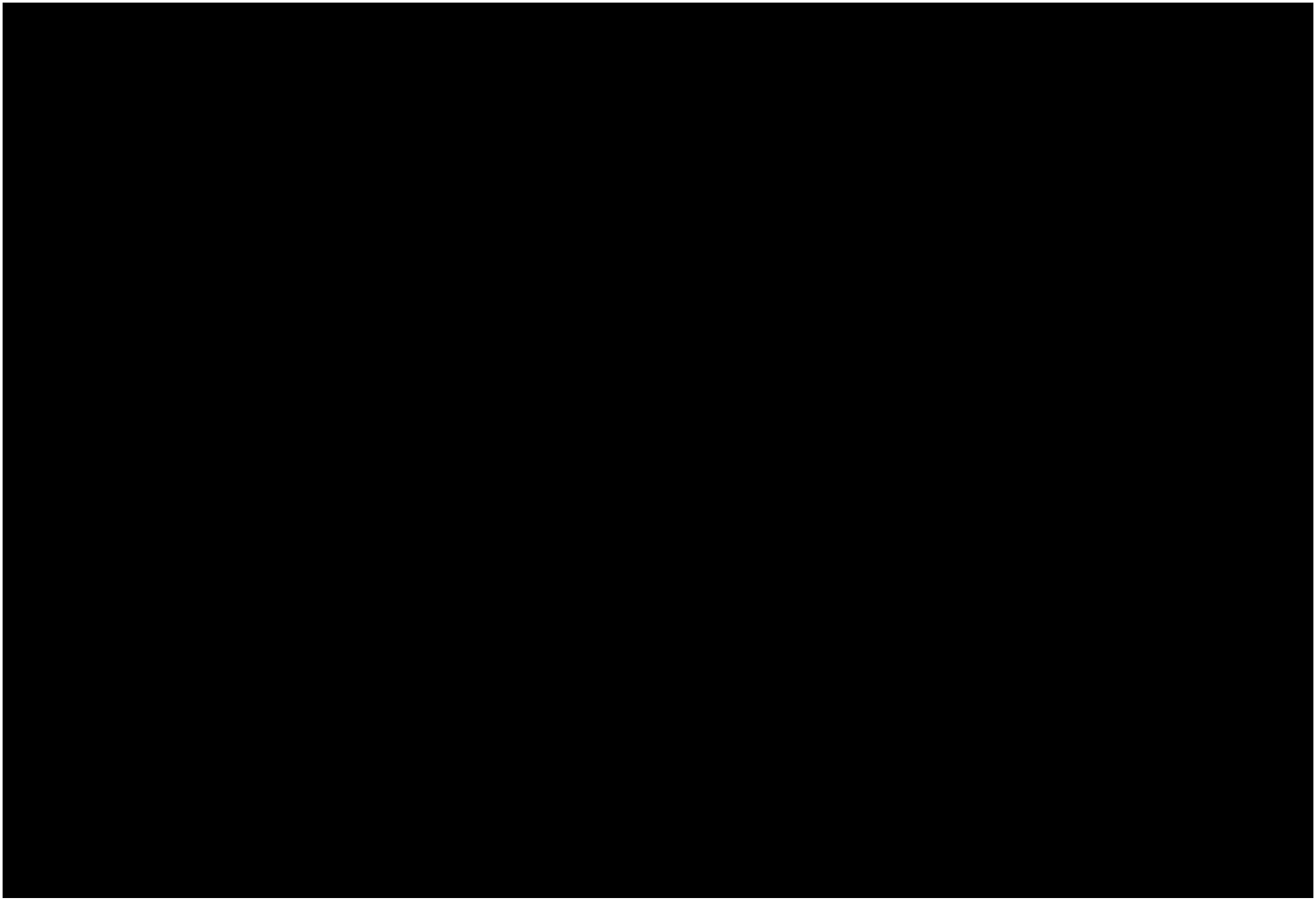
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Continental Divide Electric Cooperative, Inc.

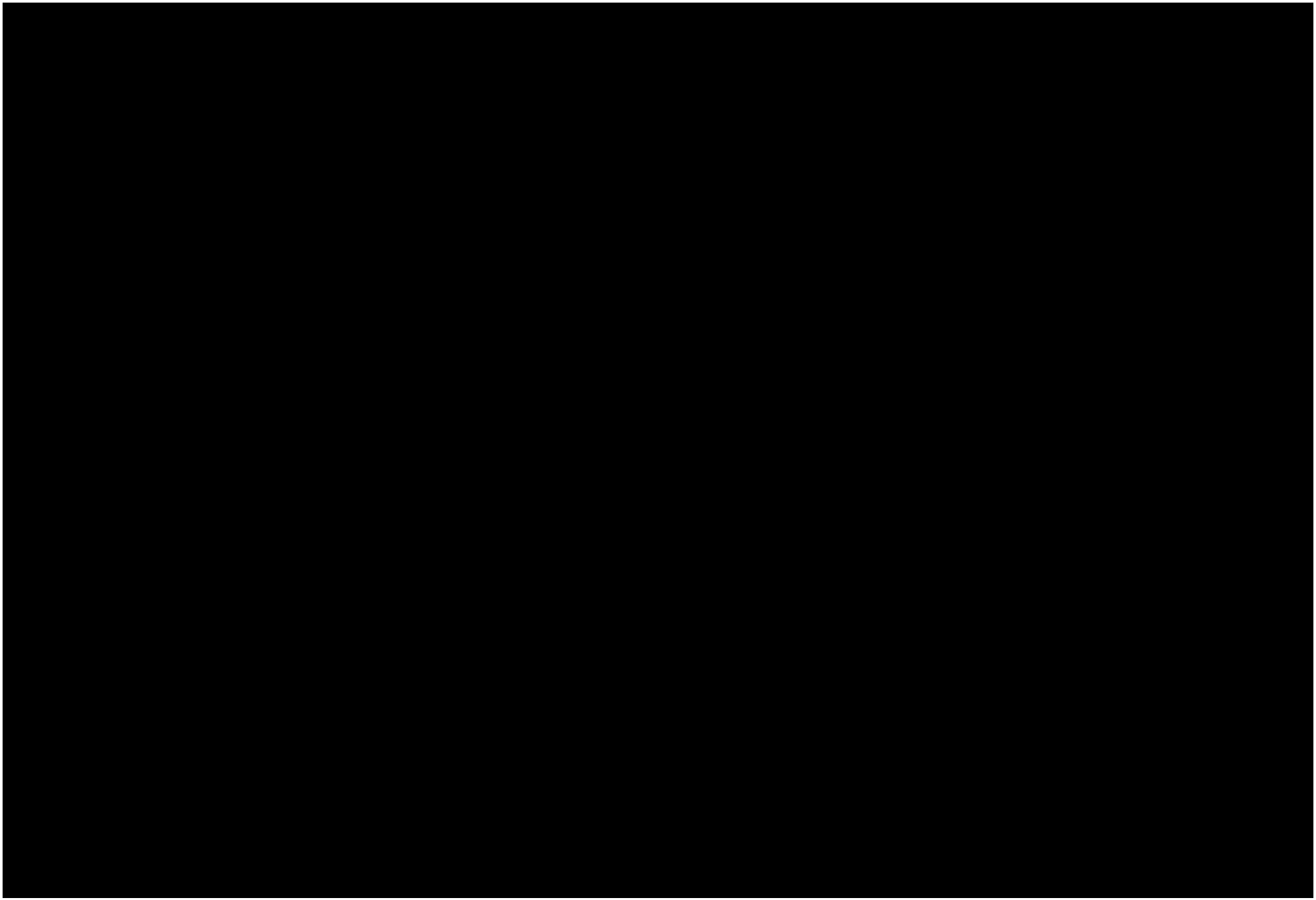
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Columbus Electric Cooperative, Inc.

Date of Off Peak Day - 01/04/2021



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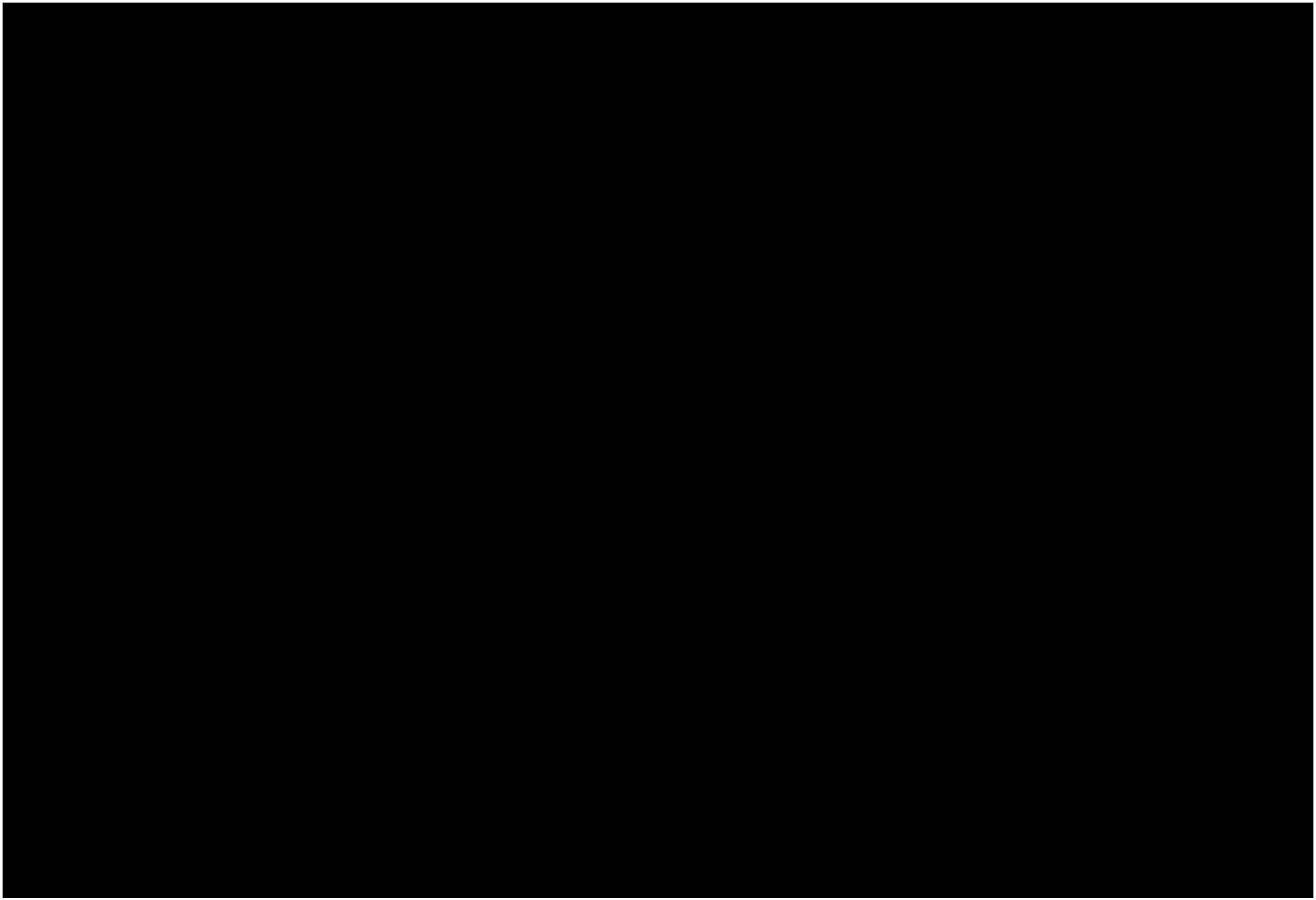
Member Forecasted Off Peak Demand Day for February 2021

Columbus Electric Cooperative, Inc.

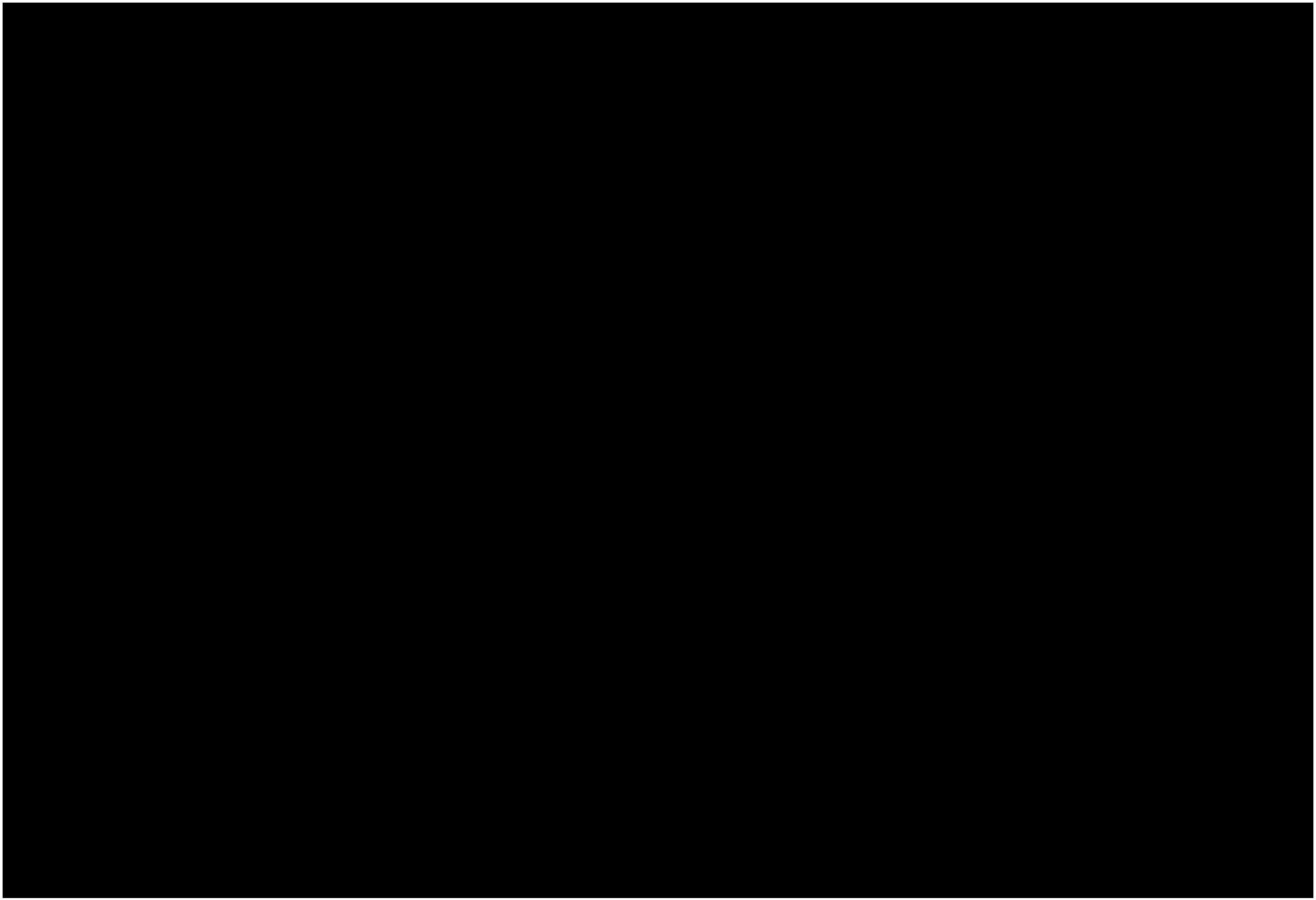
Date of Off Peak Day - 02/16/2021



Member Forecasted Off Peak Demand Day for March 2021

Columbus Electric Cooperative, Inc.

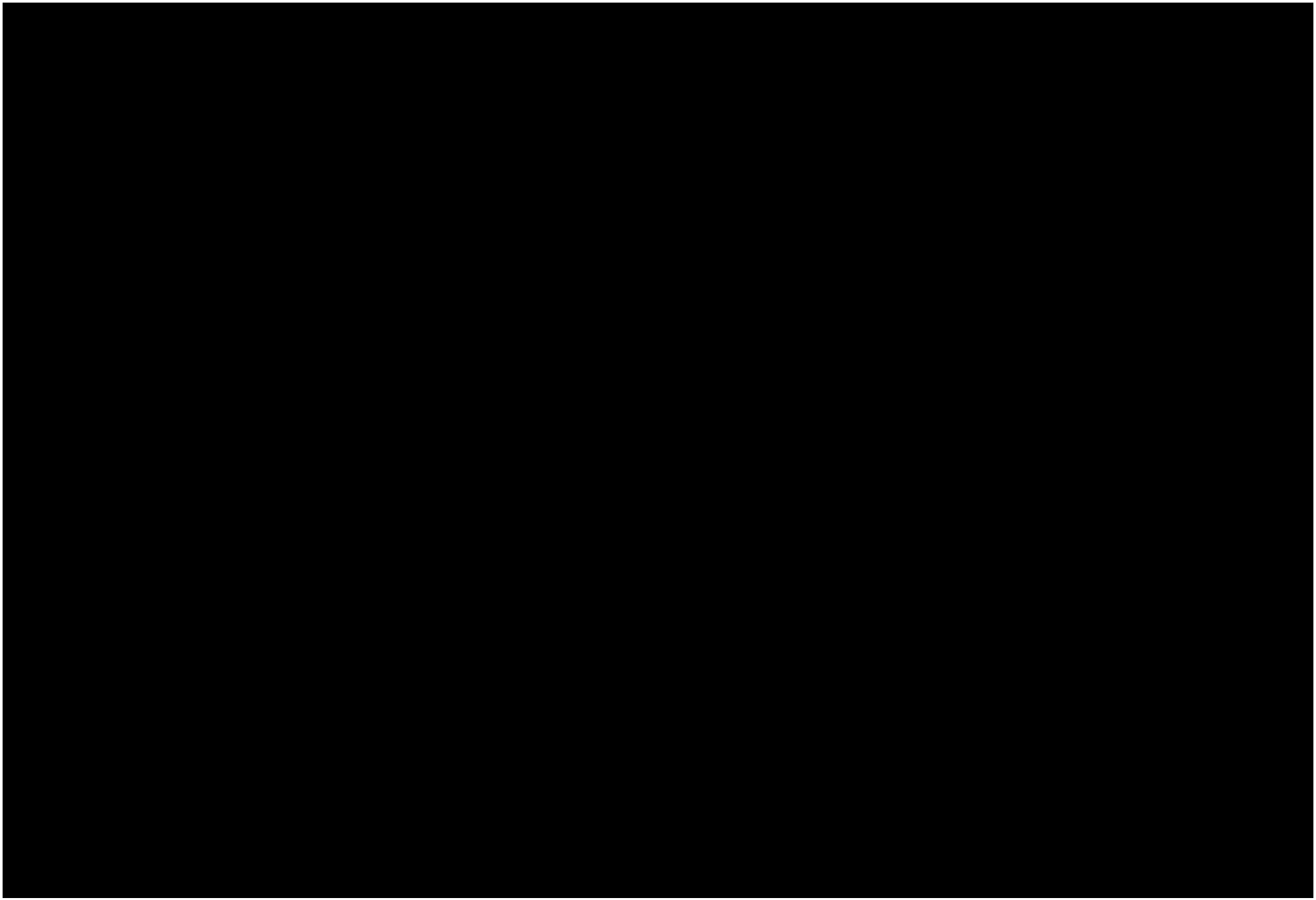
Date of Off Peak Day - 03/01/2021



Member Forecasted Off Peak Demand Day for April 2021

Columbus Electric Cooperative, Inc.

Date of Off Peak Day - 04/19/2021



Member Forecasted Off Peak Demand Day for May 2021

Columbus Electric Cooperative, Inc.

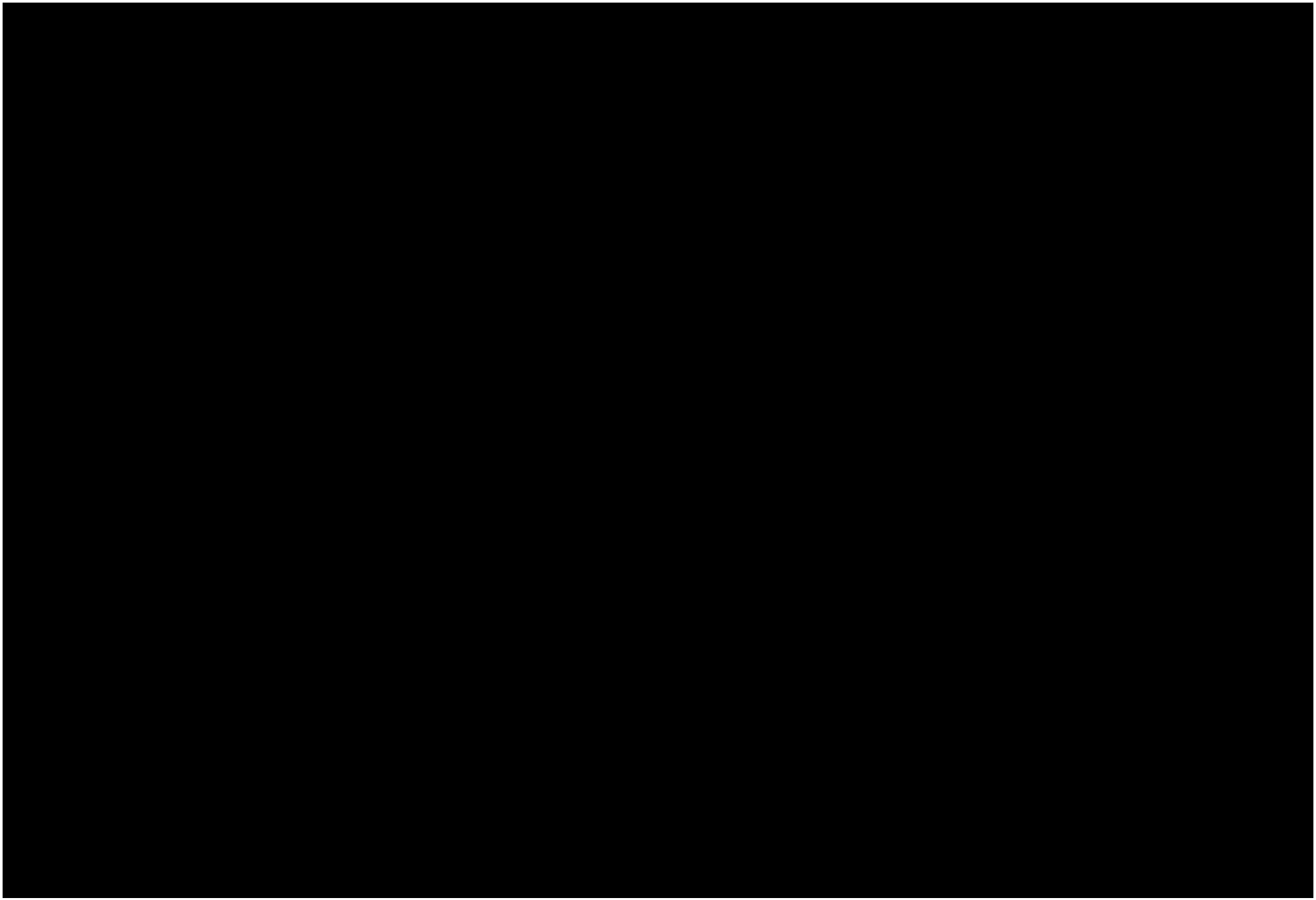
Date of Off Peak Day - 05/31/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Columbus Electric Cooperative, Inc.

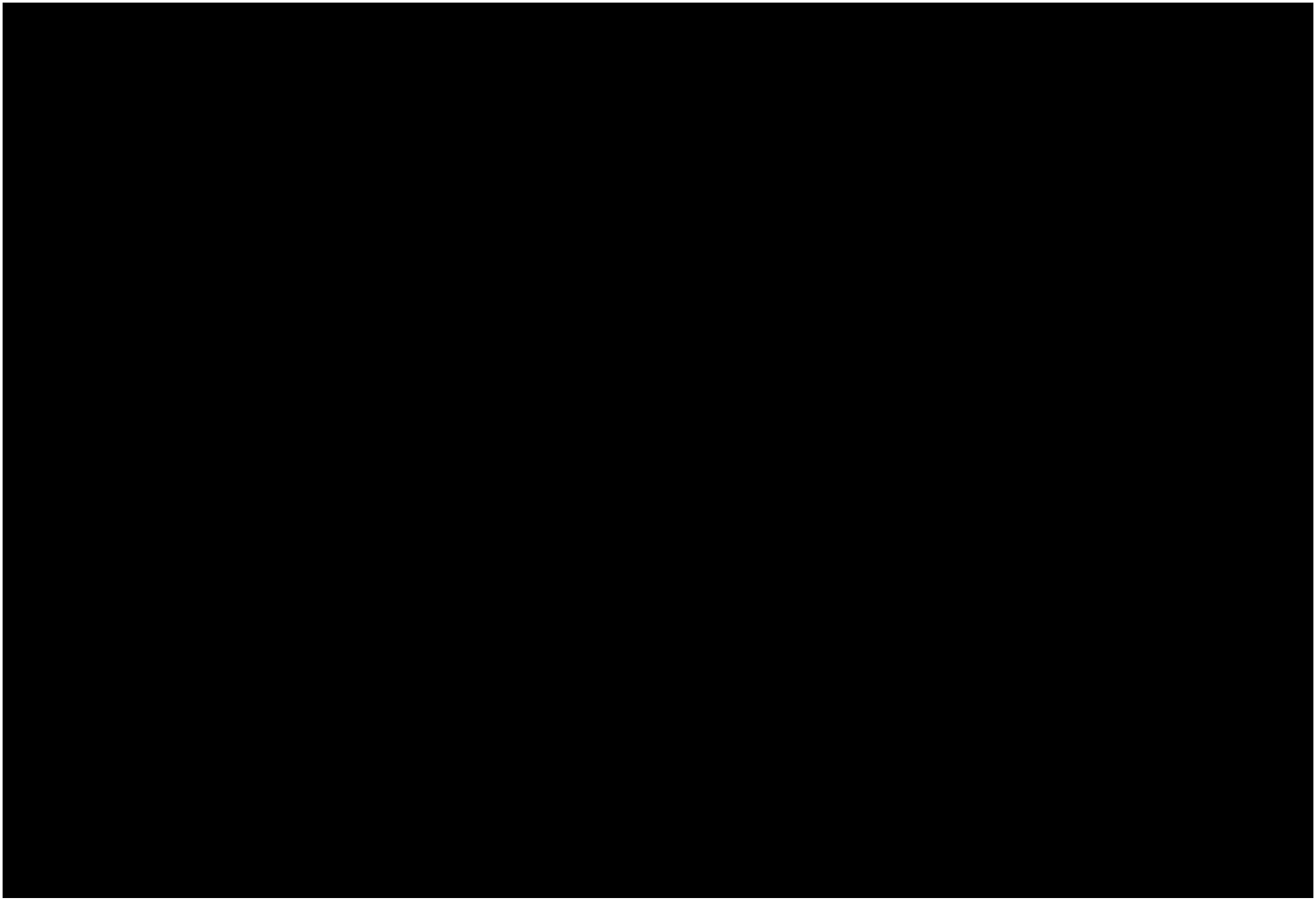
Date of Off Peak Day - 06/16/2021



Member Forecasted Off Peak Demand Day for July 2021

Columbus Electric Cooperative, Inc.

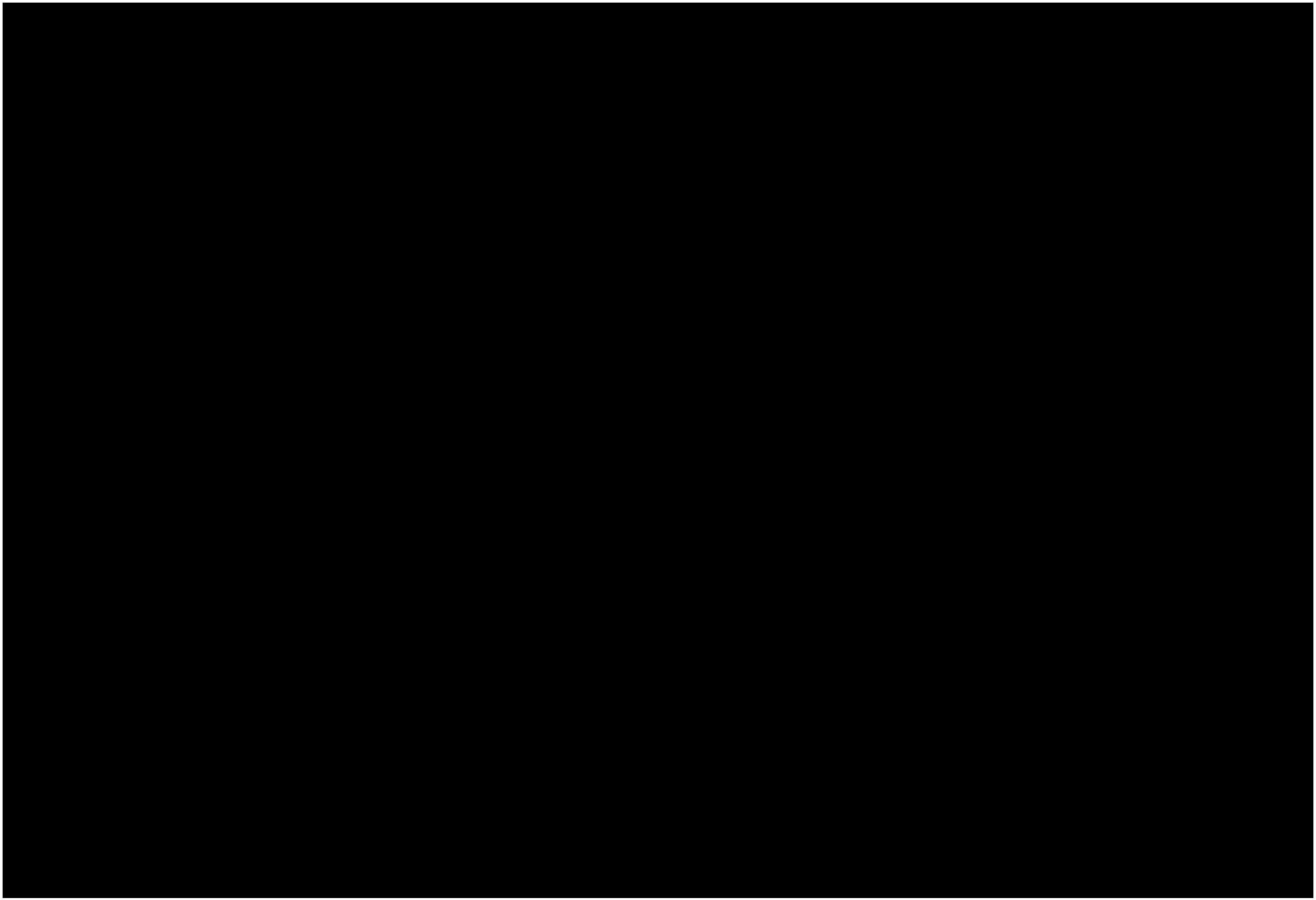
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

Columbus Electric Cooperative, Inc.

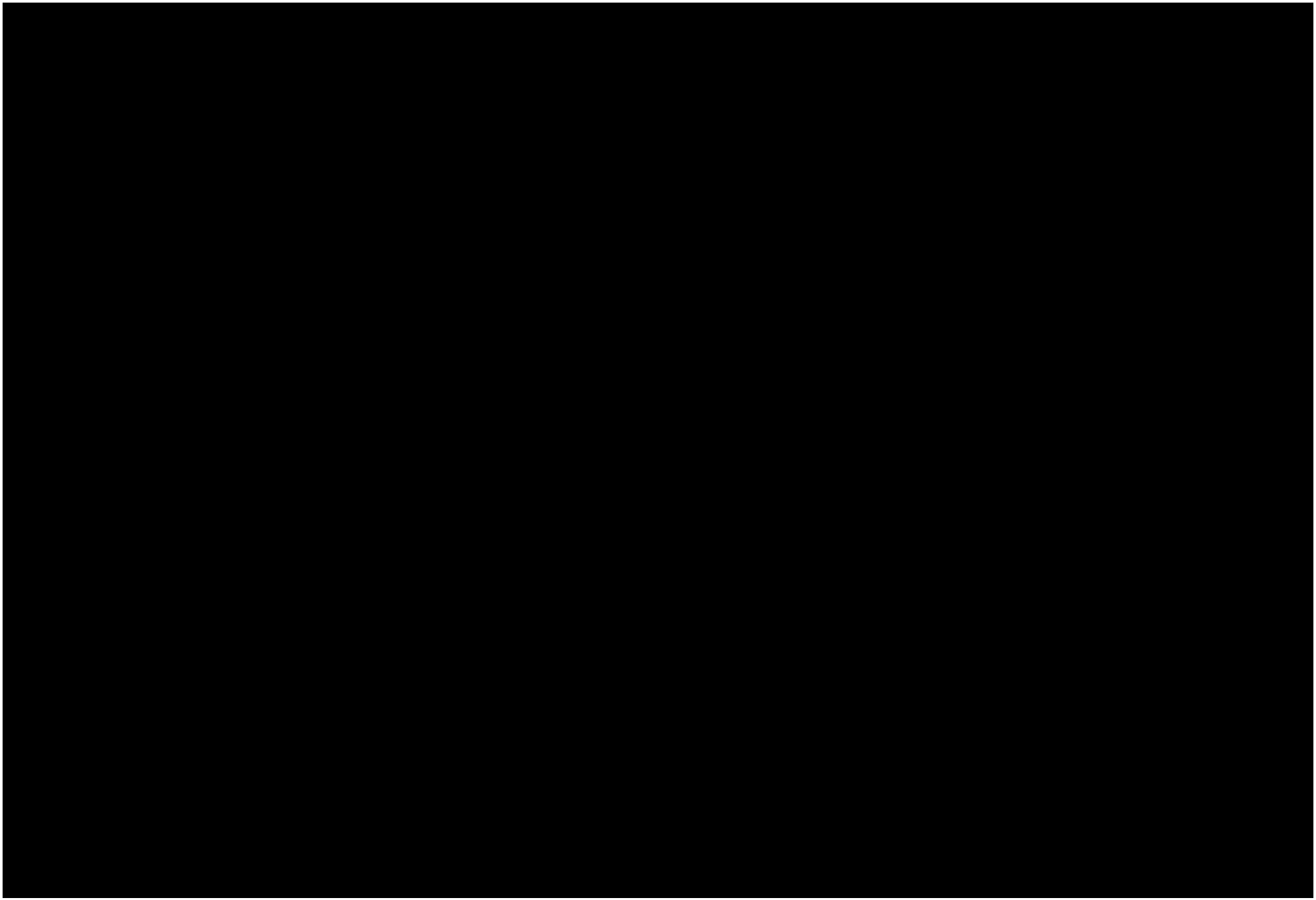
Date of Off Peak Day - 08/02/2021



Member Forecasted Off Peak Demand Day for September 2021

Columbus Electric Cooperative, Inc.

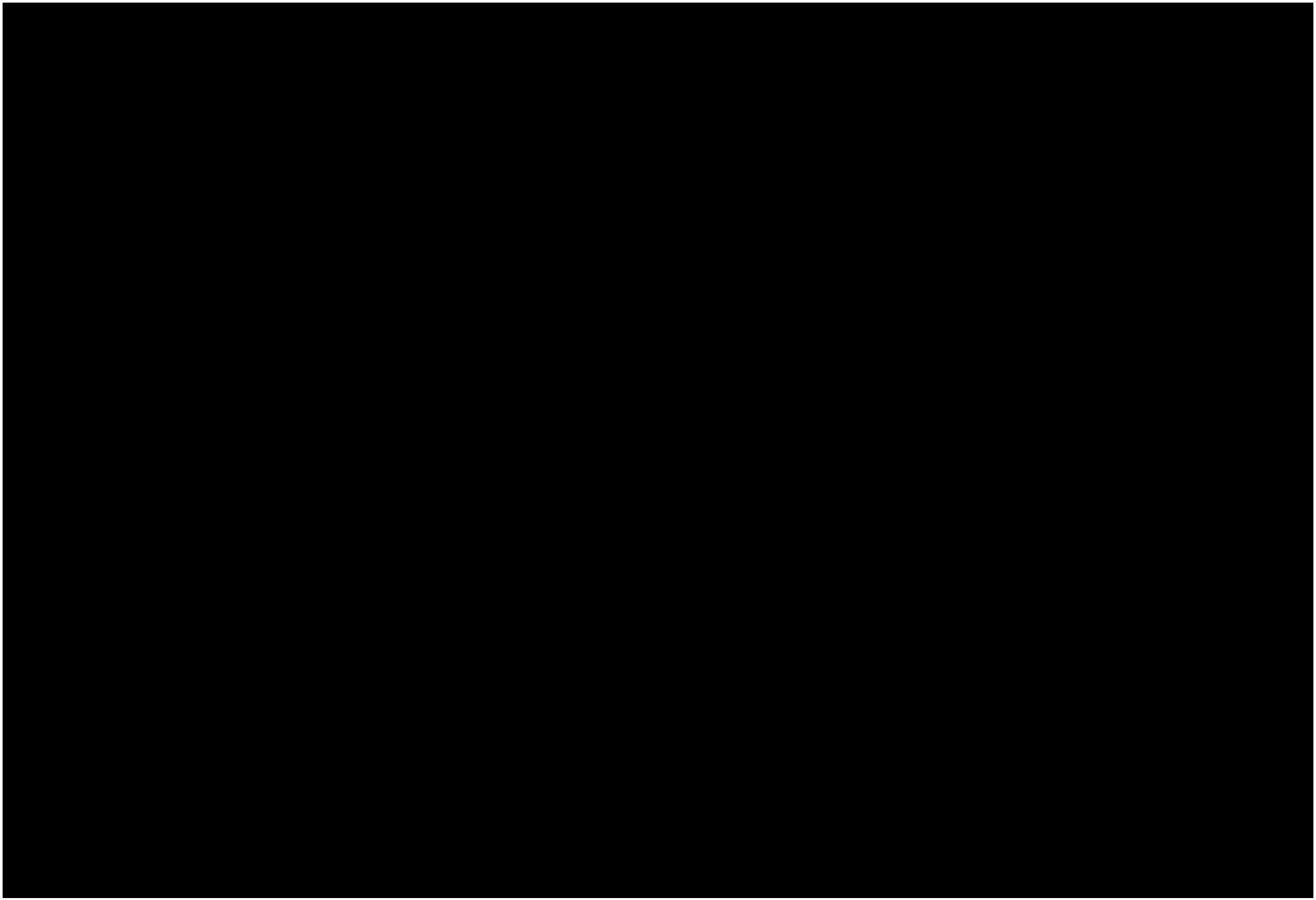
Date of Off Peak Day - 09/23/2021



Member Forecasted Off Peak Demand Day for October 2021

Columbus Electric Cooperative, Inc.

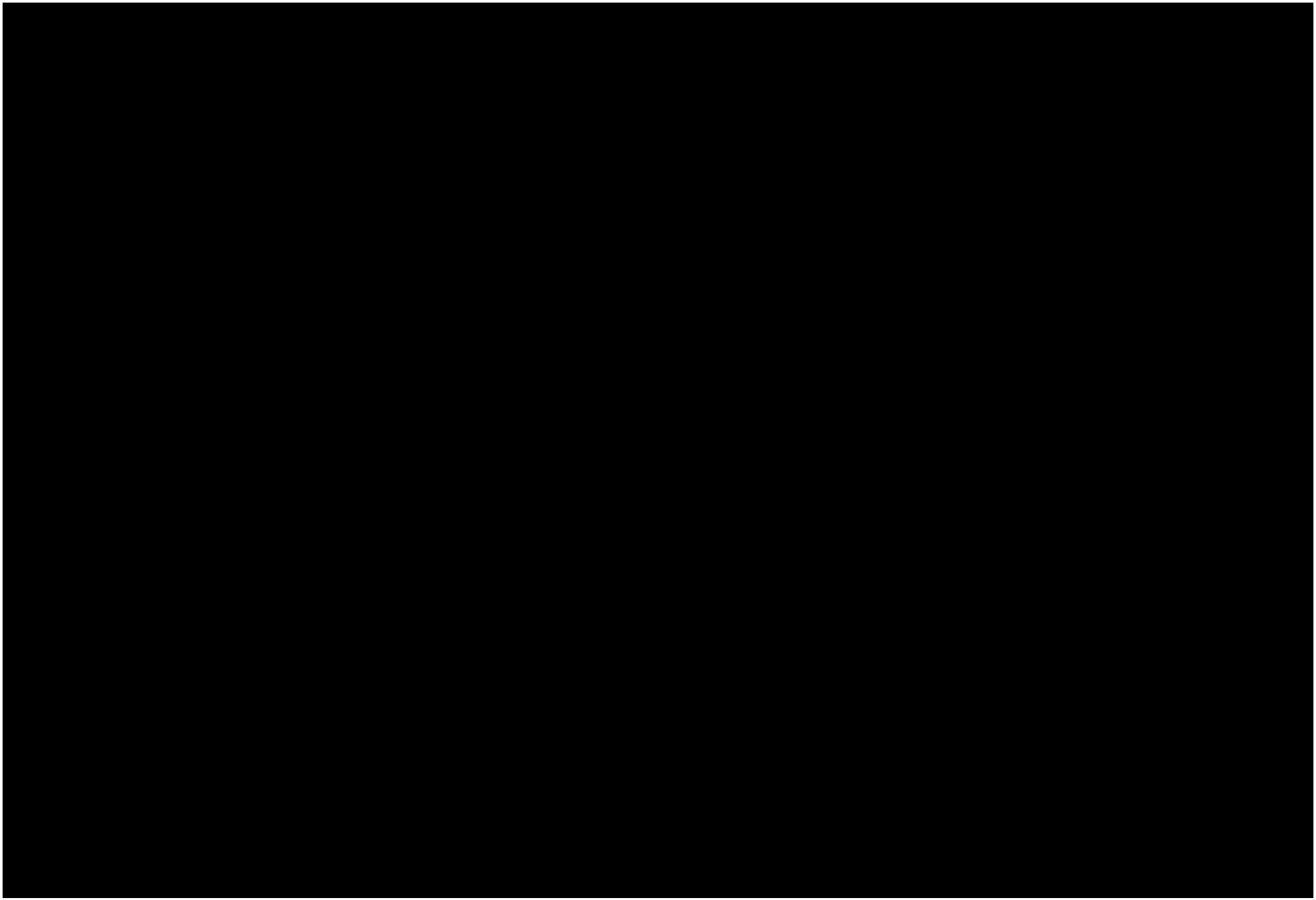
Date of Off Peak Day - 10/23/2021



Member Forecasted Off Peak Demand Day for November 2021

Columbus Electric Cooperative, Inc.

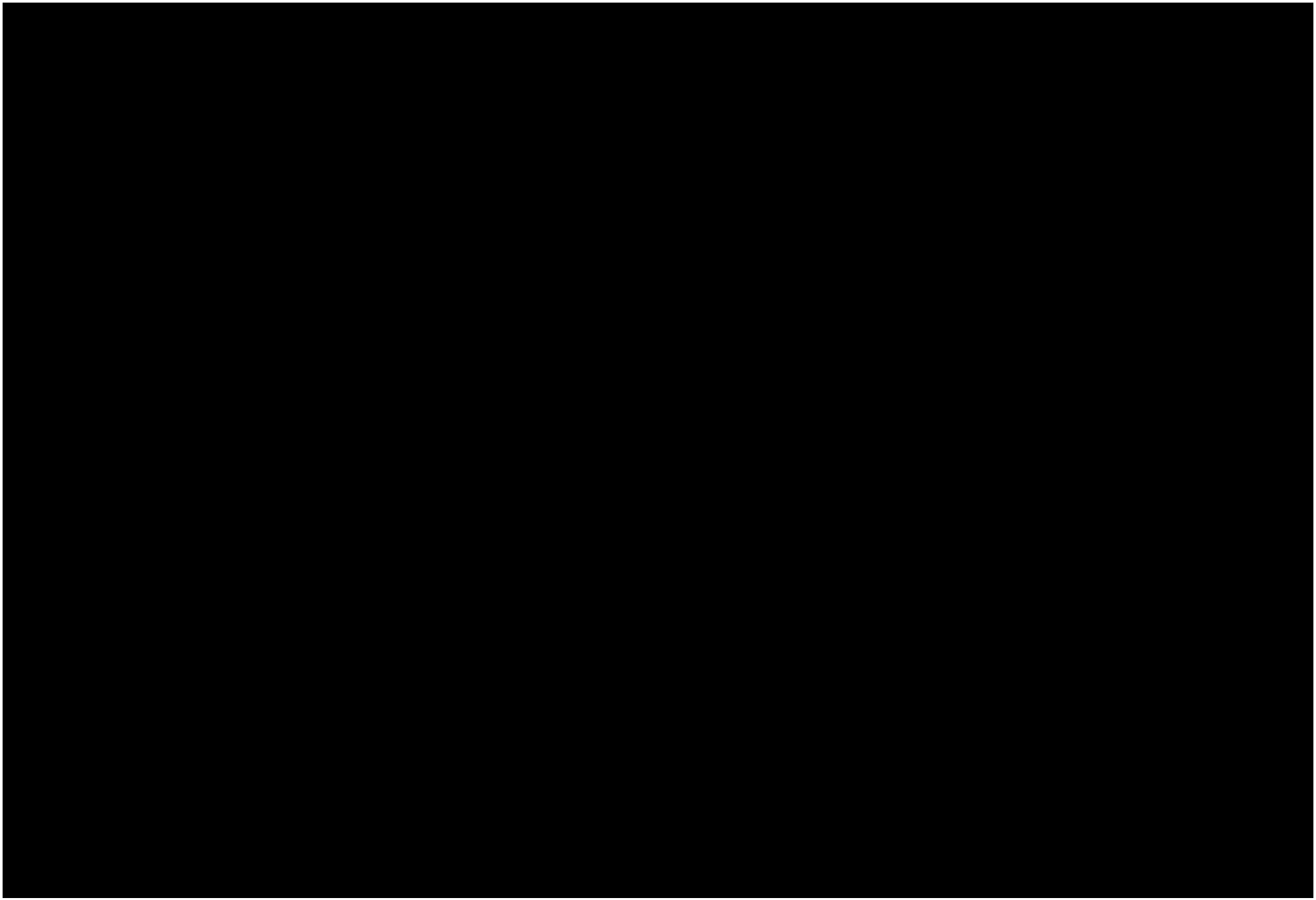
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Columbus Electric Cooperative, Inc.

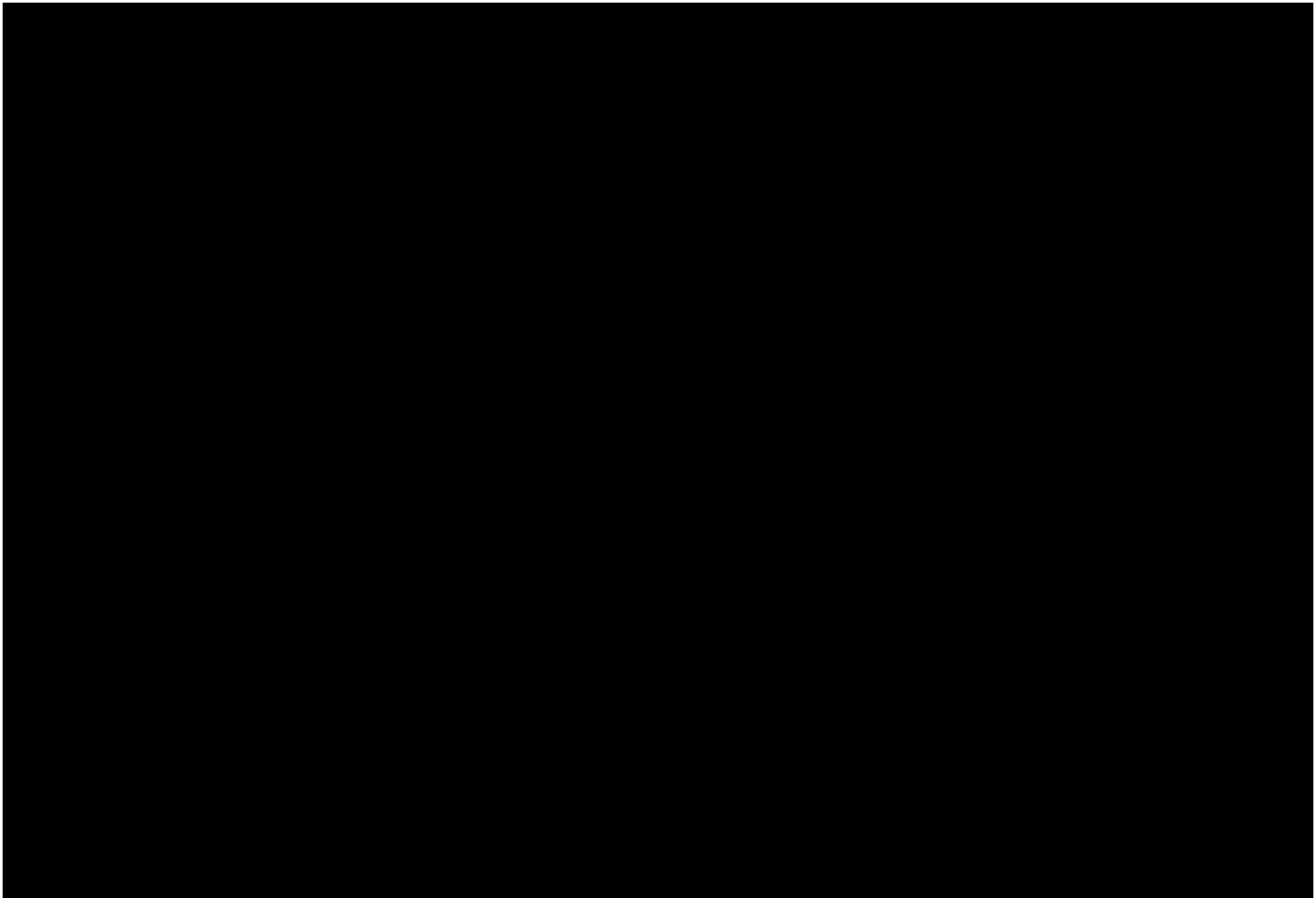
Date of Off Peak Day - 12/30/2021



Member Forecasted Off Peak Demand Day for January 2021

Central New Mexico Electric Cooperative, Inc.

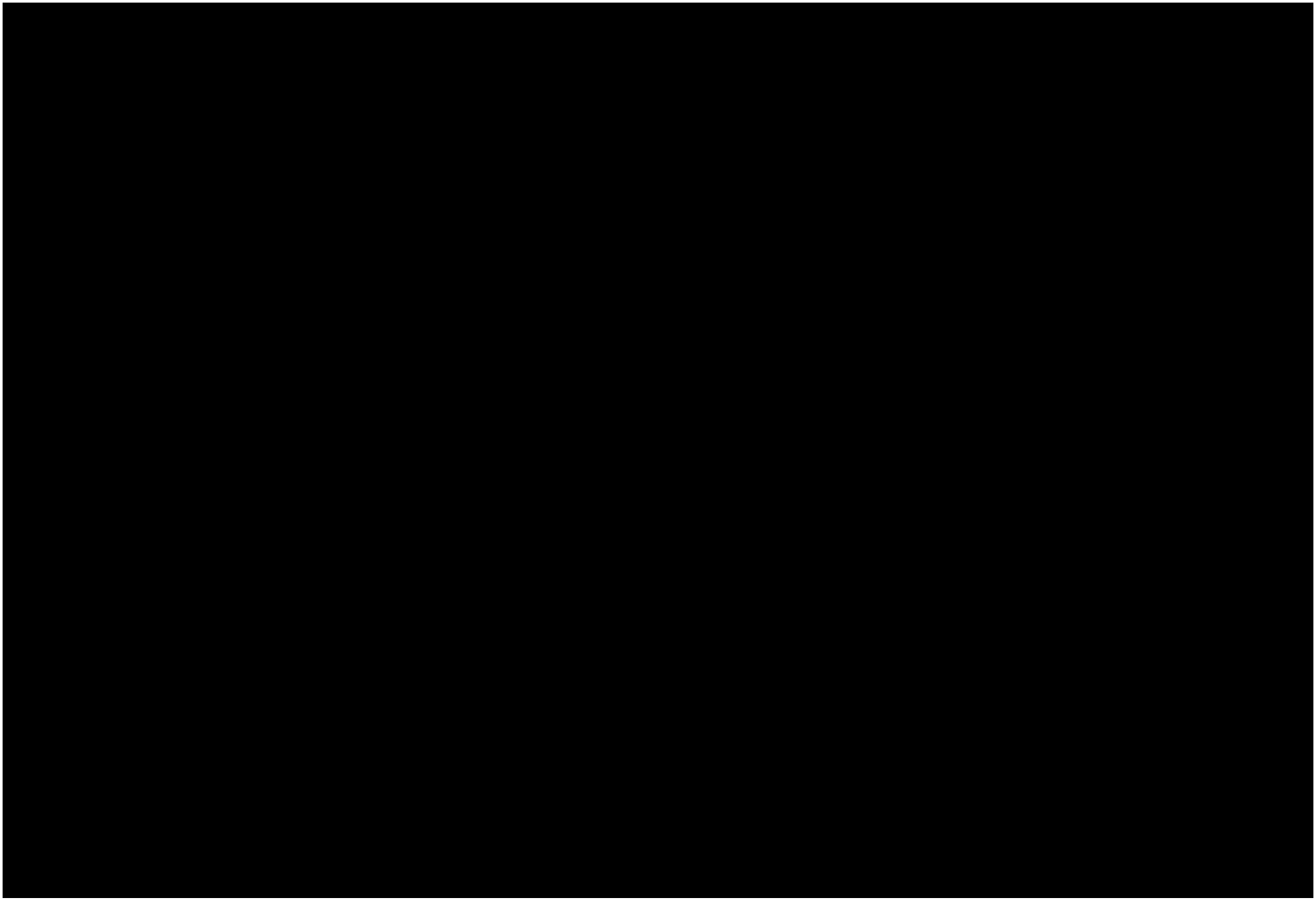
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

Central New Mexico Electric Cooperative, Inc.

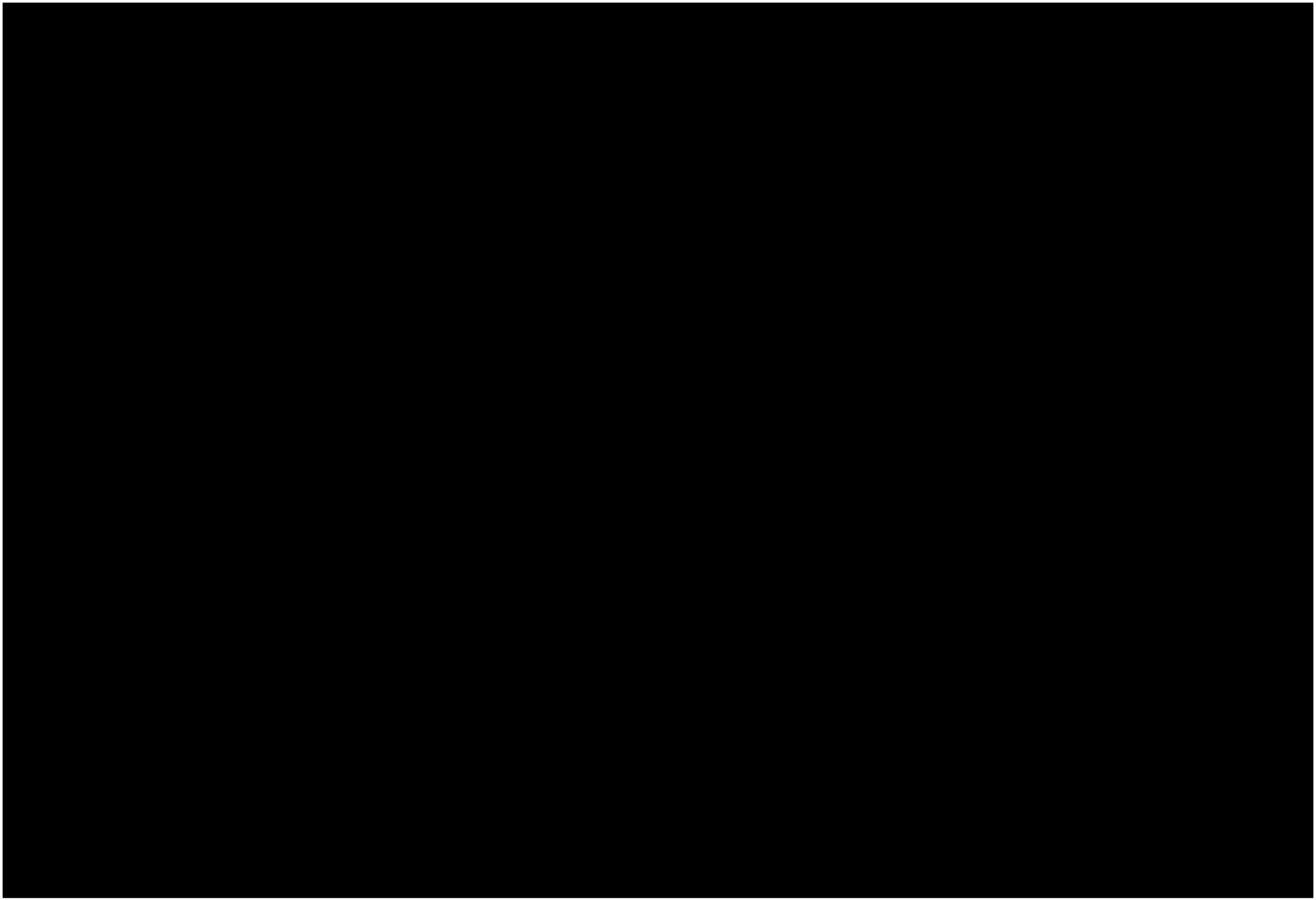
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Central New Mexico Electric Cooperative, Inc.

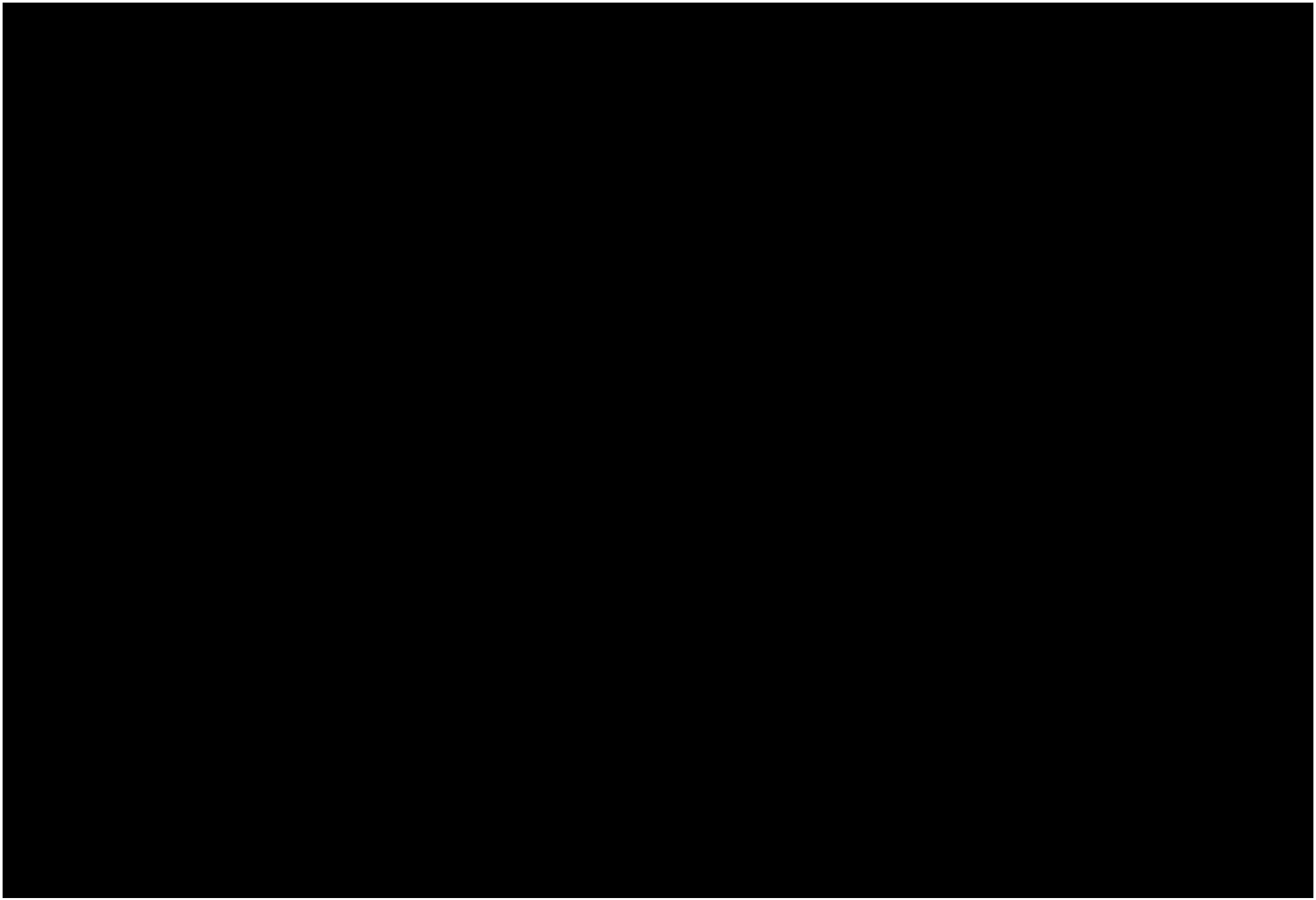
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Central New Mexico Electric Cooperative, Inc.

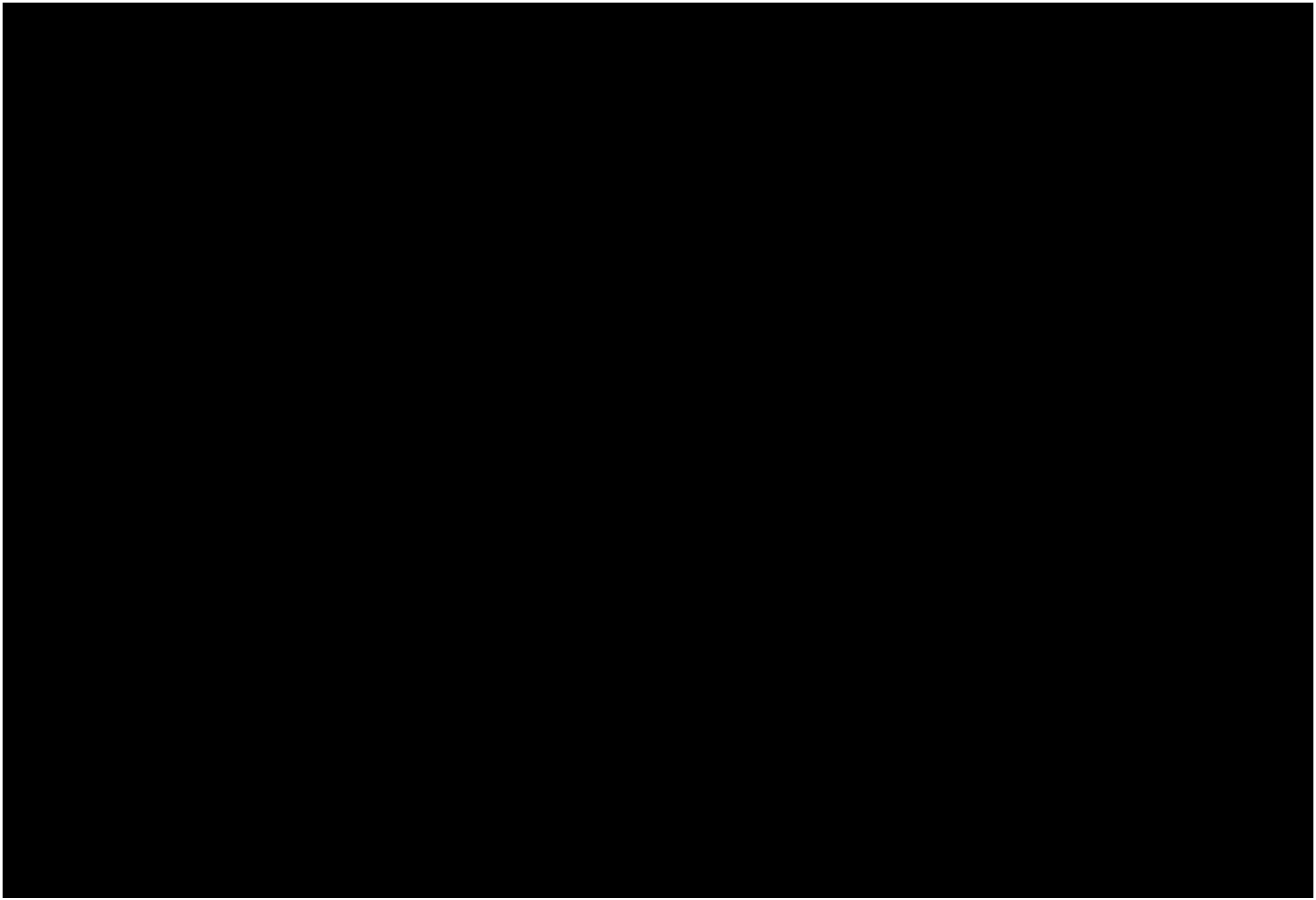
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Central New Mexico Electric Cooperative, Inc.

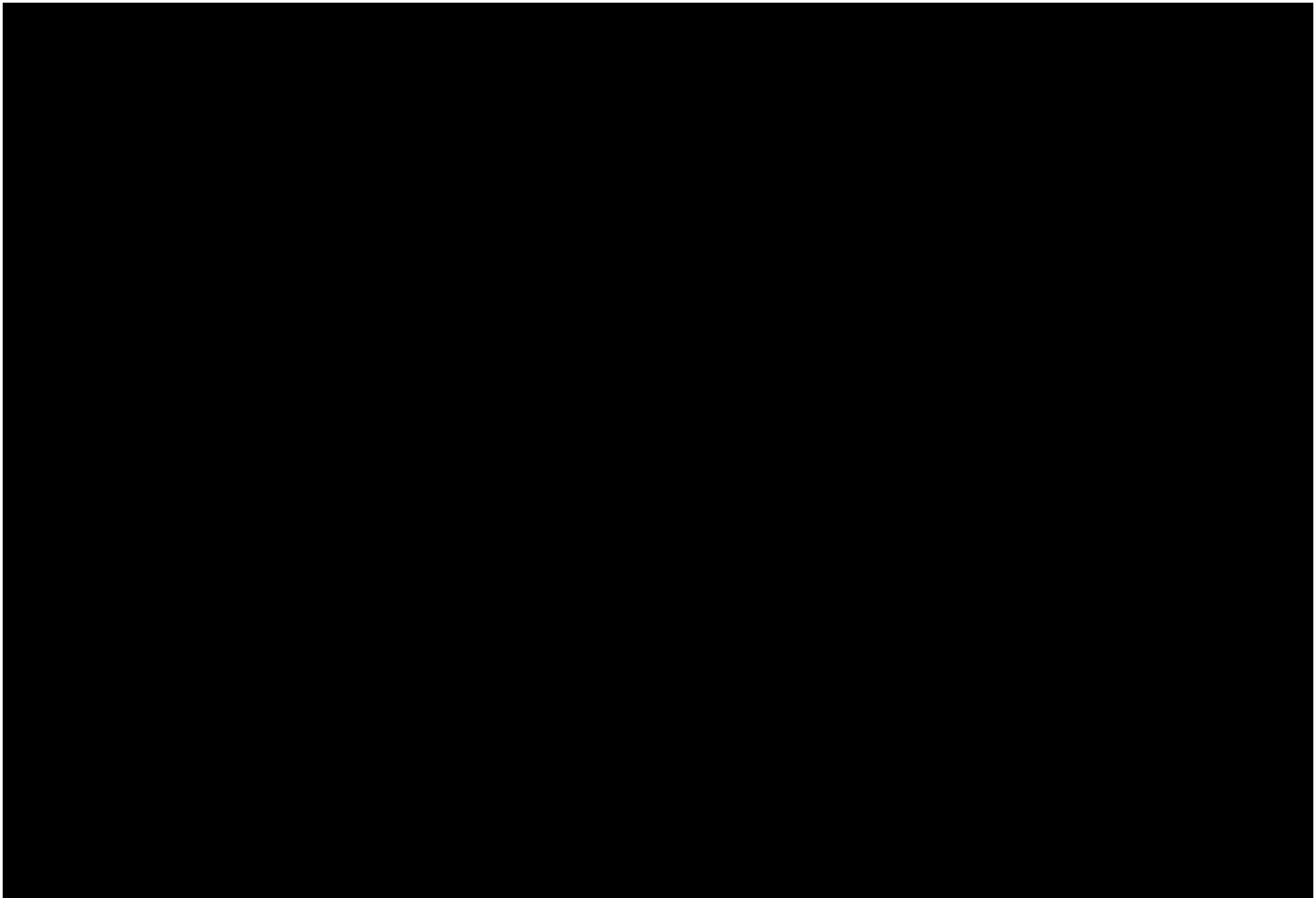
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Central New Mexico Electric Cooperative, Inc.

Date of Off Peak Day - 06/05/2021



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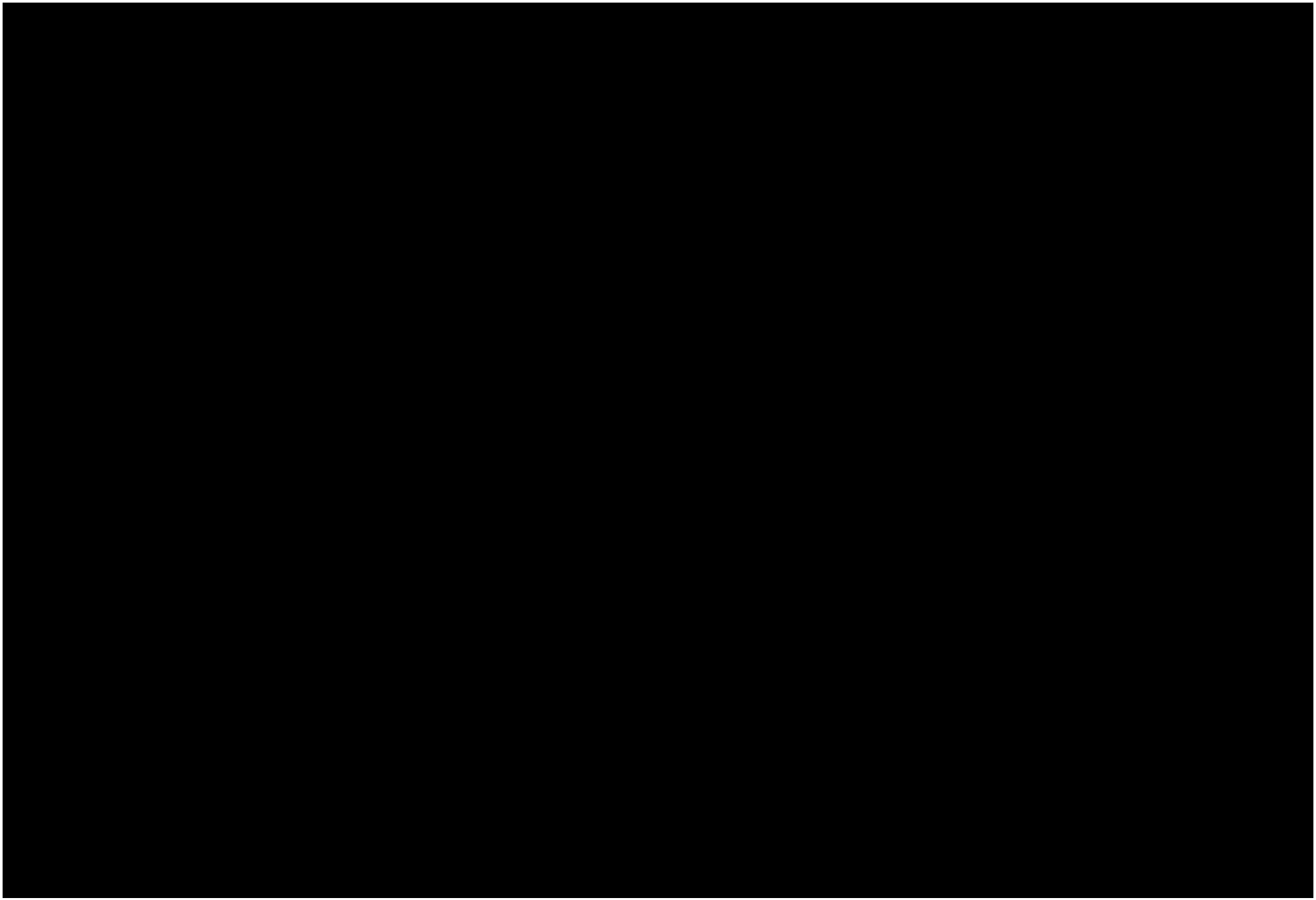
Member Forecasted Off Peak Demand Day for July 2021

Central New Mexico Electric Cooperative, Inc.

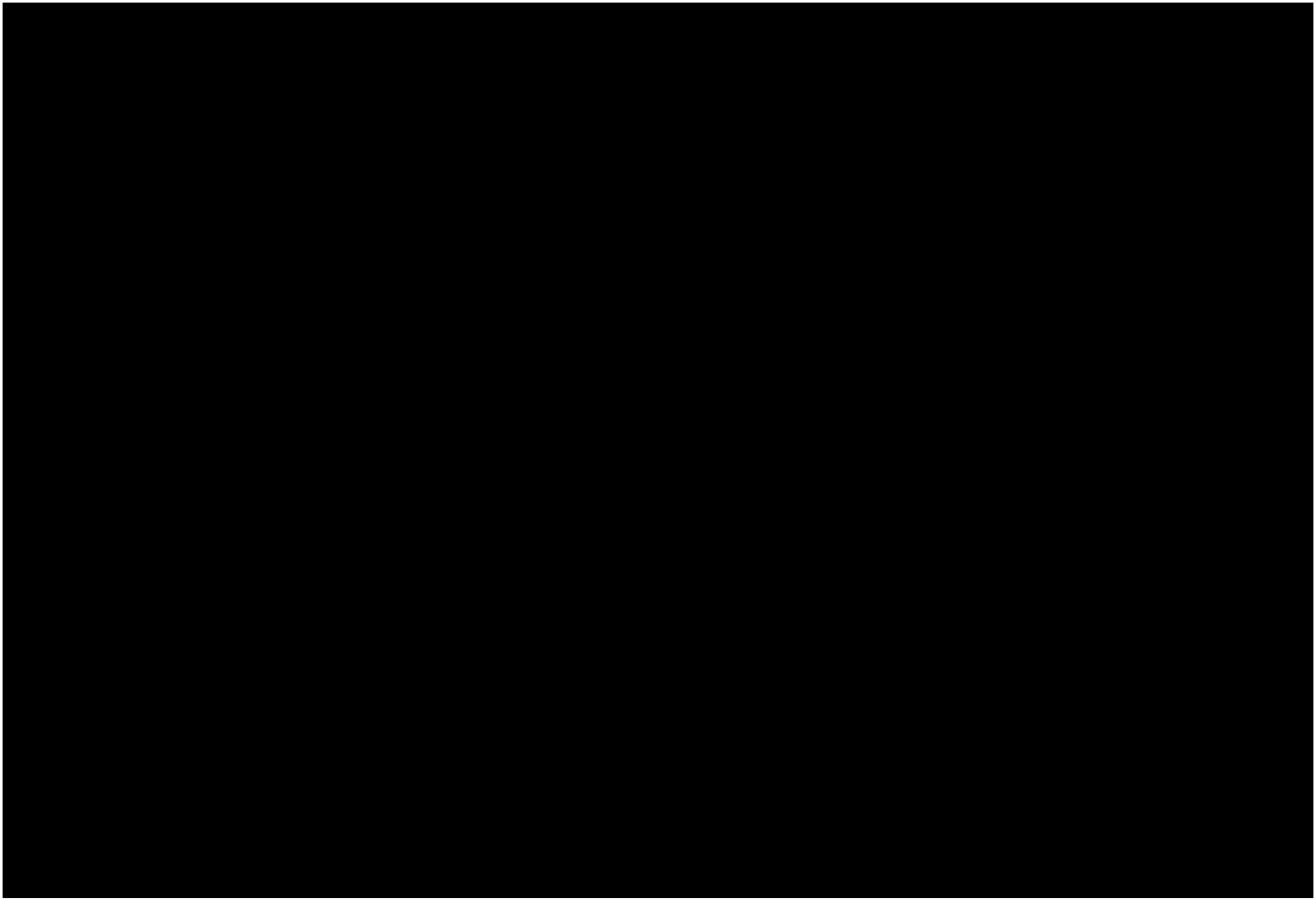
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Central New Mexico Electric Cooperative, Inc.

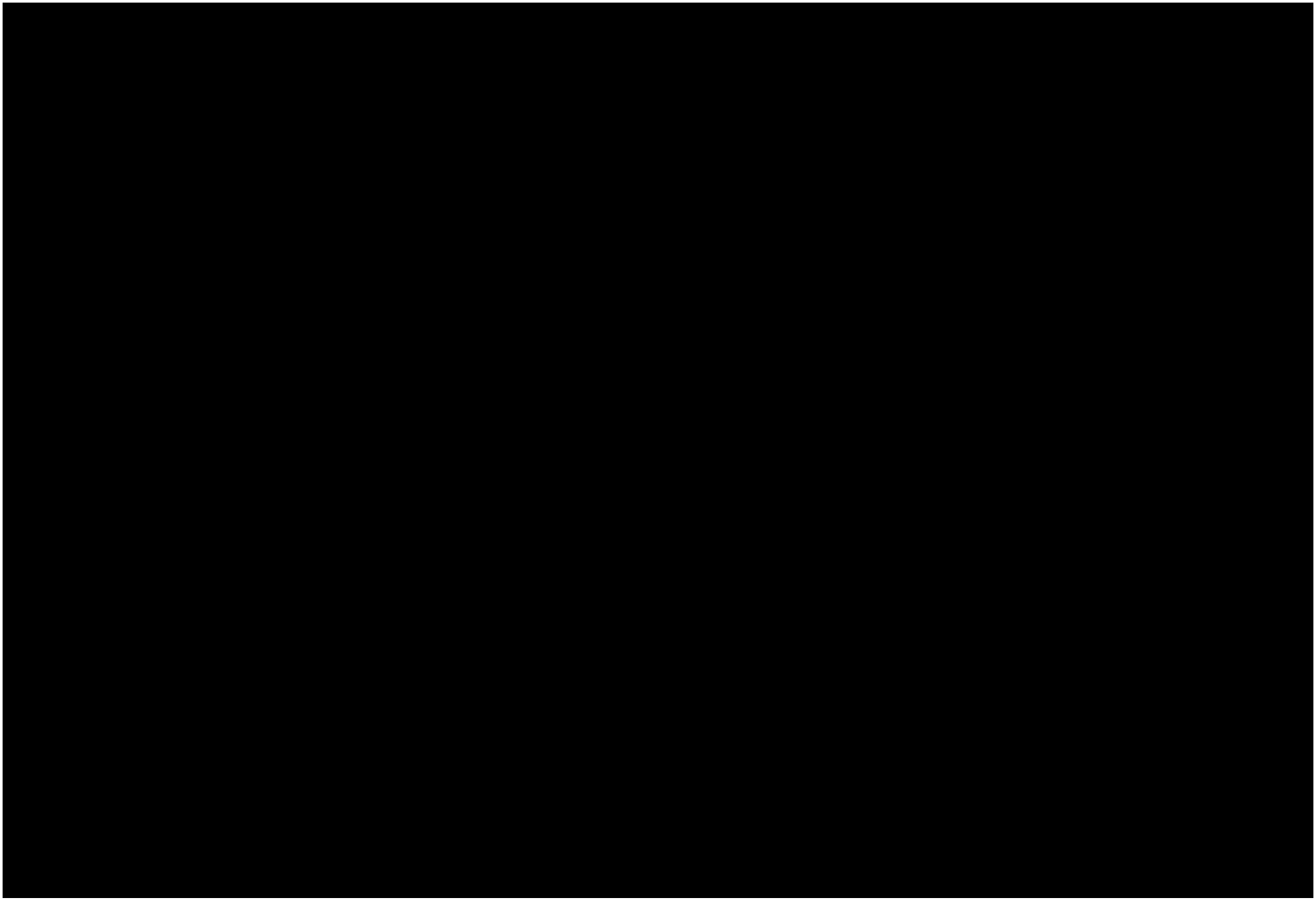
Date of Off Peak Day - 08/12/2021



Member Forecasted Off Peak Demand Day for September 2021

Central New Mexico Electric Cooperative, Inc.

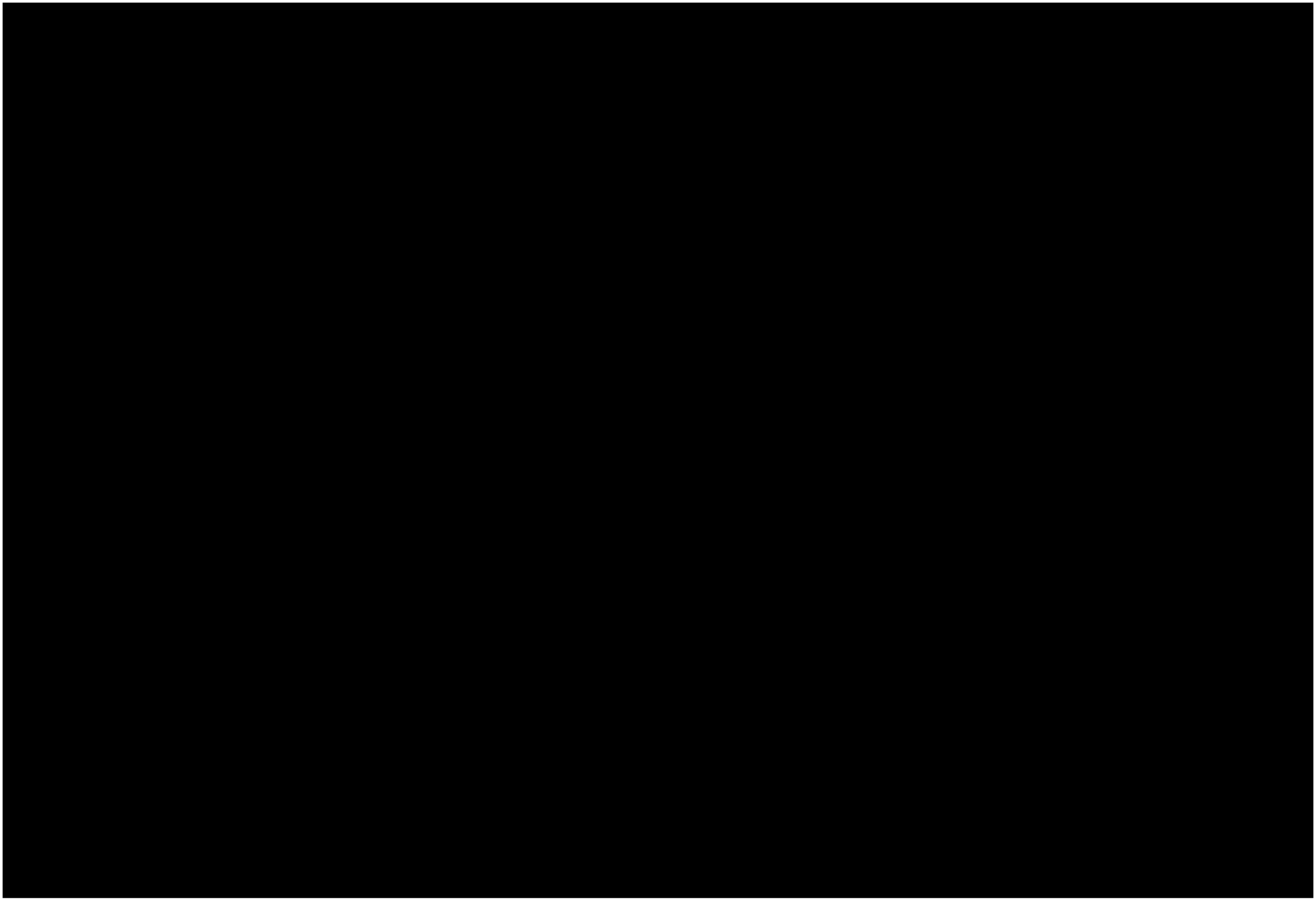
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

Central New Mexico Electric Cooperative, Inc.

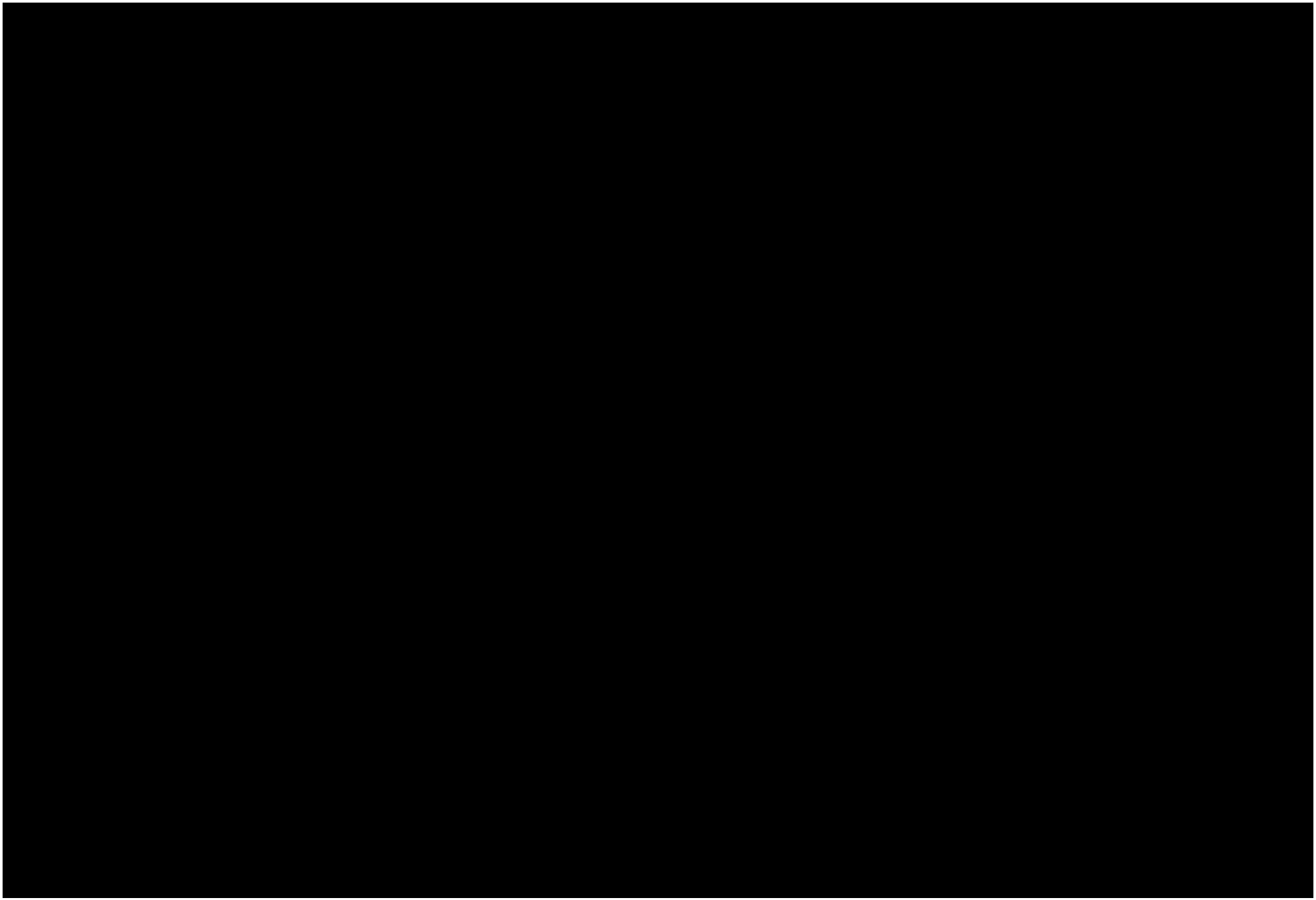
Date of Off Peak Day - 10/15/2021



Member Forecasted Off Peak Demand Day for November 2021

Central New Mexico Electric Cooperative, Inc.

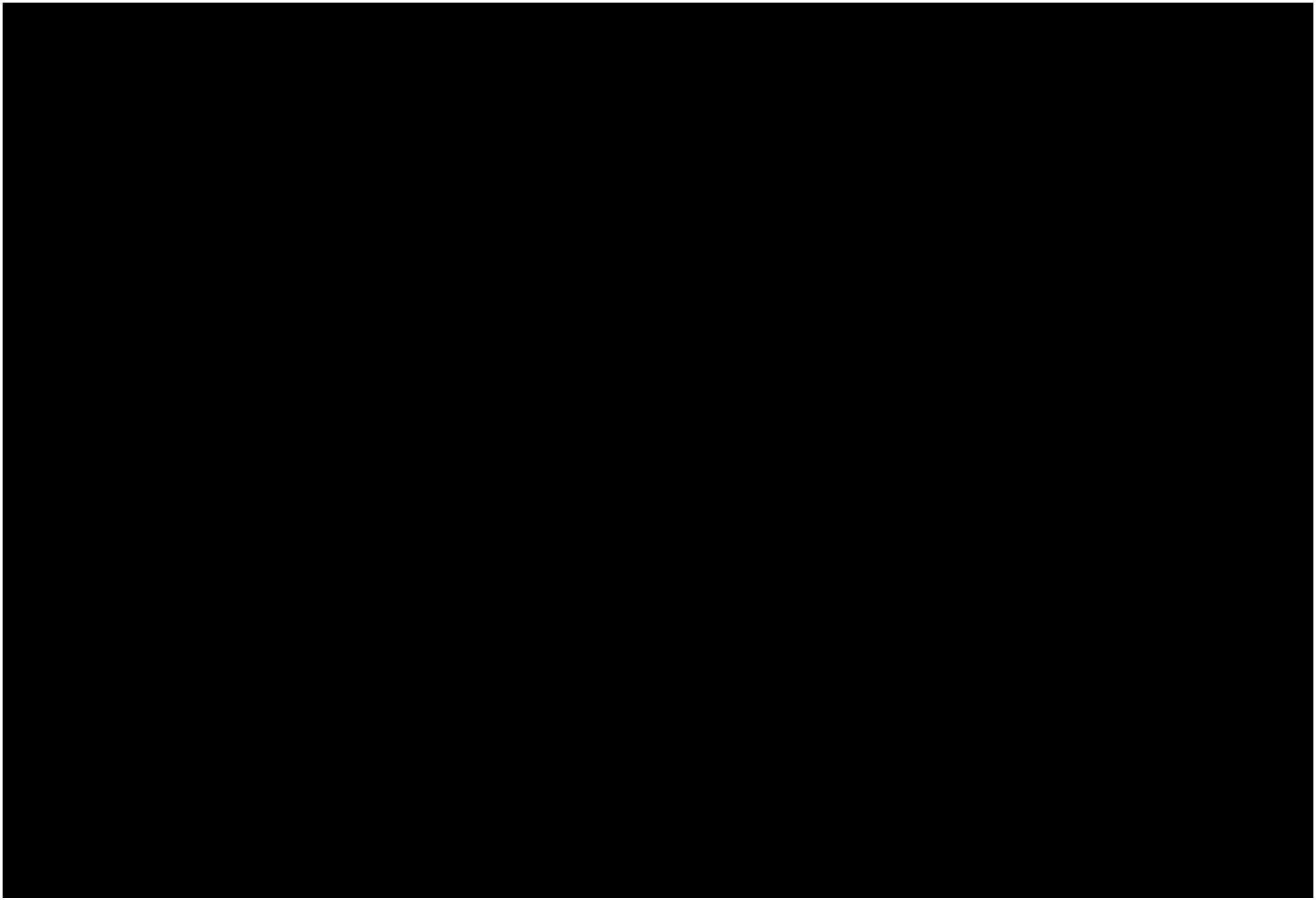
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Central New Mexico Electric Cooperative, Inc.

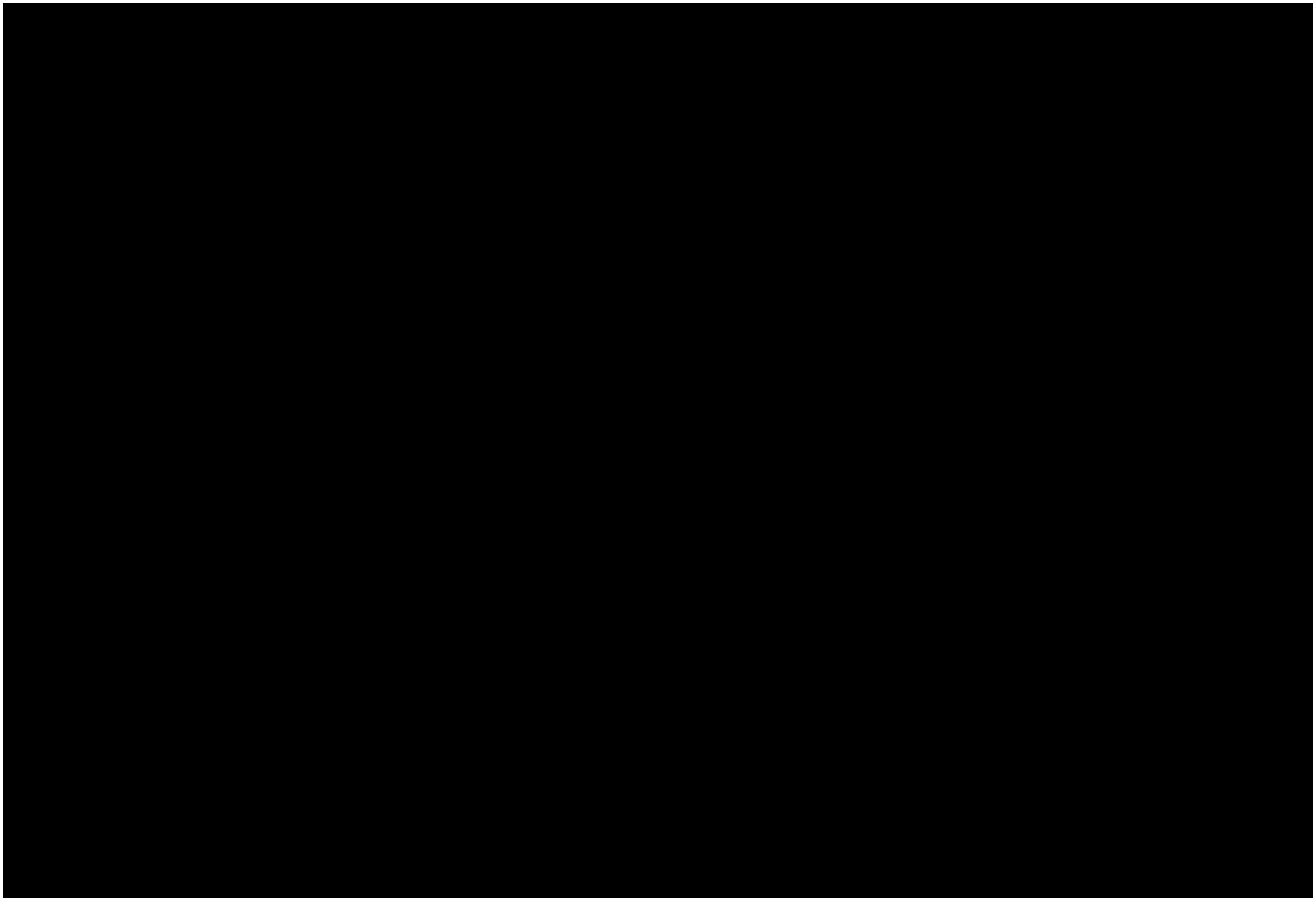
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Chimney Rock Public Power District

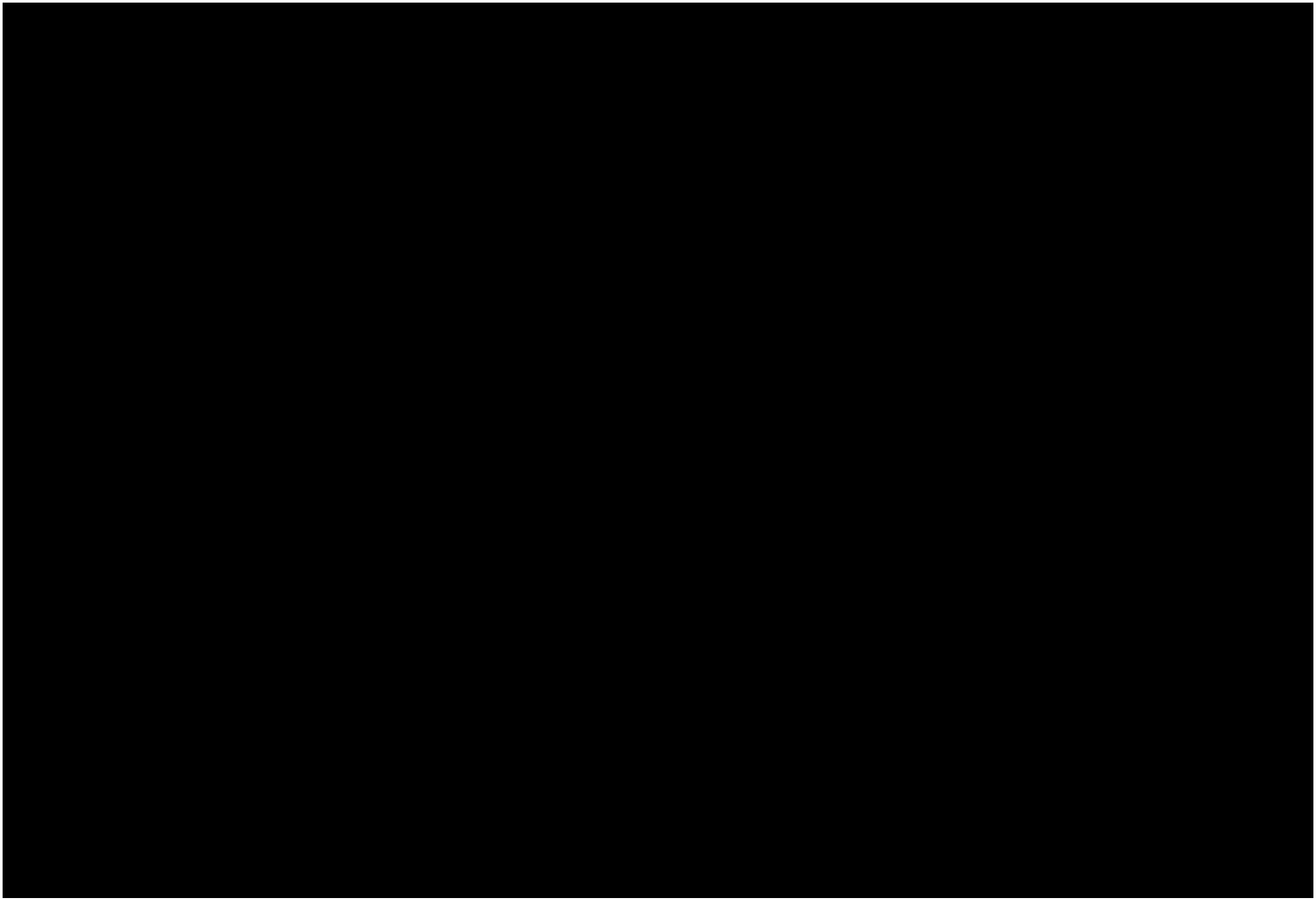
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Chimney Rock Public Power District

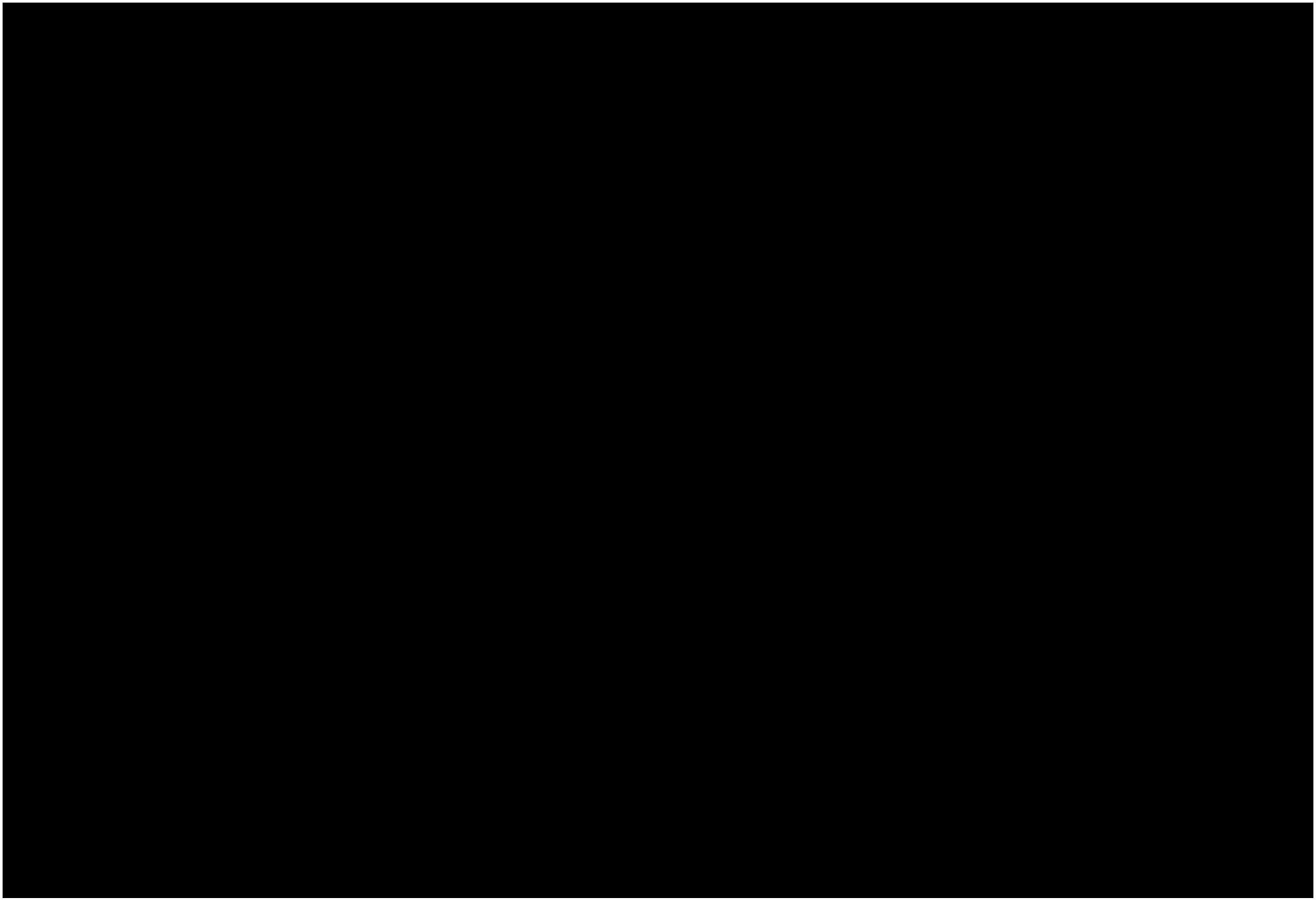
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Chimney Rock Public Power District

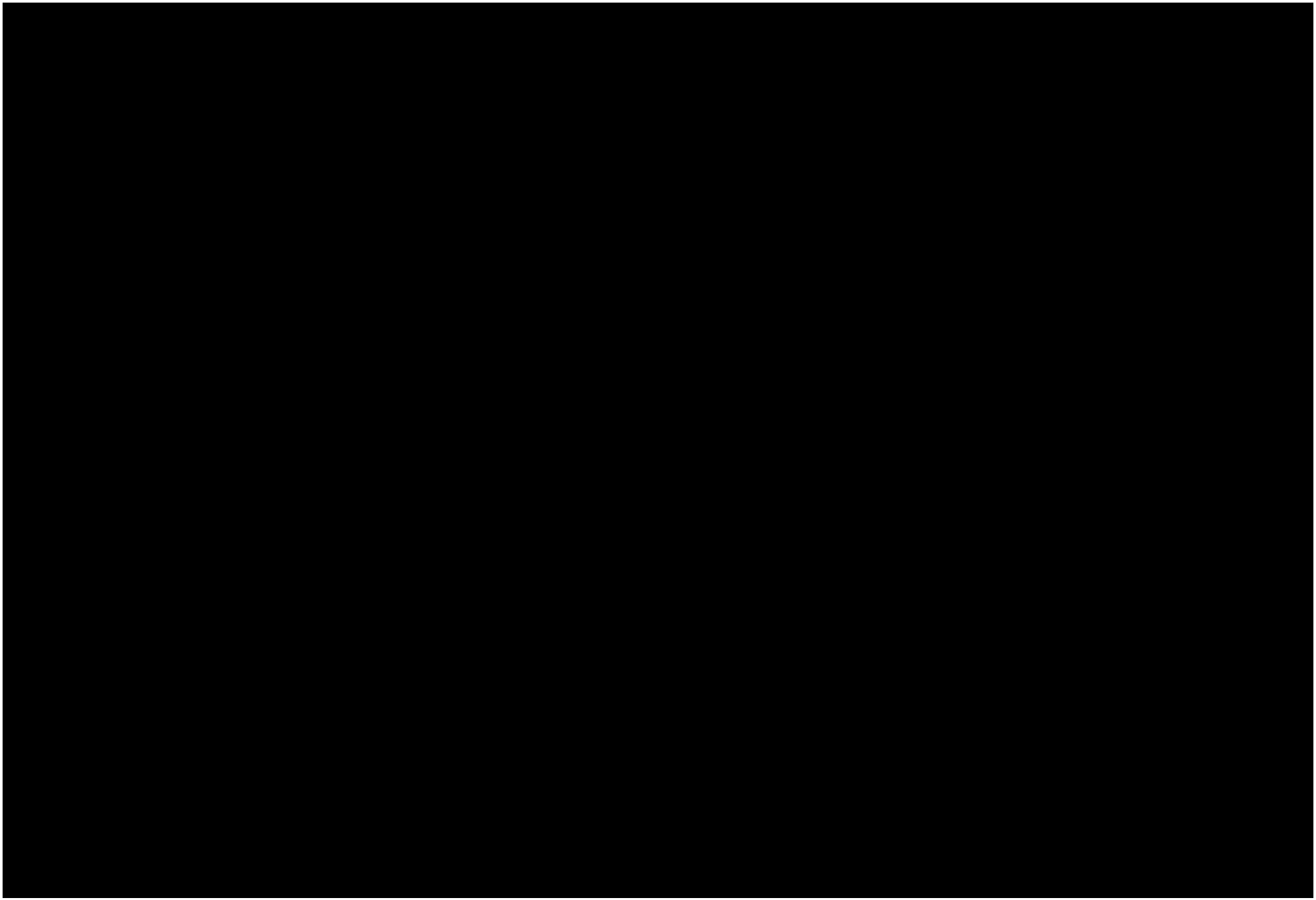
Date of Off Peak Day - 03/28/2021



Member Forecasted Off Peak Demand Day for April 2021

Chimney Rock Public Power District

Date of Off Peak Day - 04/30/2021



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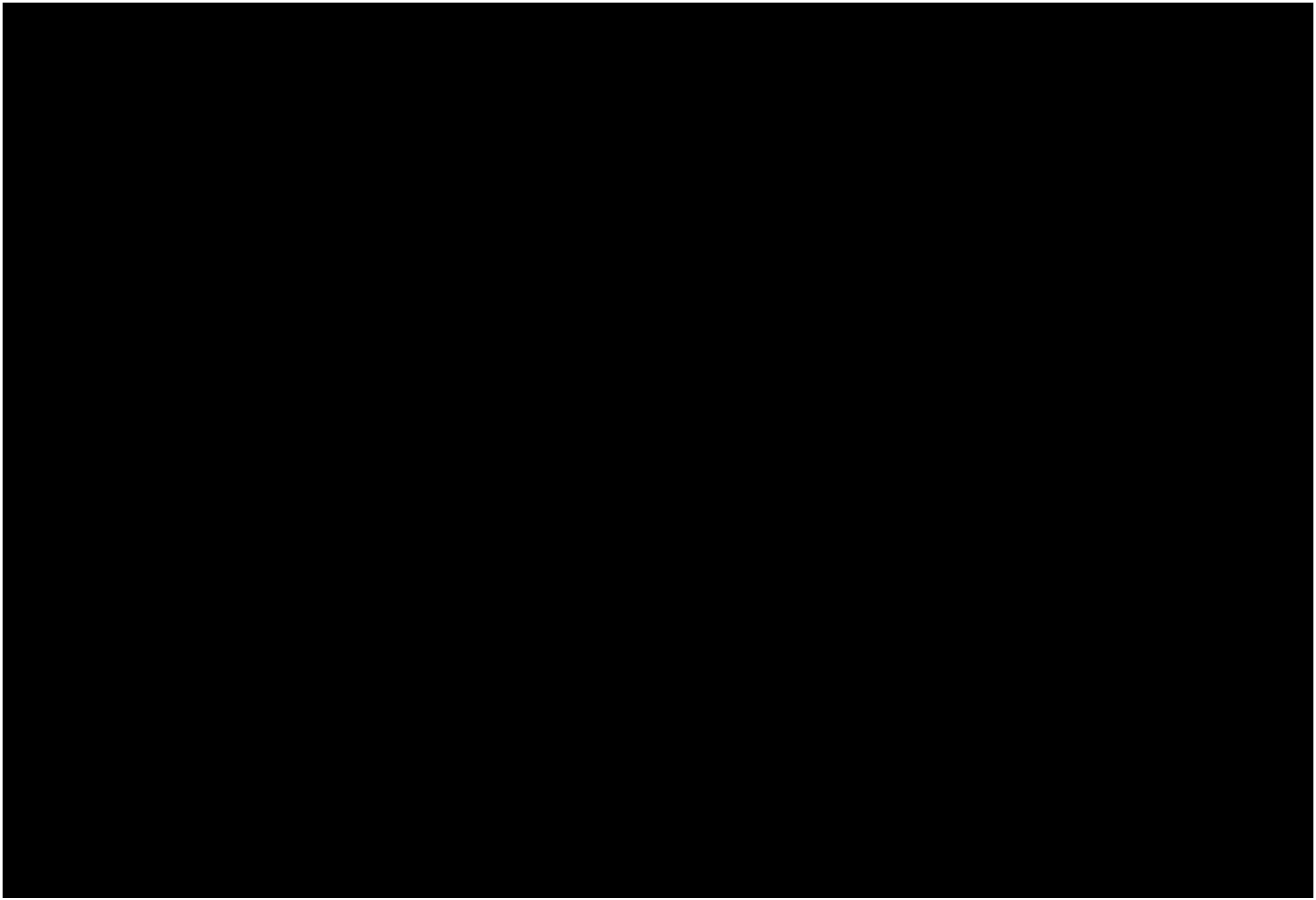
Member Forecasted Off Peak Demand Day for May 2021

Chimney Rock Public Power District

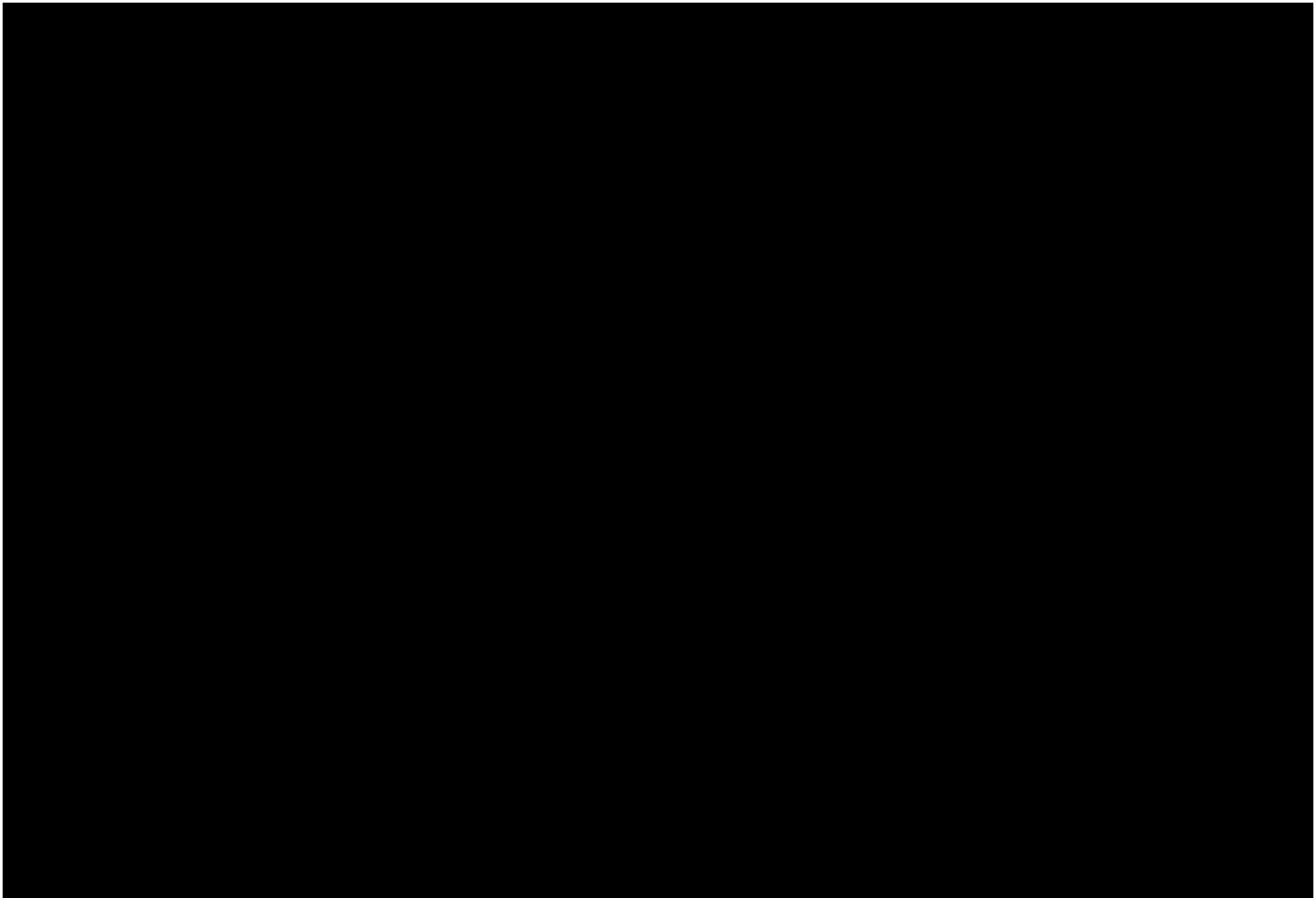
Date of Off Peak Day - 05/30/2021



Member Forecasted Off Peak Demand Day for June 2021

Chimney Rock Public Power District

Date of Off Peak Day - 06/01/2021



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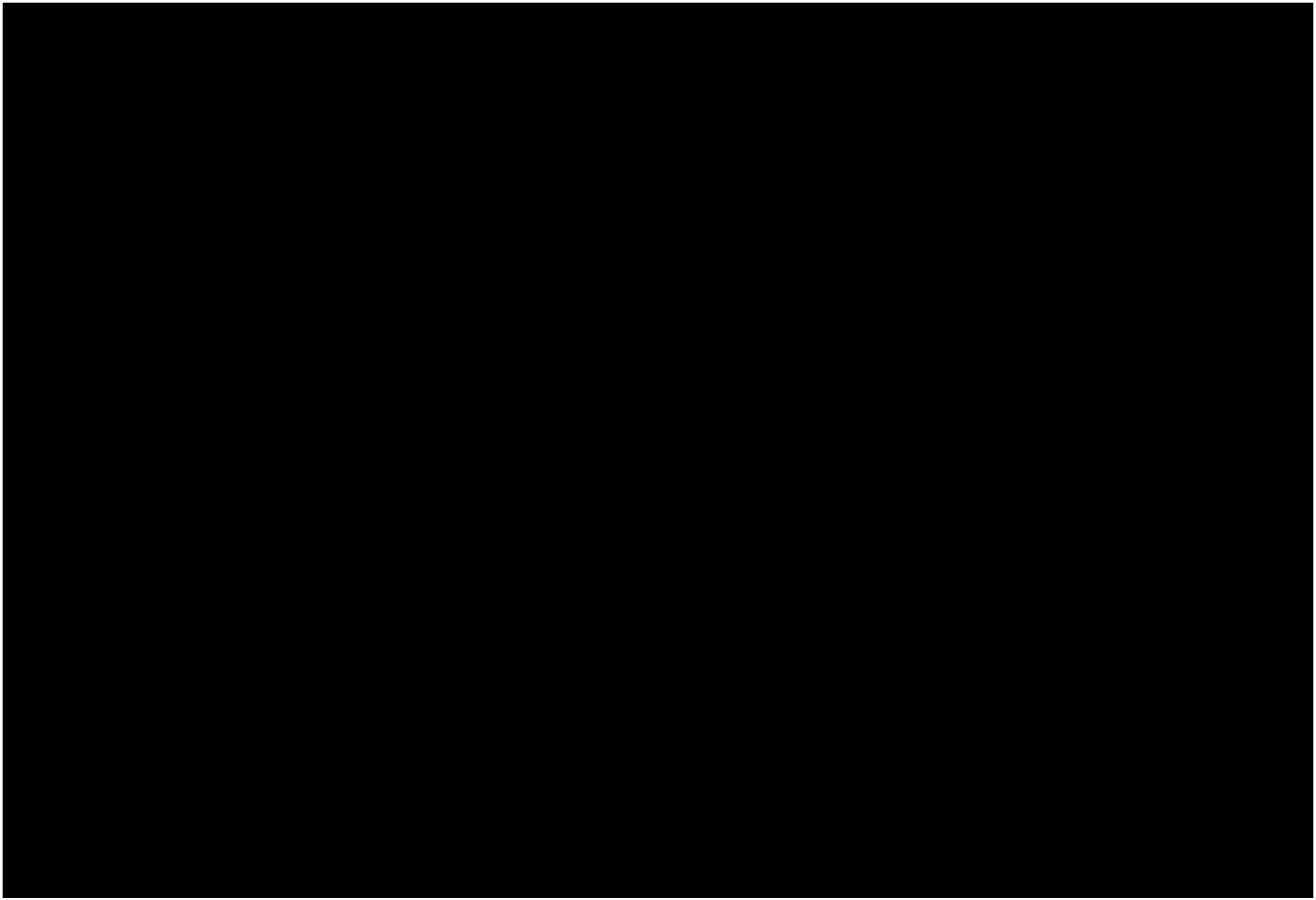
Member Forecasted Off Peak Demand Day for July 2021

Chimney Rock Public Power District

Date of Off Peak Day - 07/31/2021



Member Forecasted Off Peak Demand Day for August 2021

Chimney Rock Public Power District

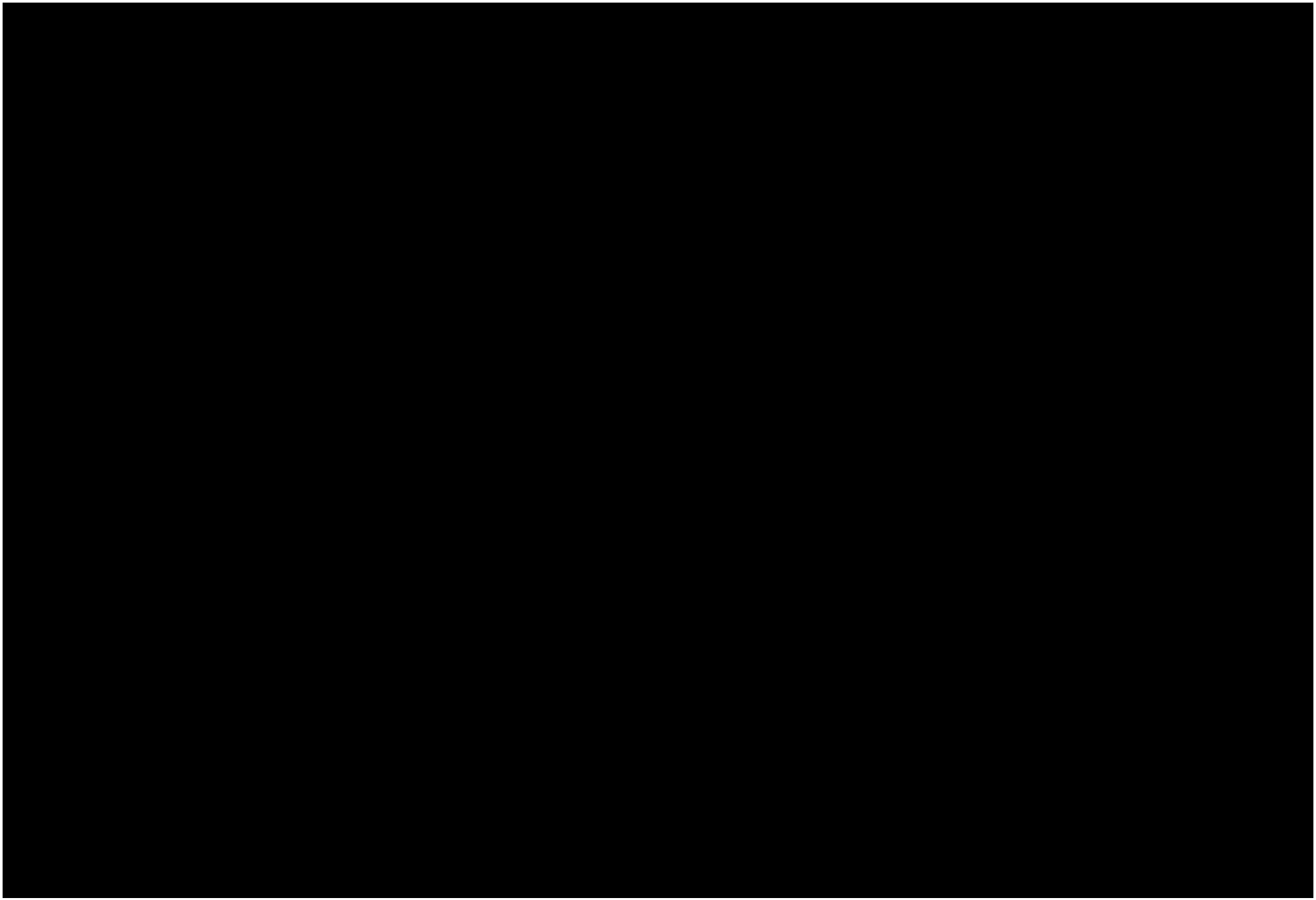
Date of Off Peak Day - 08/11/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Chimney Rock Public Power District

Date of Off Peak Day - 09/20/2021



Member Forecasted Off Peak Demand Day for October 2021

Chimney Rock Public Power District

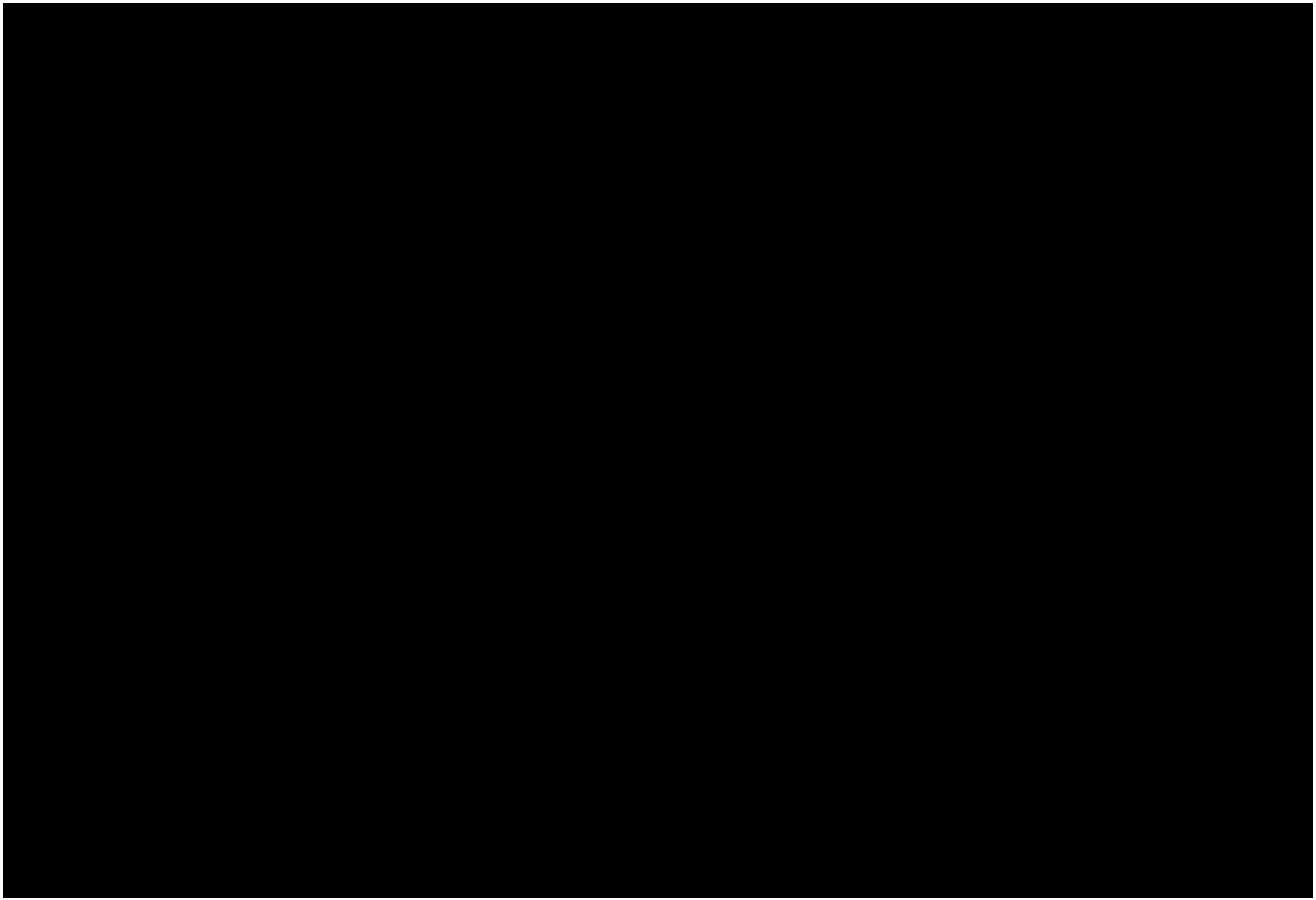
Date of Off Peak Day - 10/07/2021

[redacted]

Member Forecasted Off Peak Demand Day for November 2021

Chimney Rock Public Power District

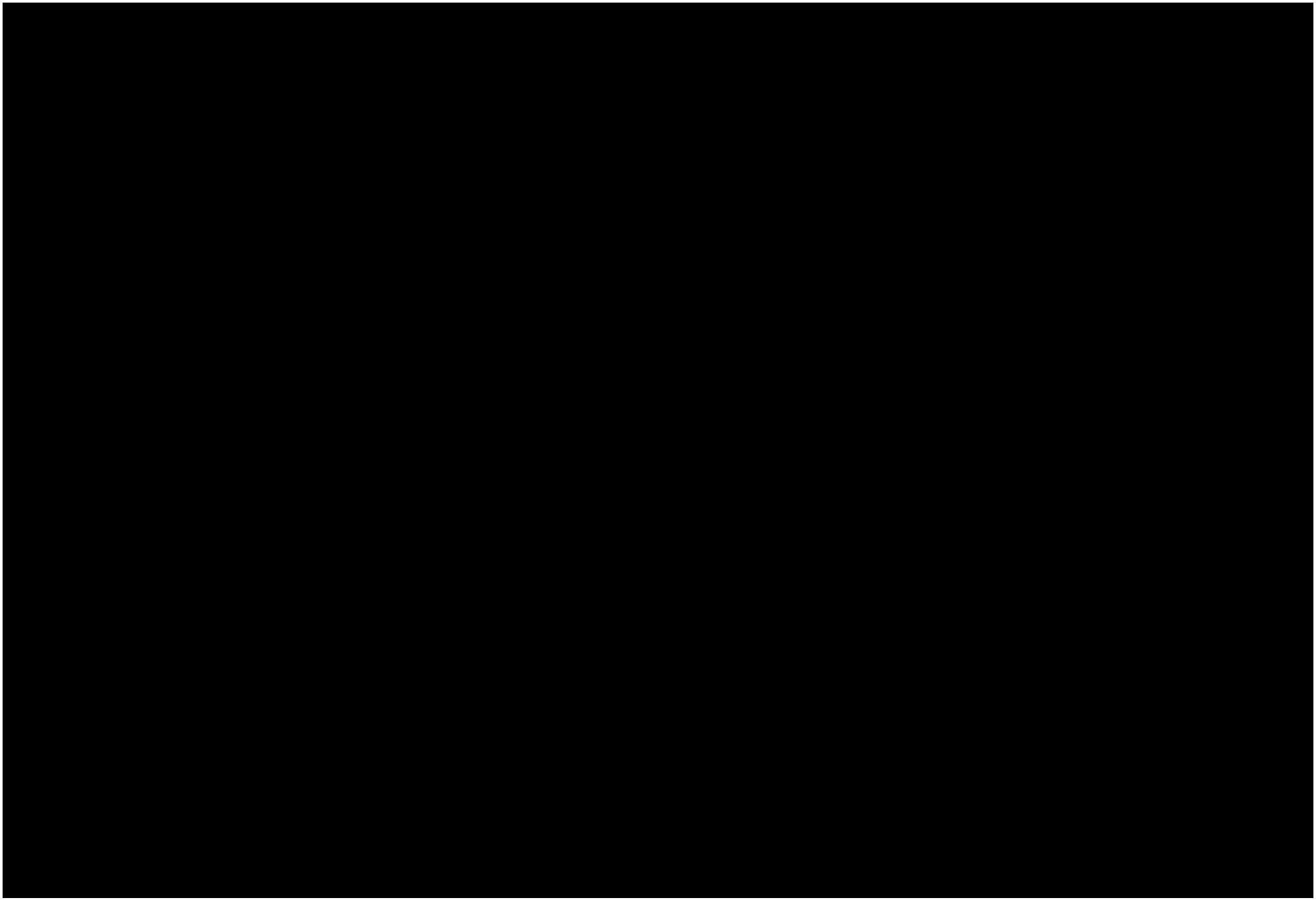
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Chimney Rock Public Power District

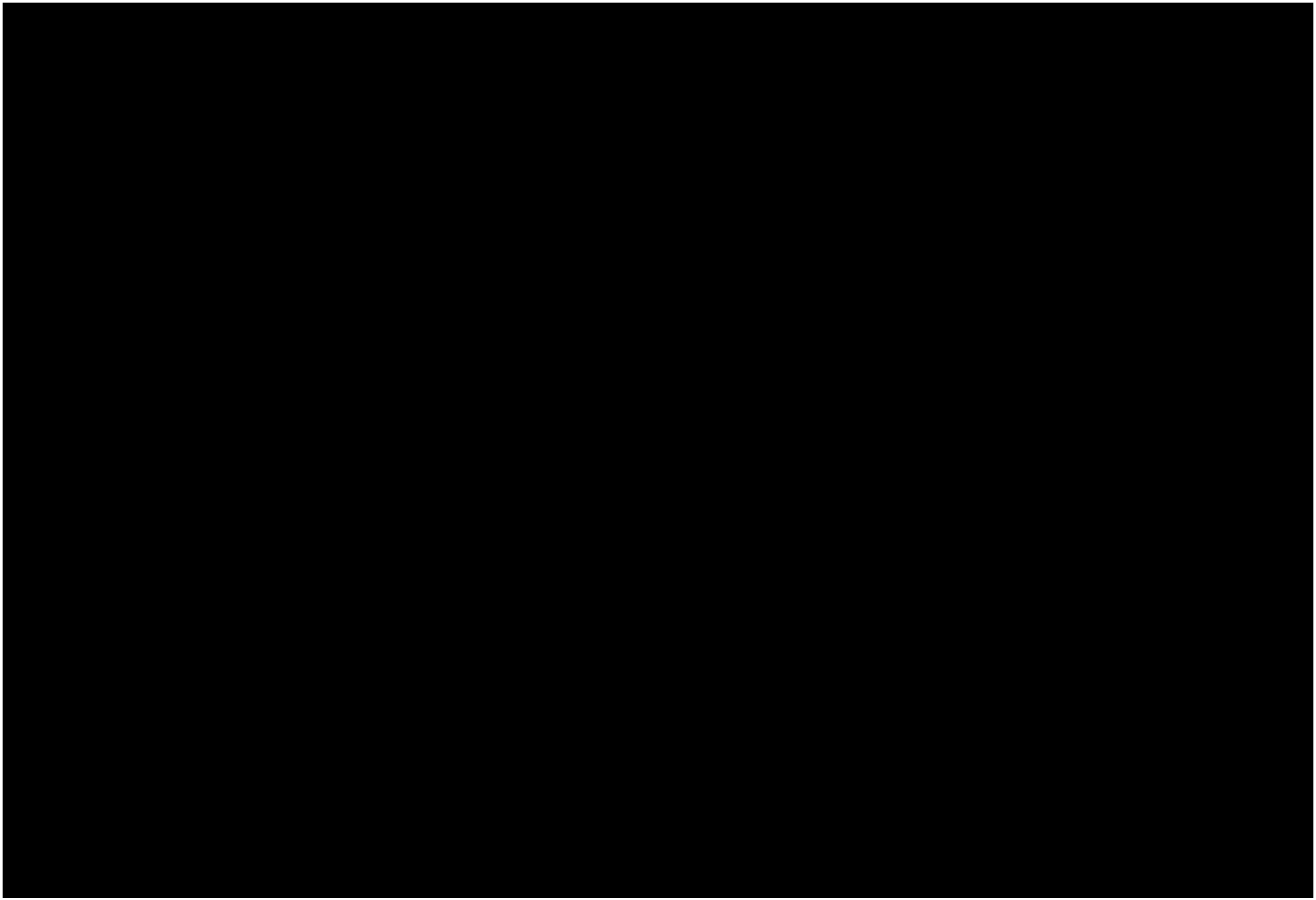
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Empire Electric Association, Inc.

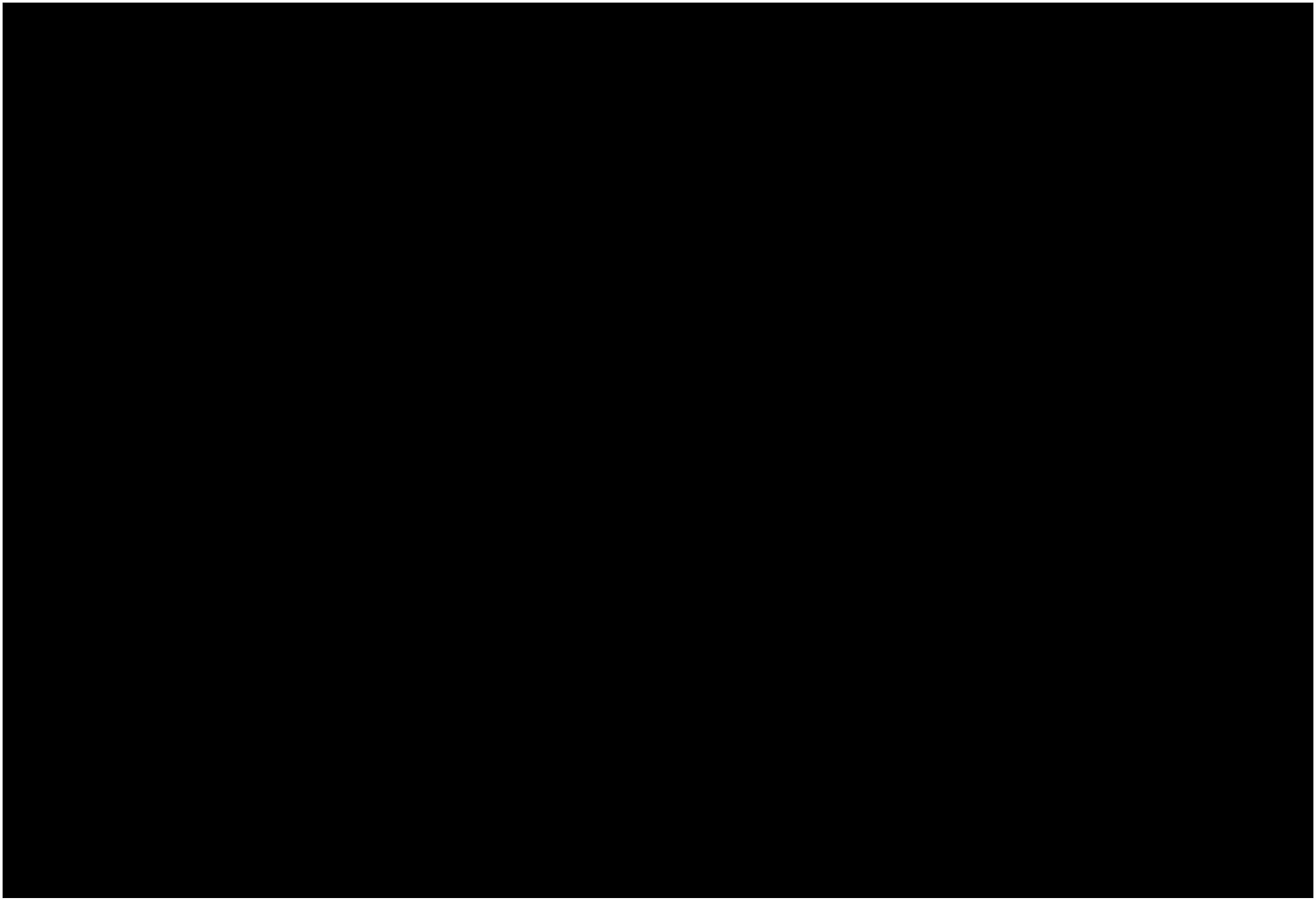
Date of Off Peak Day - 01/13/2021



Member Forecasted Off Peak Demand Day for February 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 02/05/2021



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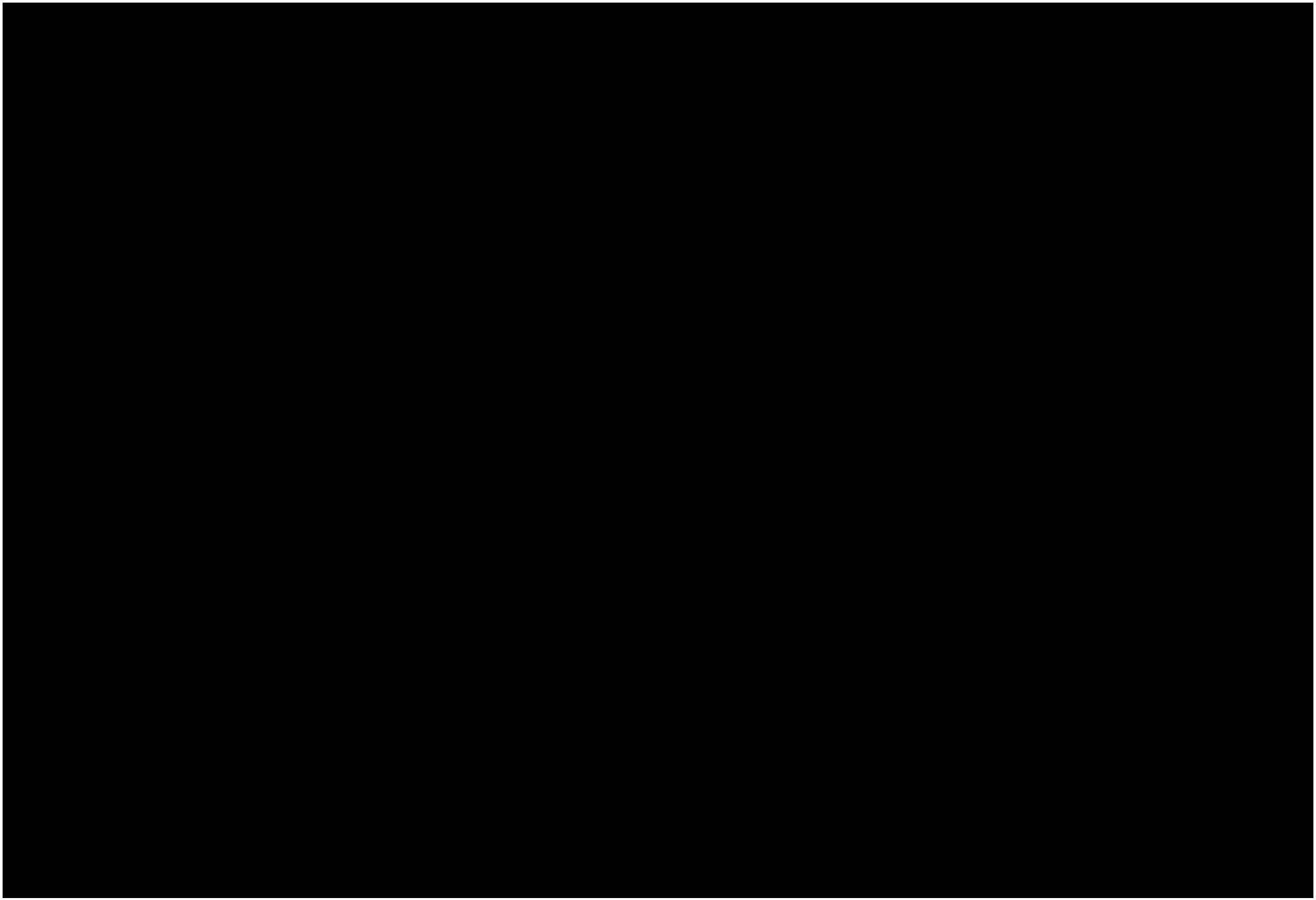
Member Forecasted Off Peak Demand Day for March 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 04/11/2021

[redacted]

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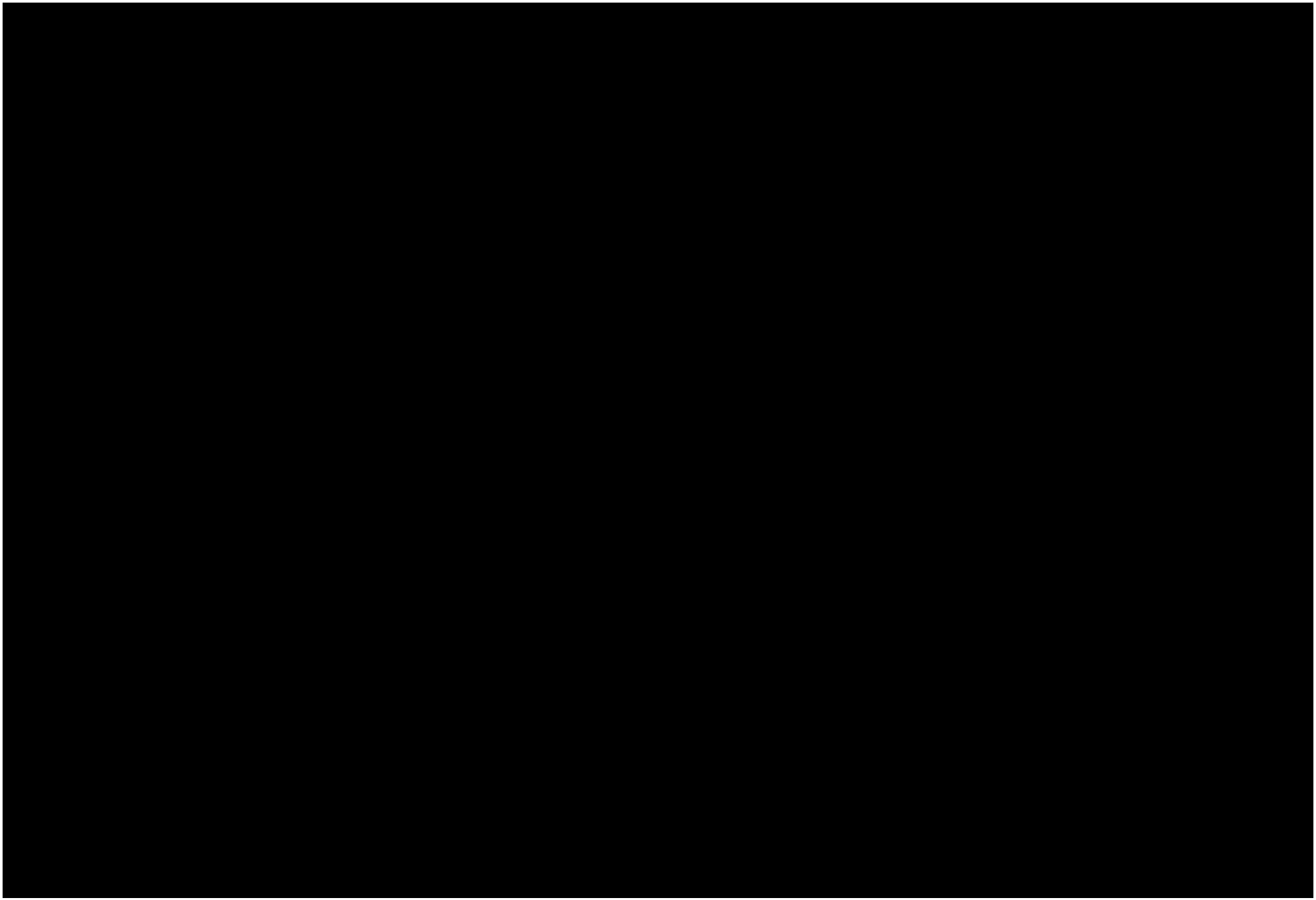
Member Forecasted Off Peak Demand Day for May 2021

Empire Electric Association, Inc.

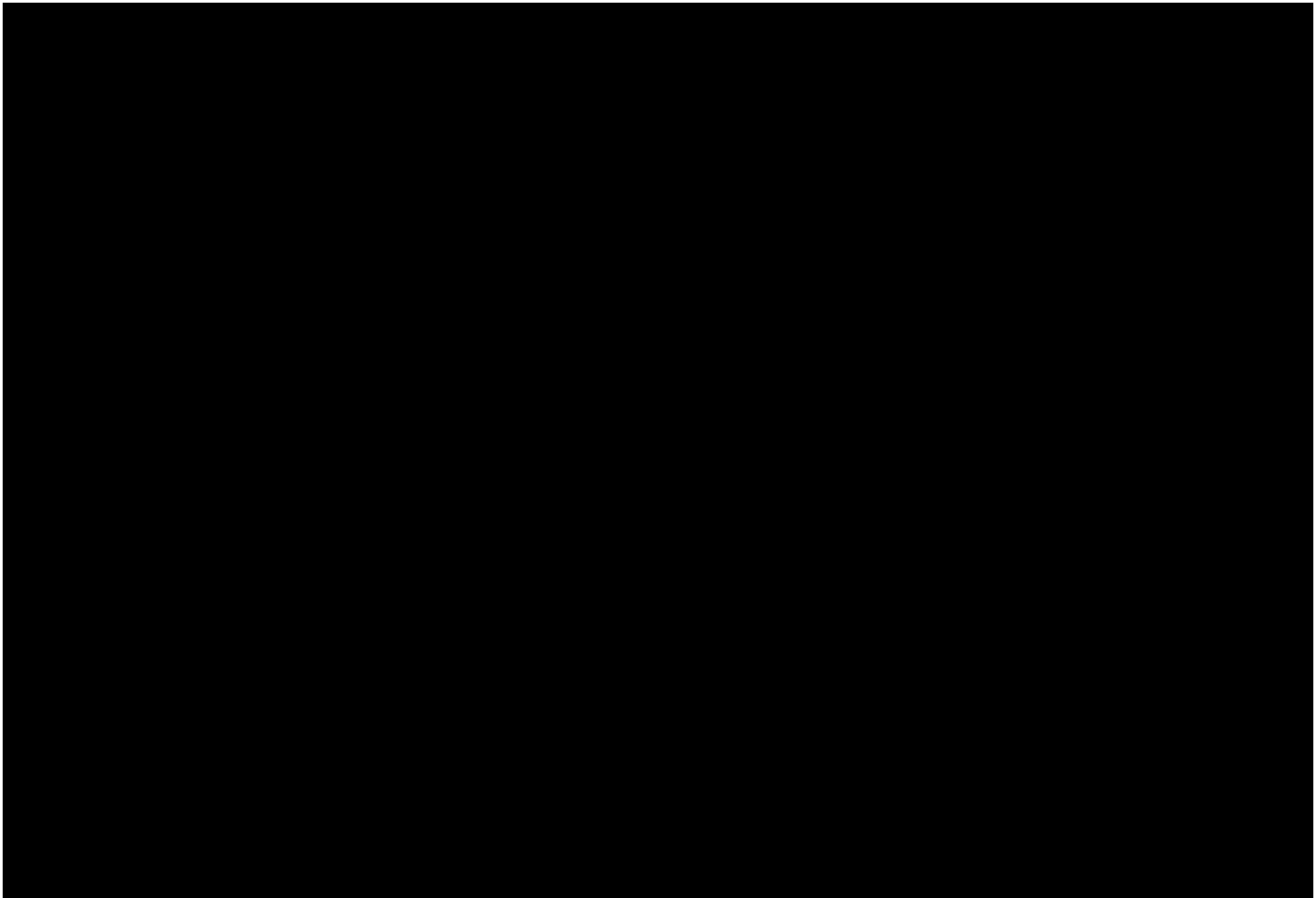
Date of Off Peak Day - 05/02/2021



Member Forecasted Off Peak Demand Day for June 2021

Empire Electric Association, Inc.

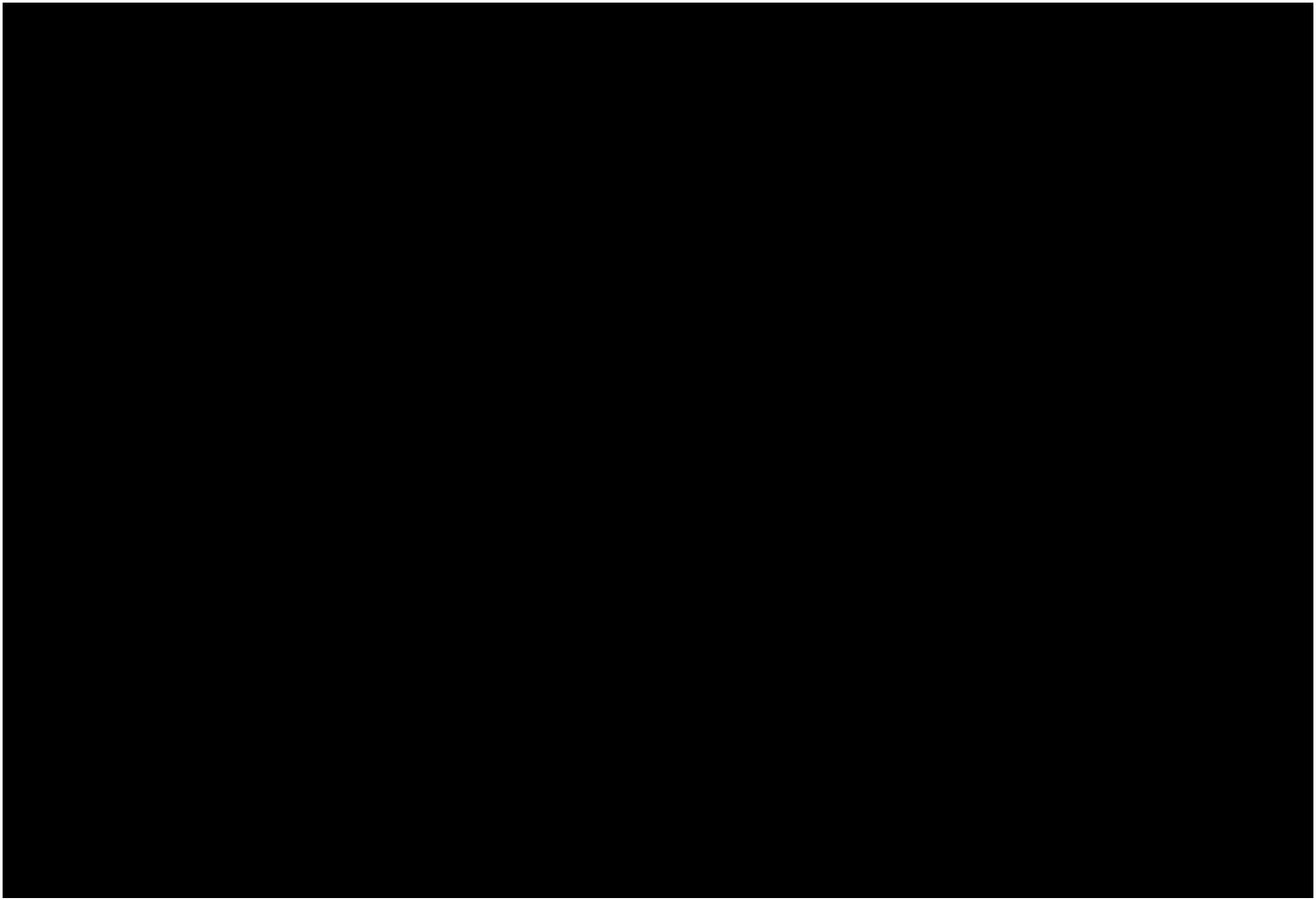
Date of Off Peak Day - 06/28/2021



Member Forecasted Off Peak Demand Day for July 2021

Empire Electric Association, Inc.

Date of Off Peak Day - 07/18/2021



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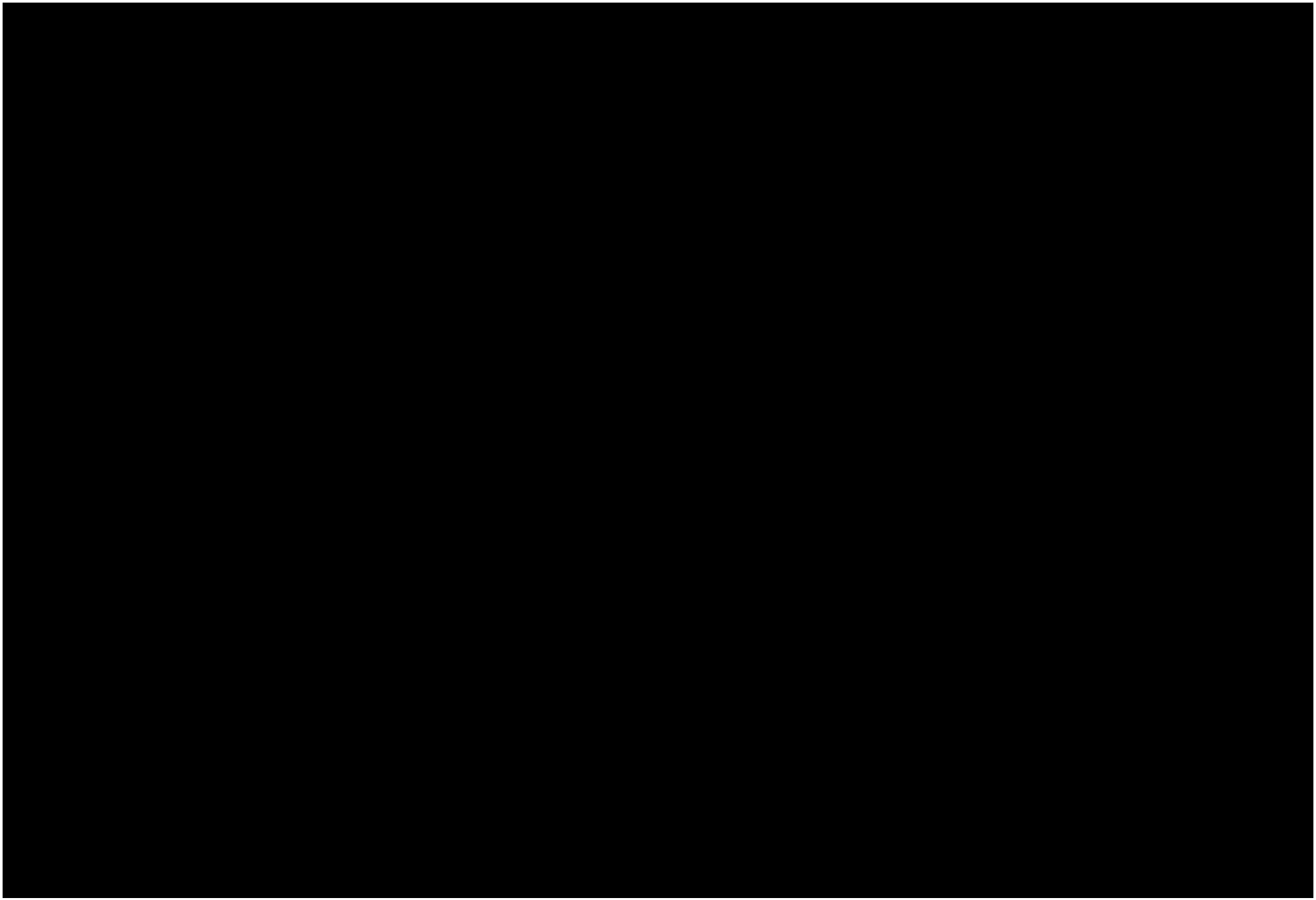
Member Forecasted Off Peak Demand Day for August 2021

Empire Electric Association, Inc.

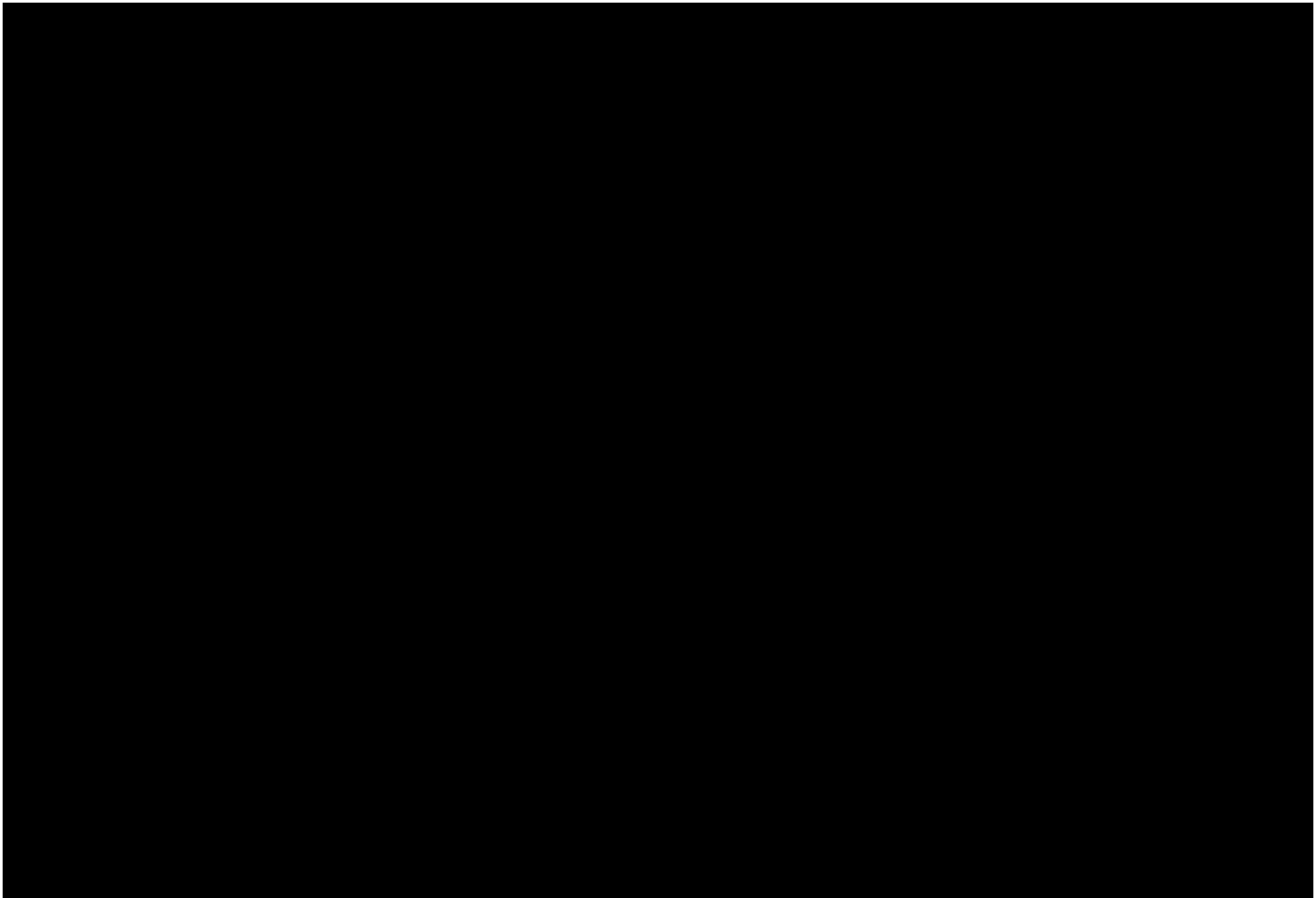
Date of Off Peak Day - 08/12/2021



Member Forecasted Off Peak Demand Day for September 2021

Empire Electric Association, Inc.

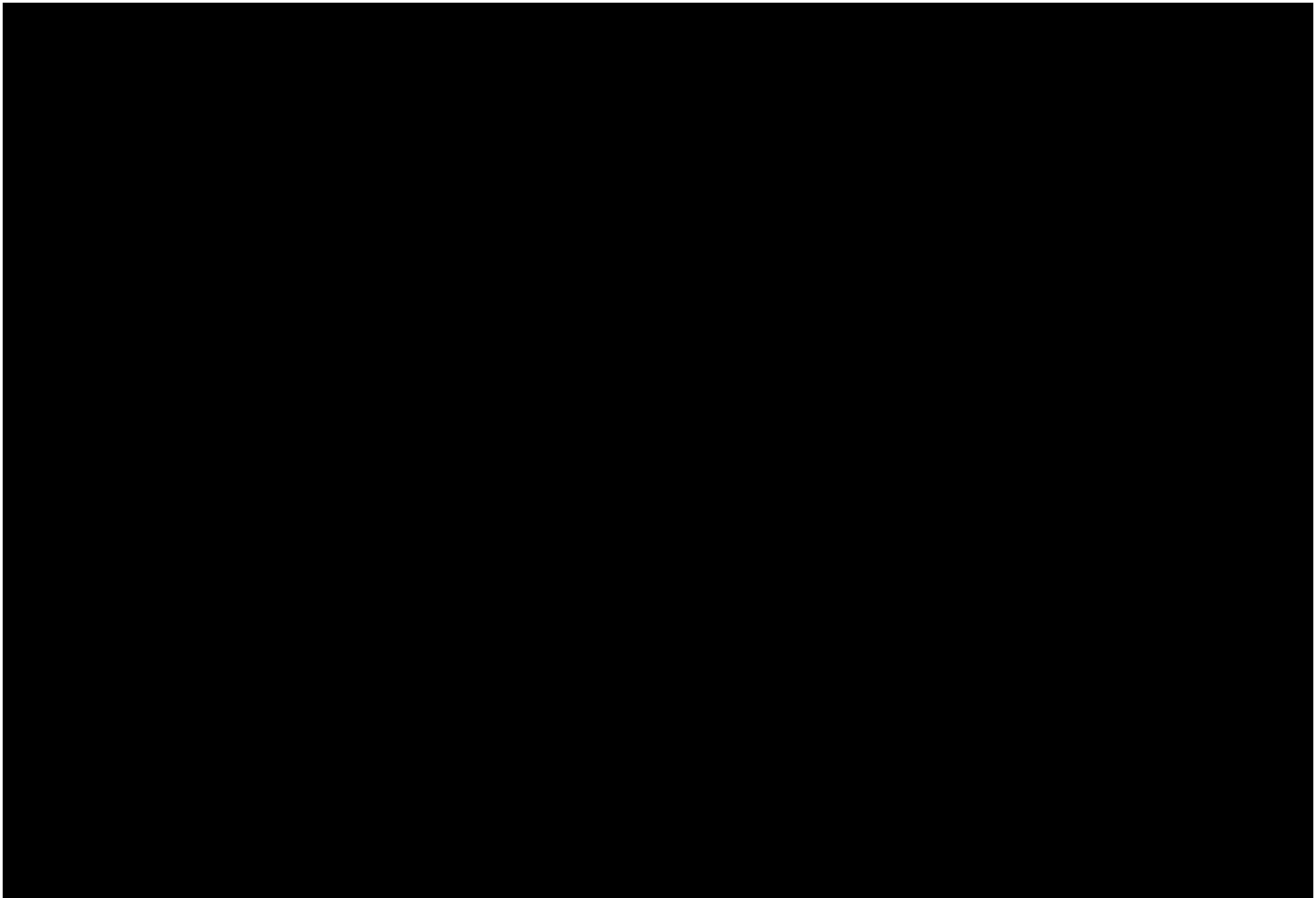
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Empire Electric Association, Inc.

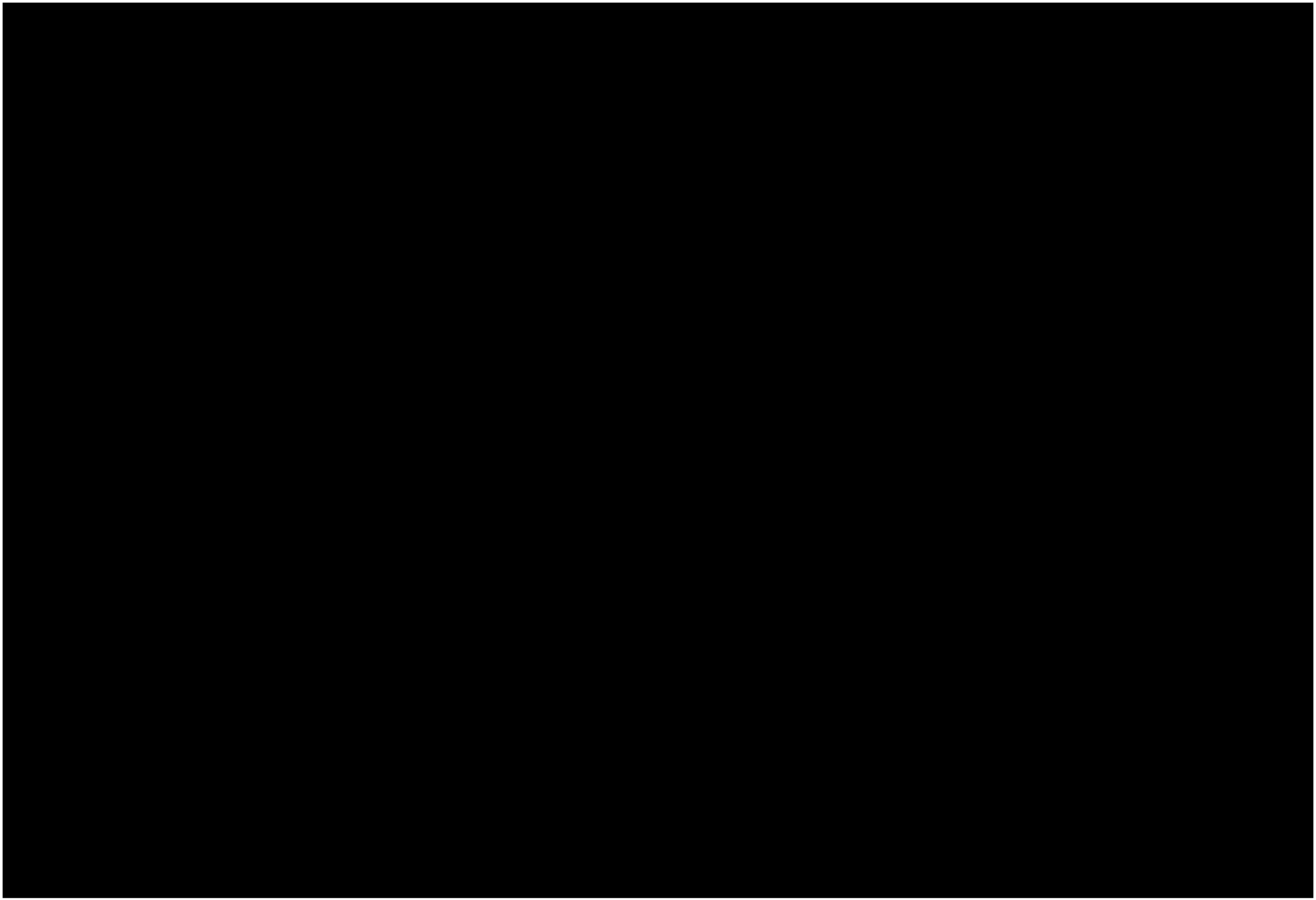
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Empire Electric Association, Inc.

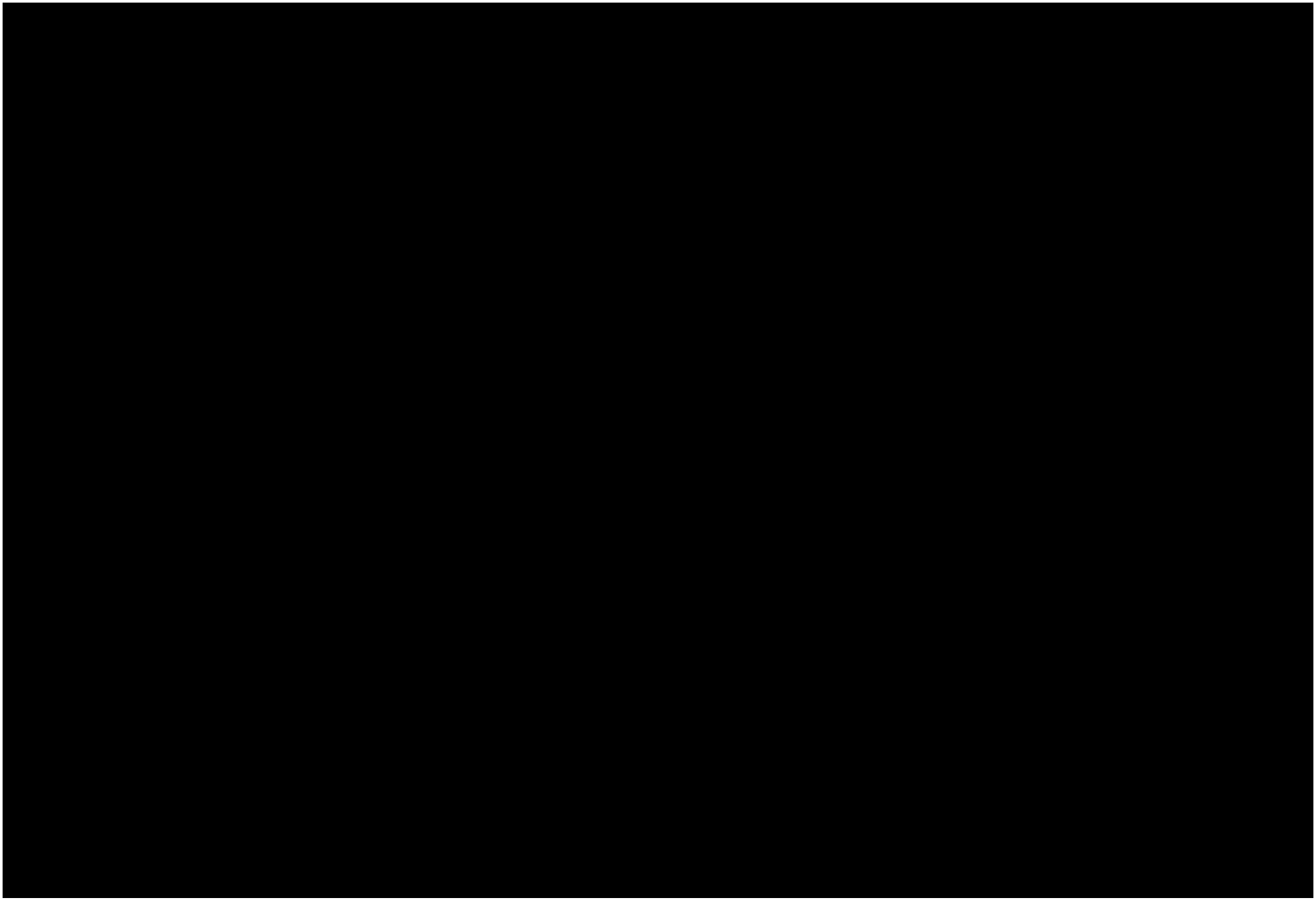
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Empire Electric Association, Inc.

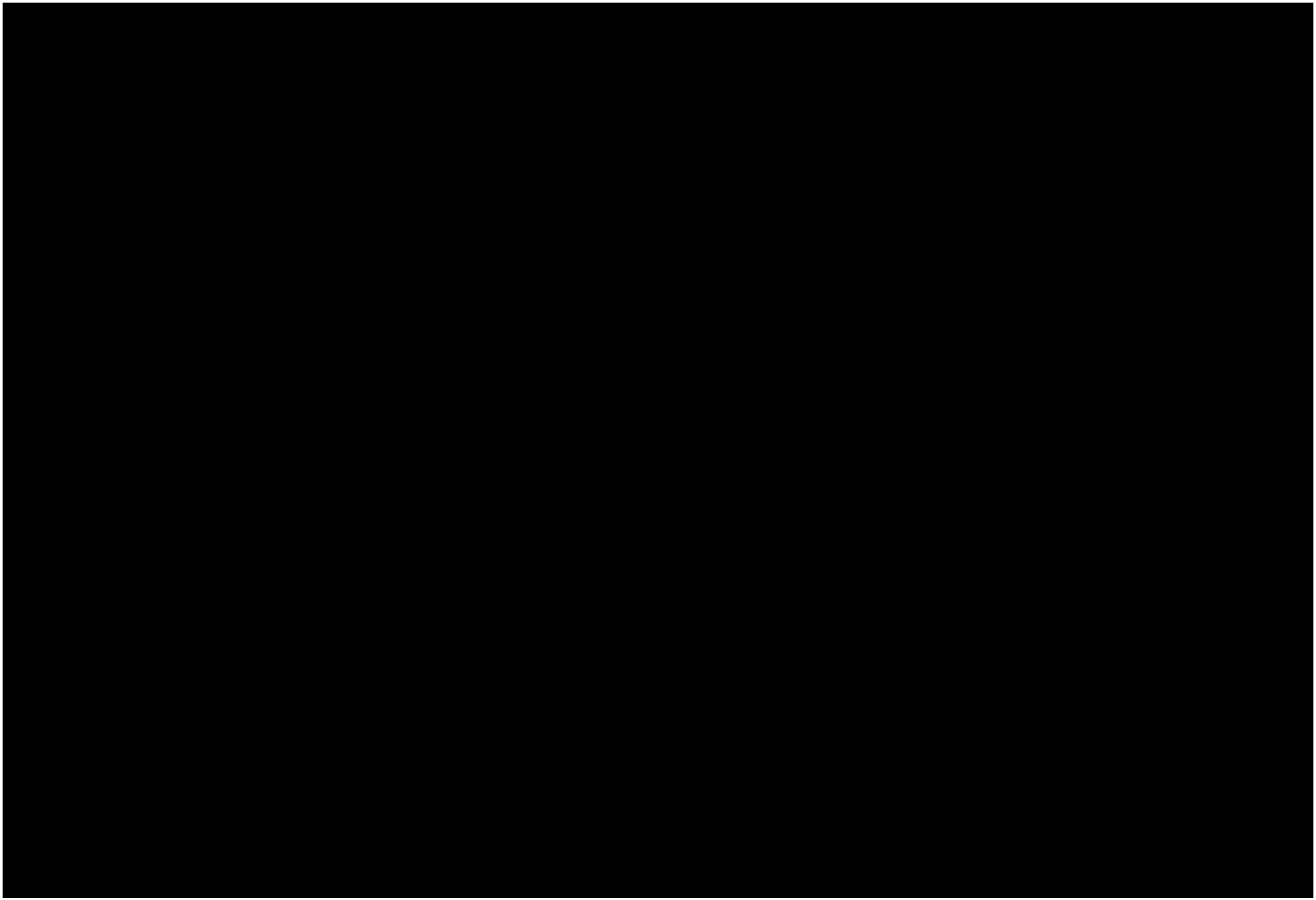
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Gunnison County Electric Association, Inc.

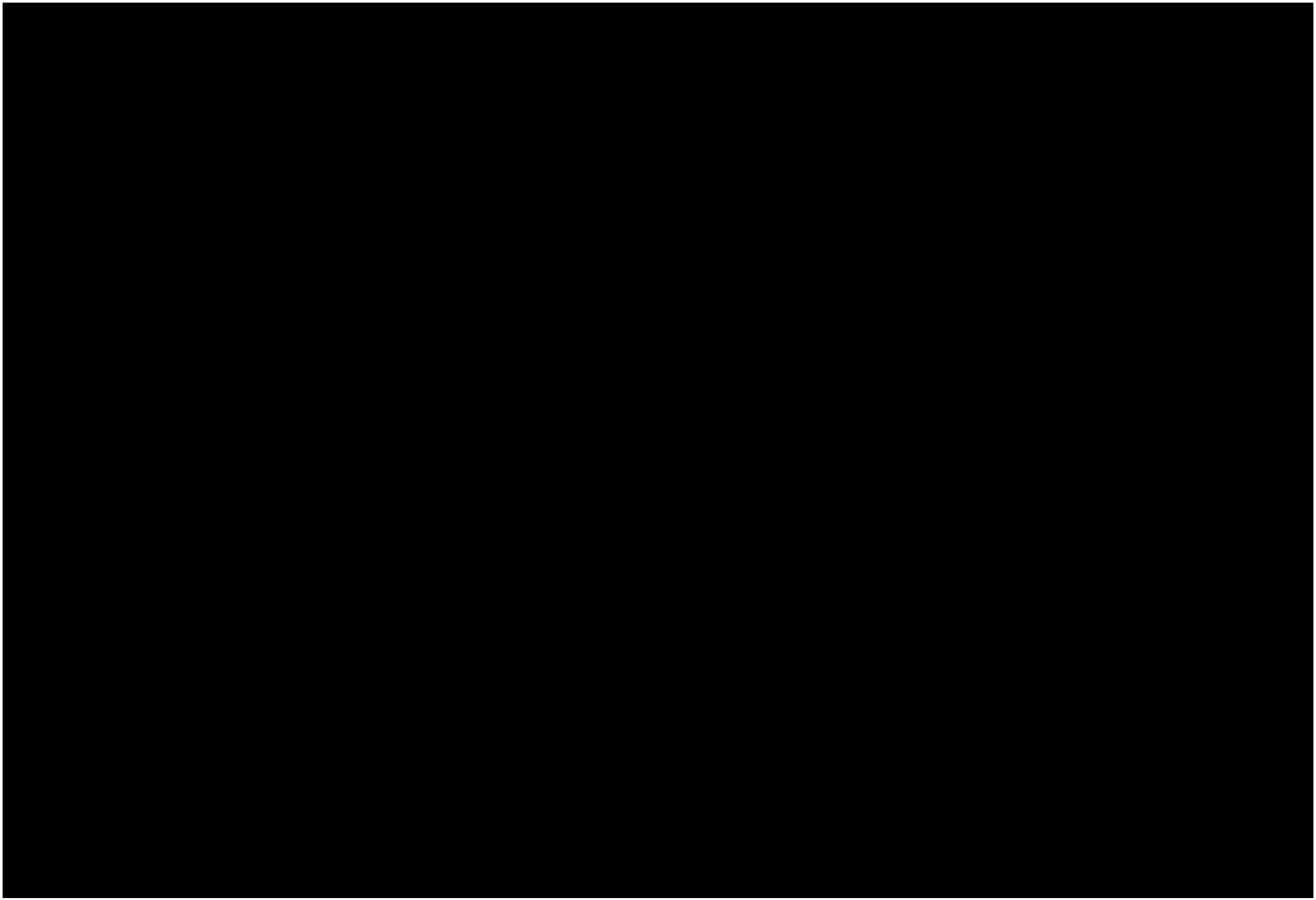
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Gunnison County Electric Association, Inc.

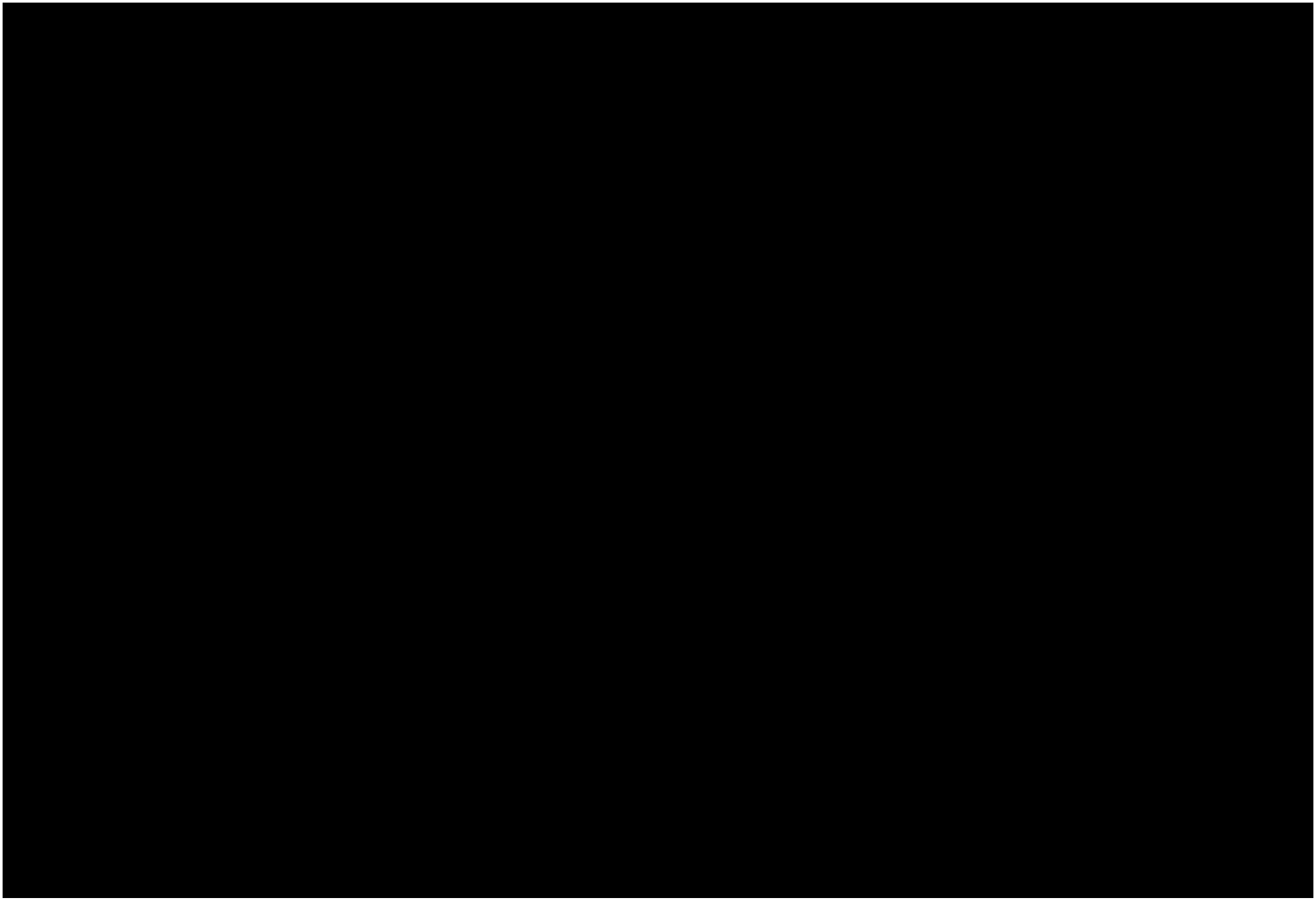
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Gunnison County Electric Association, Inc.

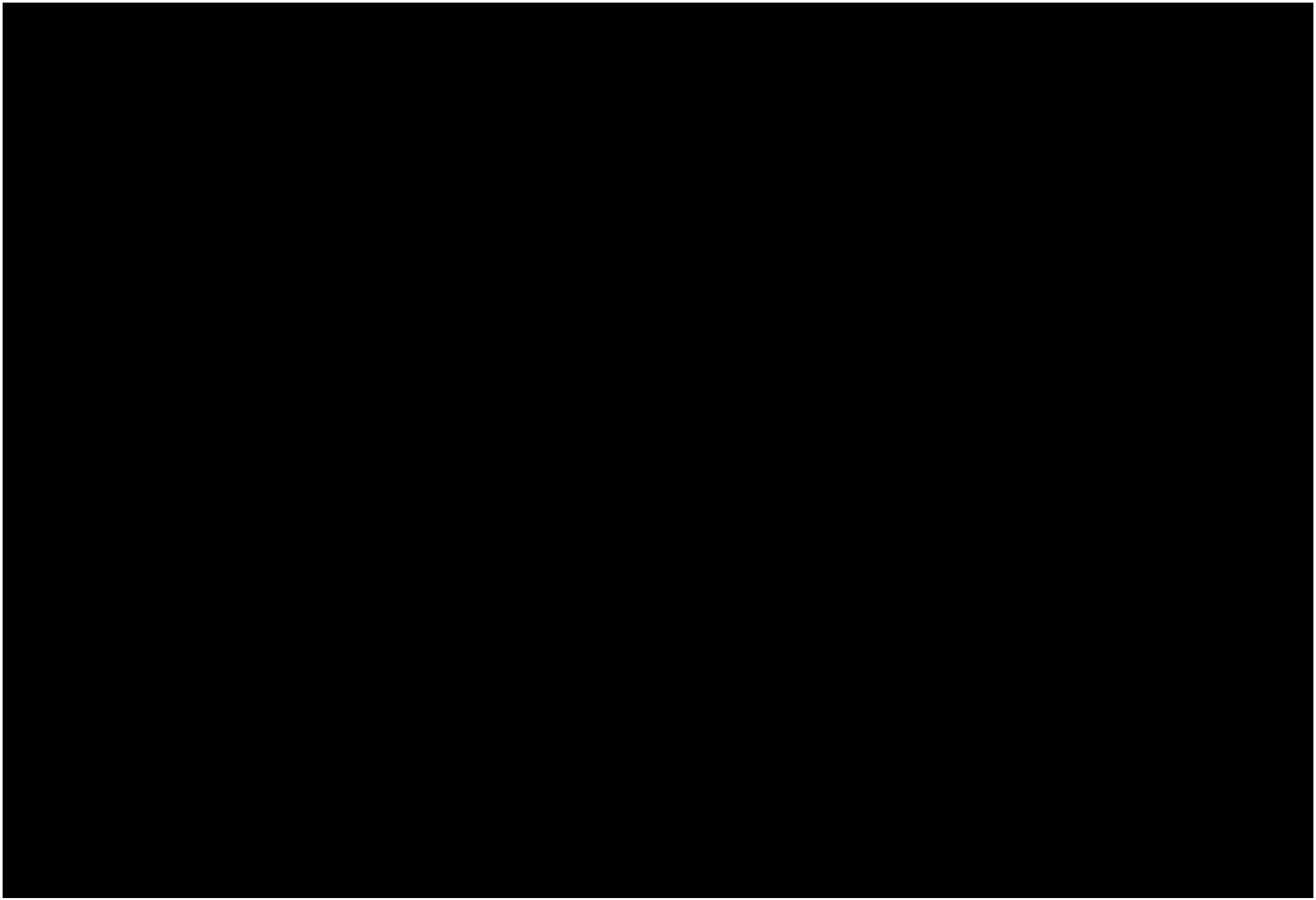
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Gunnison County Electric Association, Inc.

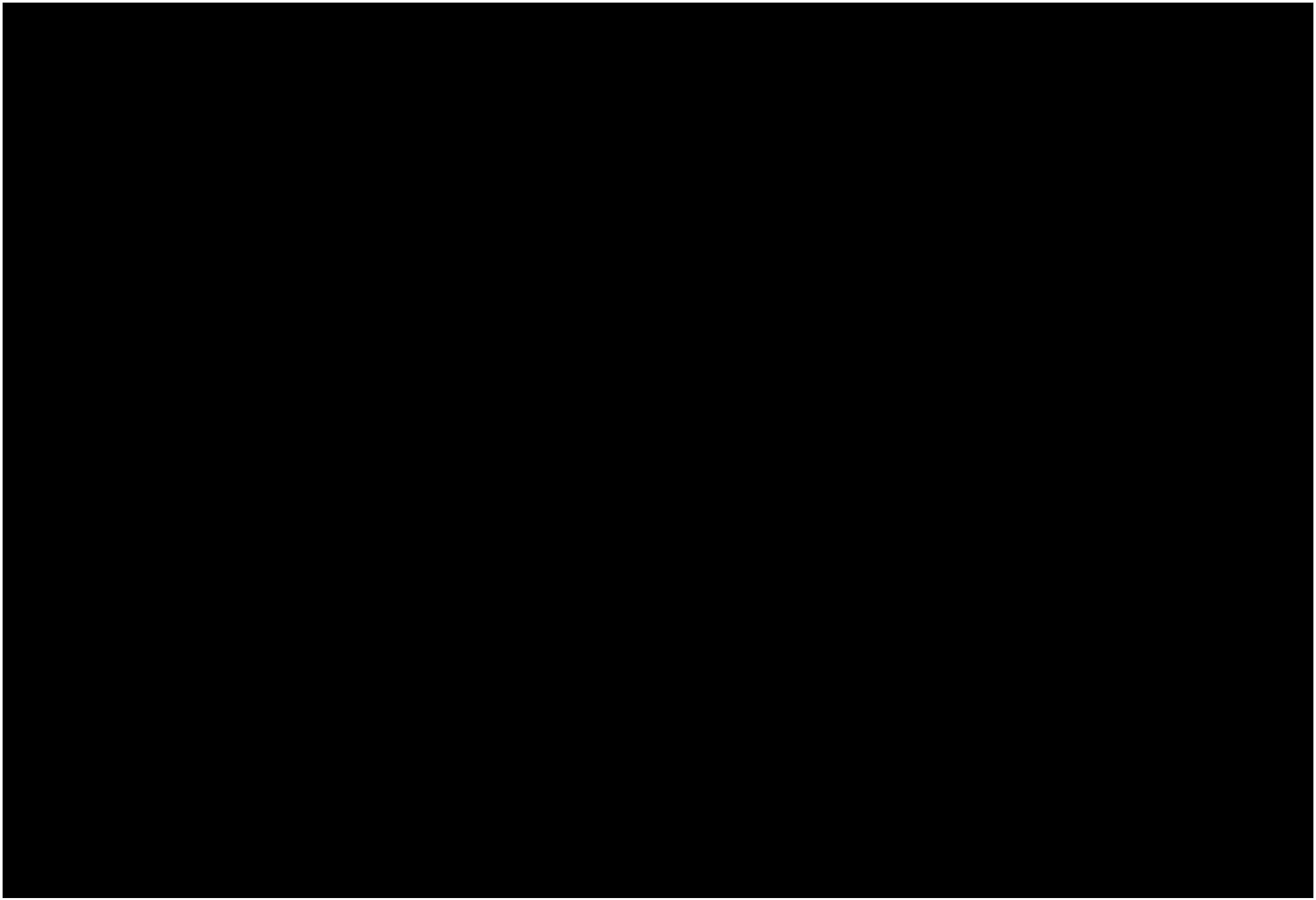
Date of Off Peak Day - 04/12/2021



Member Forecasted Off Peak Demand Day for May 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 05/31/2021



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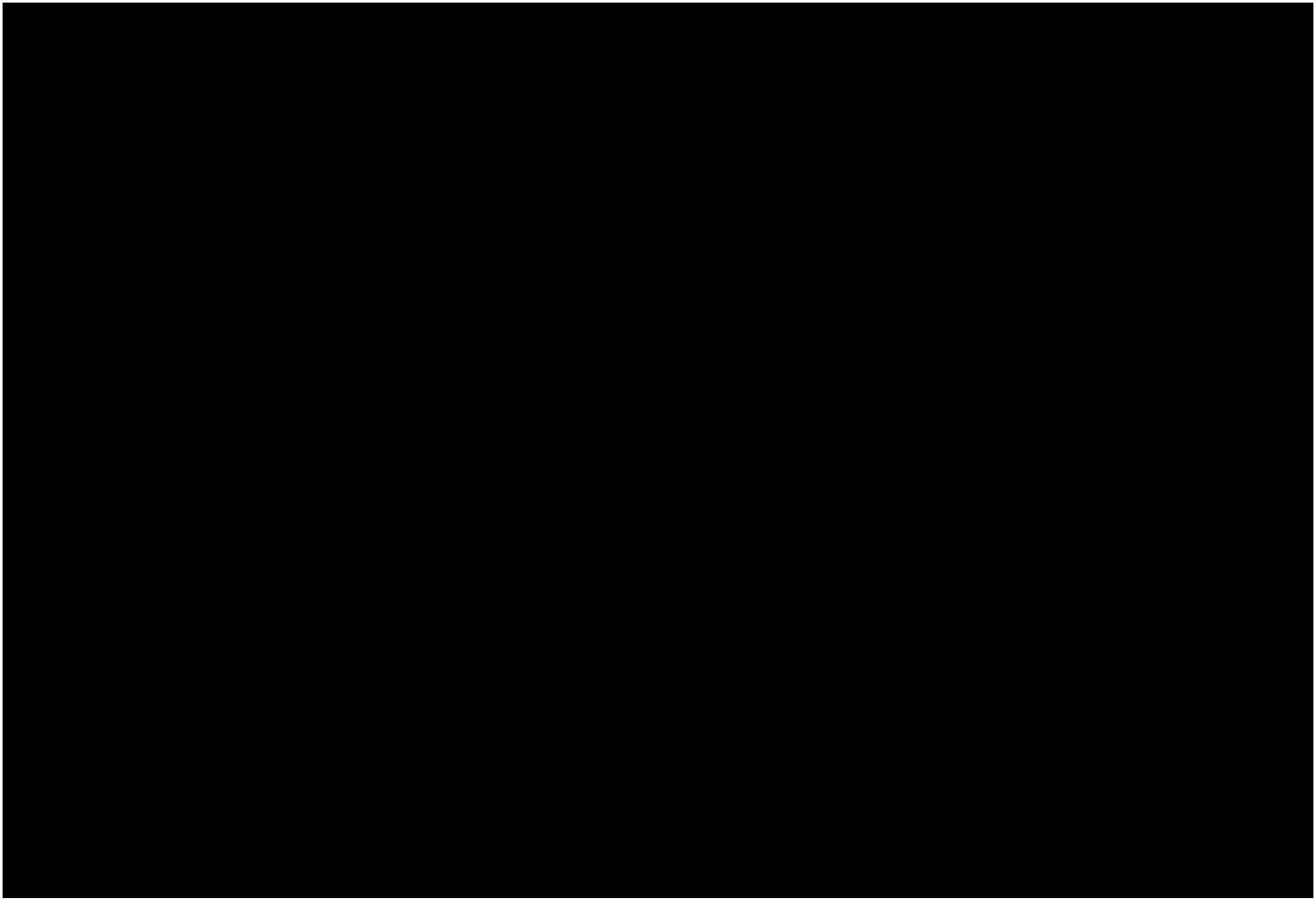
Member Forecasted Off Peak Demand Day for June 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 06/16/2021



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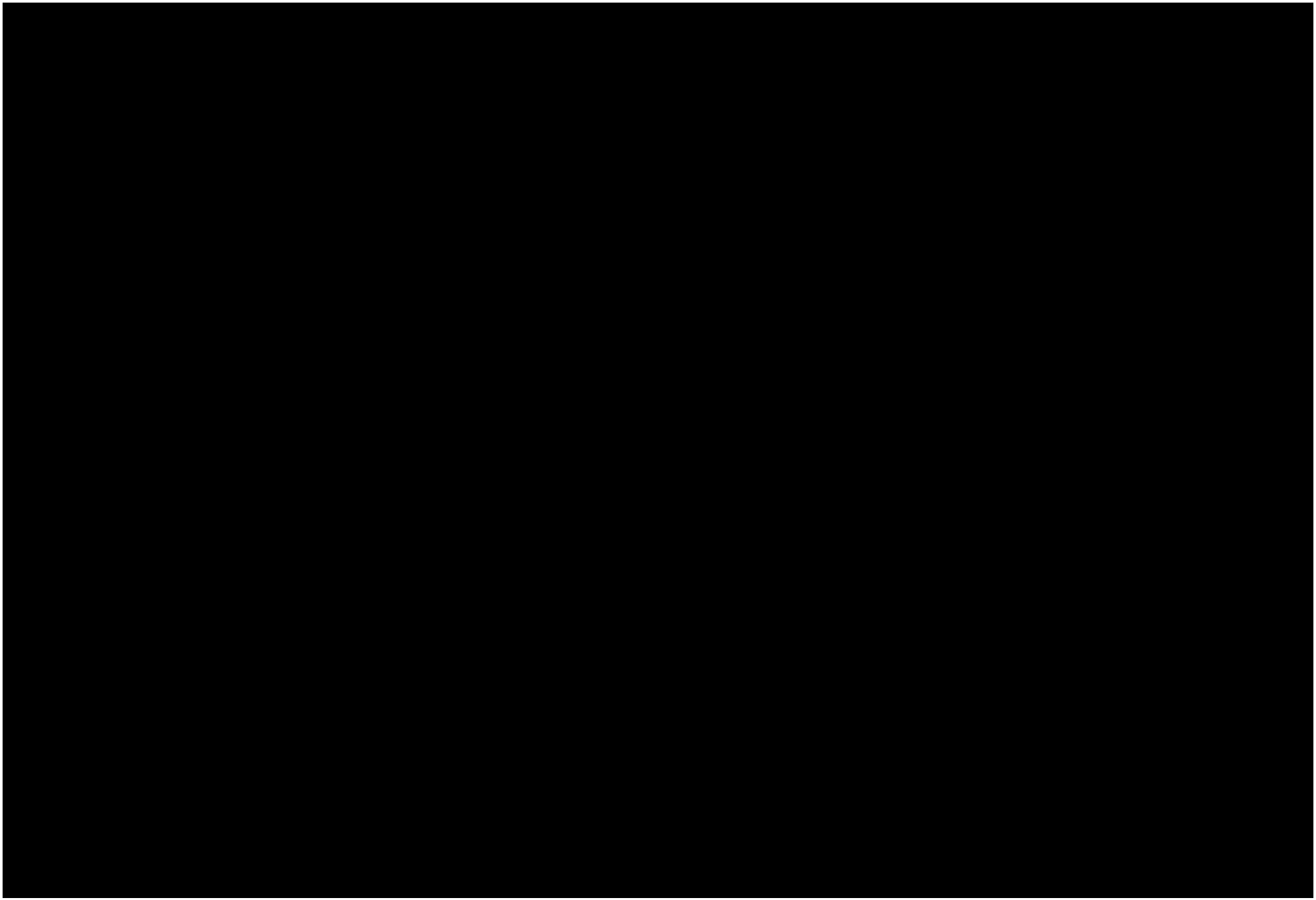
Member Forecasted Off Peak Demand Day for July 2021

Gunnison County Electric Association, Inc.

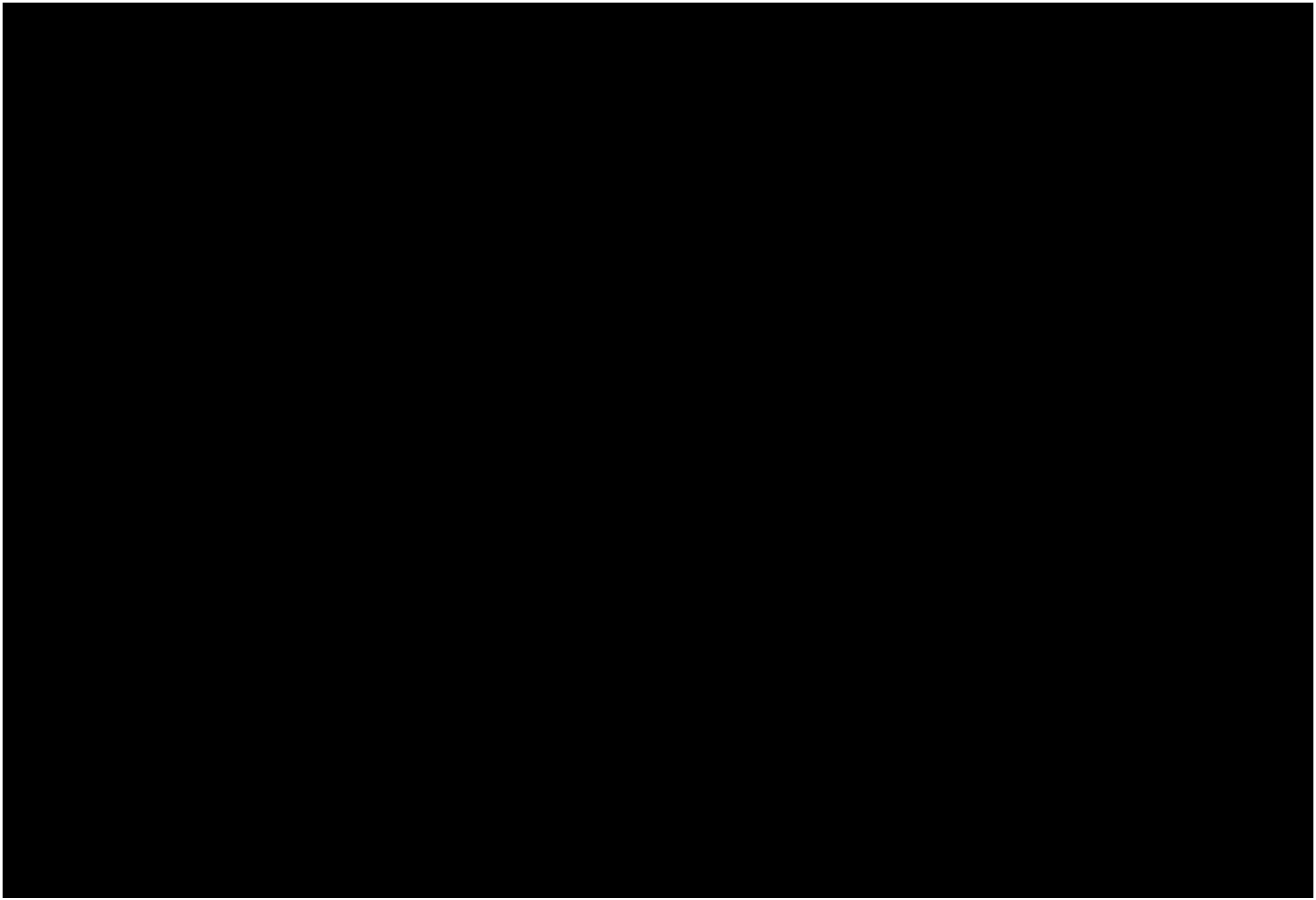
Date of Off Peak Day - 07/01/2021



Member Forecasted Off Peak Demand Day for August 2021

Gunnison County Electric Association, Inc.

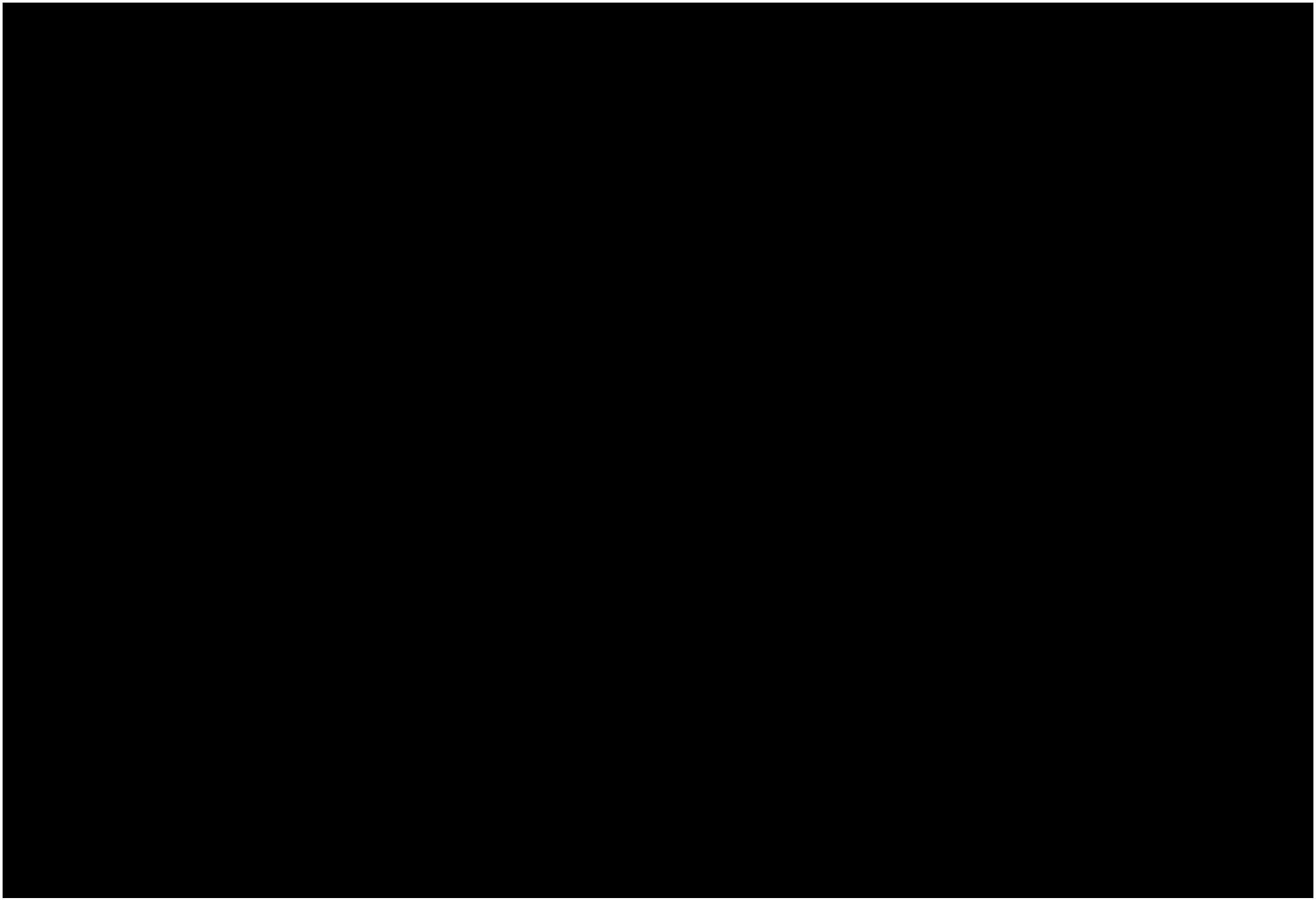
Date of Off Peak Day - 08/31/2021



Member Forecasted Off Peak Demand Day for September 2021

Gunnison County Electric Association, Inc.

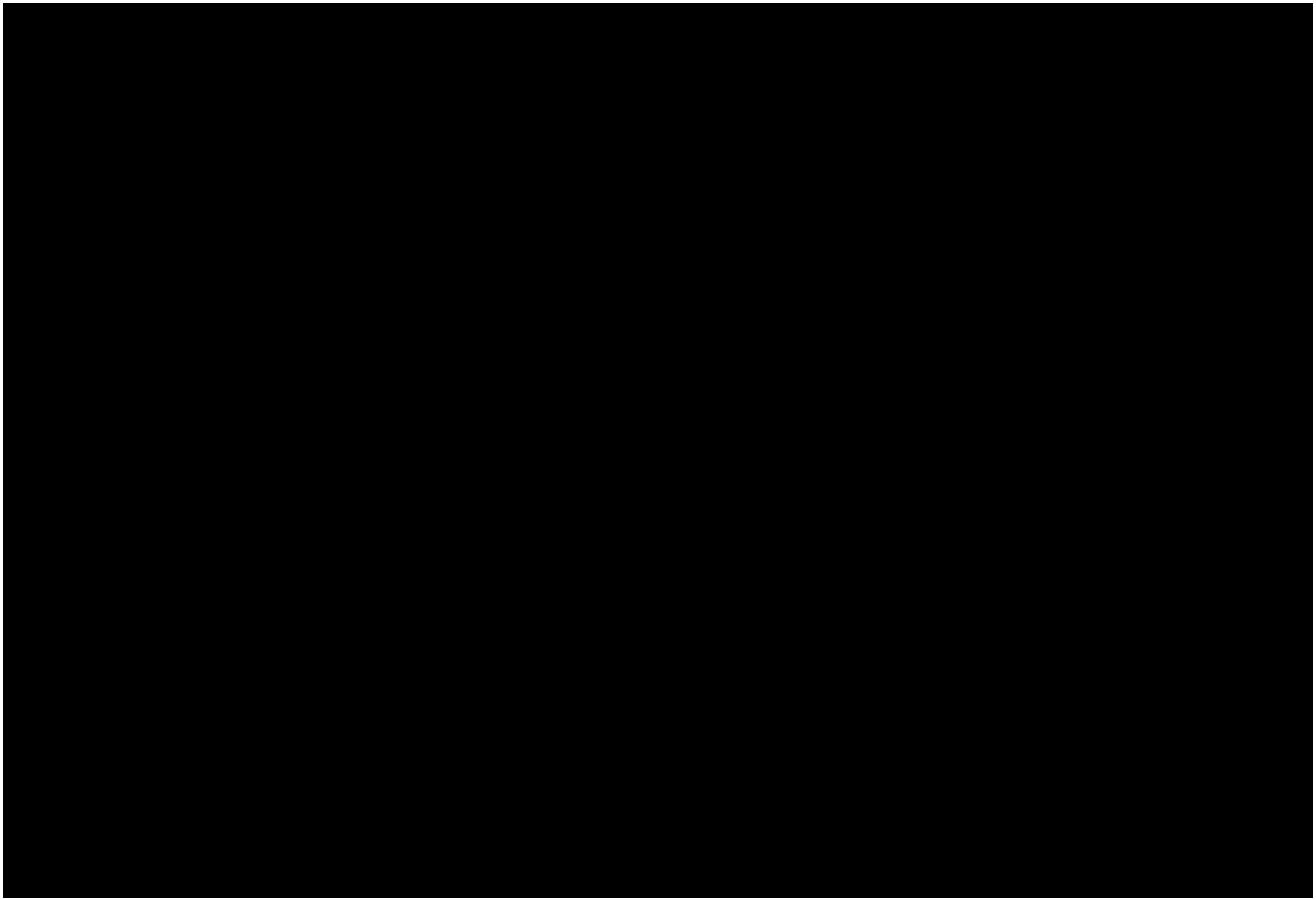
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Gunnison County Electric Association, Inc.

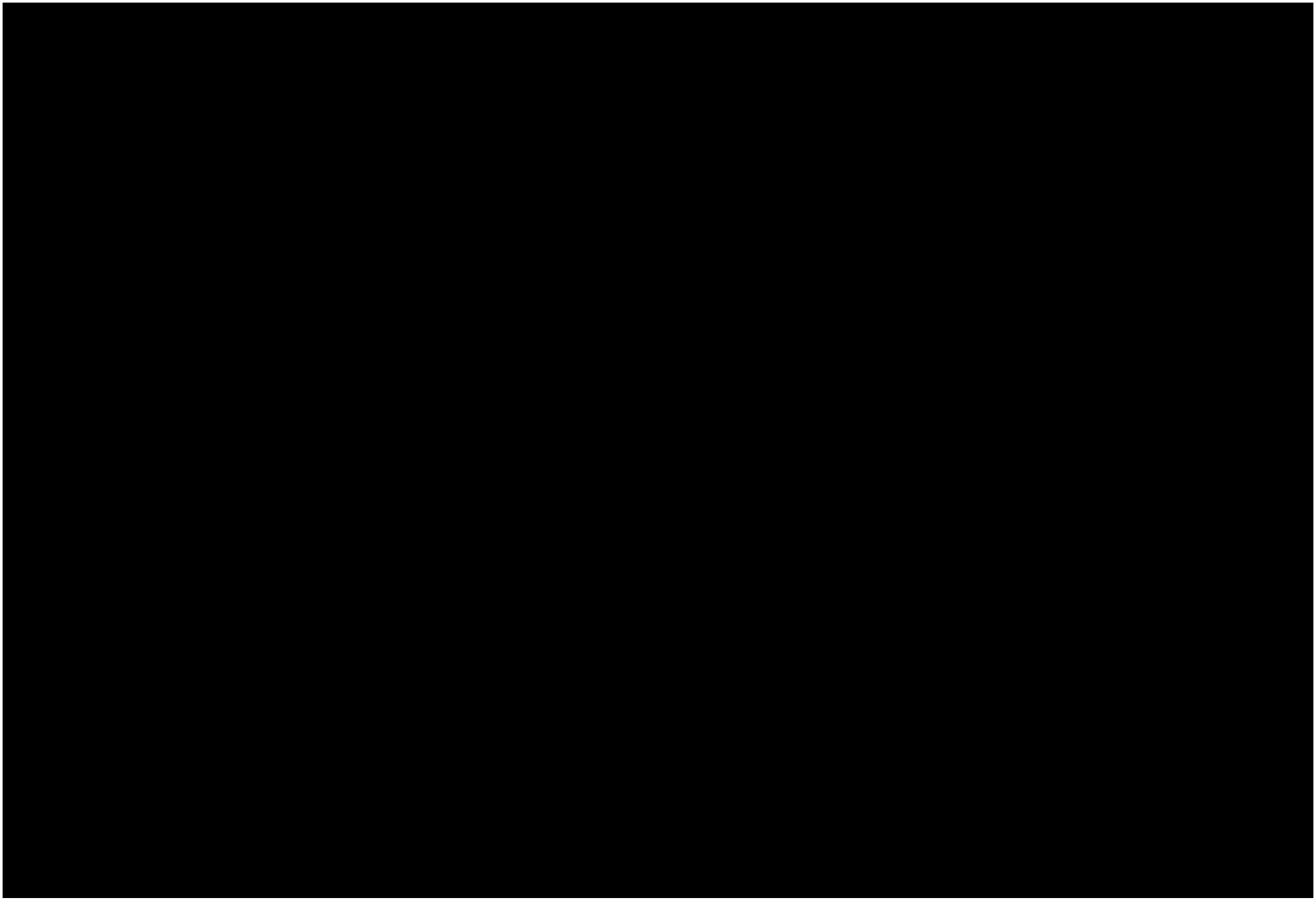
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

Gunnison County Electric Association, Inc.

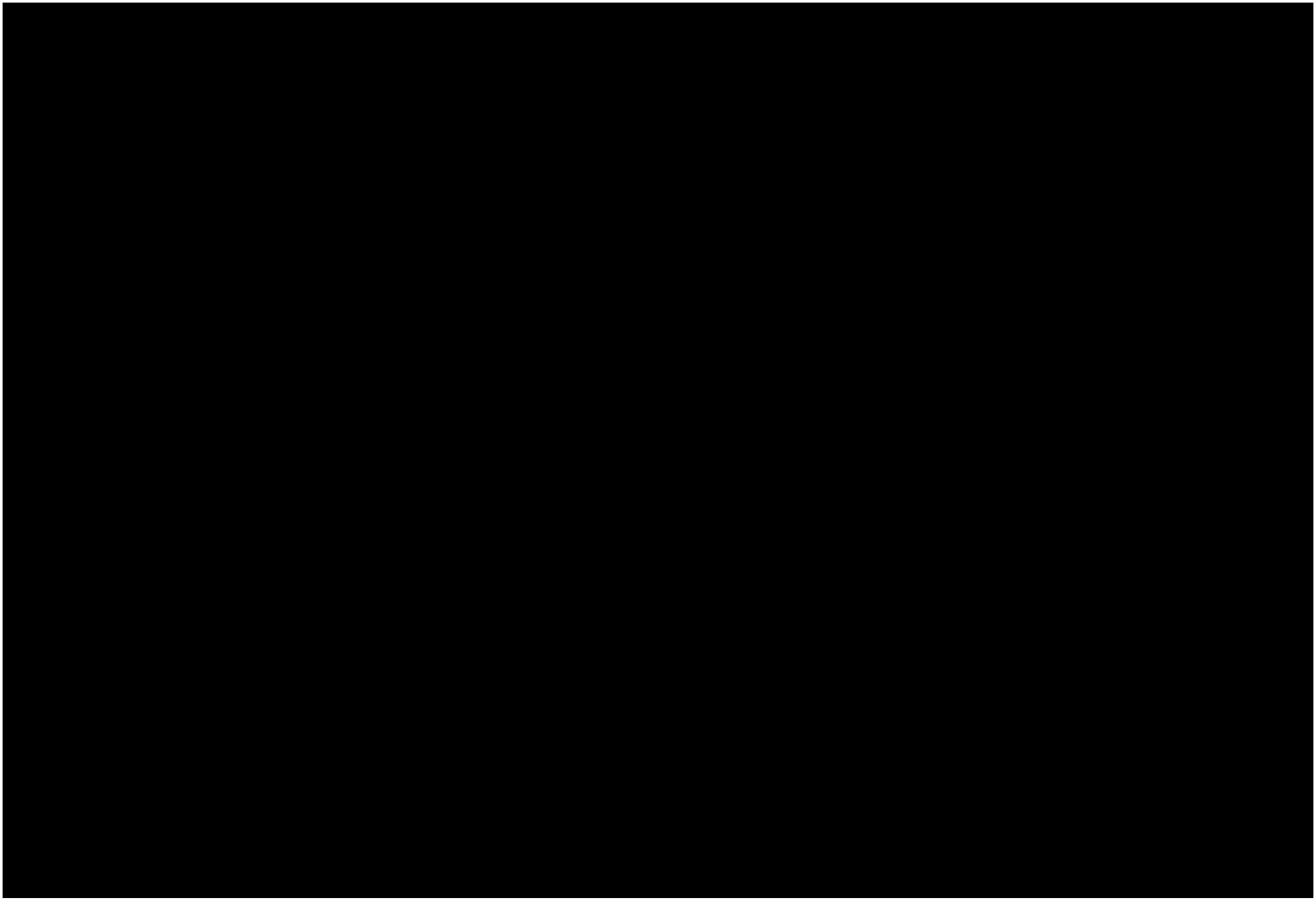
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Gunnison County Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



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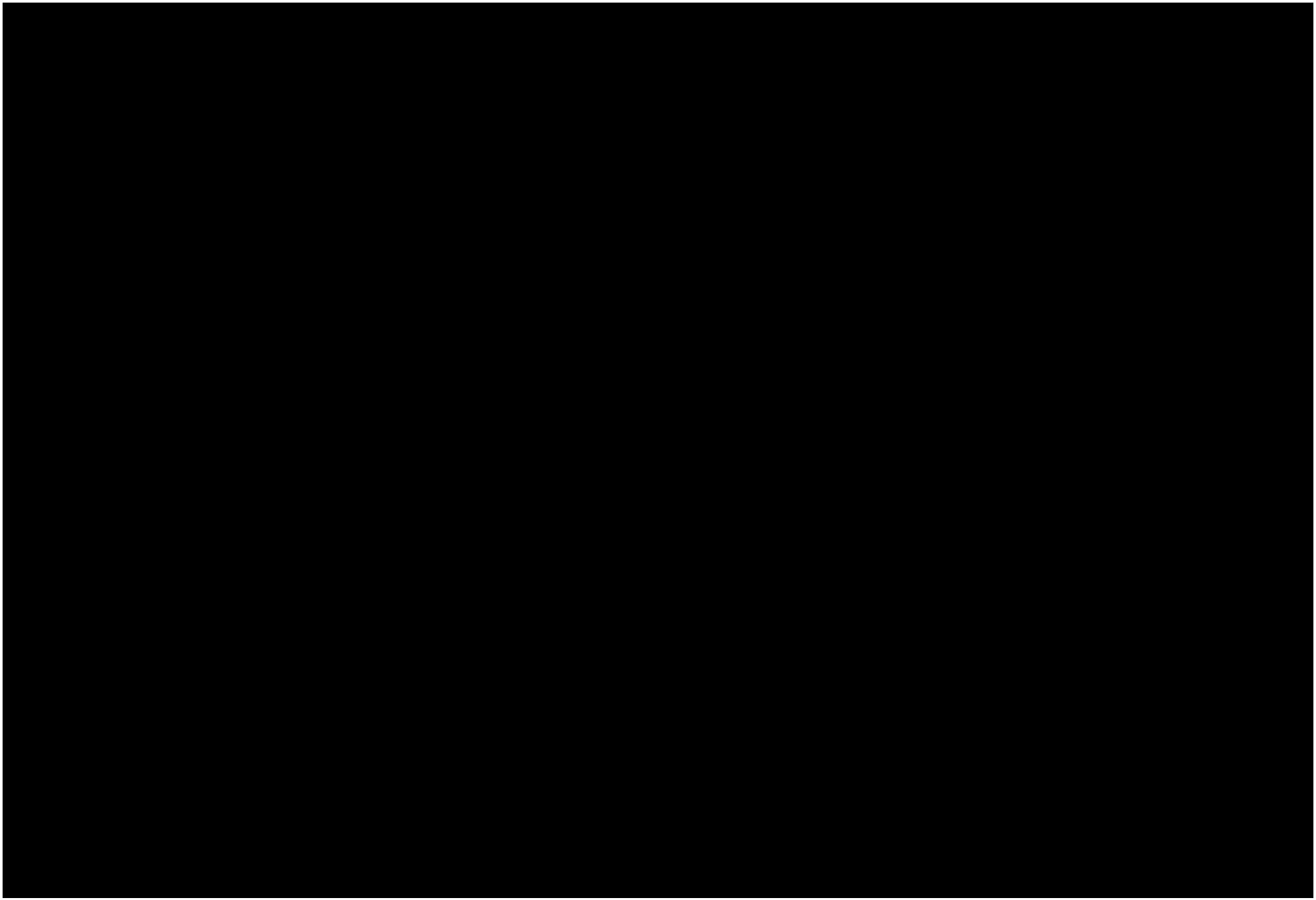
Member Forecasted Off Peak Demand Day for January 2021

Garland Light and Power Company

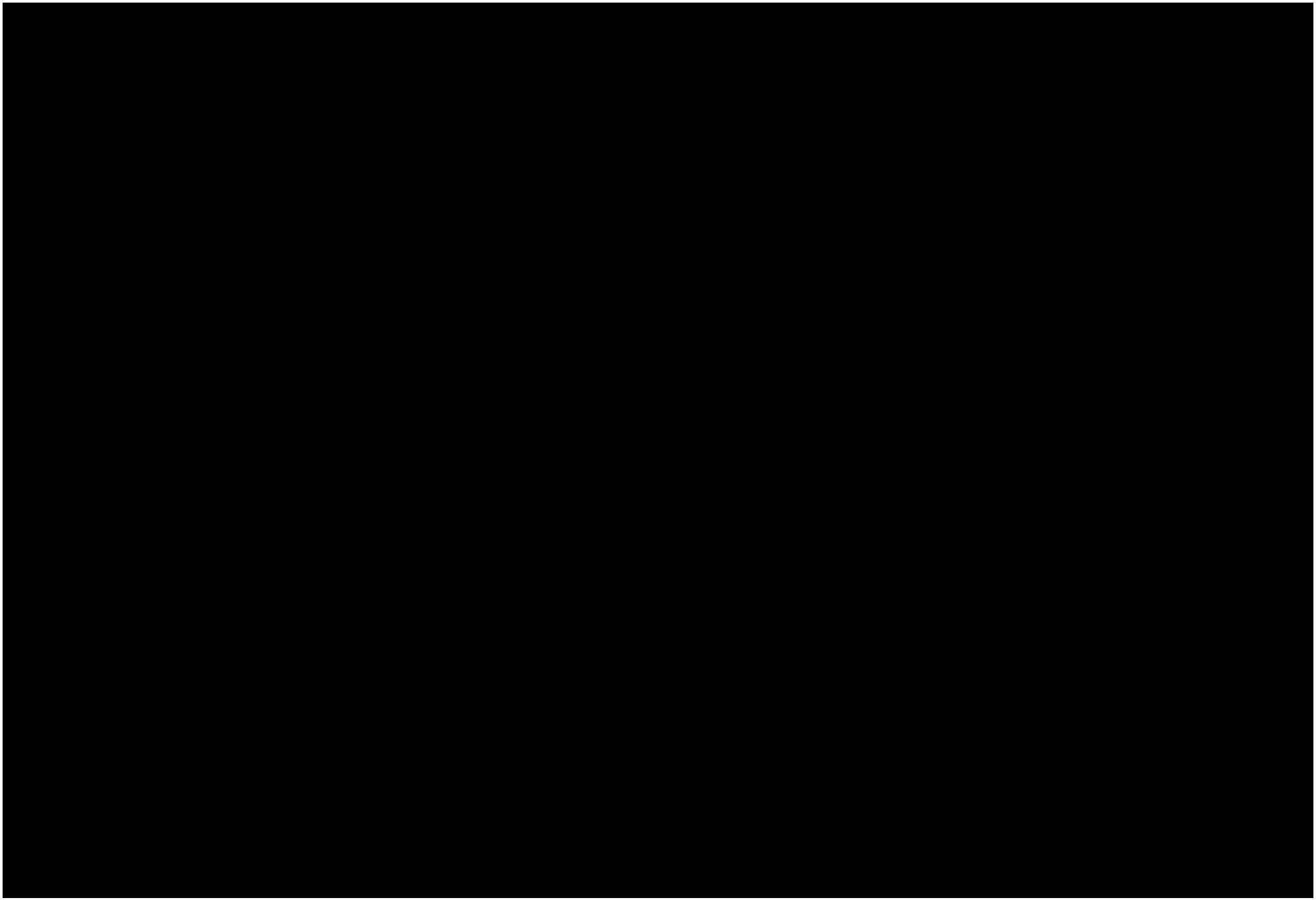
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Garland Light and Power Company

Date of Off Peak Day - 02/22/2021



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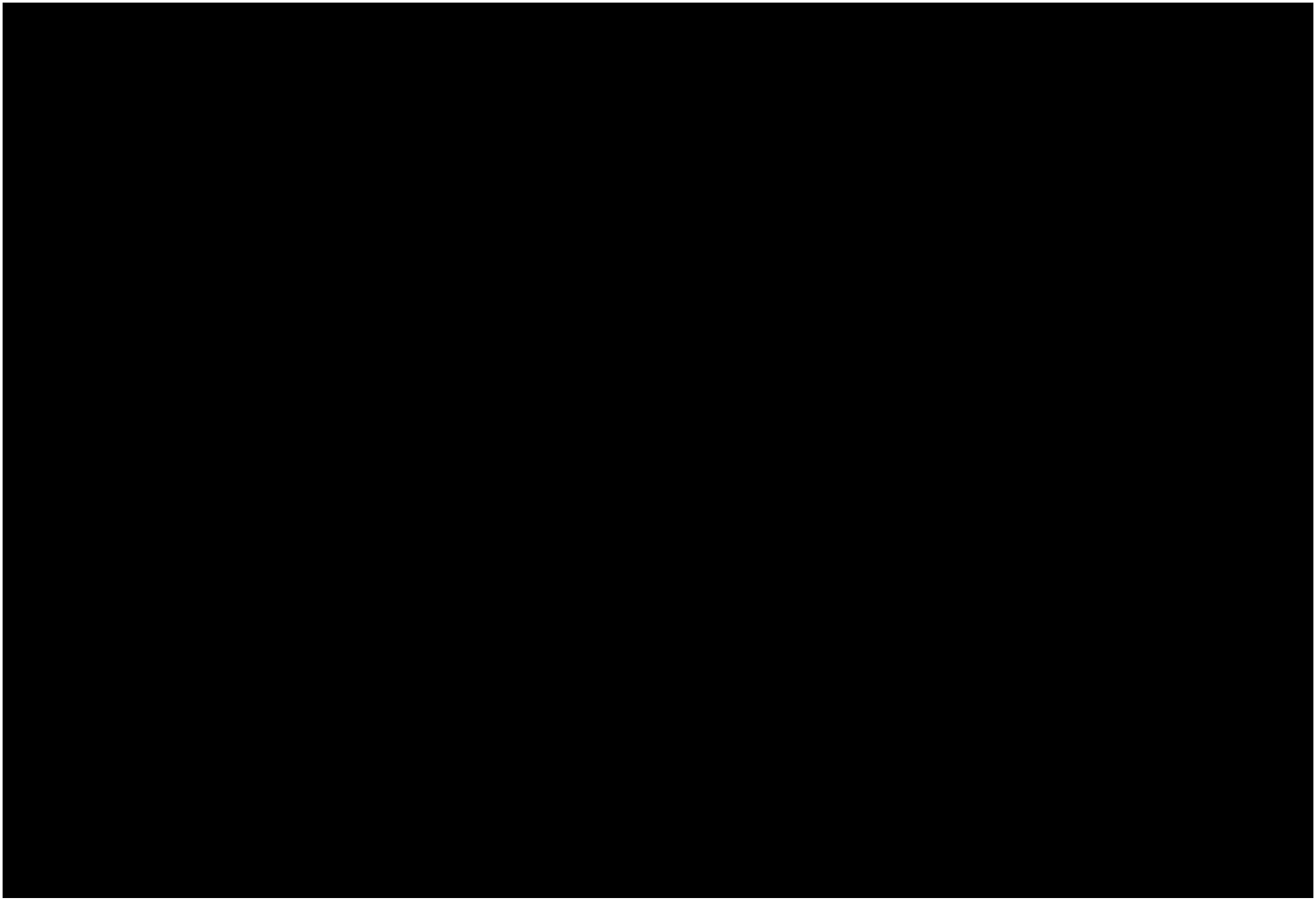
Member Forecasted Off Peak Demand Day for March 2021

Garland Light and Power Company

Date of Off Peak Day - 03/28/2021



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Member Forecasted Off Peak Demand Day for April 2021

Garland Light and Power Company

Date of Off Peak Day - 04/14/2021

[redacted]

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Member Forecasted Off Peak Demand Day for May 2021

Garland Light and Power Company

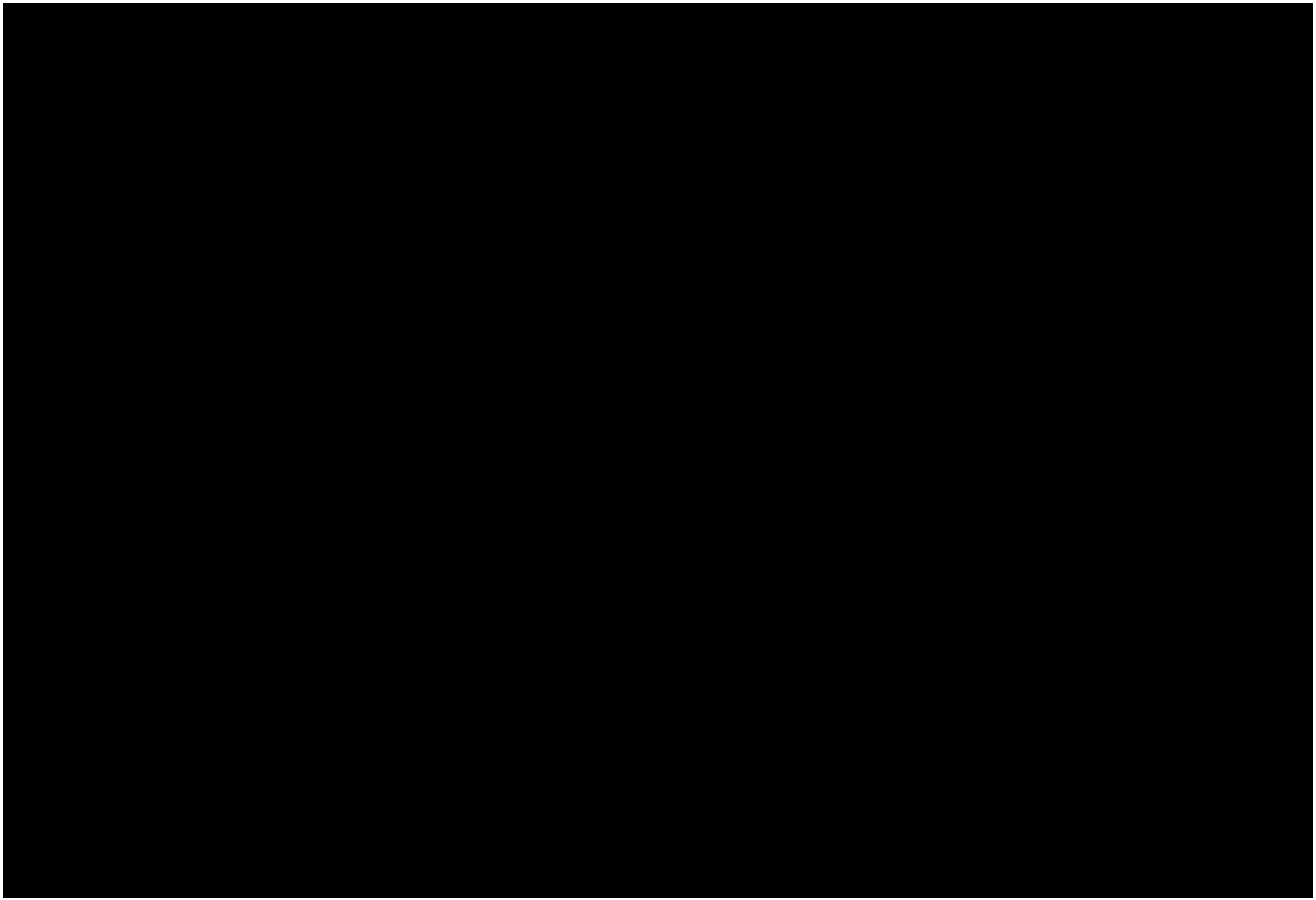
Date of Off Peak Day - 05/05/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Garland Light and Power Company

Date of Off Peak Day - 06/21/2021



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Member Forecasted Off Peak Demand Day for July 2021

Garland Light and Power Company

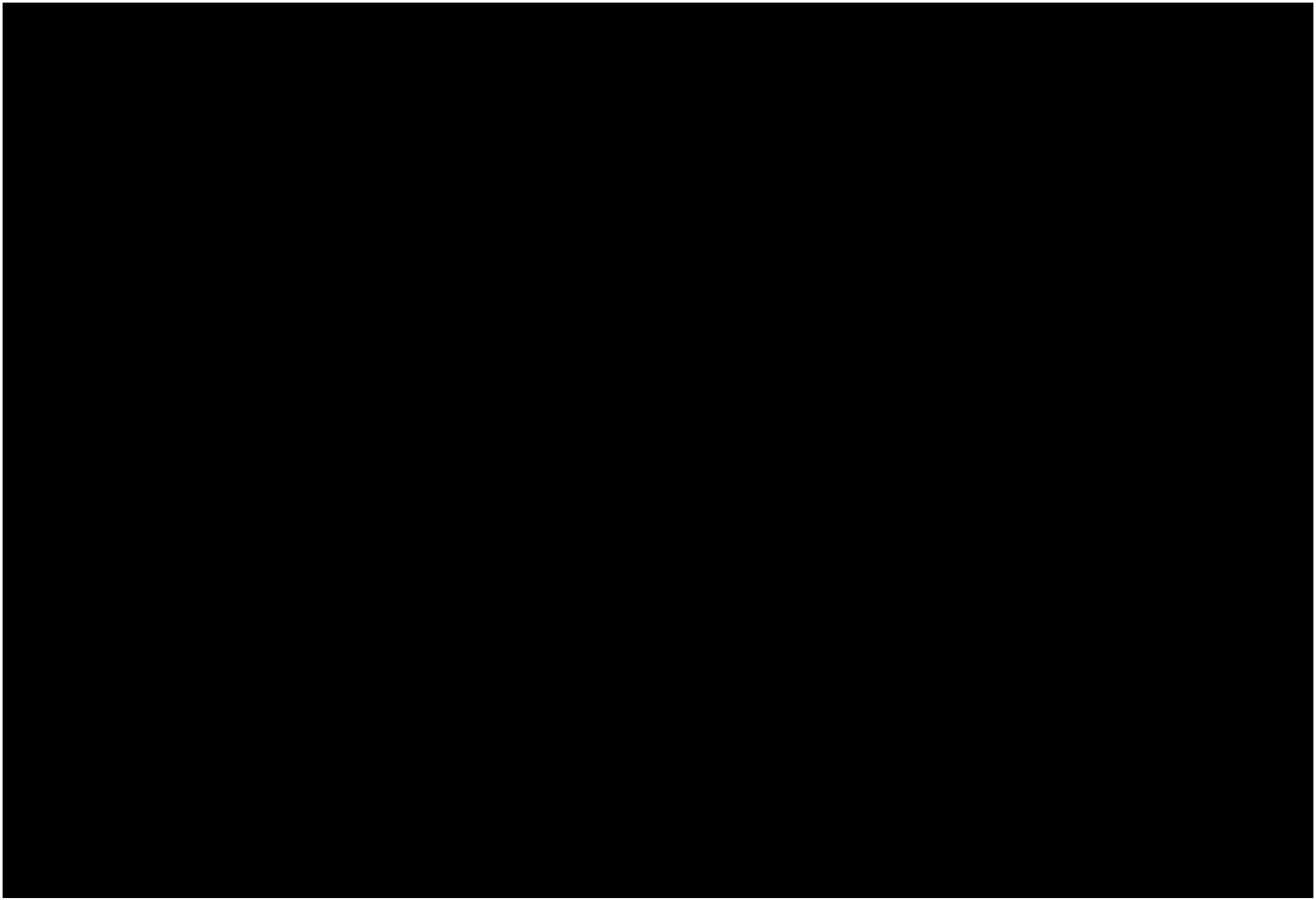
Date of Off Peak Day - 07/12/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Garland Light and Power Company

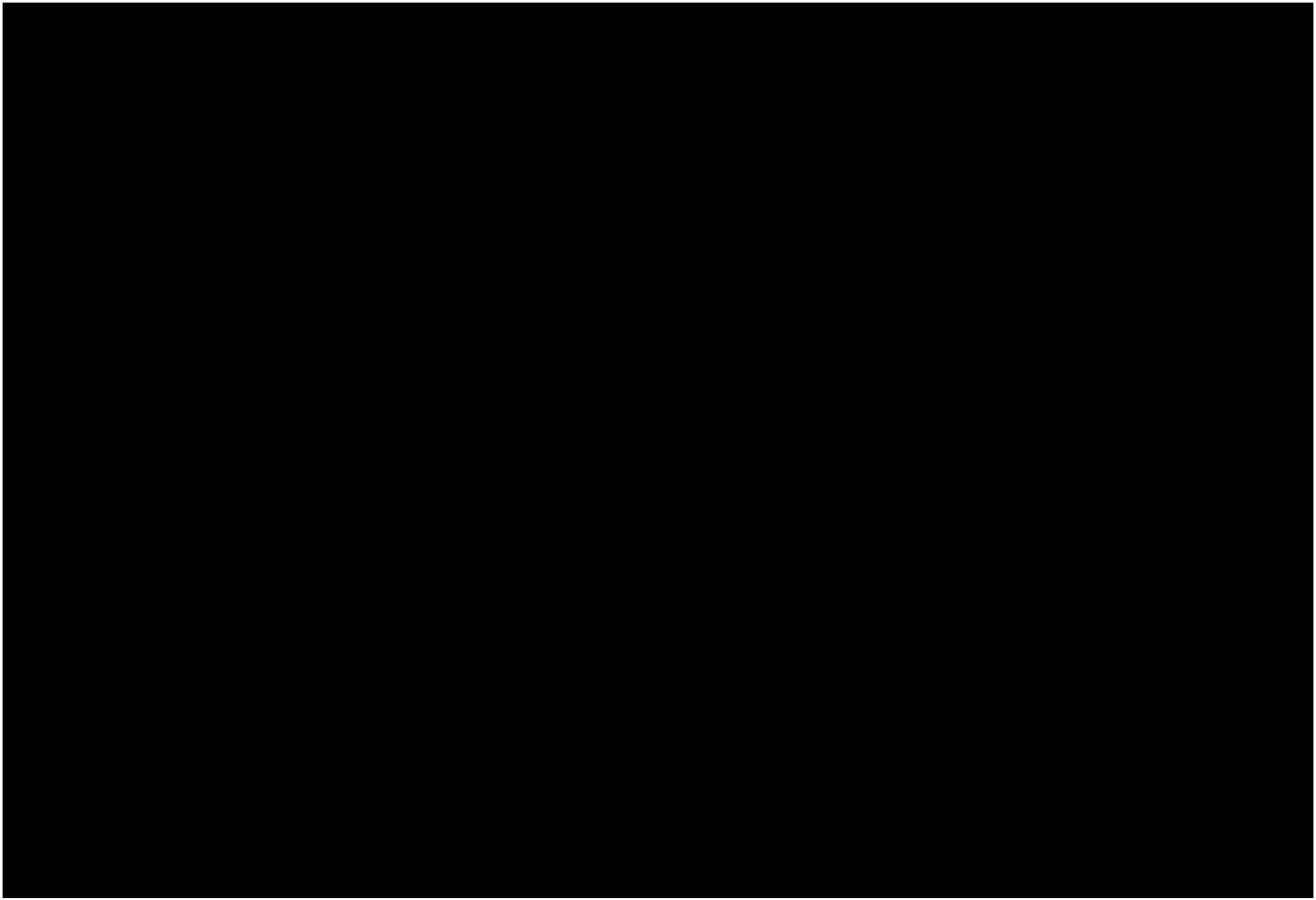
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Garland Light and Power Company

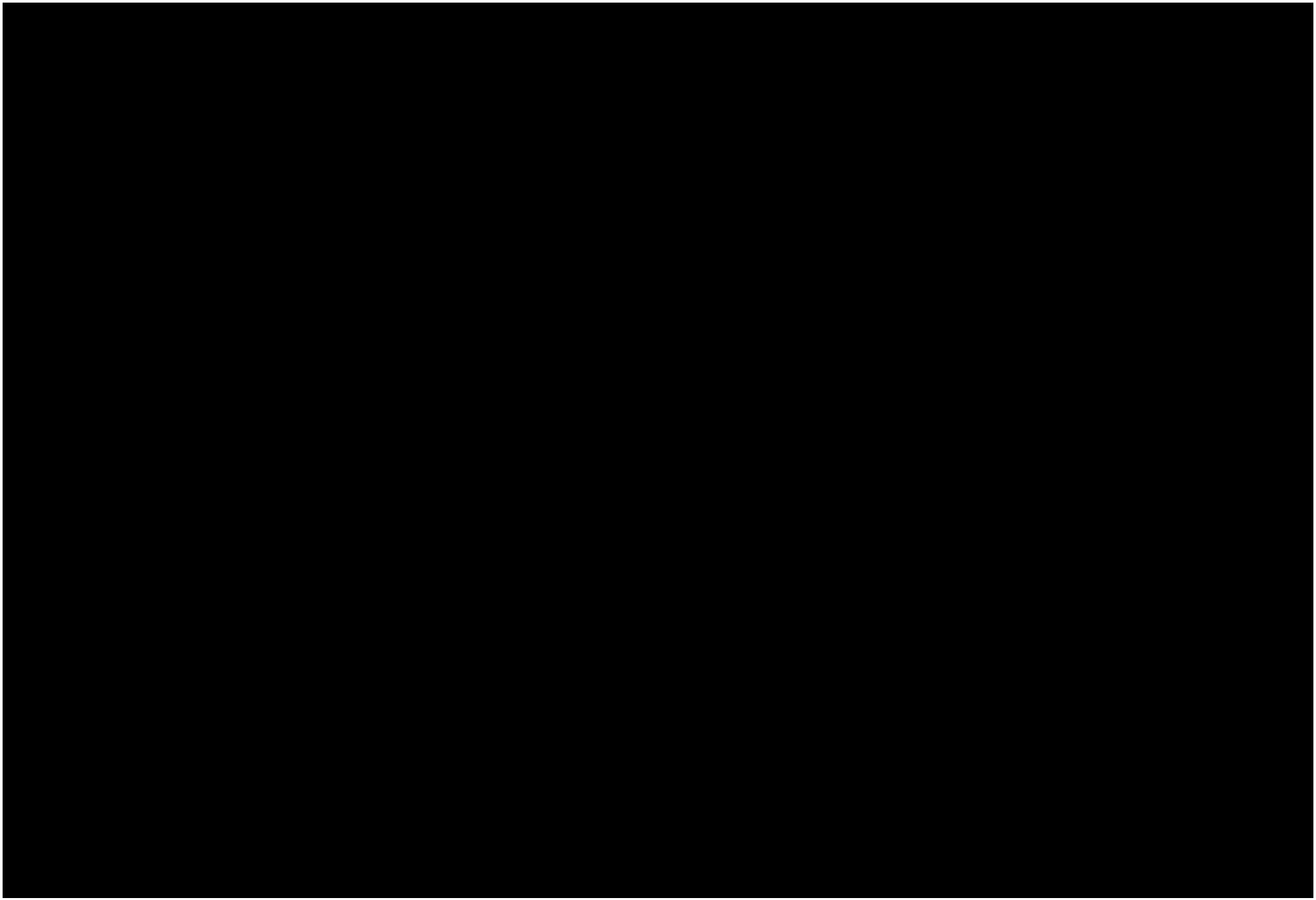
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

Garland Light and Power Company

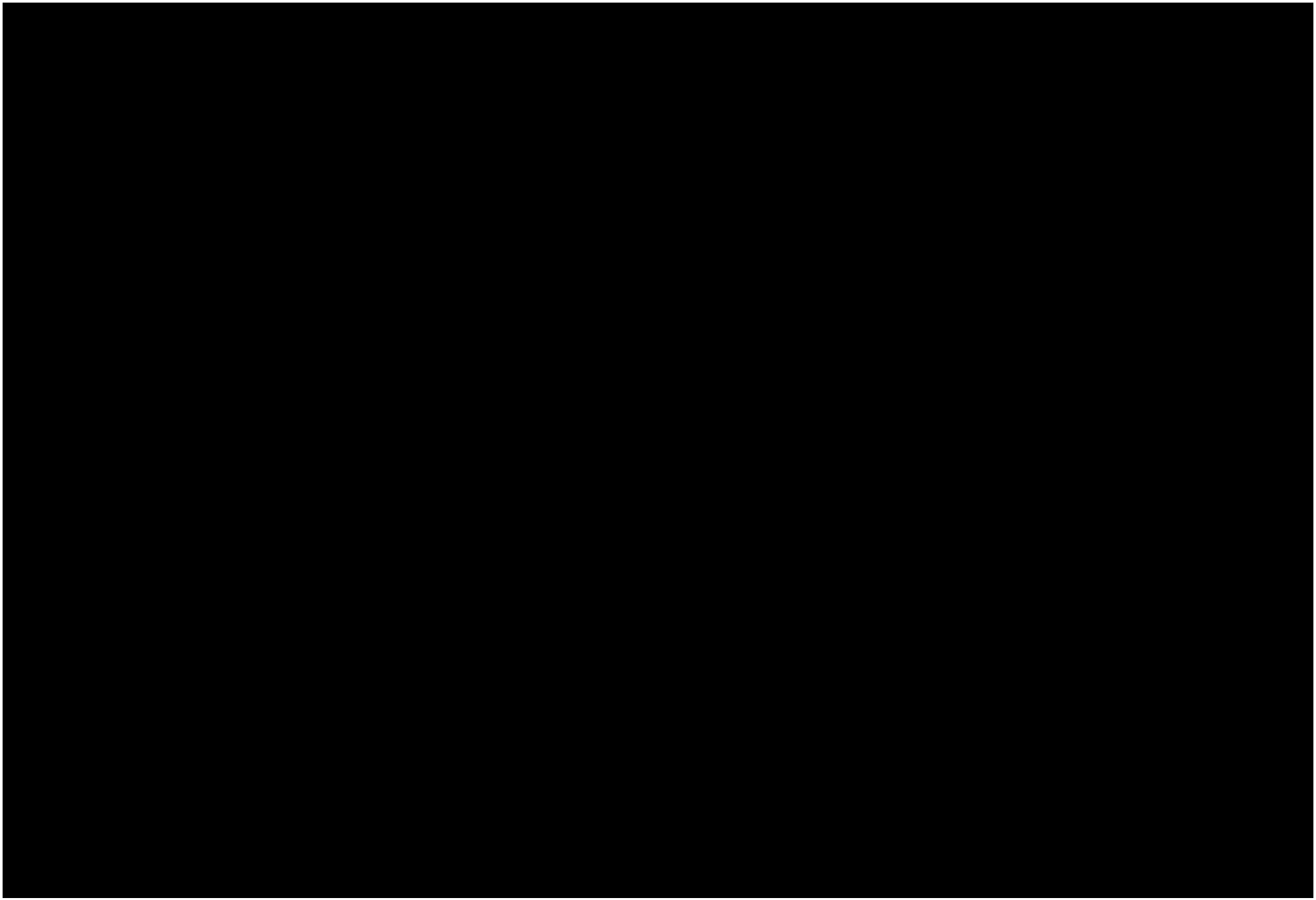
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Garland Light and Power Company

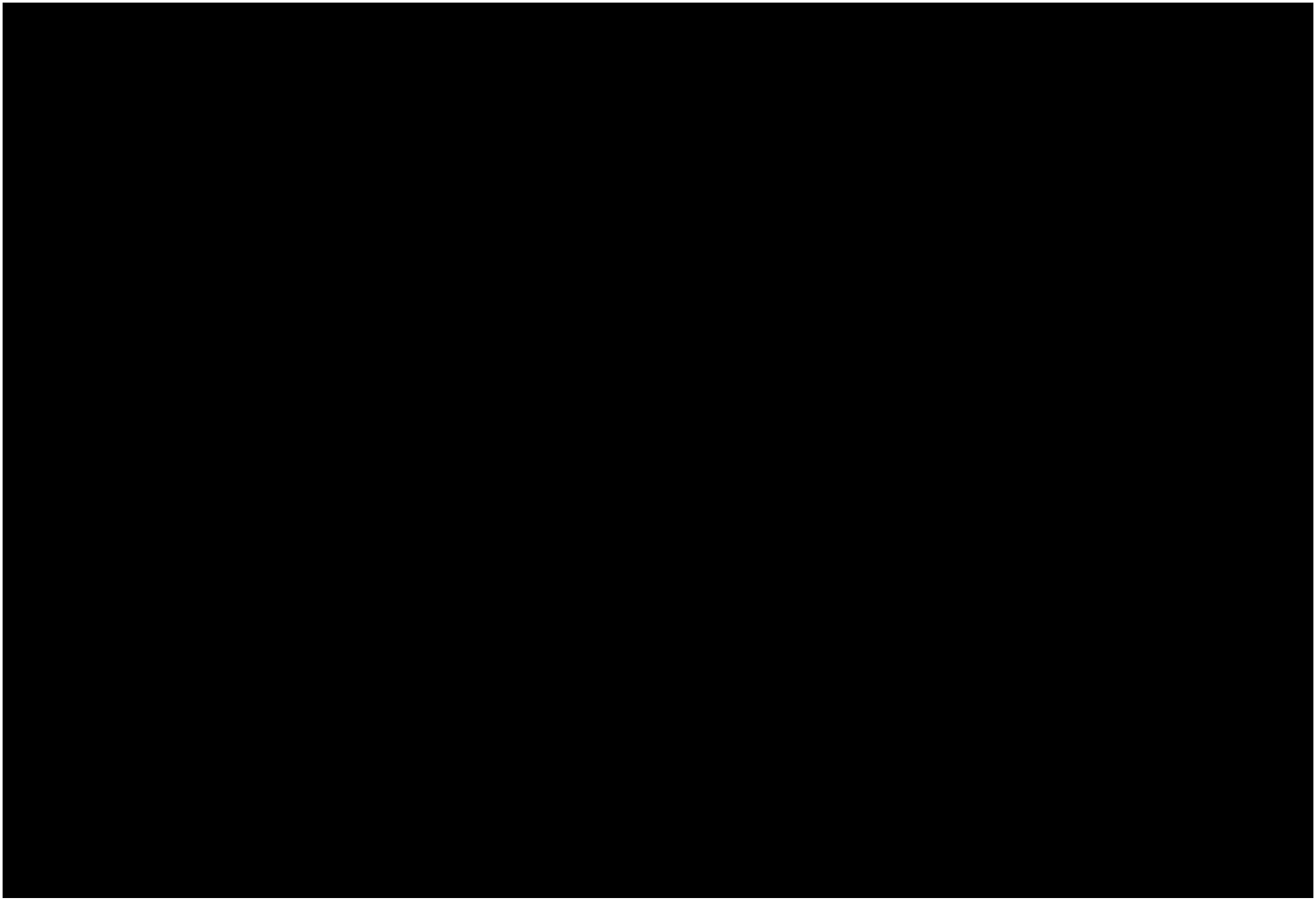
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Garland Light and Power Company

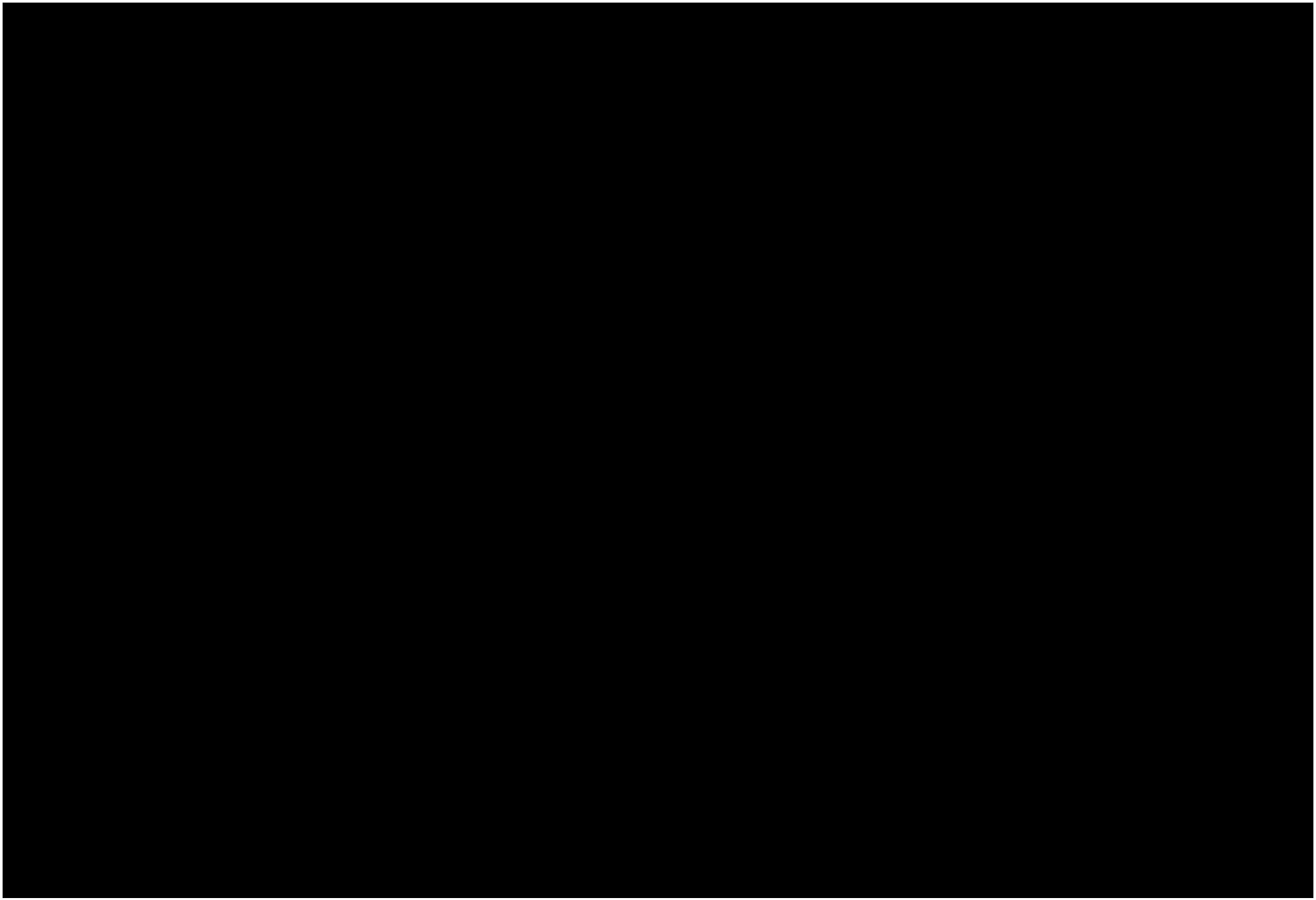
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

Highline Electric Association

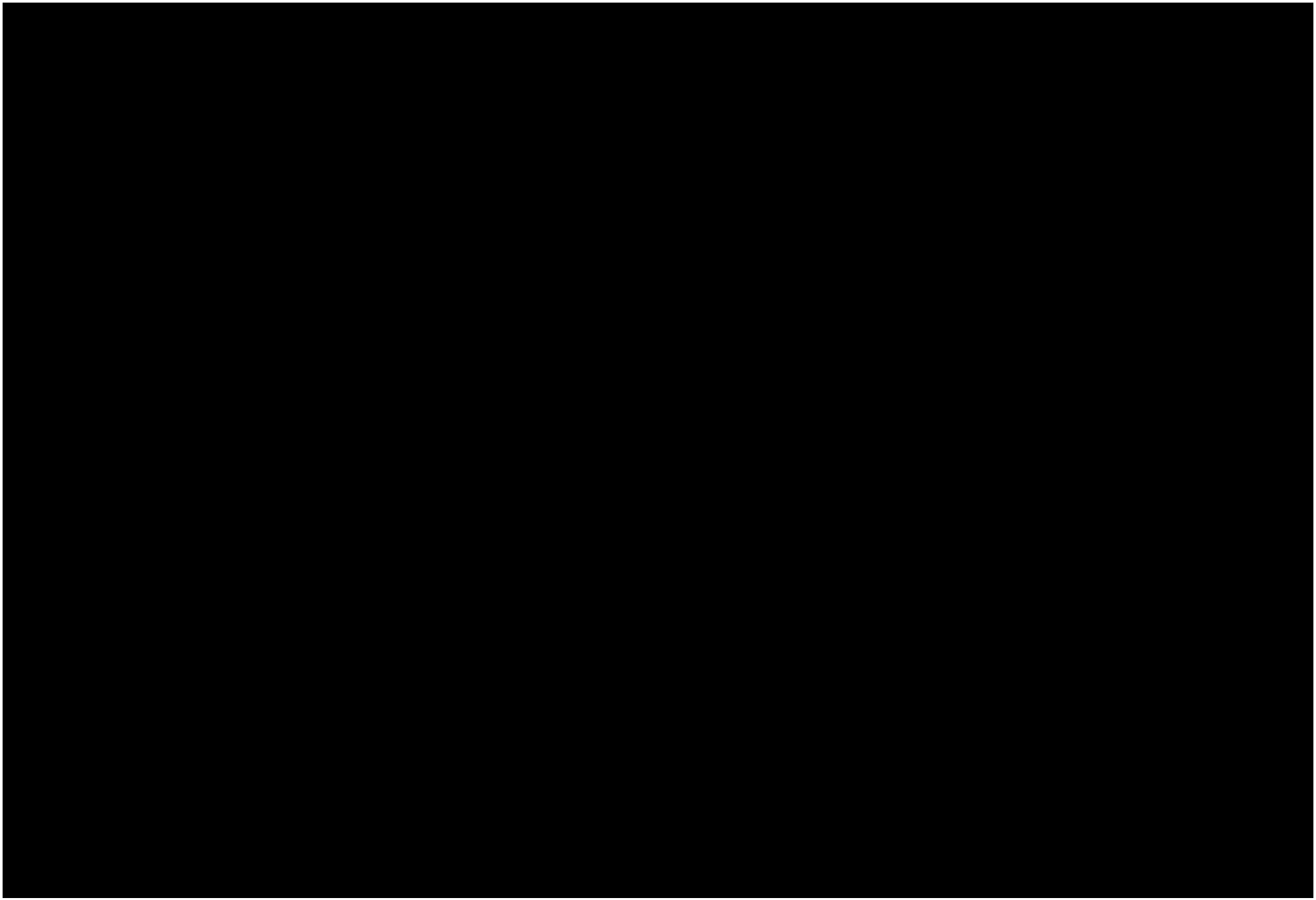
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

Highline Electric Association

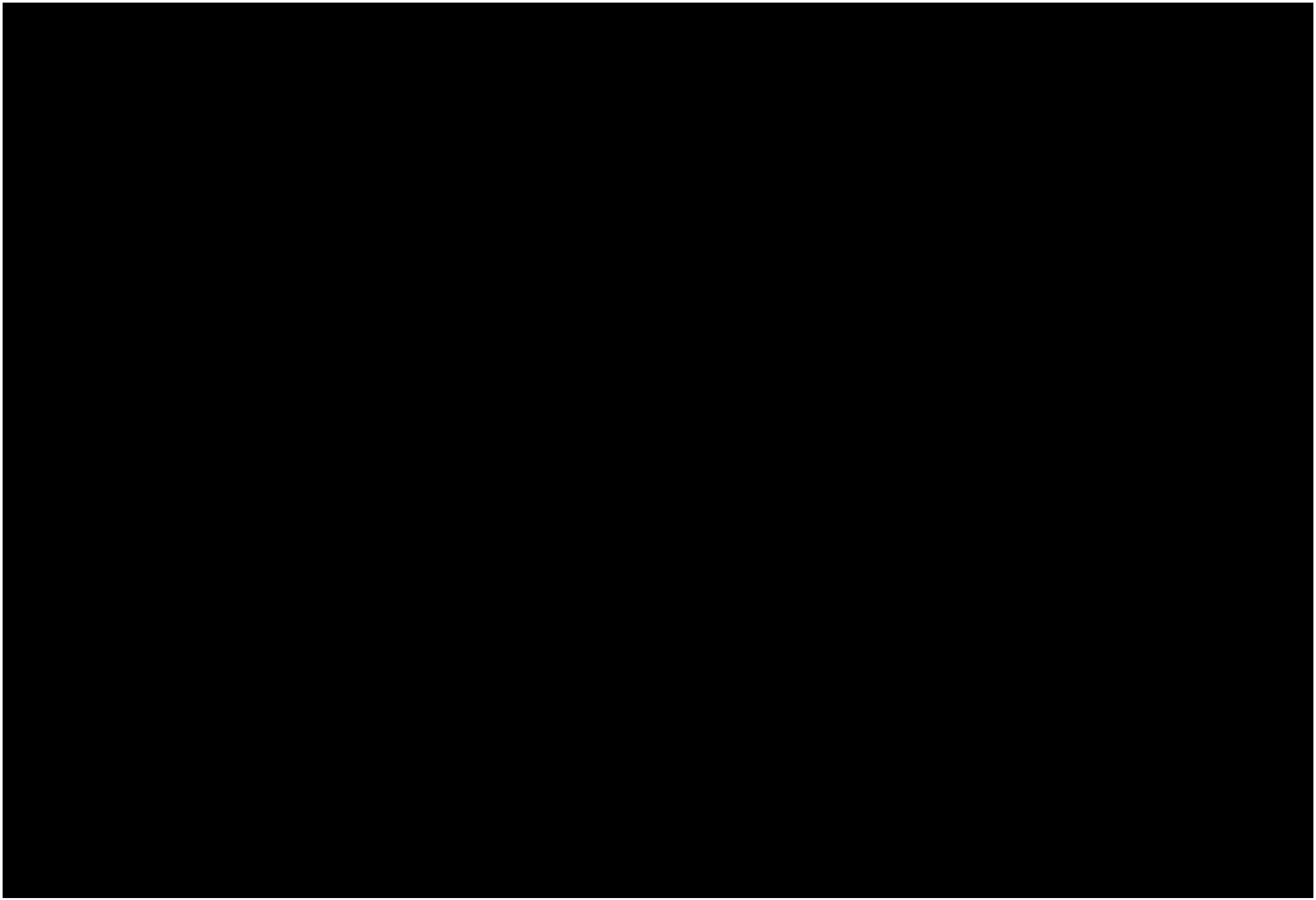
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Highline Electric Association

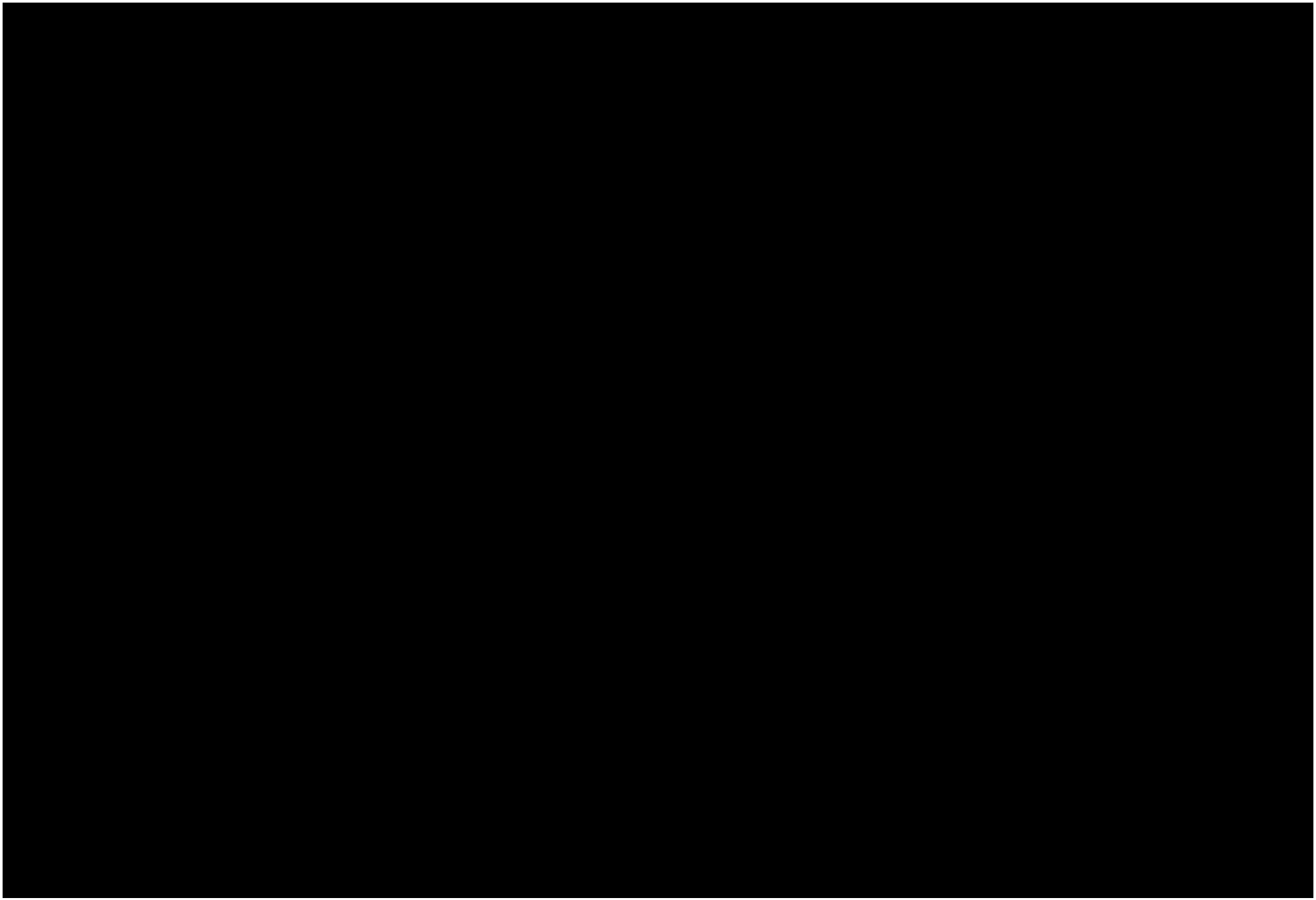
Date of Off Peak Day - 03/14/2021



Member Forecasted Off Peak Demand Day for April 2021

Highline Electric Association

Date of Off Peak Day - 04/09/2021



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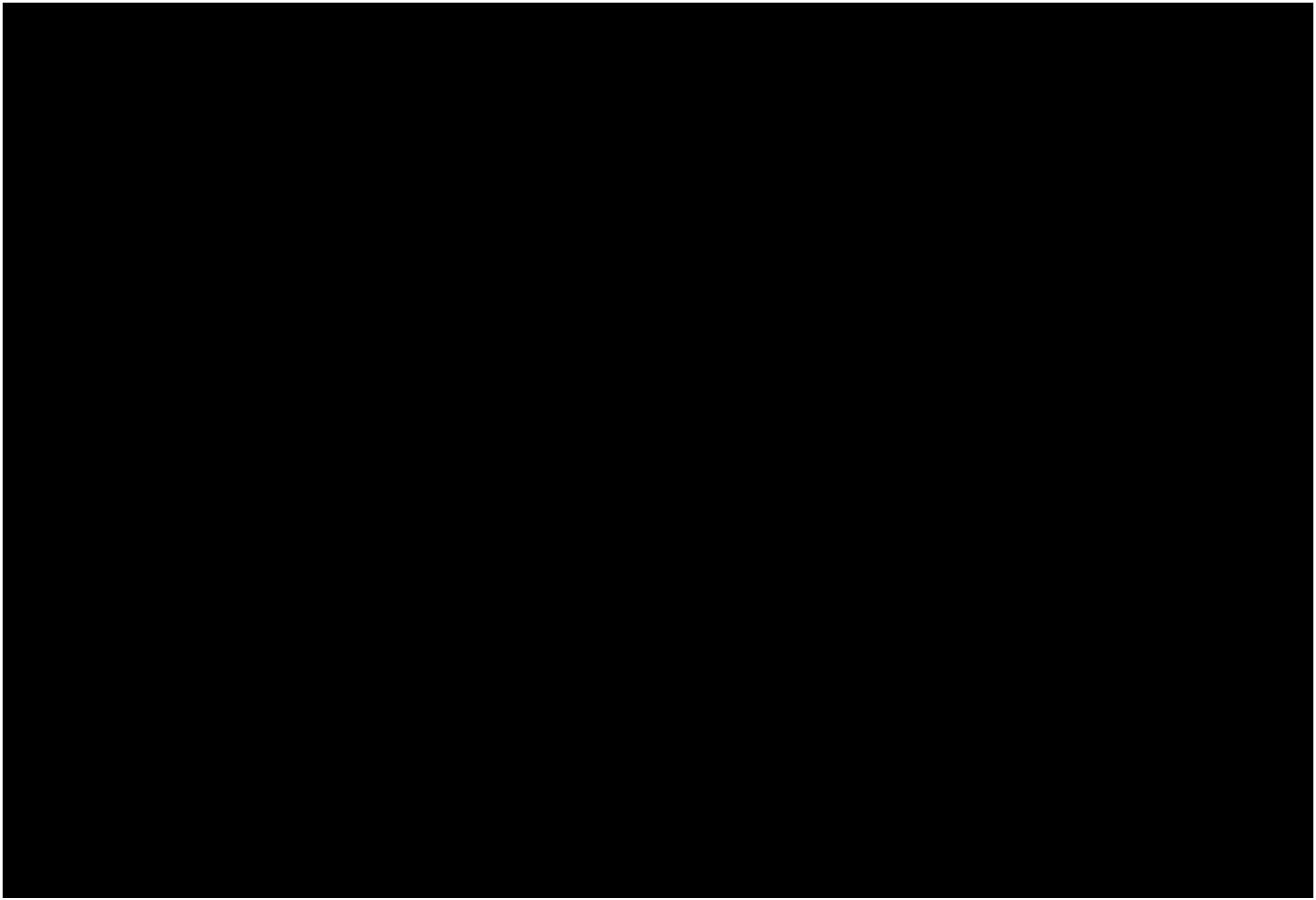
Member Forecasted Off Peak Demand Day for May 2021

Highline Electric Association

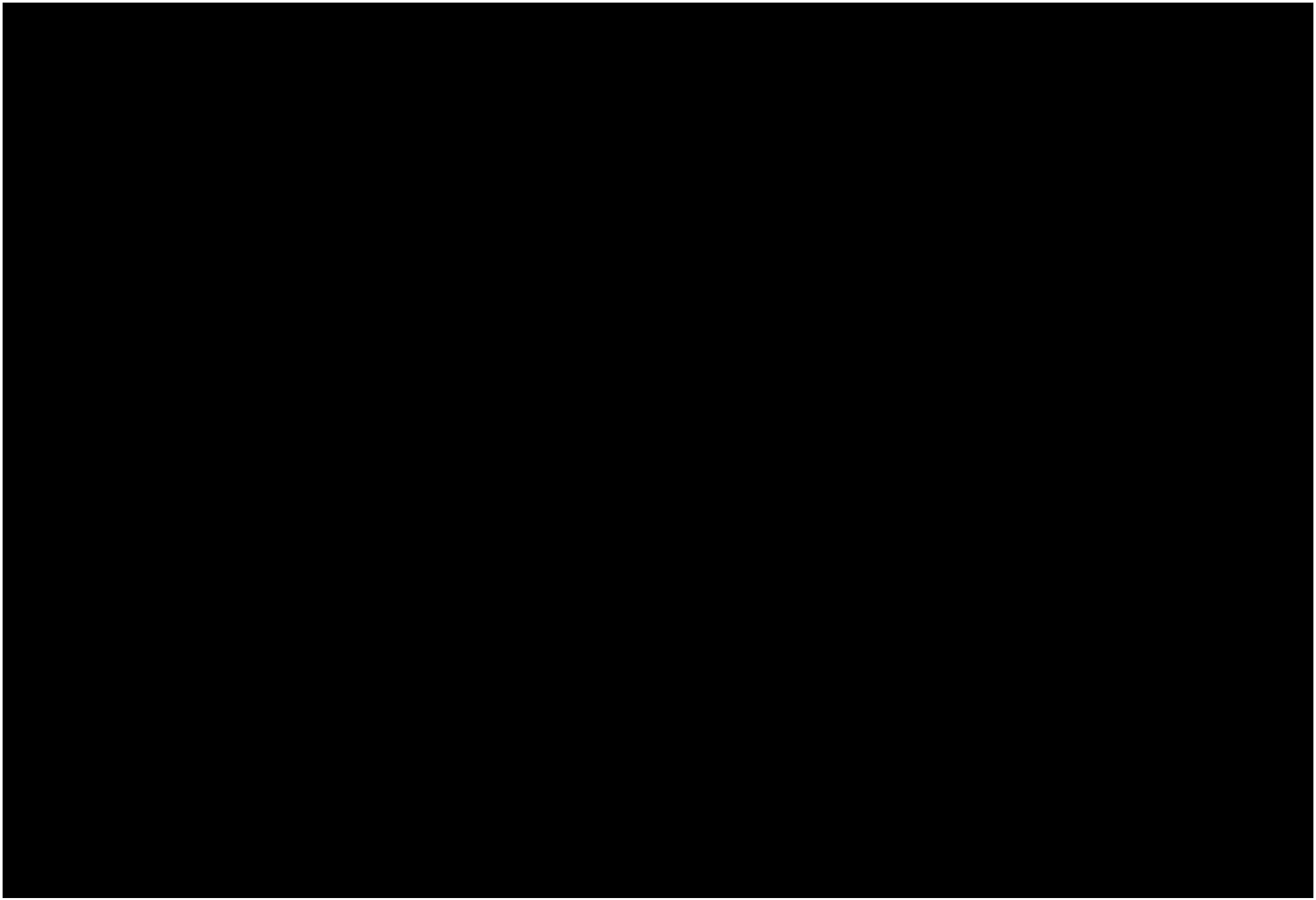
Date of Off Peak Day - 05/09/2021



Member Forecasted Off Peak Demand Day for June 2021

Highline Electric Association

Date of Off Peak Day - 06/01/2021



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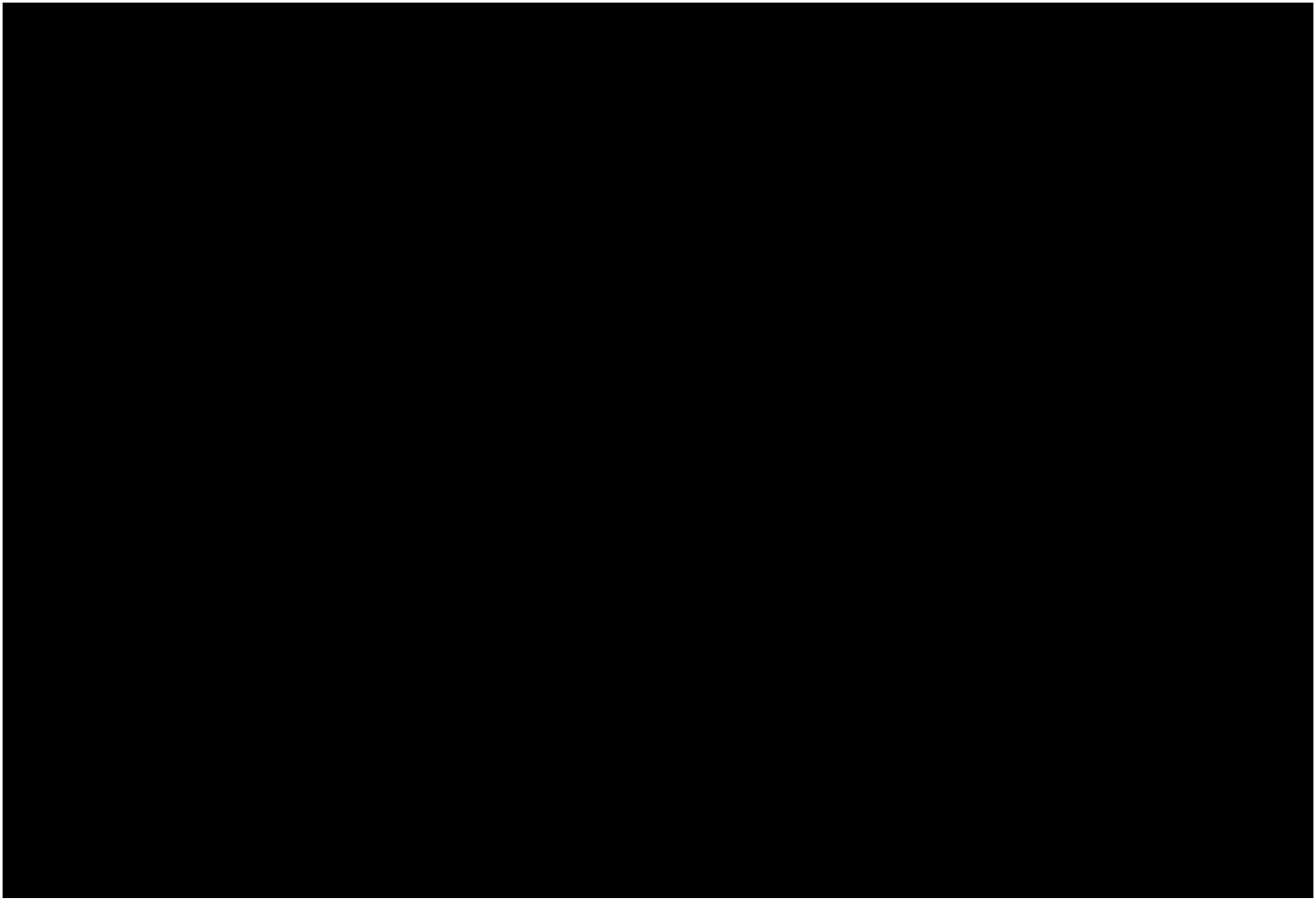
Member Forecasted Off Peak Demand Day for July 2021

Highline Electric Association

Date of Off Peak Day - 07/03/2021



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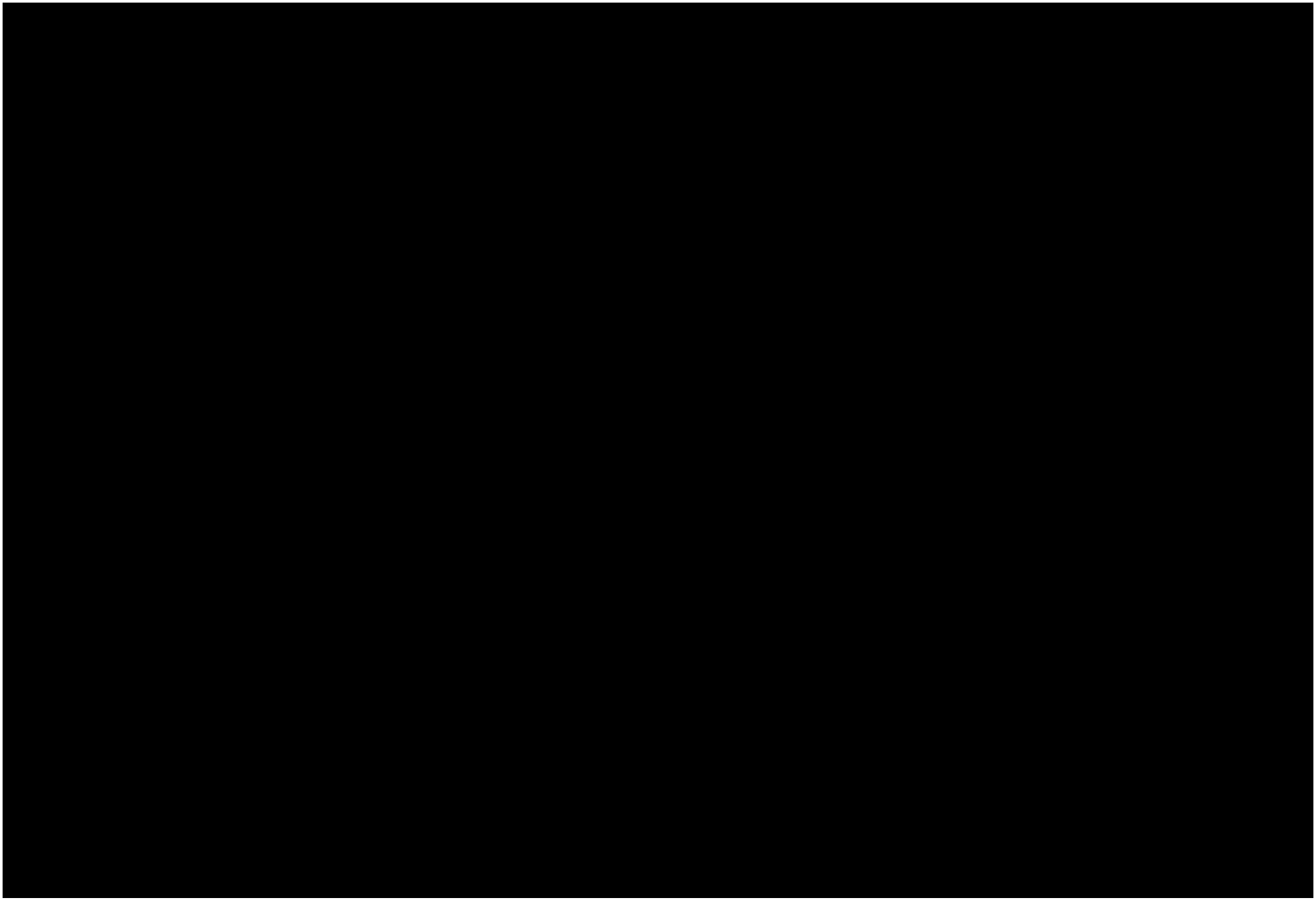
Member Forecasted Off Peak Demand Day for August 2021

Highline Electric Association

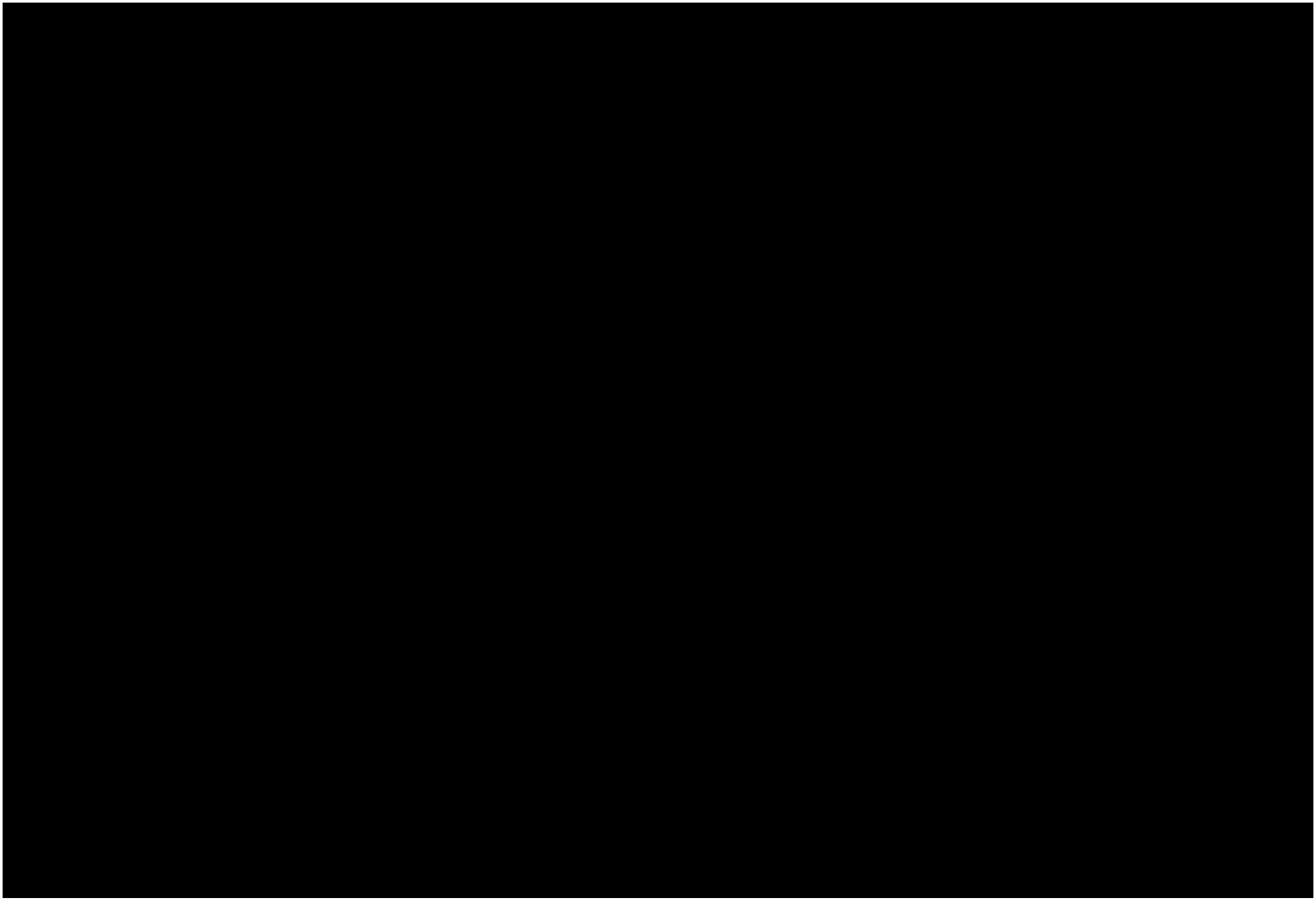
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Highline Electric Association

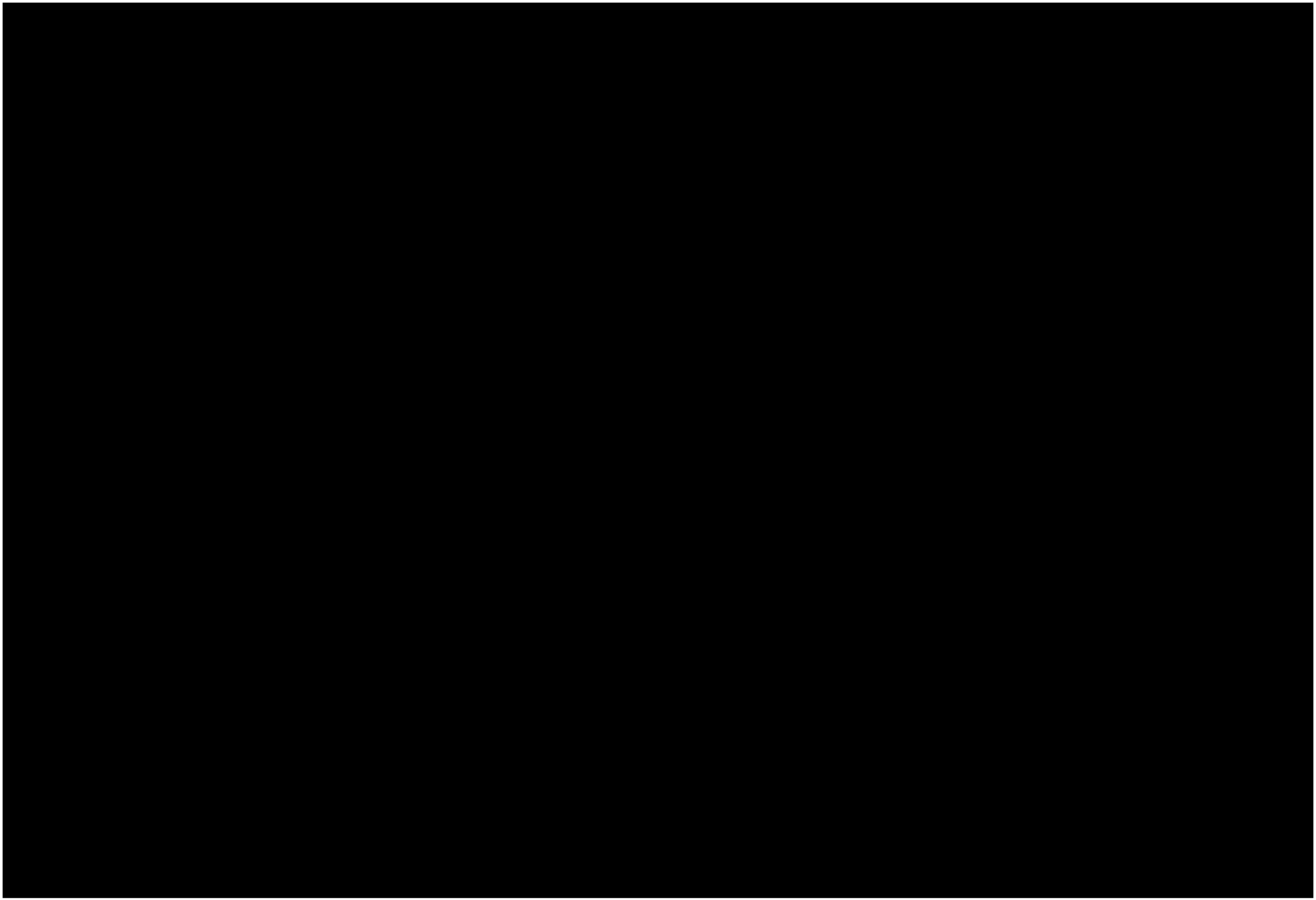
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Highline Electric Association

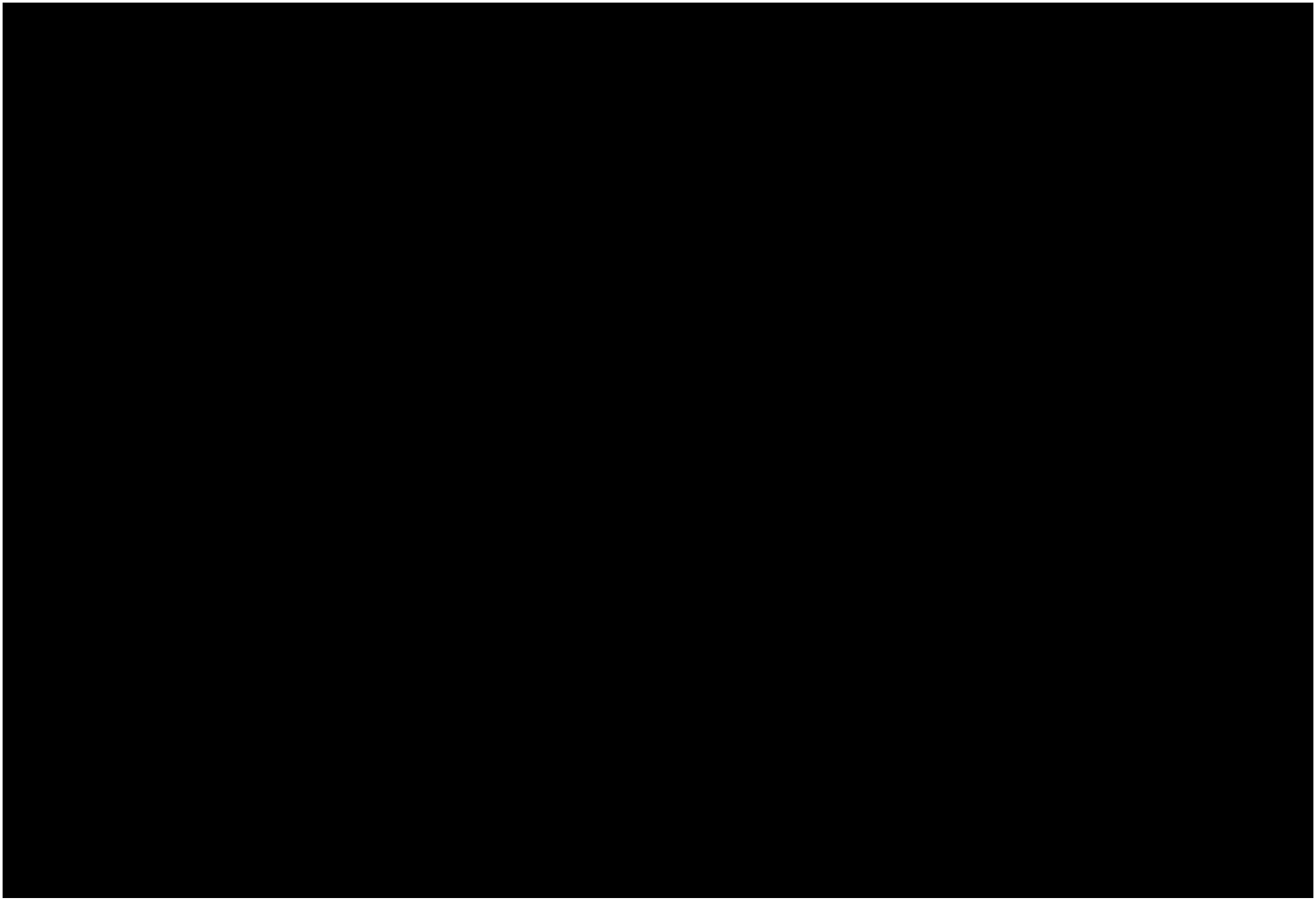
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Highline Electric Association

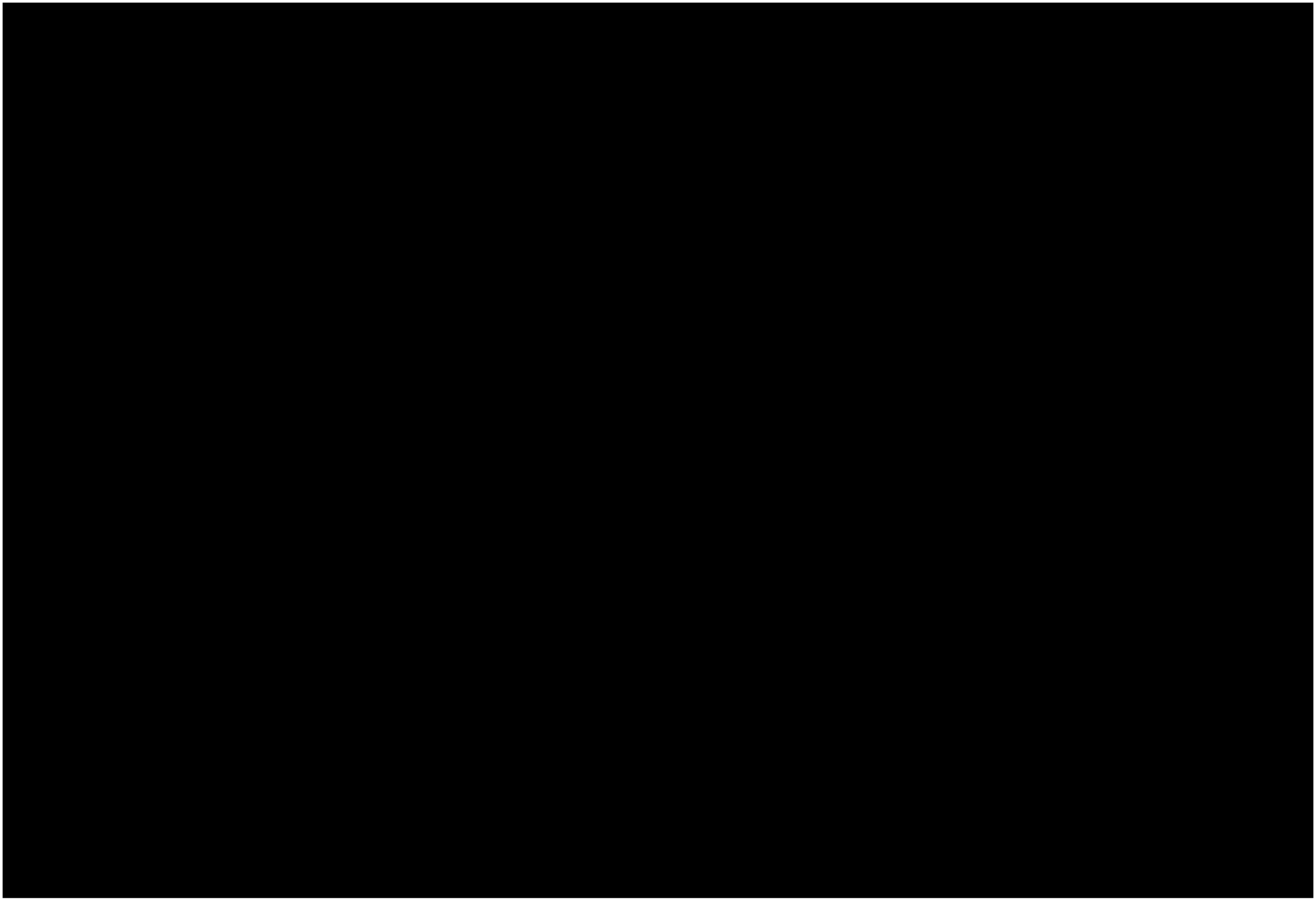
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Highline Electric Association

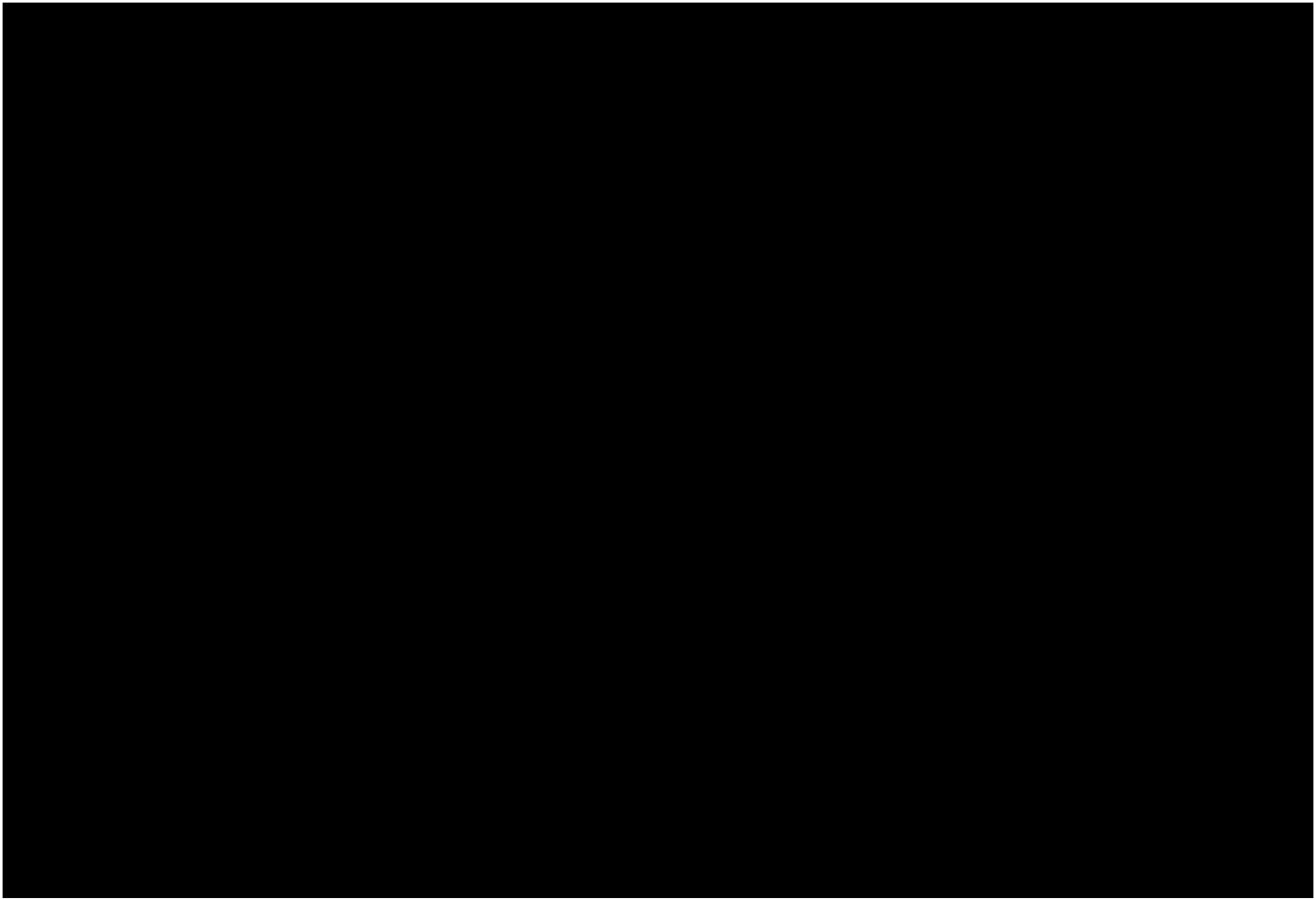
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

High Plains Power, Inc.

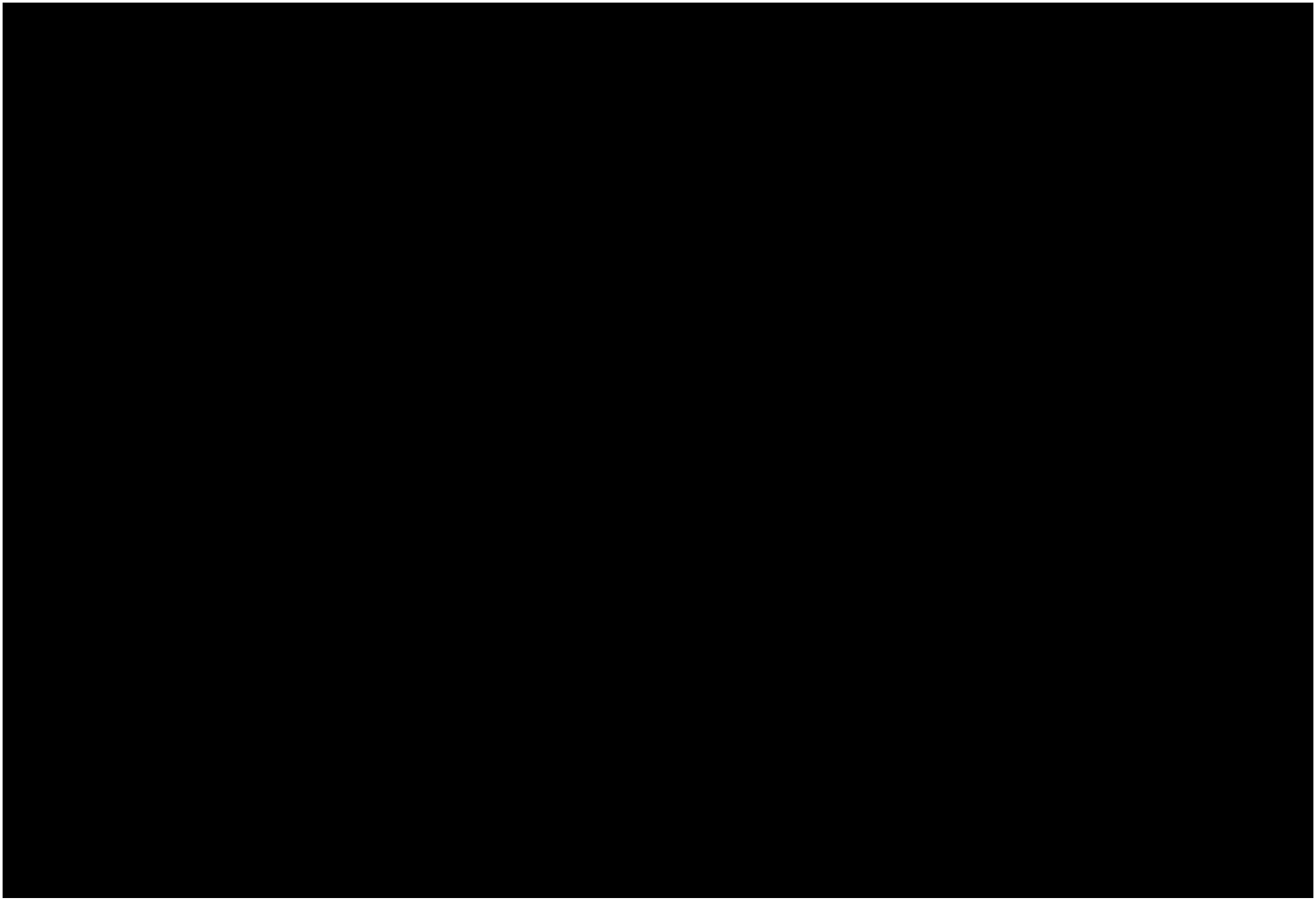
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

High Plains Power, Inc.

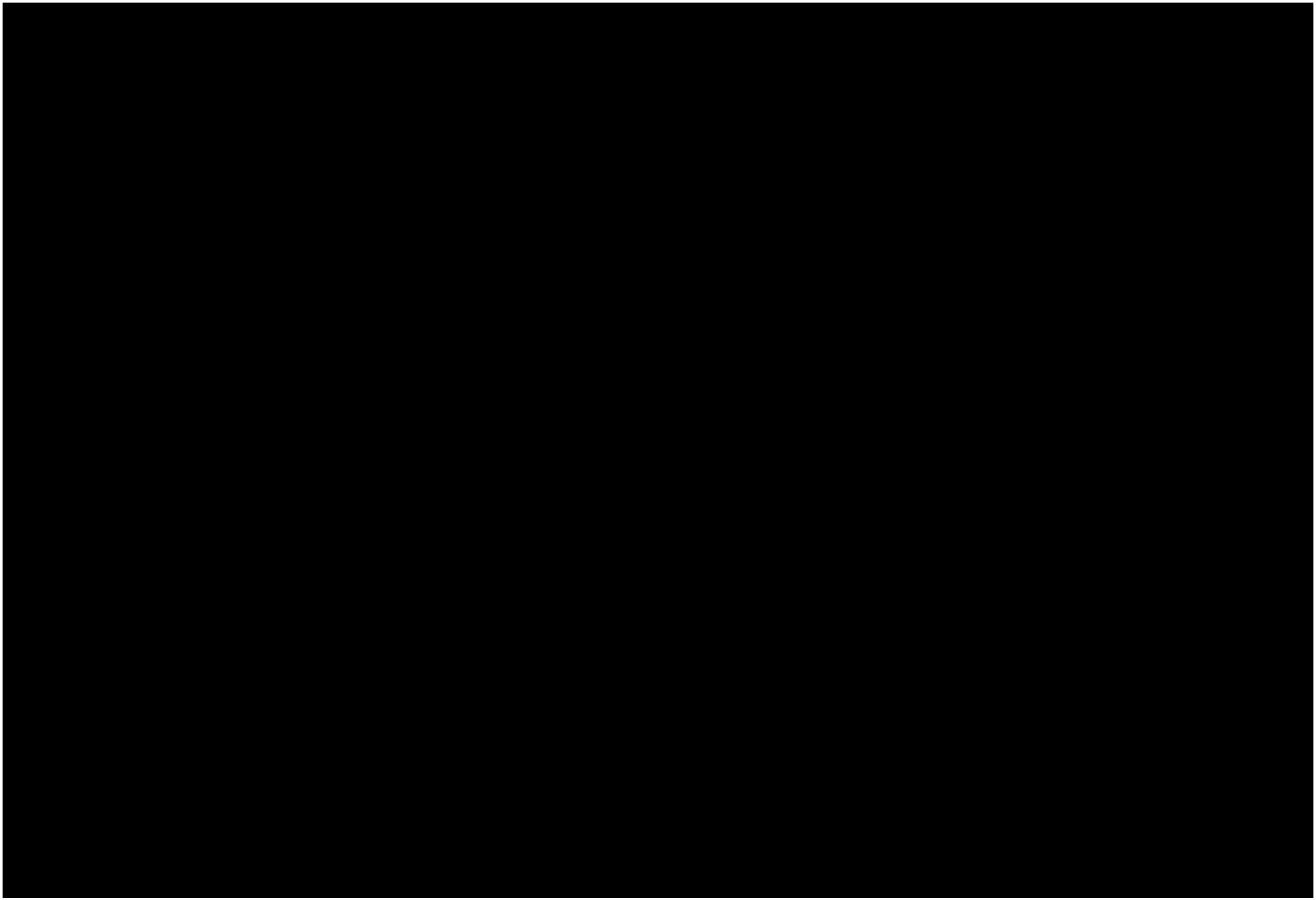
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

High Plains Power, Inc.

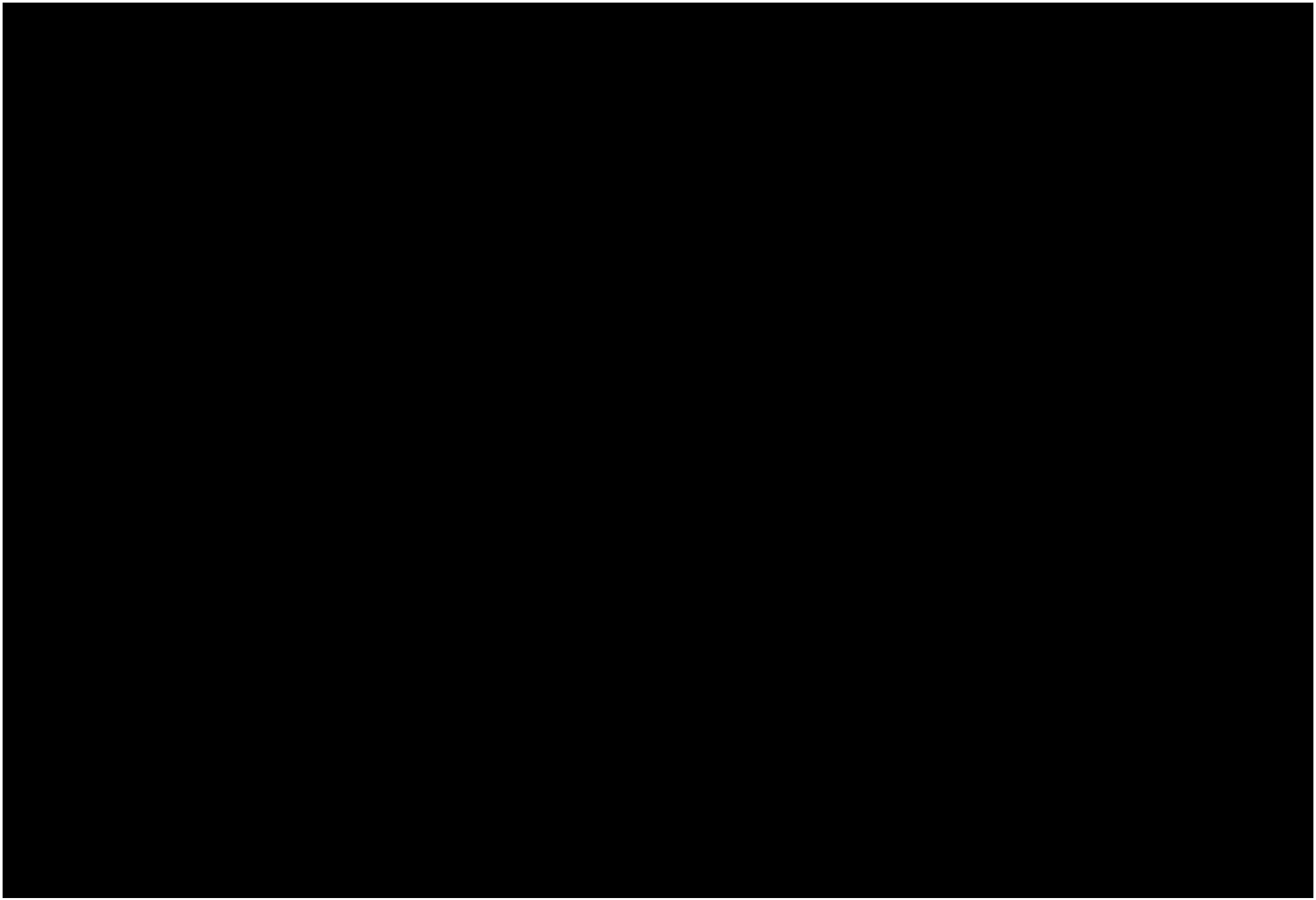
Date of Off Peak Day - 03/31/2021



Member Forecasted Off Peak Demand Day for April 2021

High Plains Power, Inc.

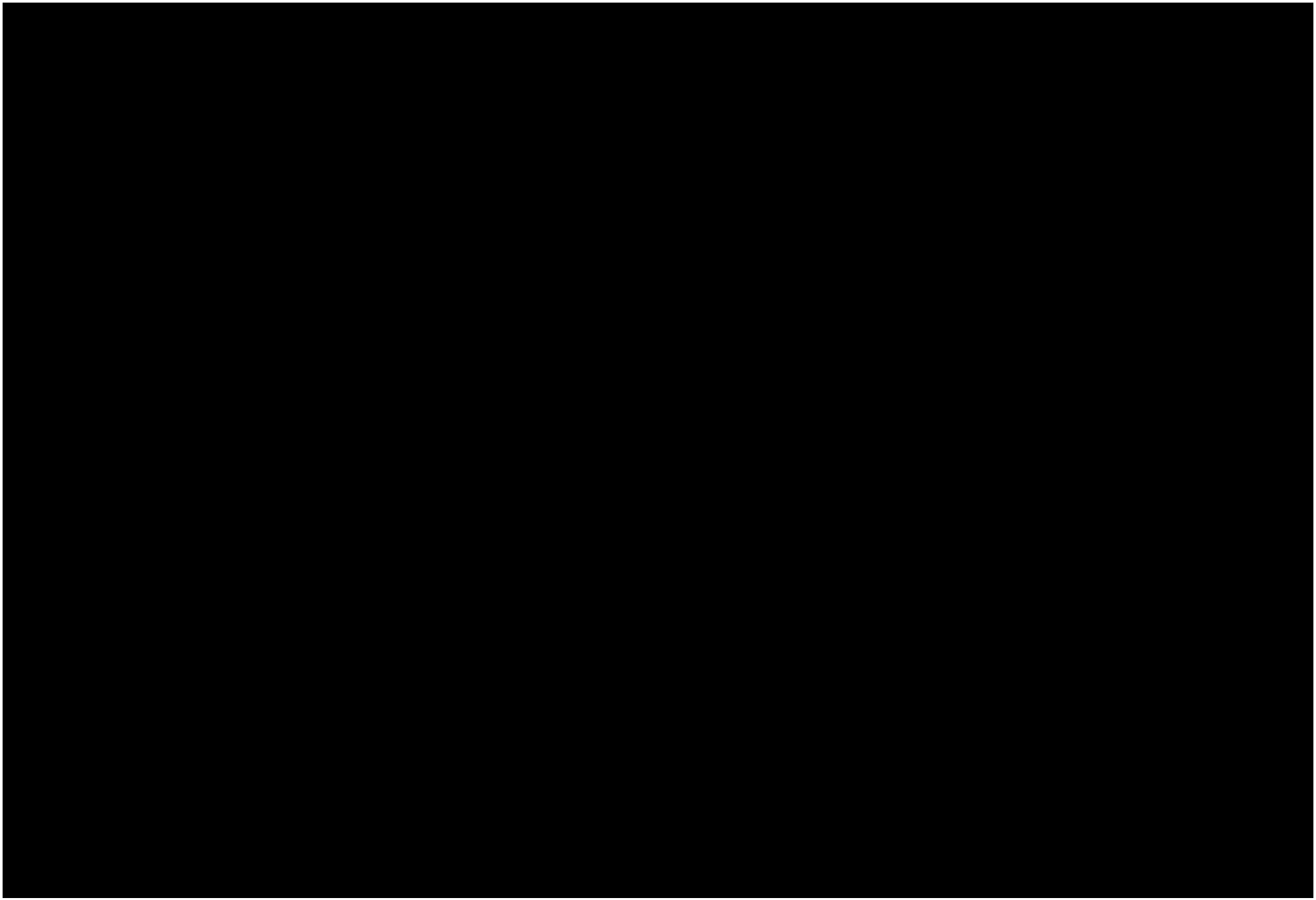
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

High Plains Power, Inc.

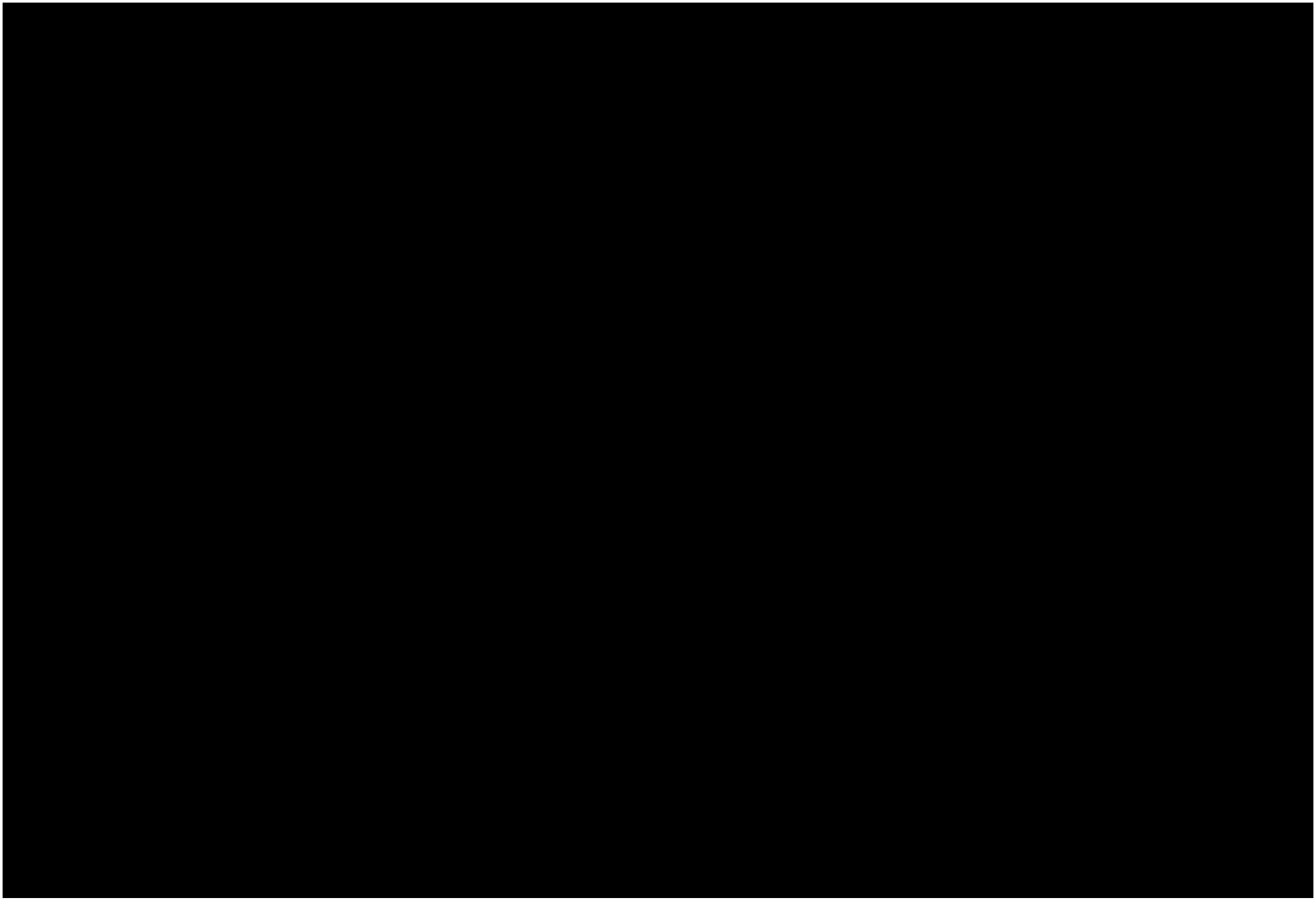
Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

High Plains Power, Inc.

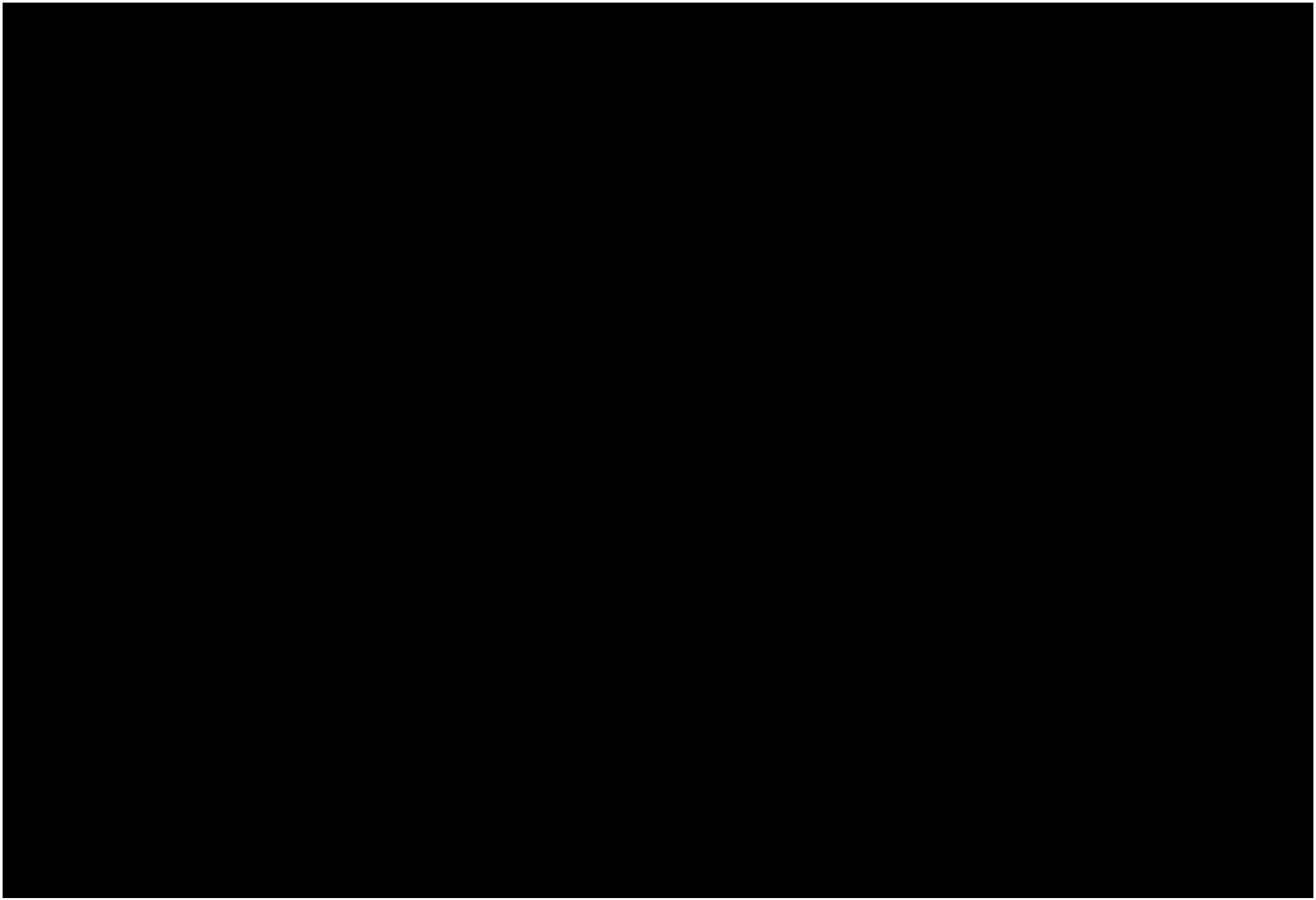
Date of Off Peak Day - 06/02/2021



Member Forecasted Off Peak Demand Day for July 2021

High Plains Power, Inc.

Date of Off Peak Day - 07/31/2021



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Member Forecasted Off Peak Demand Day for August 2021

High Plains Power, Inc.

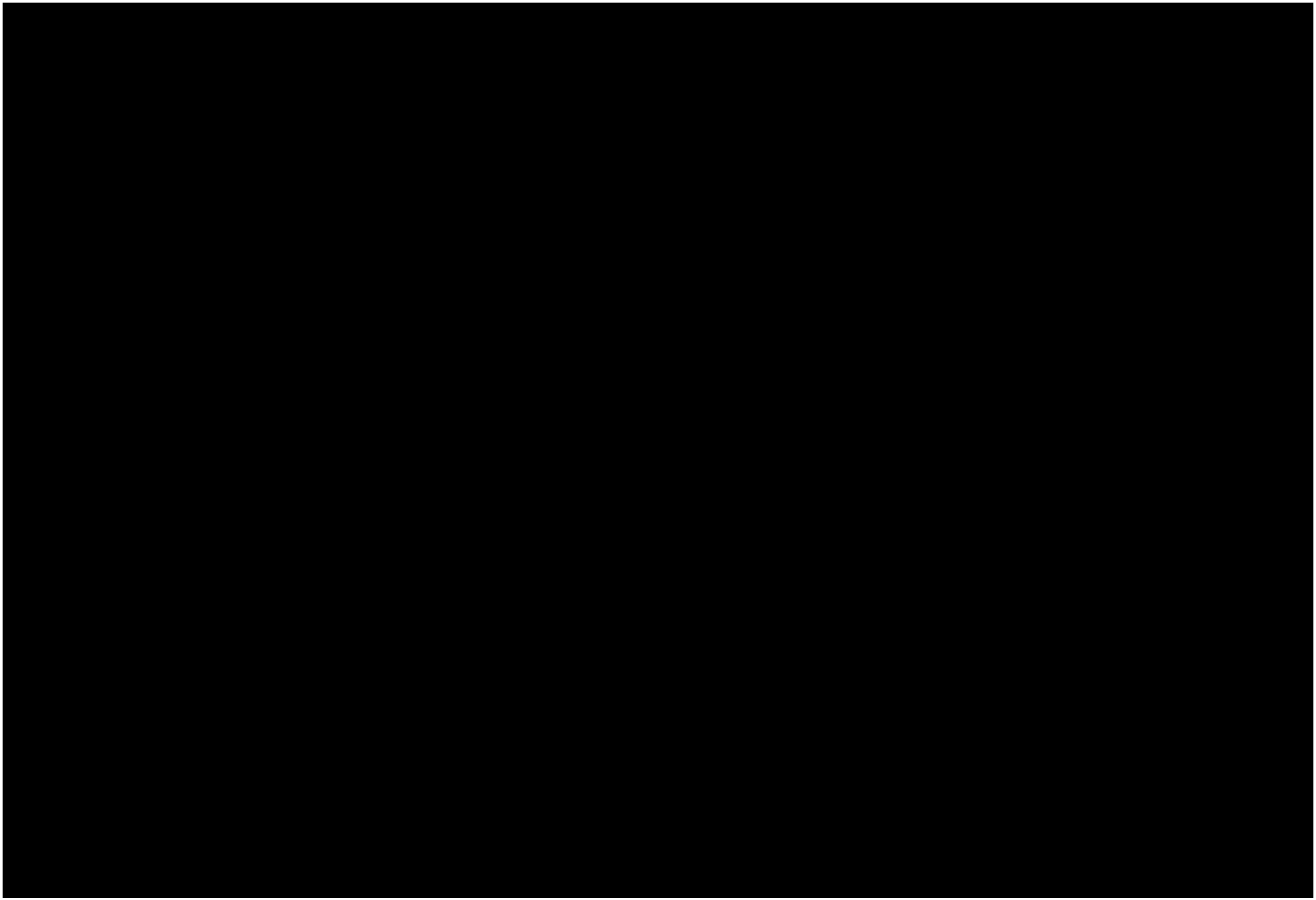
Date of Off Peak Day - 08/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

High Plains Power, Inc.

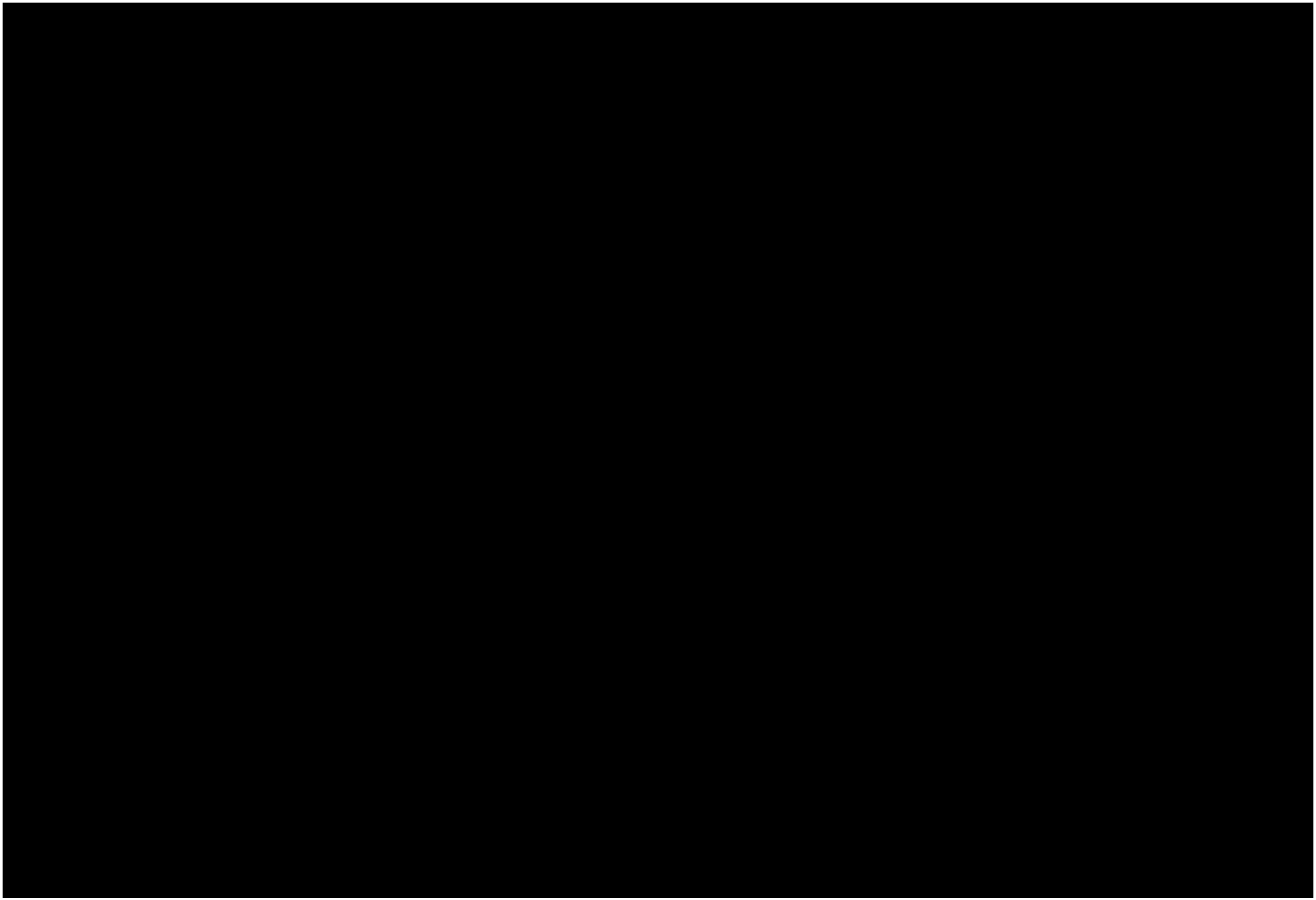
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

High Plains Power, Inc.

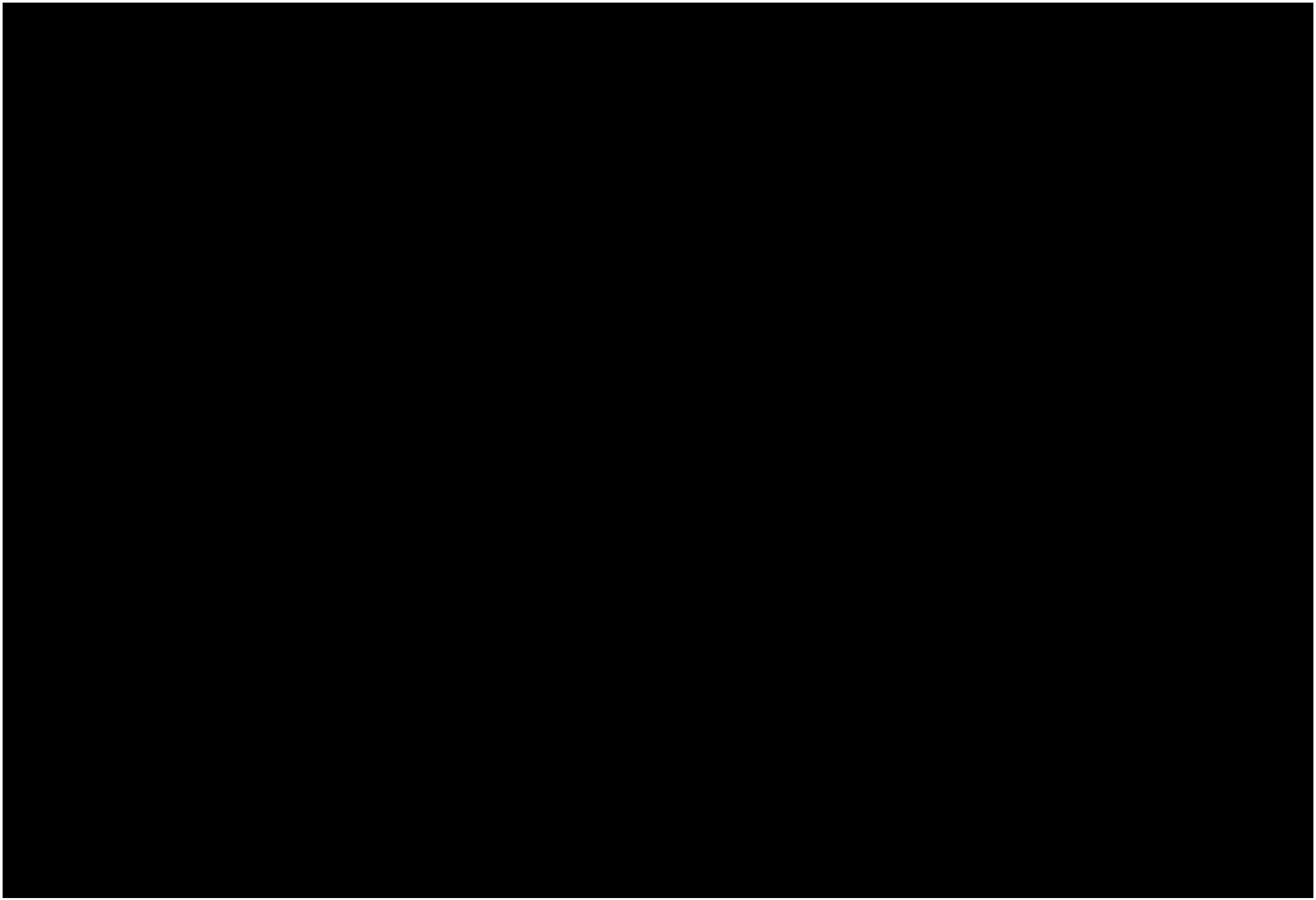
Date of Off Peak Day - 10/02/2021



Member Forecasted Off Peak Demand Day for November 2021

High Plains Power, Inc.

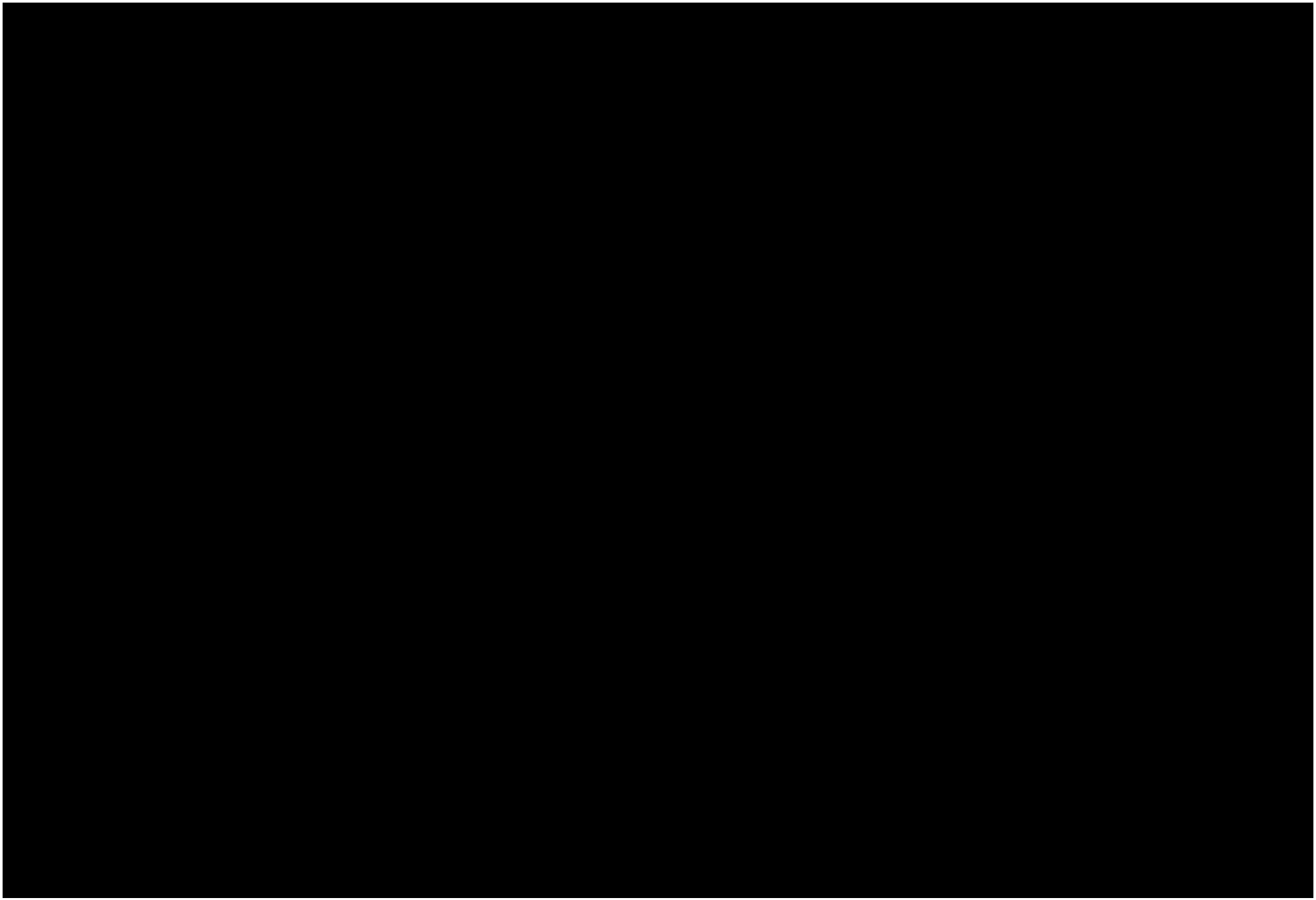
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

High Plains Power, Inc.

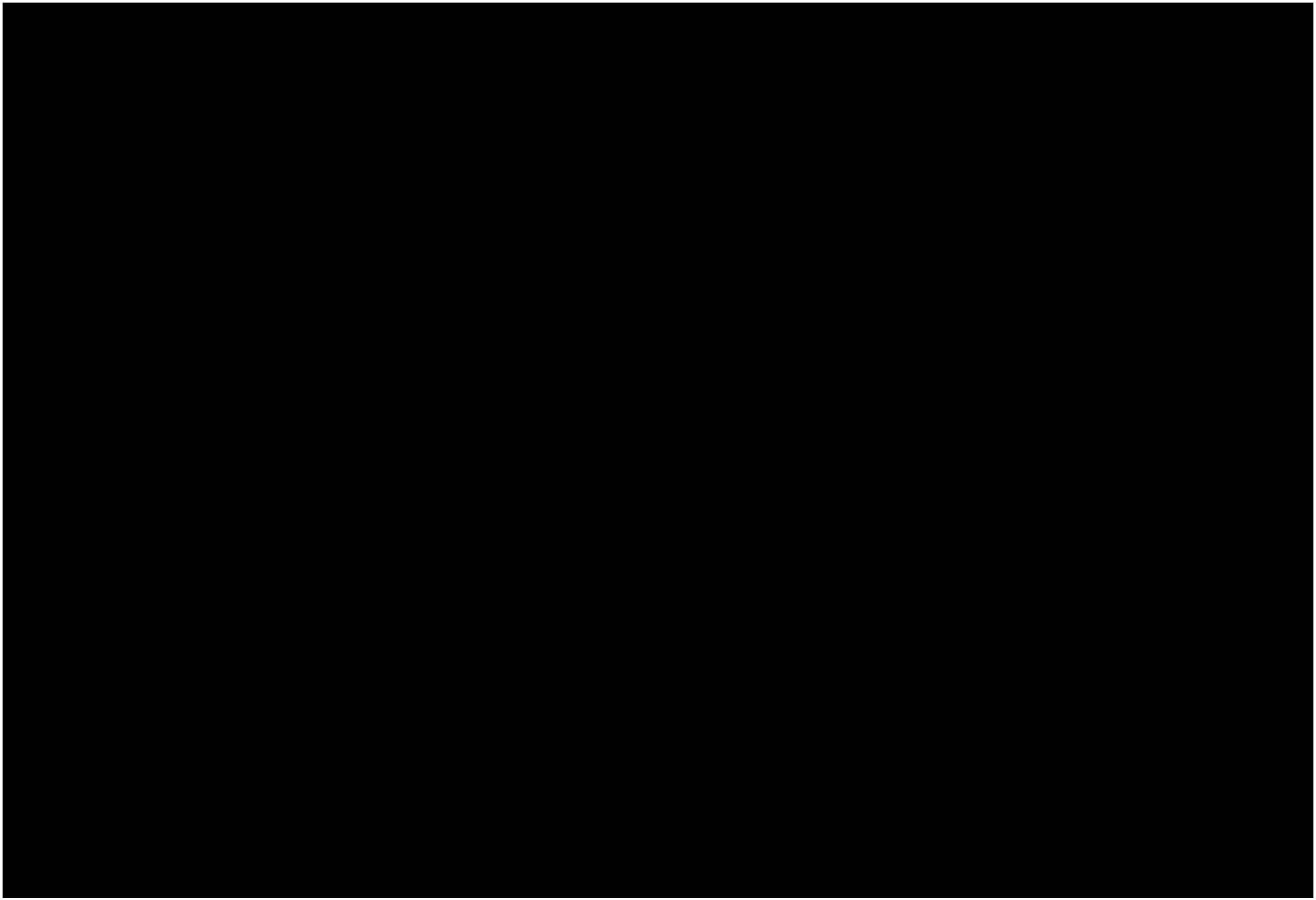
Date of Off Peak Day - 12/09/2021



Member Forecasted Off Peak Demand Day for January 2021

High West Energy, Inc.

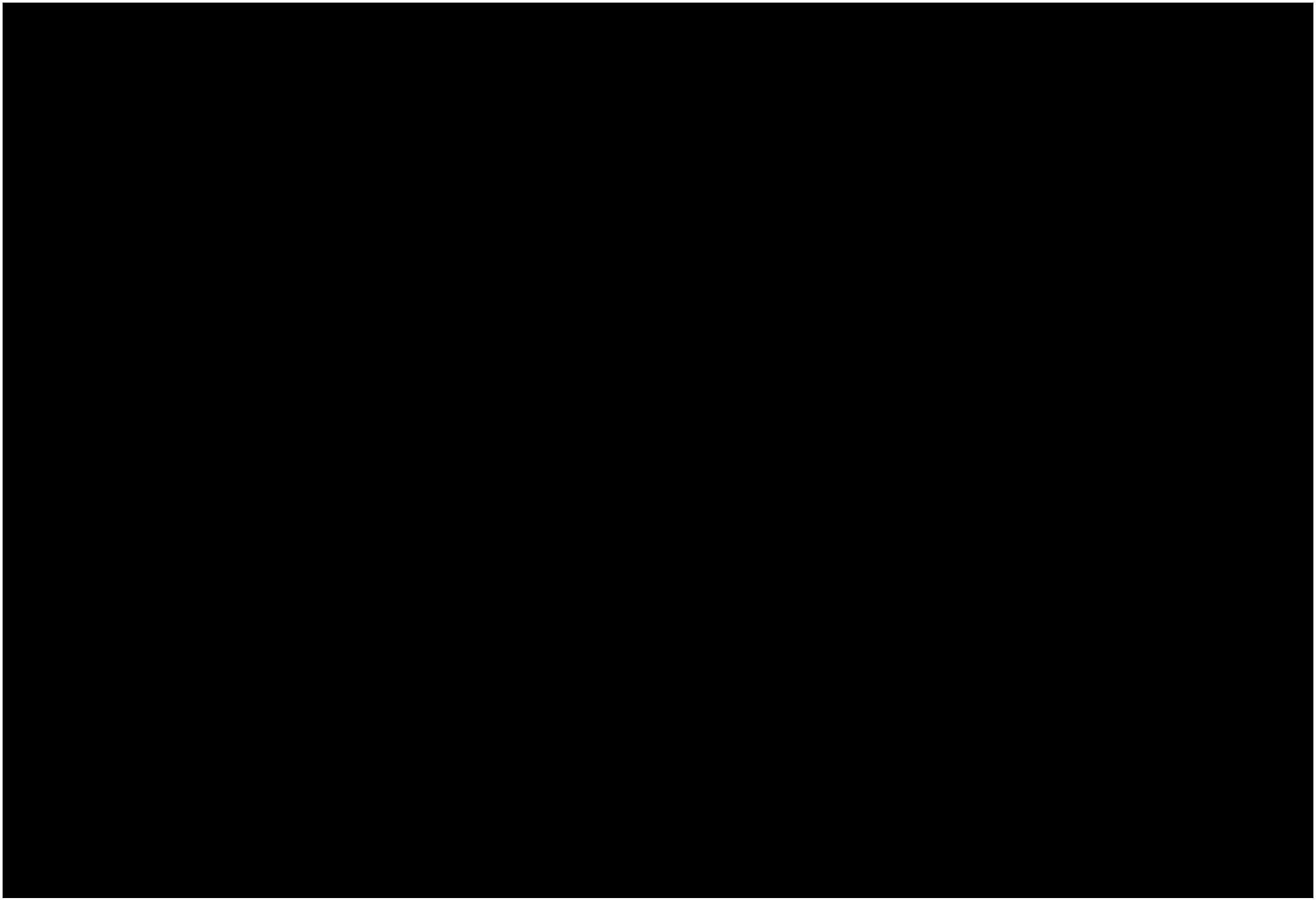
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

High West Energy, Inc.

Date of Off Peak Day - 02/10/2021



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Member Forecasted Off Peak Demand Day for March 2021

High West Energy, Inc.

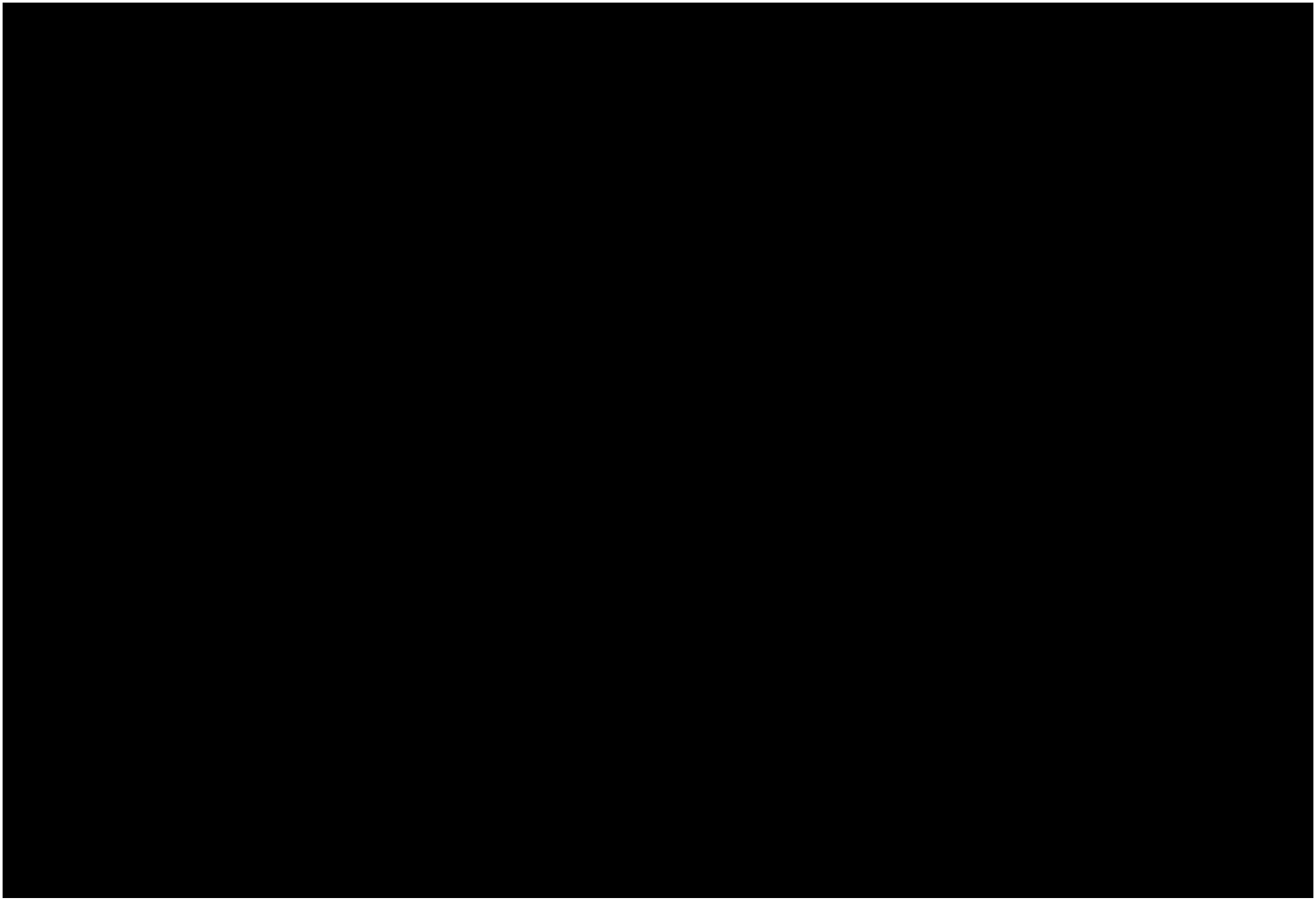
Date of Off Peak Day - 03/28/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

High West Energy, Inc.

Date of Off Peak Day - 04/29/2021



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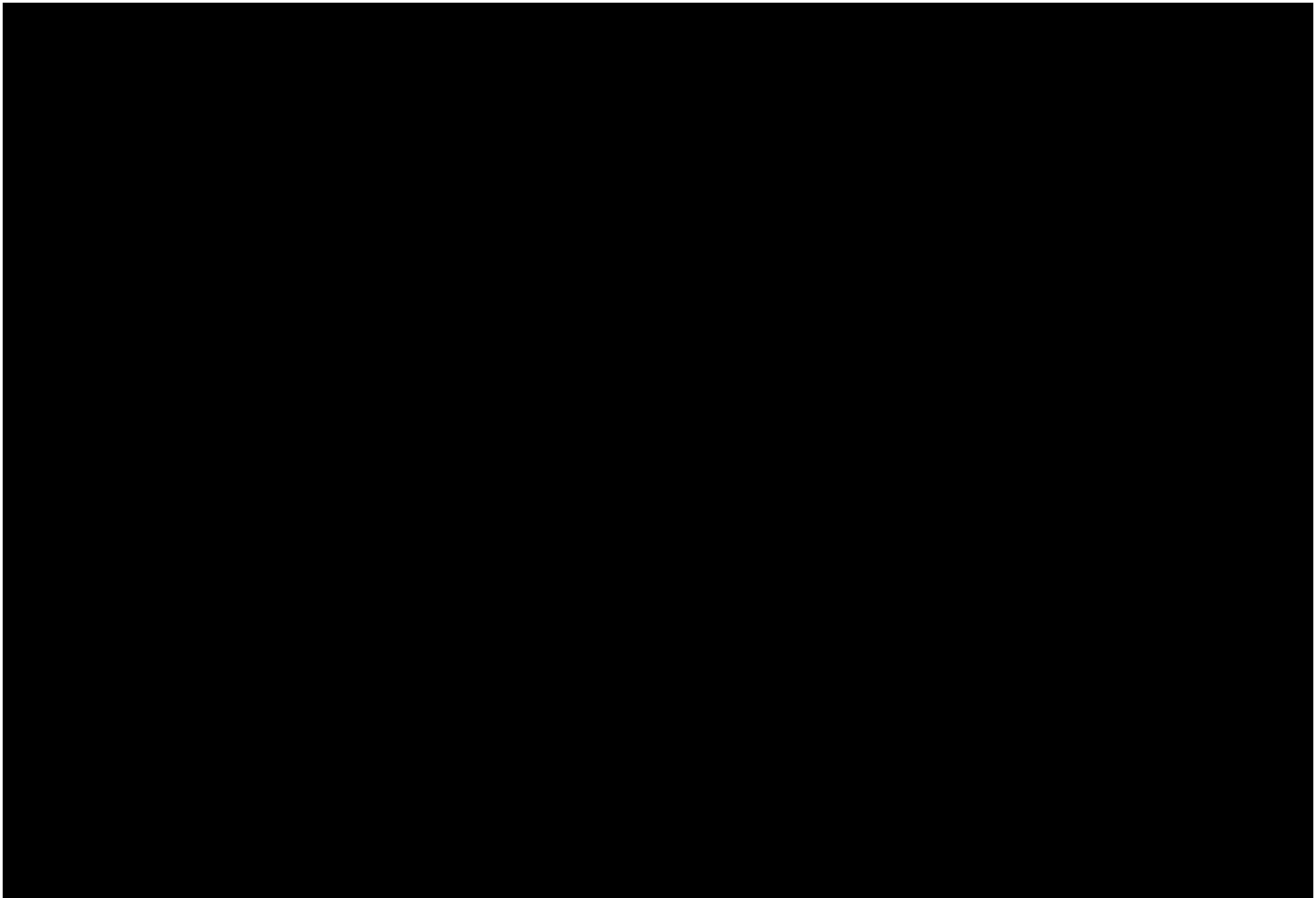
Member Forecasted Off Peak Demand Day for May 2021

High West Energy, Inc.

Date of Off Peak Day - 05/12/2021



Member Forecasted Off Peak Demand Day for June 2021

High West Energy, Inc.

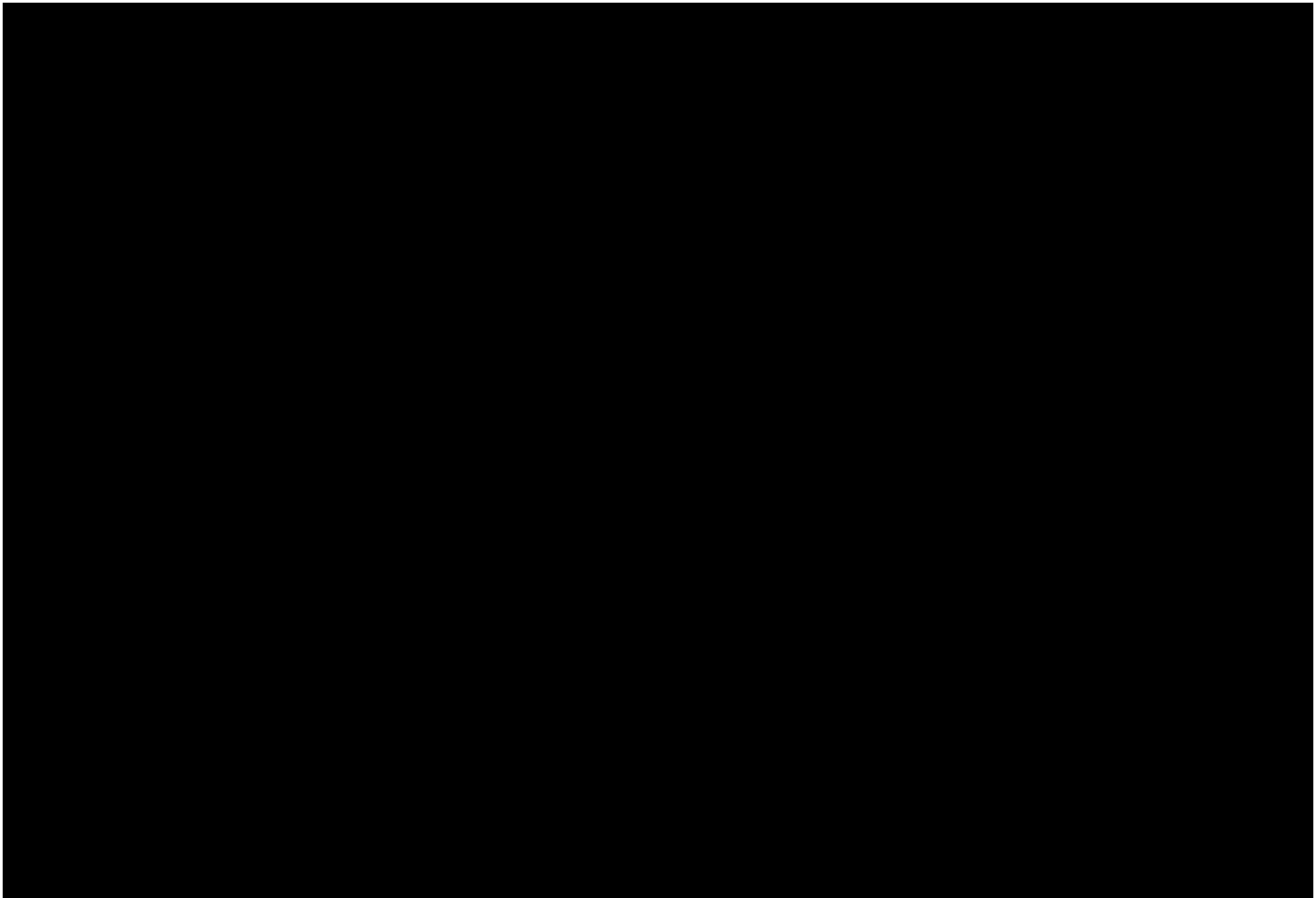
Date of Off Peak Day - 06/21/2021

[redacted]

Member Forecasted Off Peak Demand Day for July 2021

High West Energy, Inc.

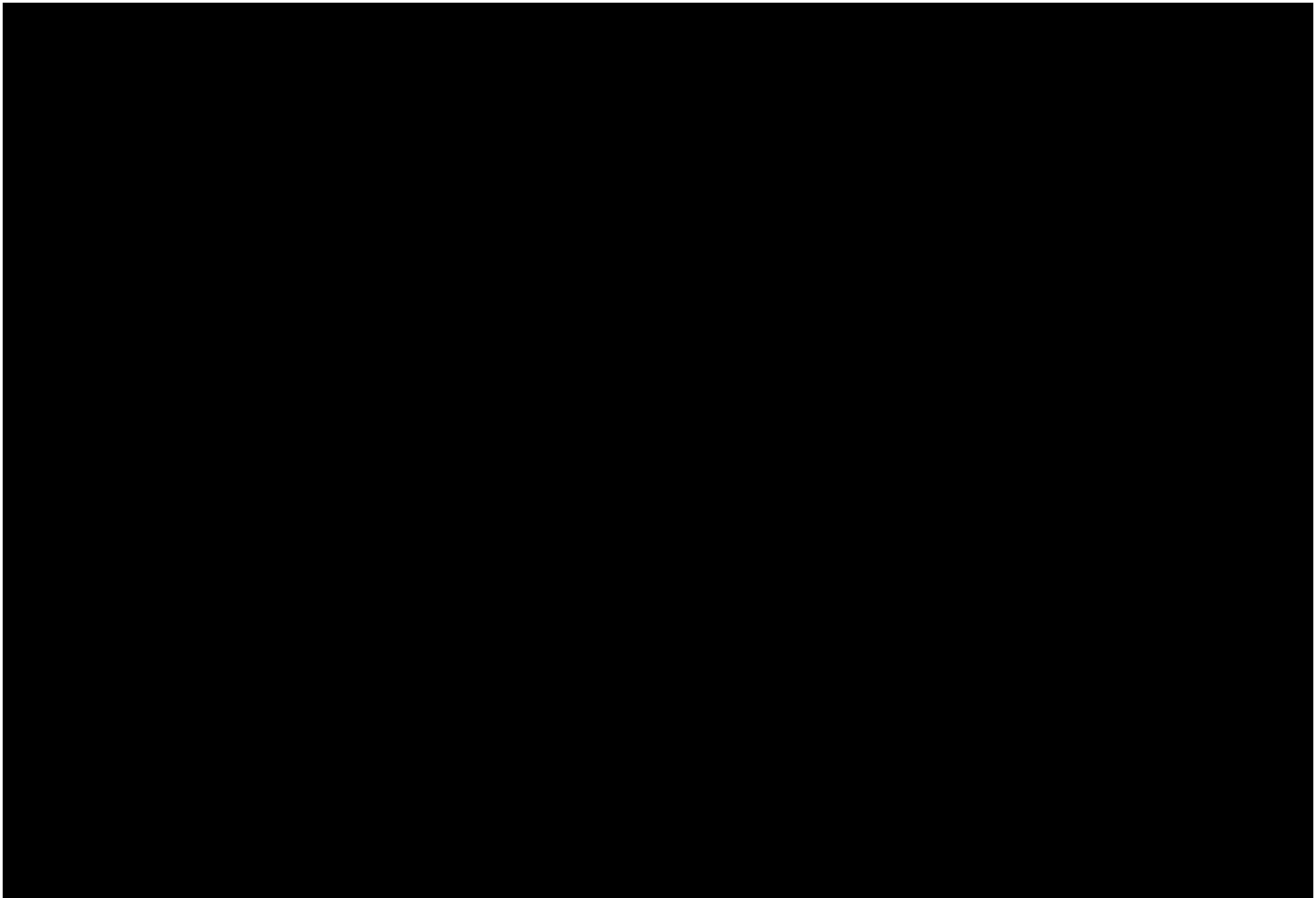
Date of Off Peak Day - 07/01/2021



Member Forecasted Off Peak Demand Day for August 2021

High West Energy, Inc.

Date of Off Peak Day - 08/16/2021



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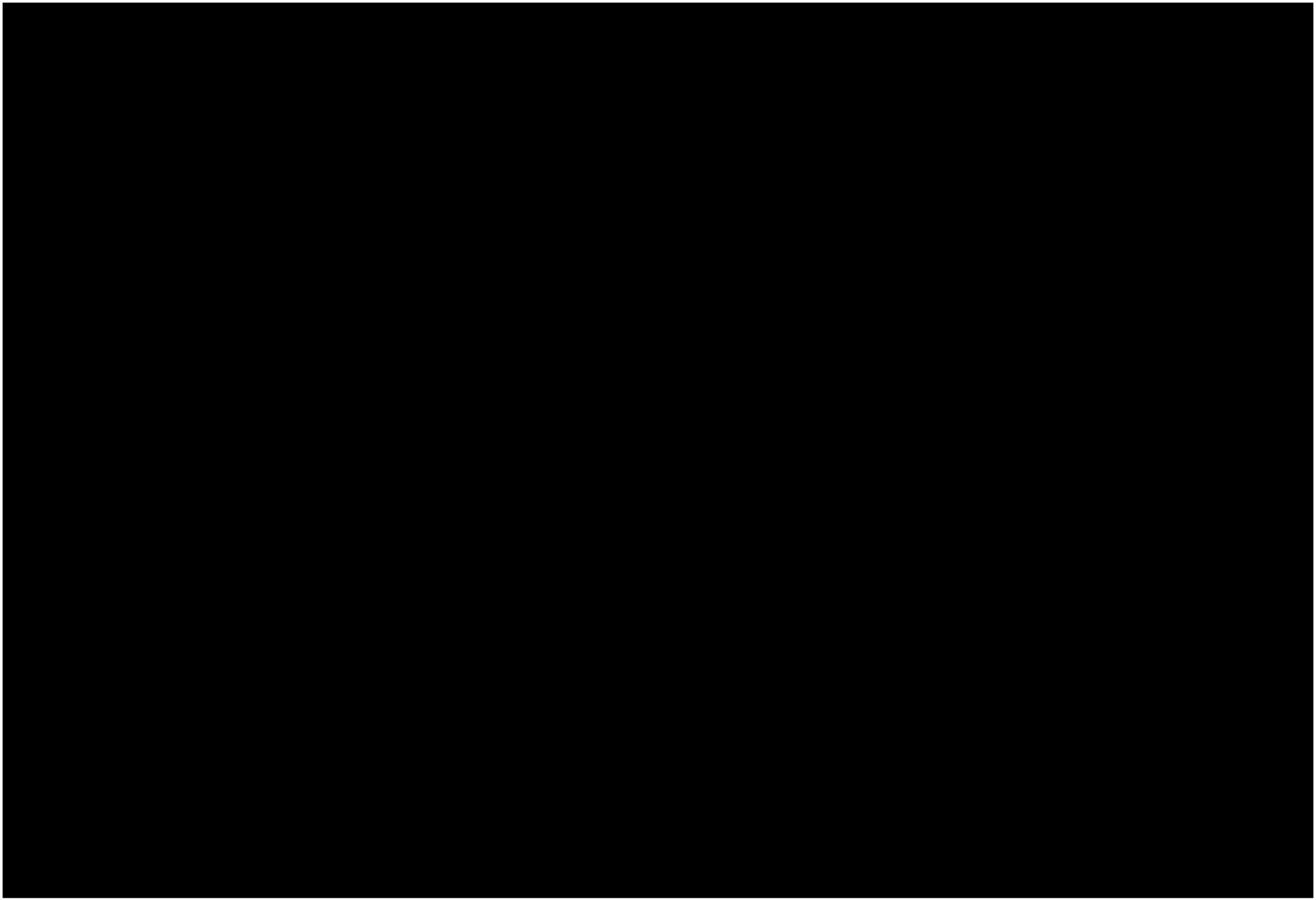
Member Forecasted Off Peak Demand Day for September 2021

High West Energy, Inc.

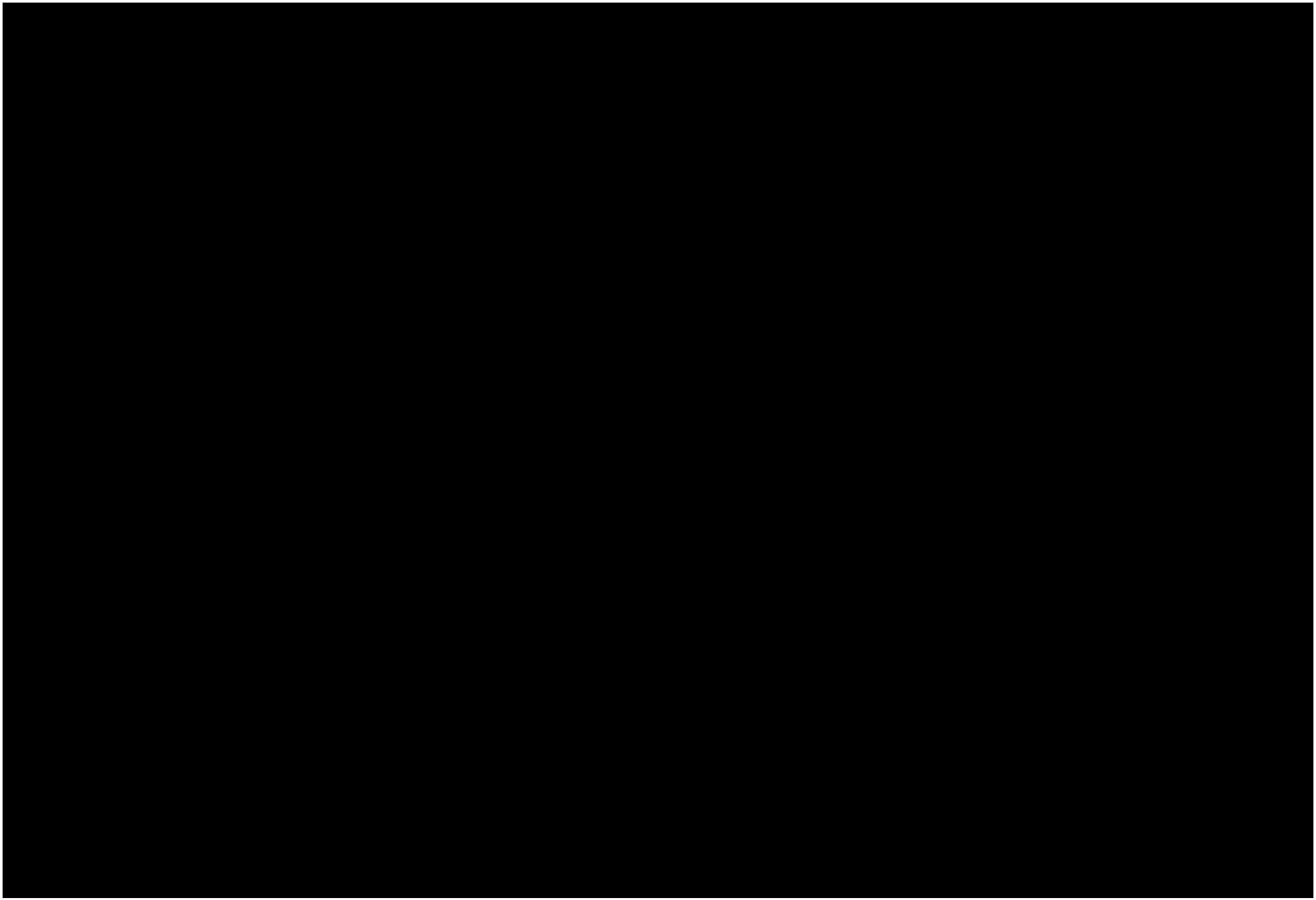
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

High West Energy, Inc.

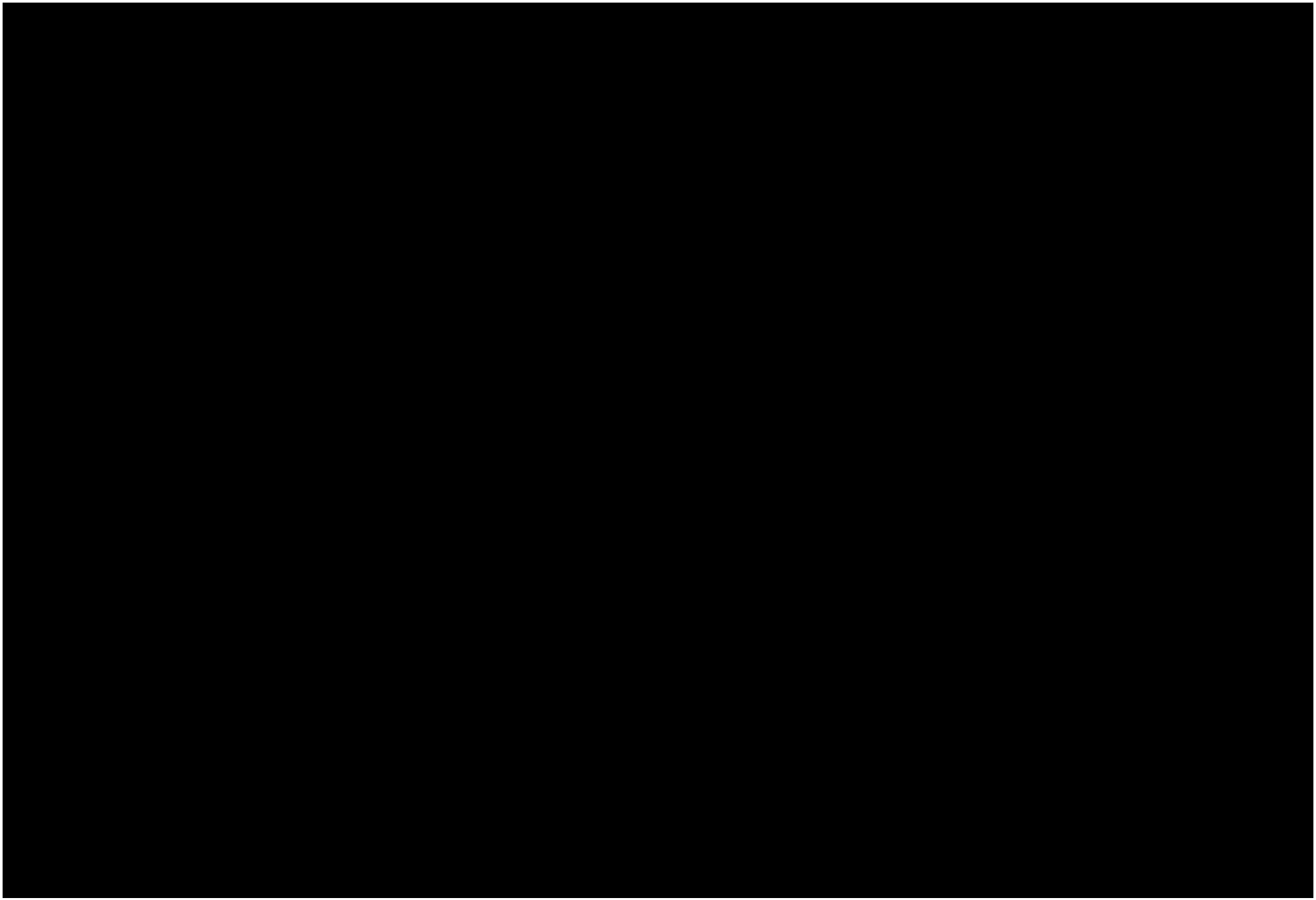
Date of Off Peak Day - 10/17/2021



Member Forecasted Off Peak Demand Day for November 2021

High West Energy, Inc.

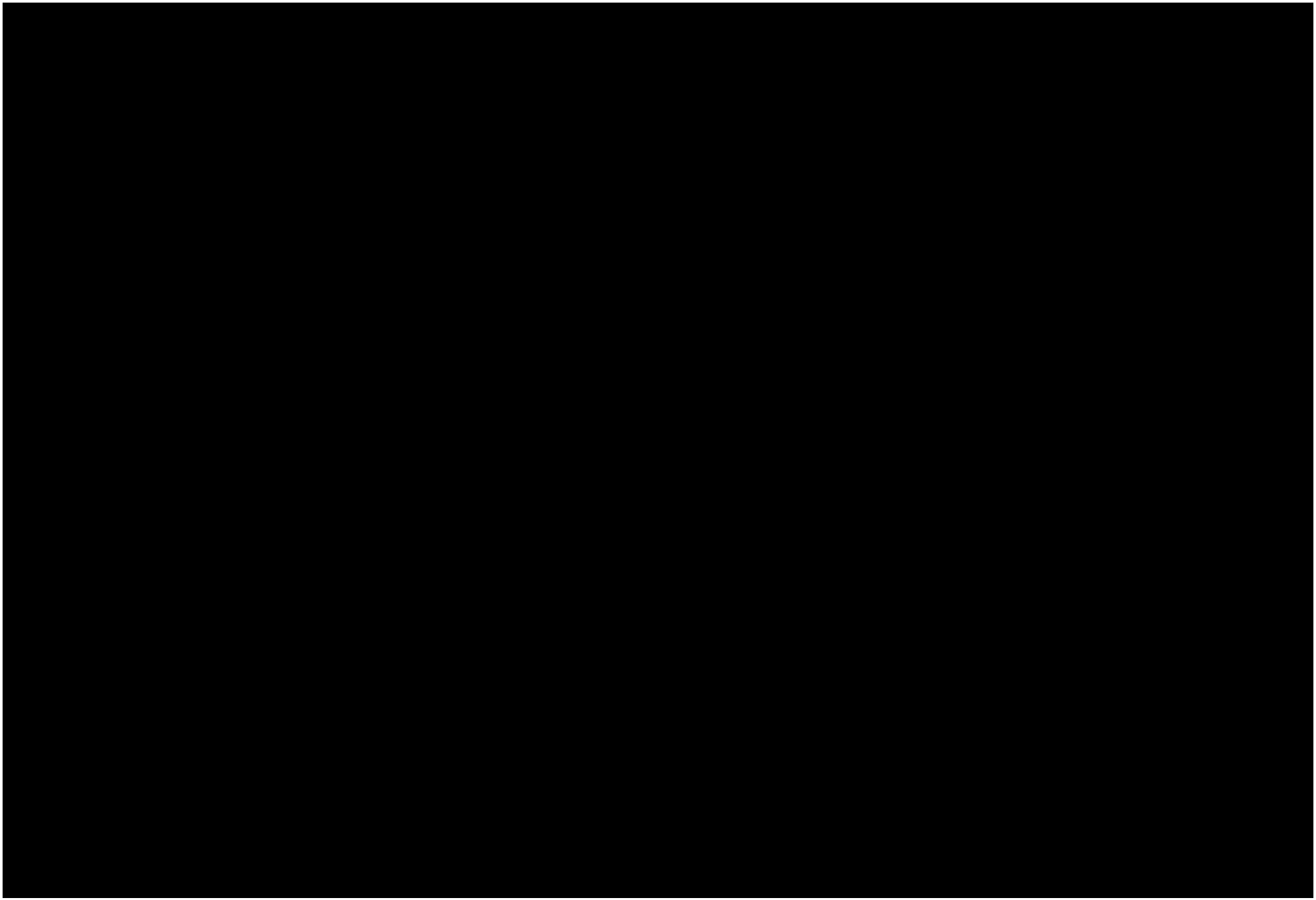
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

High West Energy, Inc.

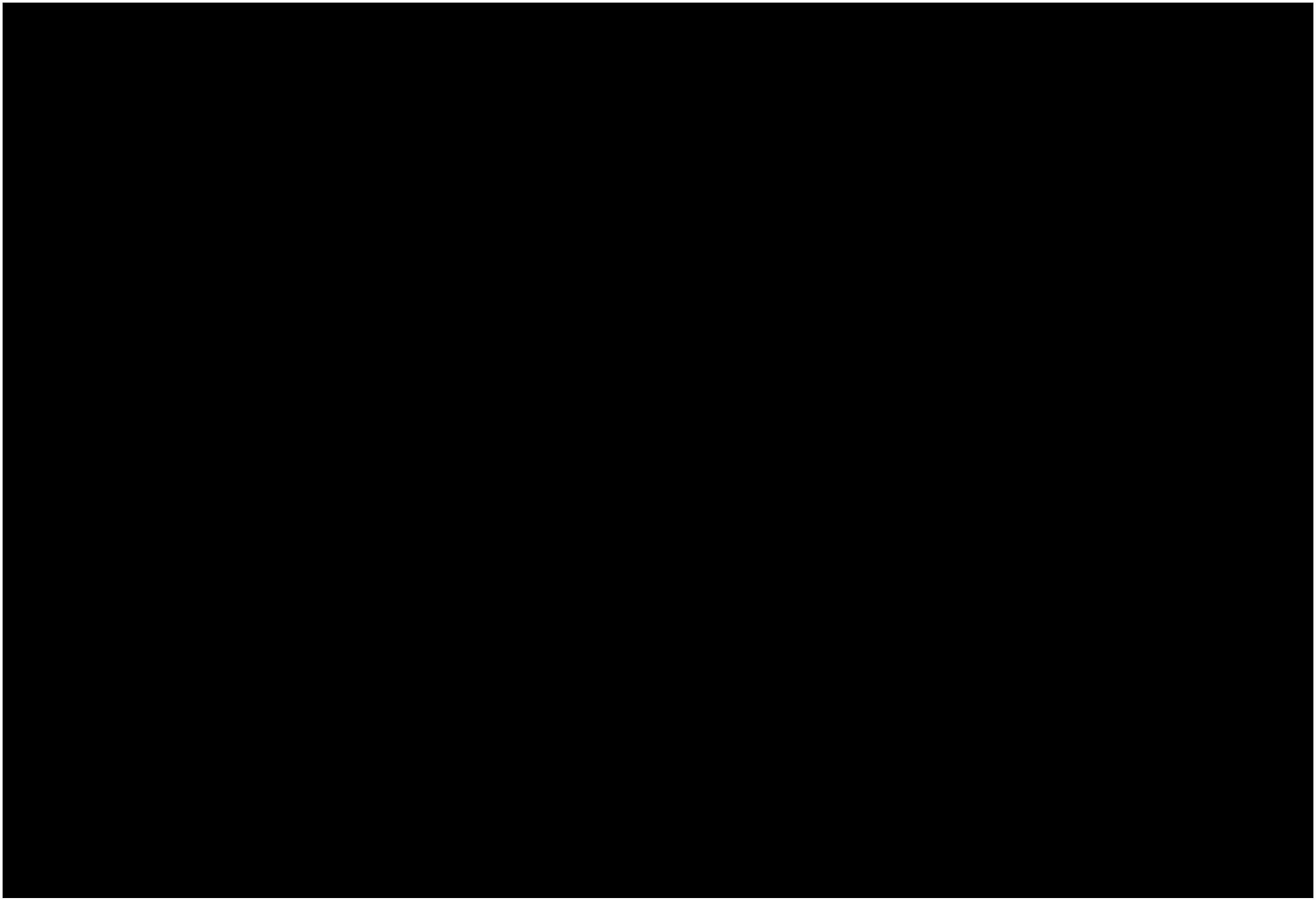
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

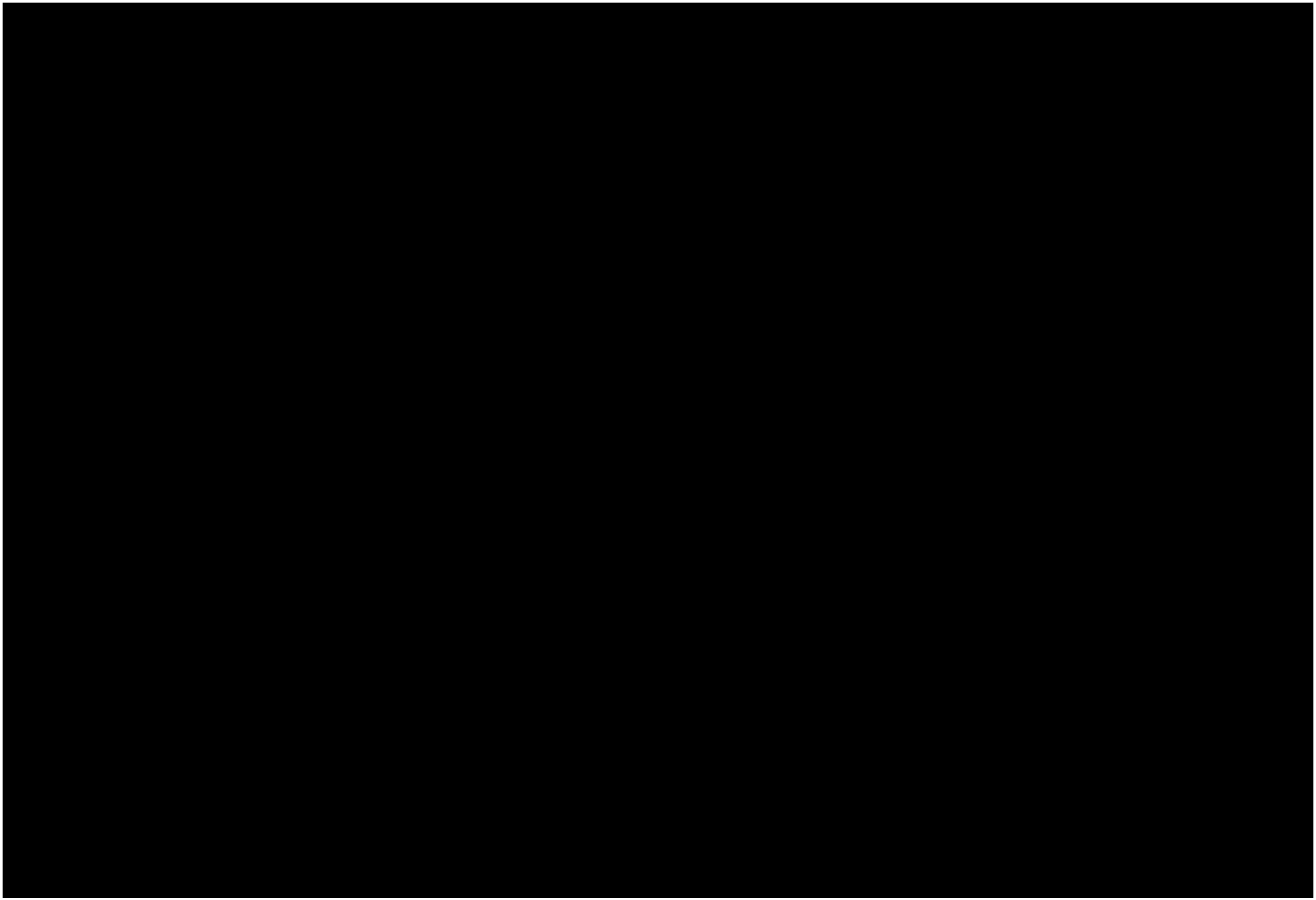
Date of Off Peak Day - 01/13/2021



Member Forecasted Off Peak Demand Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

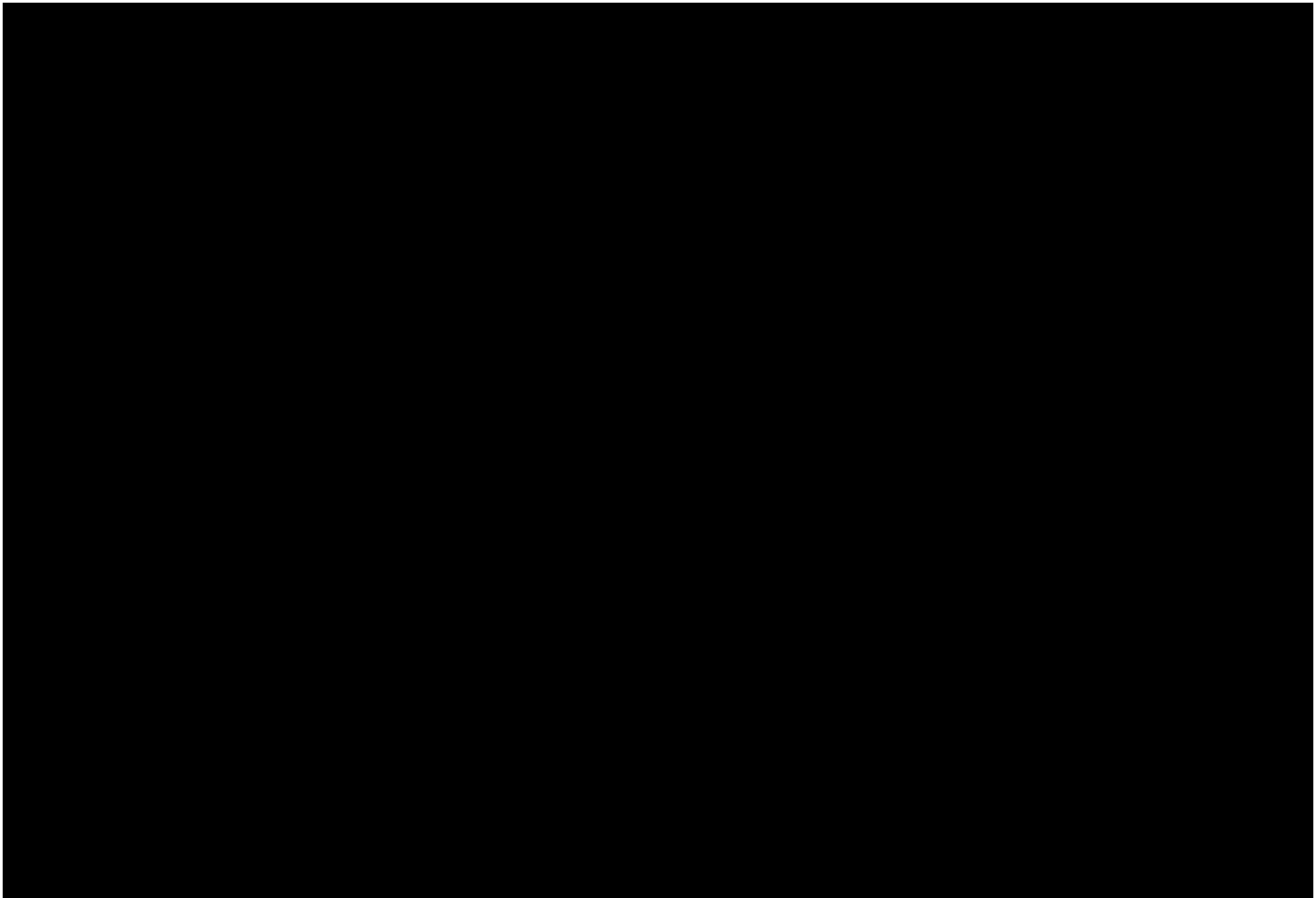
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Jemez Mountains Electric Cooperative, Inc.

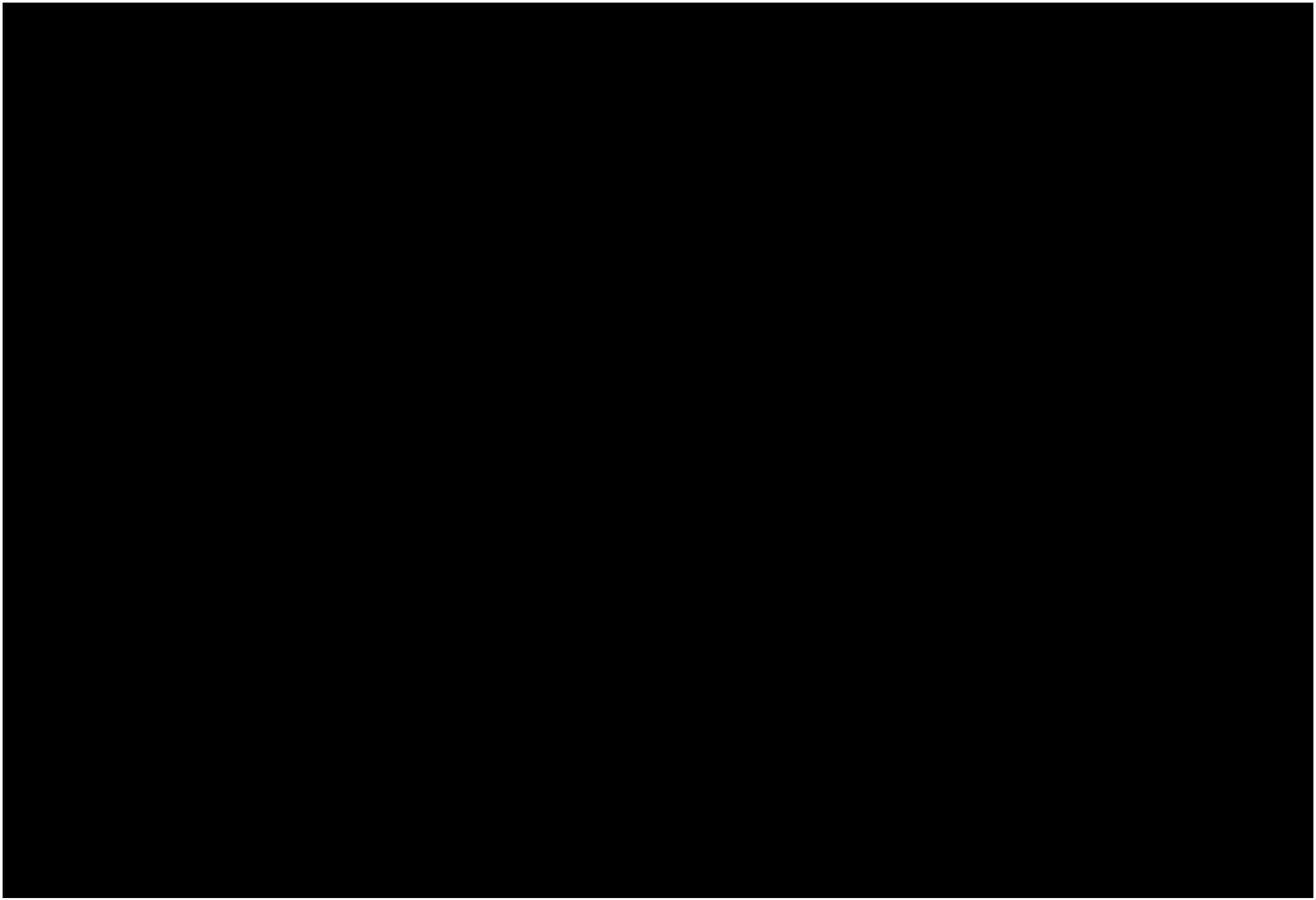
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

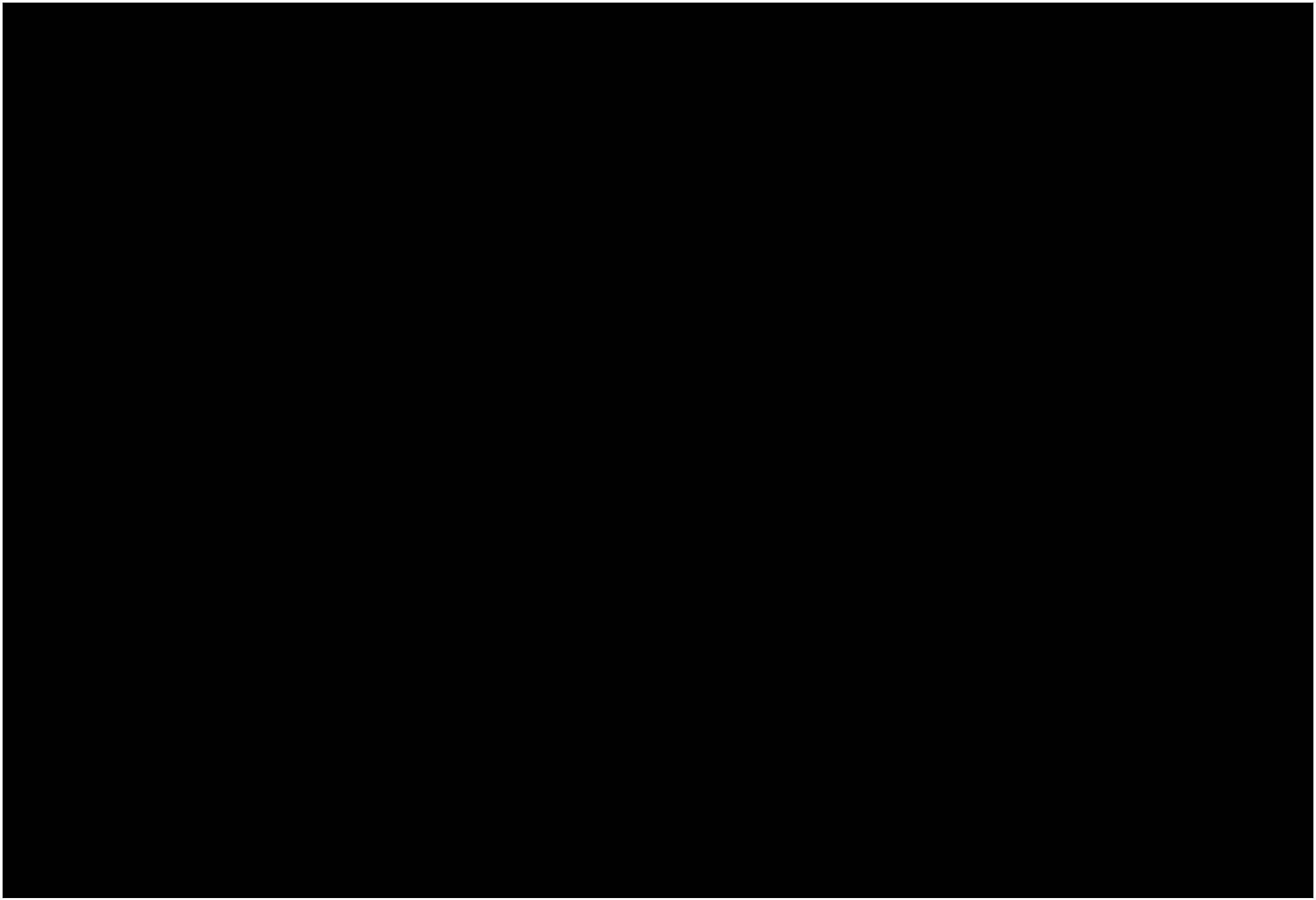
Date of Off Peak Day - 04/07/2021



Member Forecasted Off Peak Demand Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

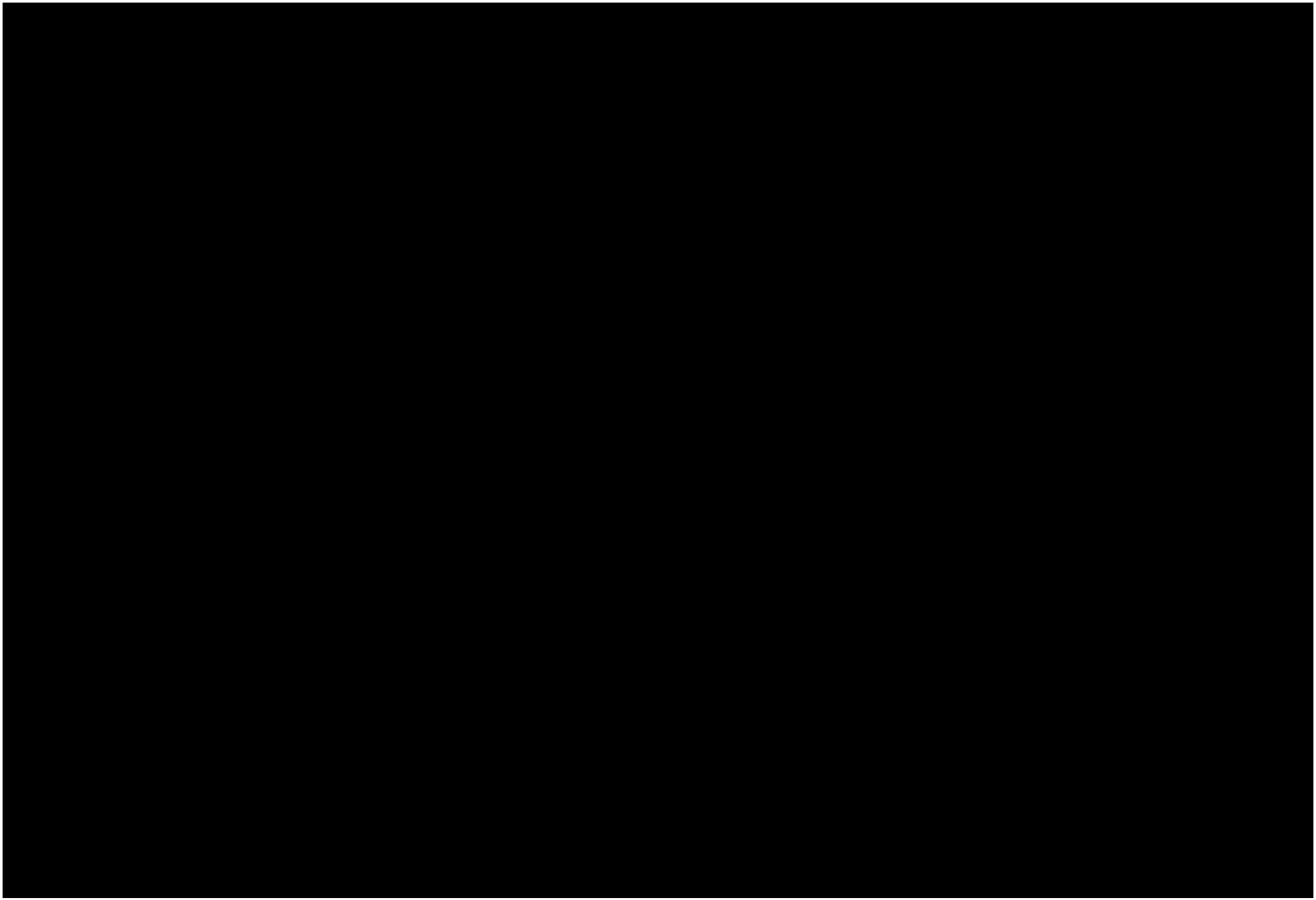
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

Date of Off Peak Day - 06/01/2021



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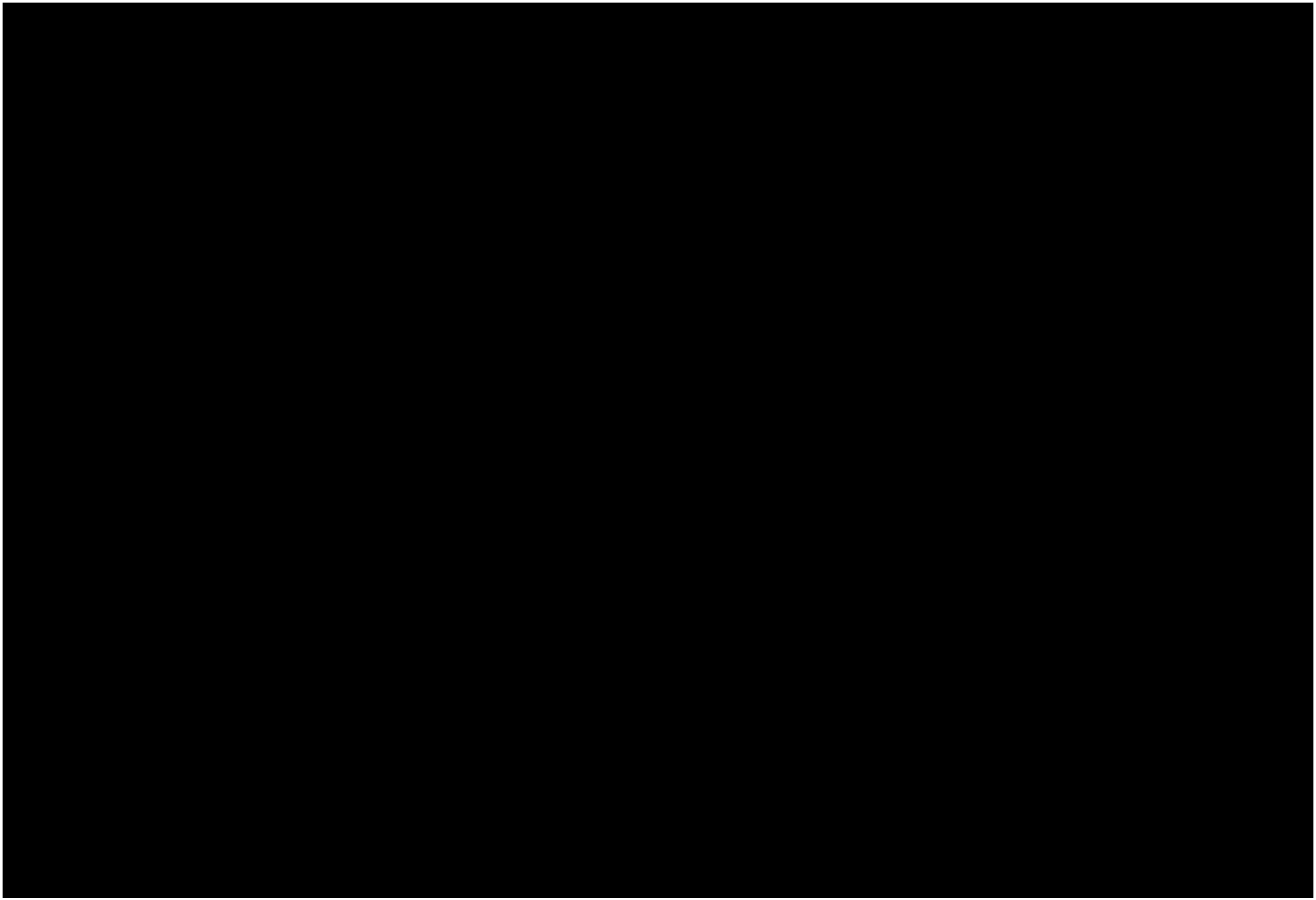
Member Forecasted Off Peak Demand Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

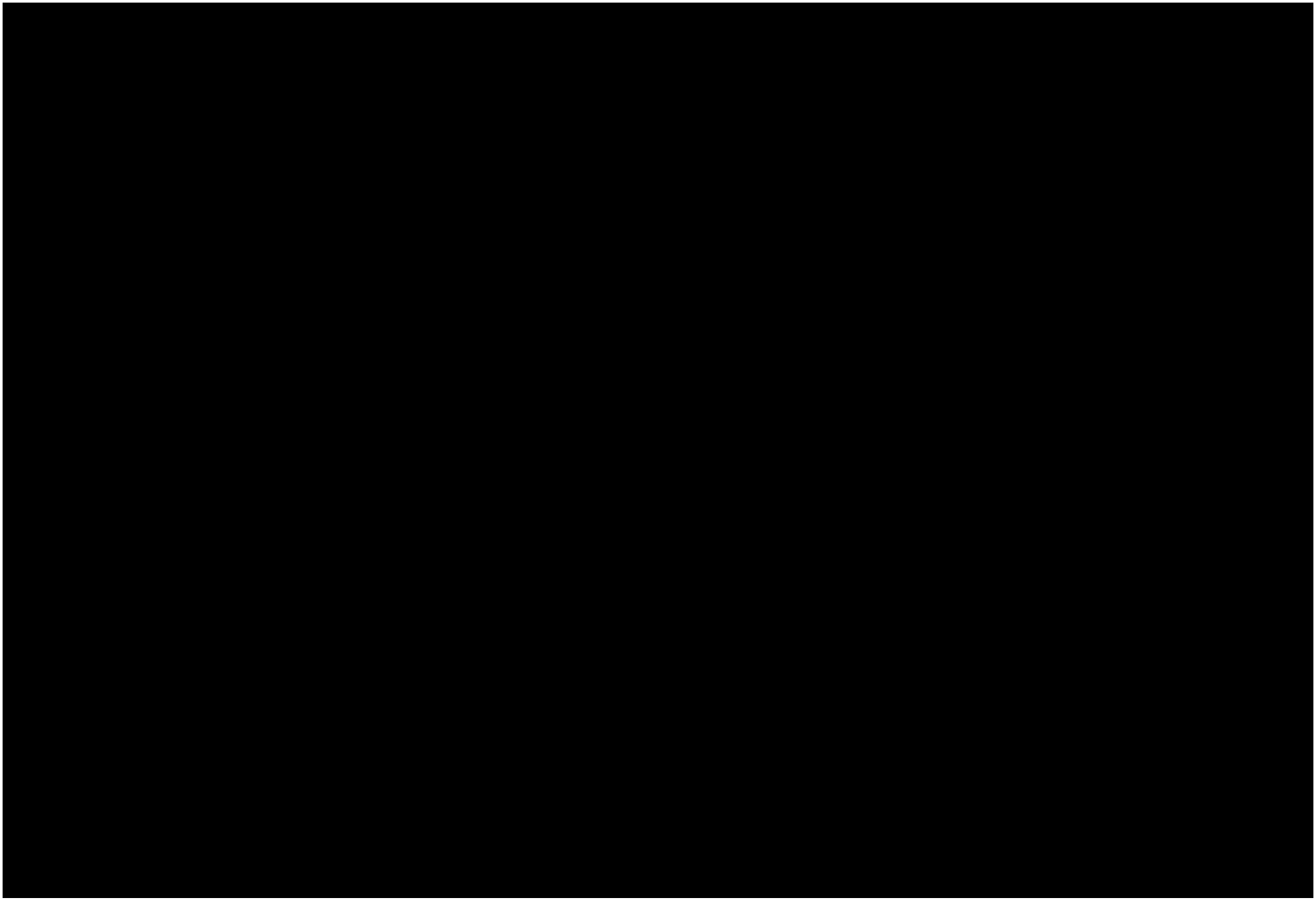
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

Jemez Mountains Electric Cooperative, Inc.

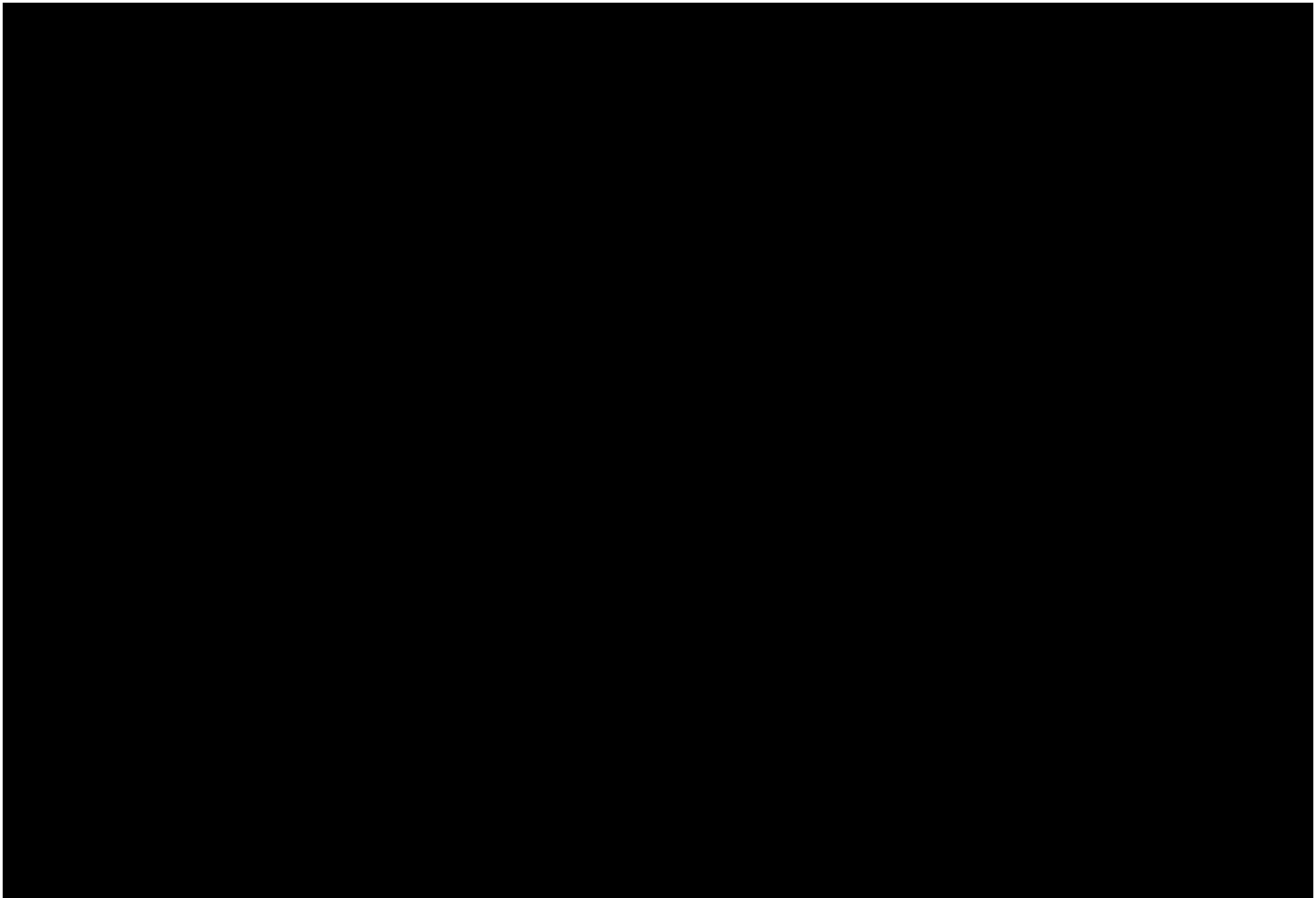
Date of Off Peak Day - 08/14/2021



Member Forecasted Off Peak Demand Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

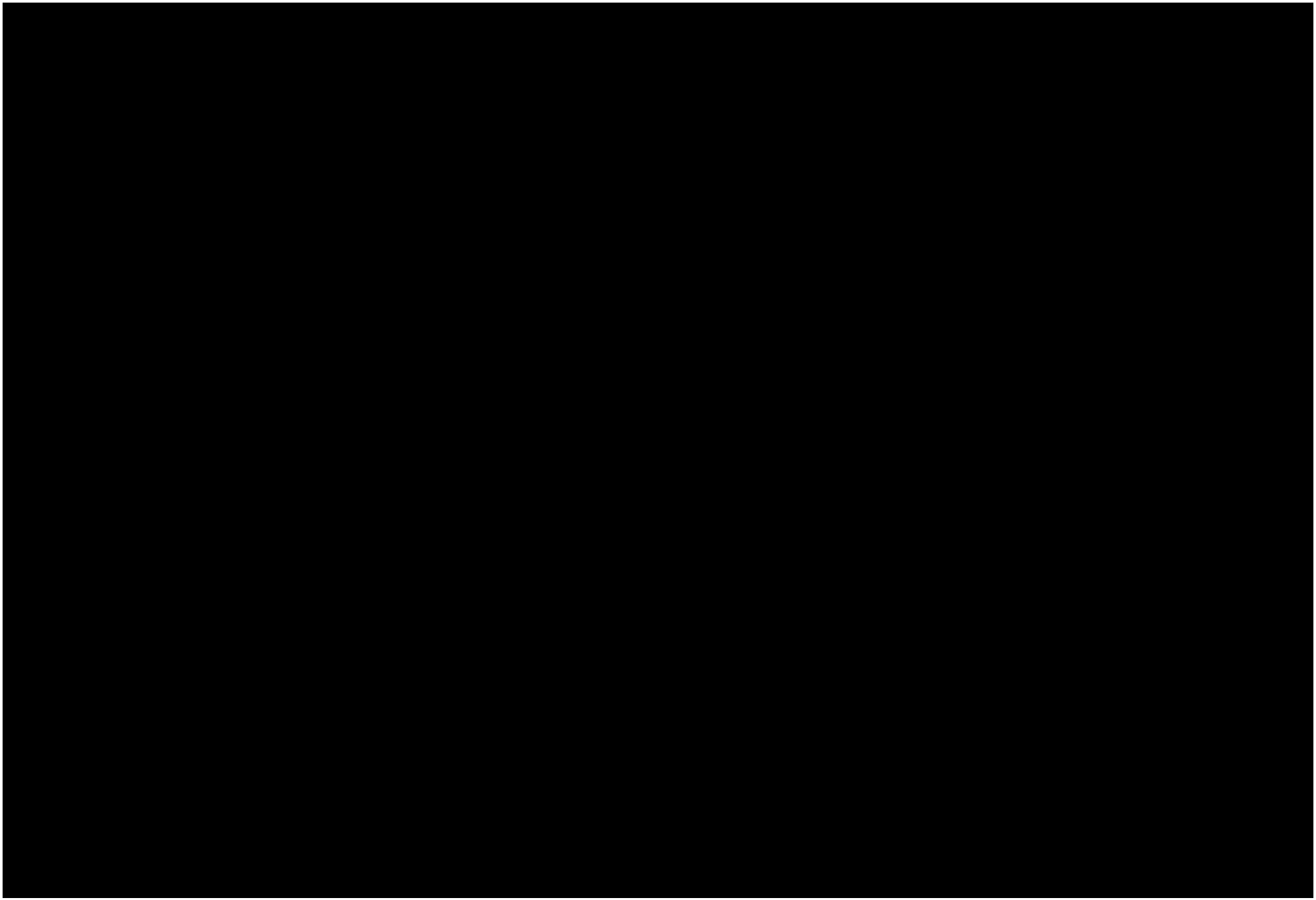
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

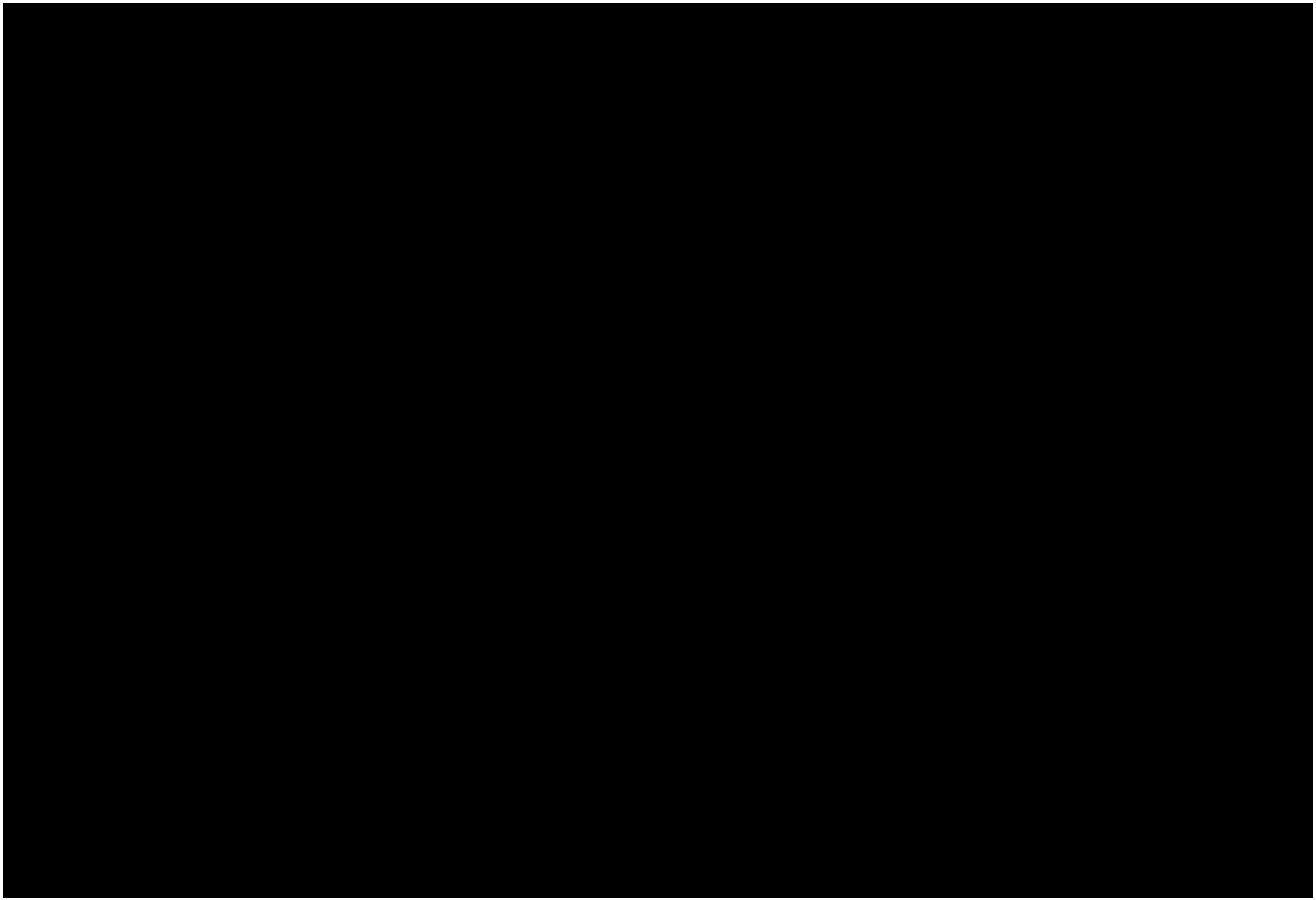
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

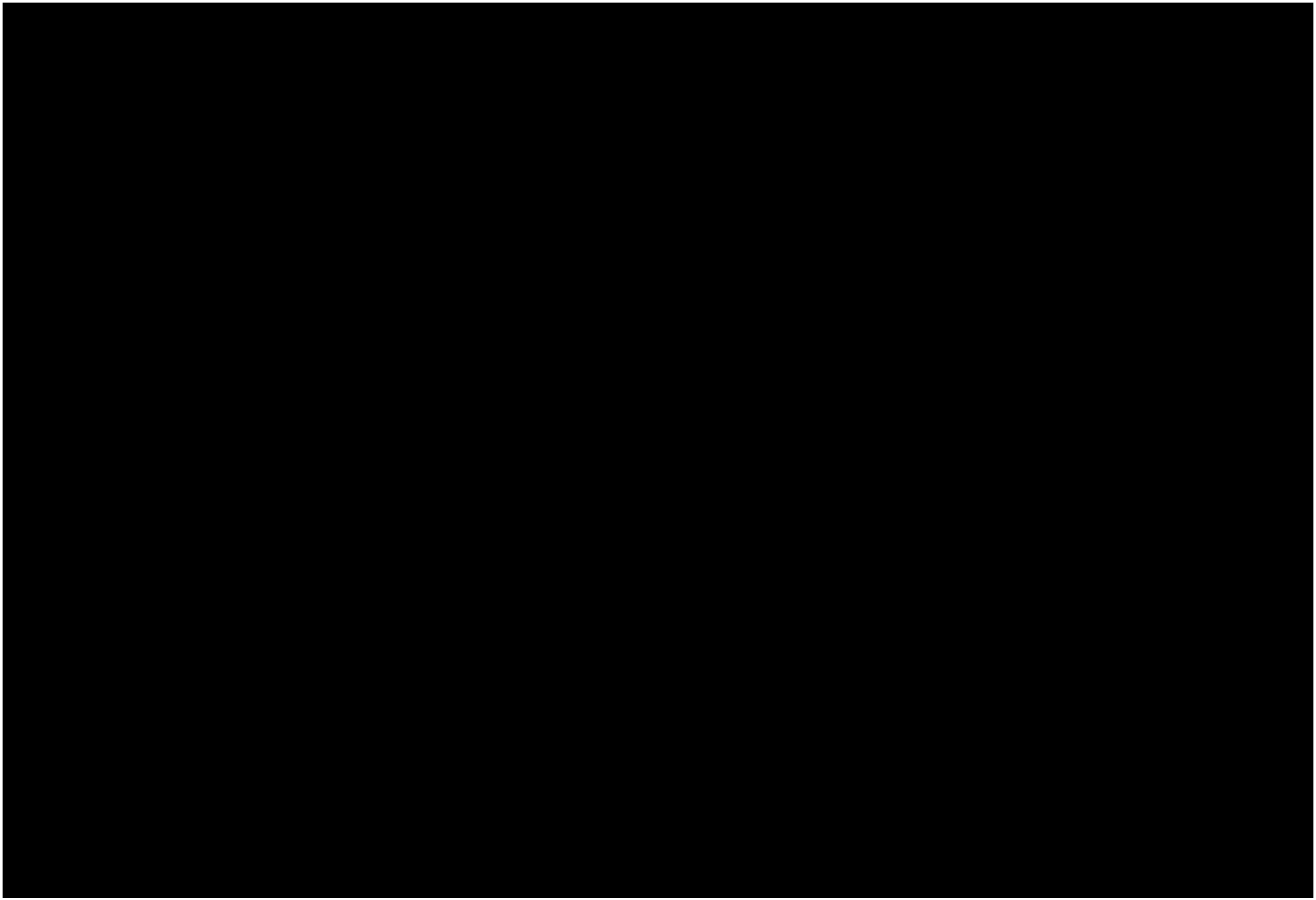
Date of Off Peak Day - 11/01/2021



Member Forecasted Off Peak Demand Day for December 2021

Jemez Mountains Electric Cooperative, Inc.

Date of Off Peak Day - 12/12/2021



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Member Forecasted Off Peak Demand Day for January 2021

K.C. Electric Association, Inc.

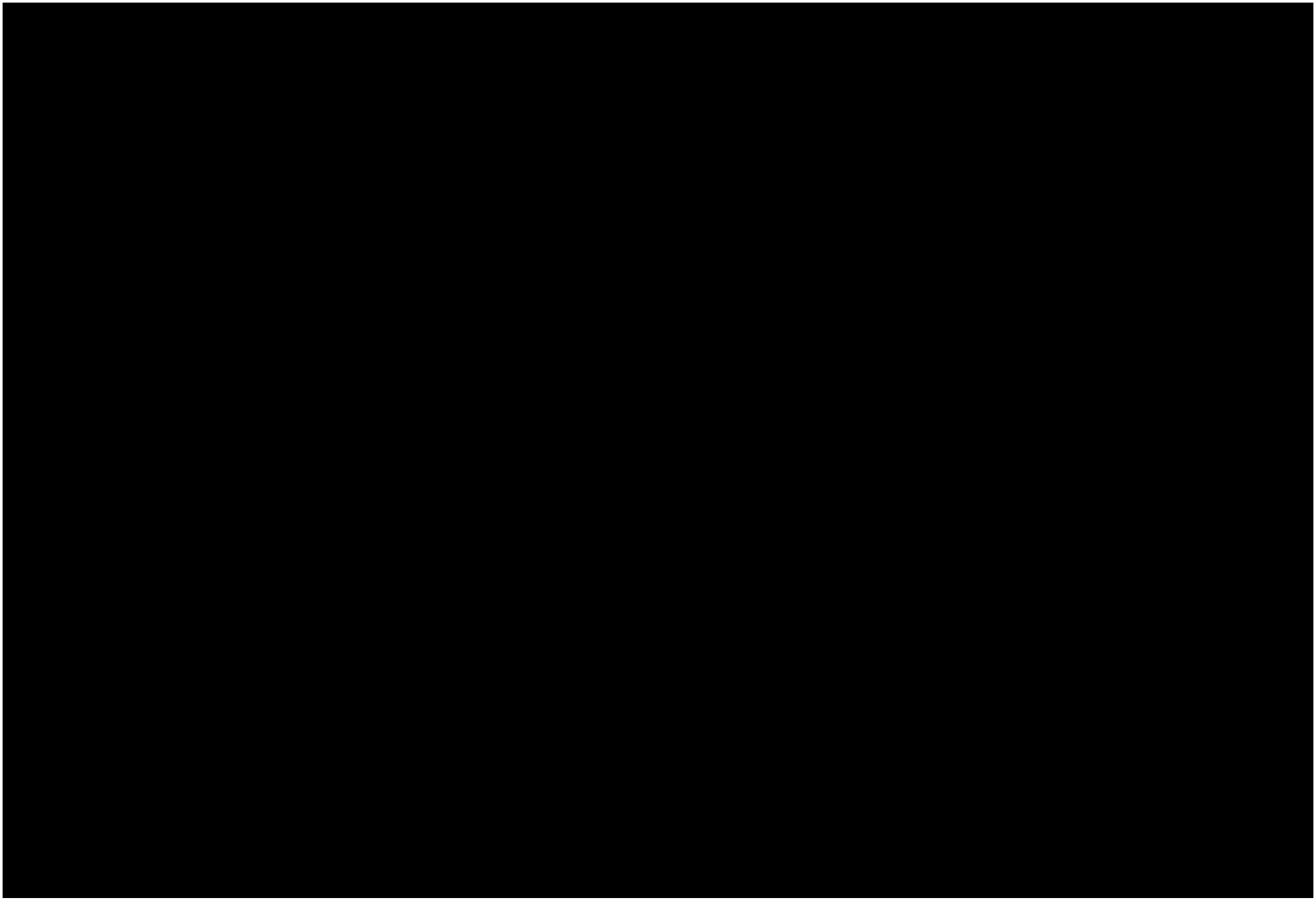
Date of Off Peak Day - 01/19/2021

[redacted]

Member Forecasted Off Peak Demand Day for February 2021

K.C. Electric Association, Inc.

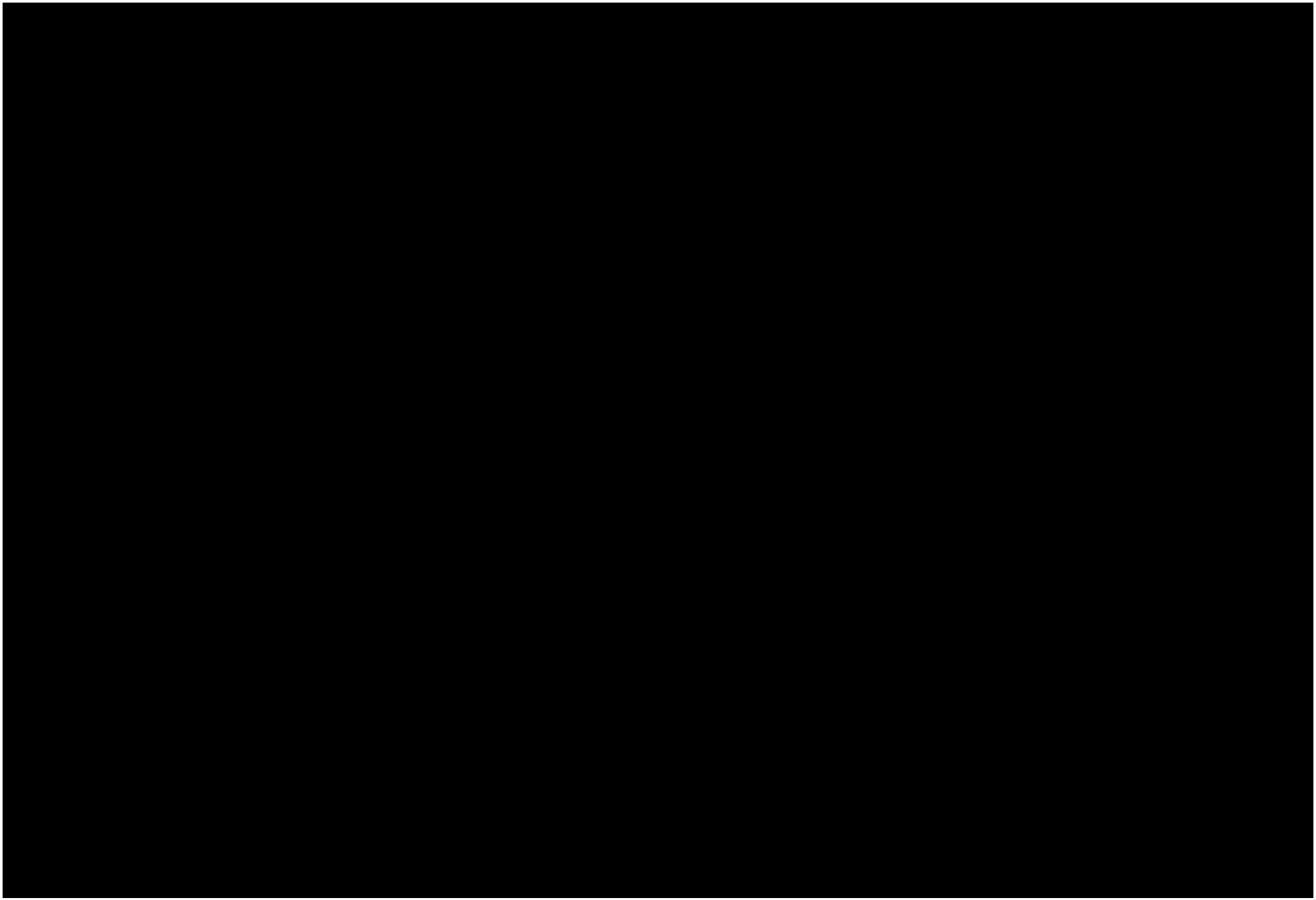
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

K.C. Electric Association, Inc.

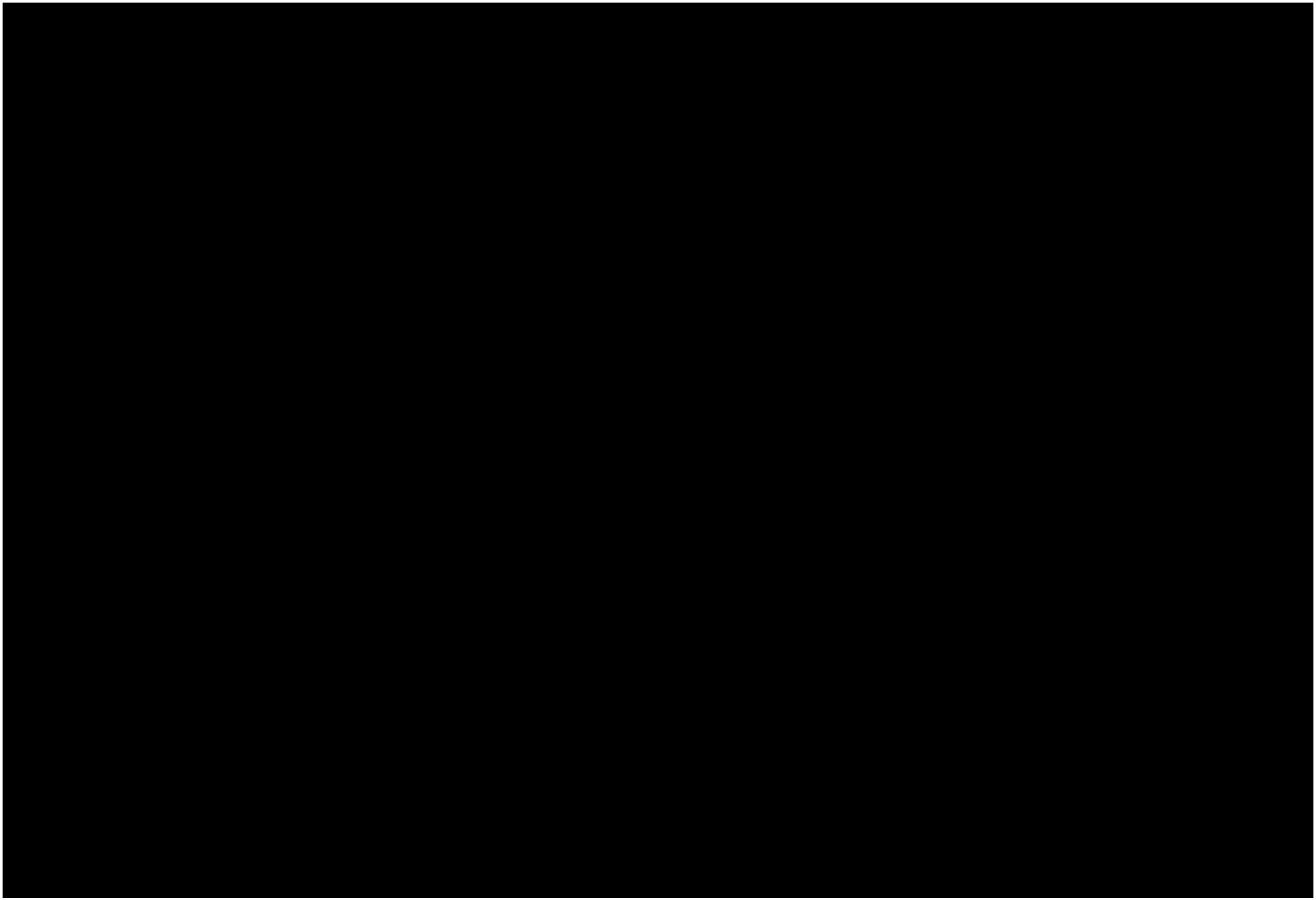
Date of Off Peak Day - 03/08/2021



Member Forecasted Off Peak Demand Day for April 2021

K.C. Electric Association, Inc.

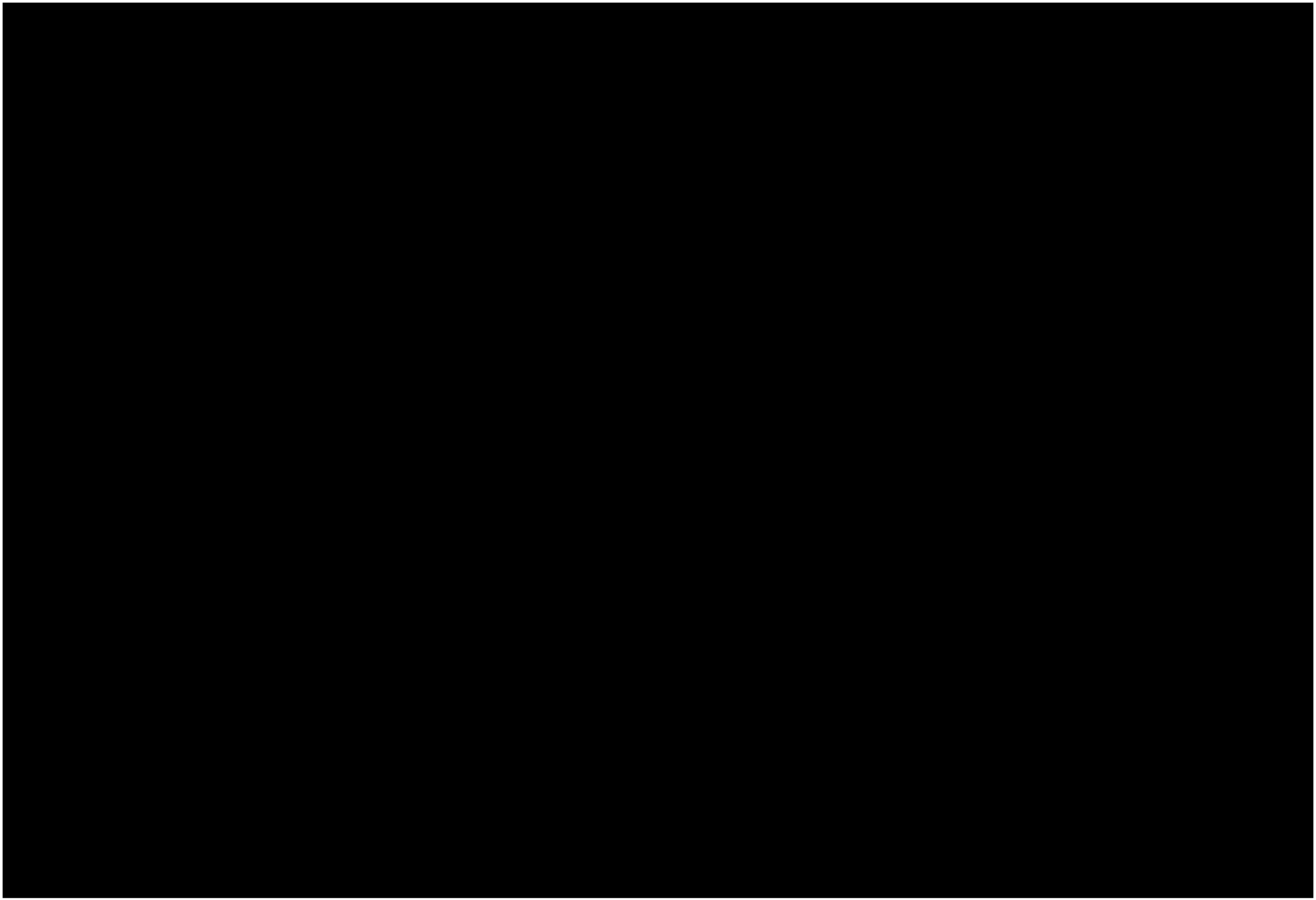
Date of Off Peak Day - 04/23/2021



Member Forecasted Off Peak Demand Day for May 2021

K.C. Electric Association, Inc.

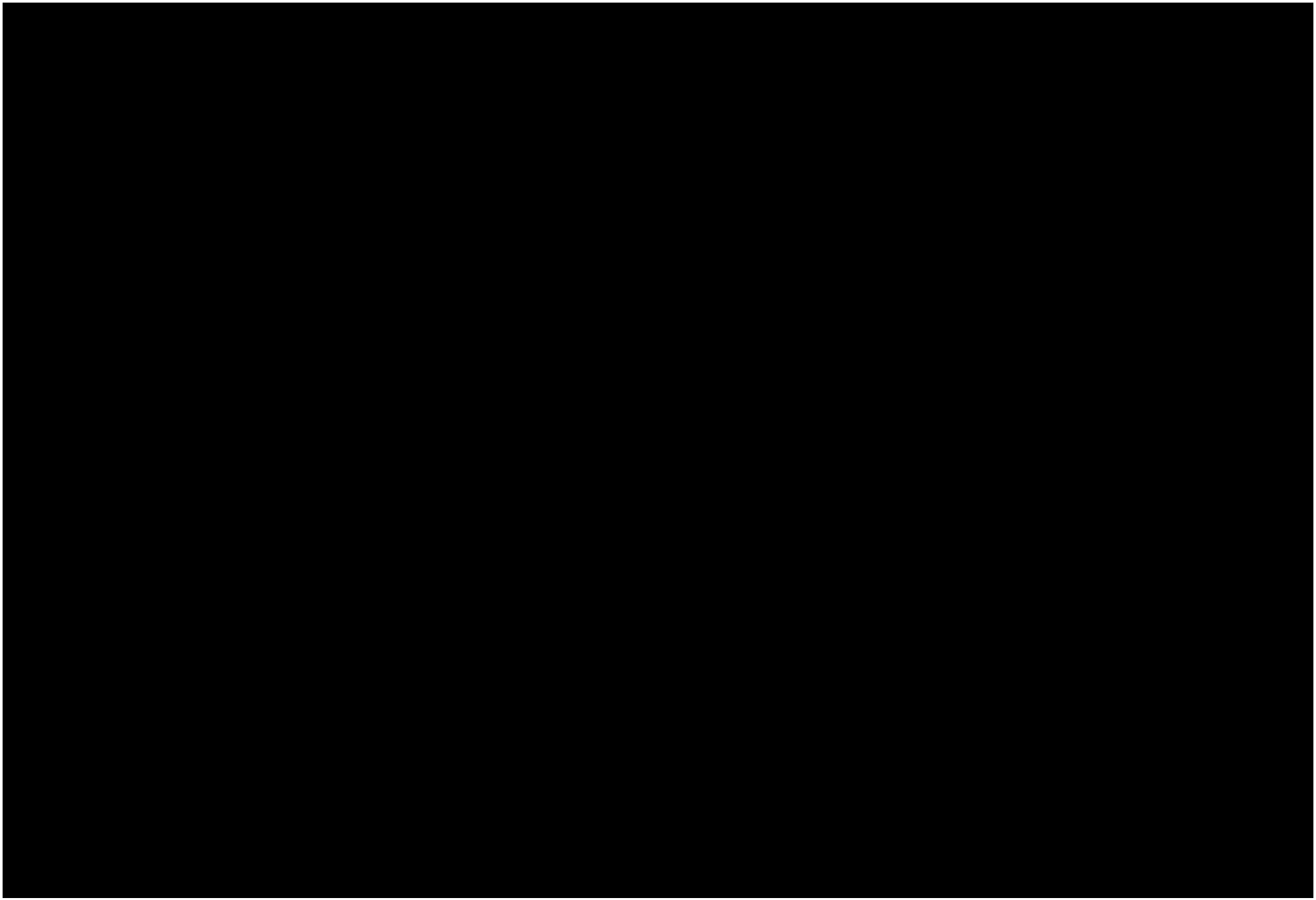
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

K.C. Electric Association, Inc.

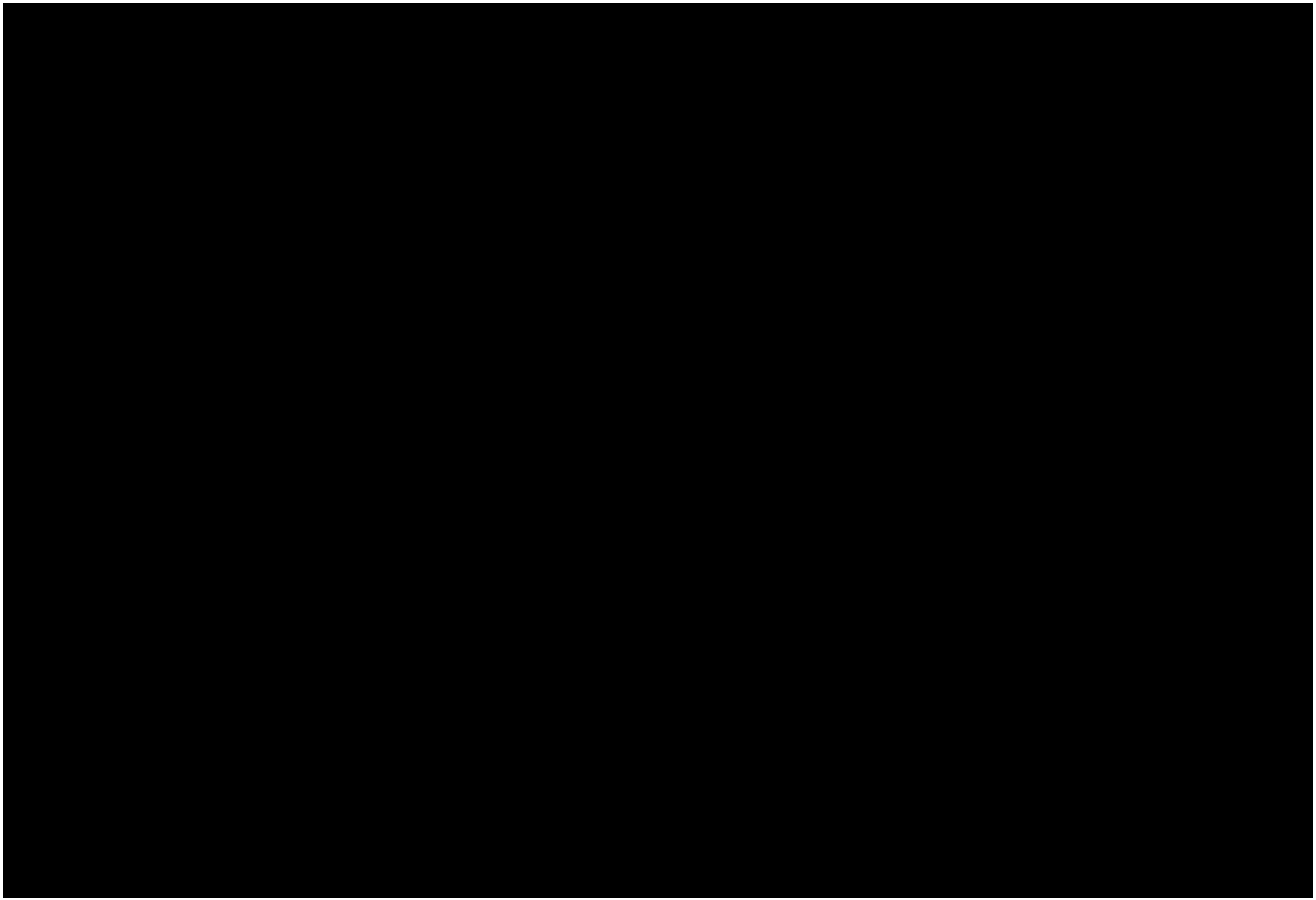
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

K.C. Electric Association, Inc.

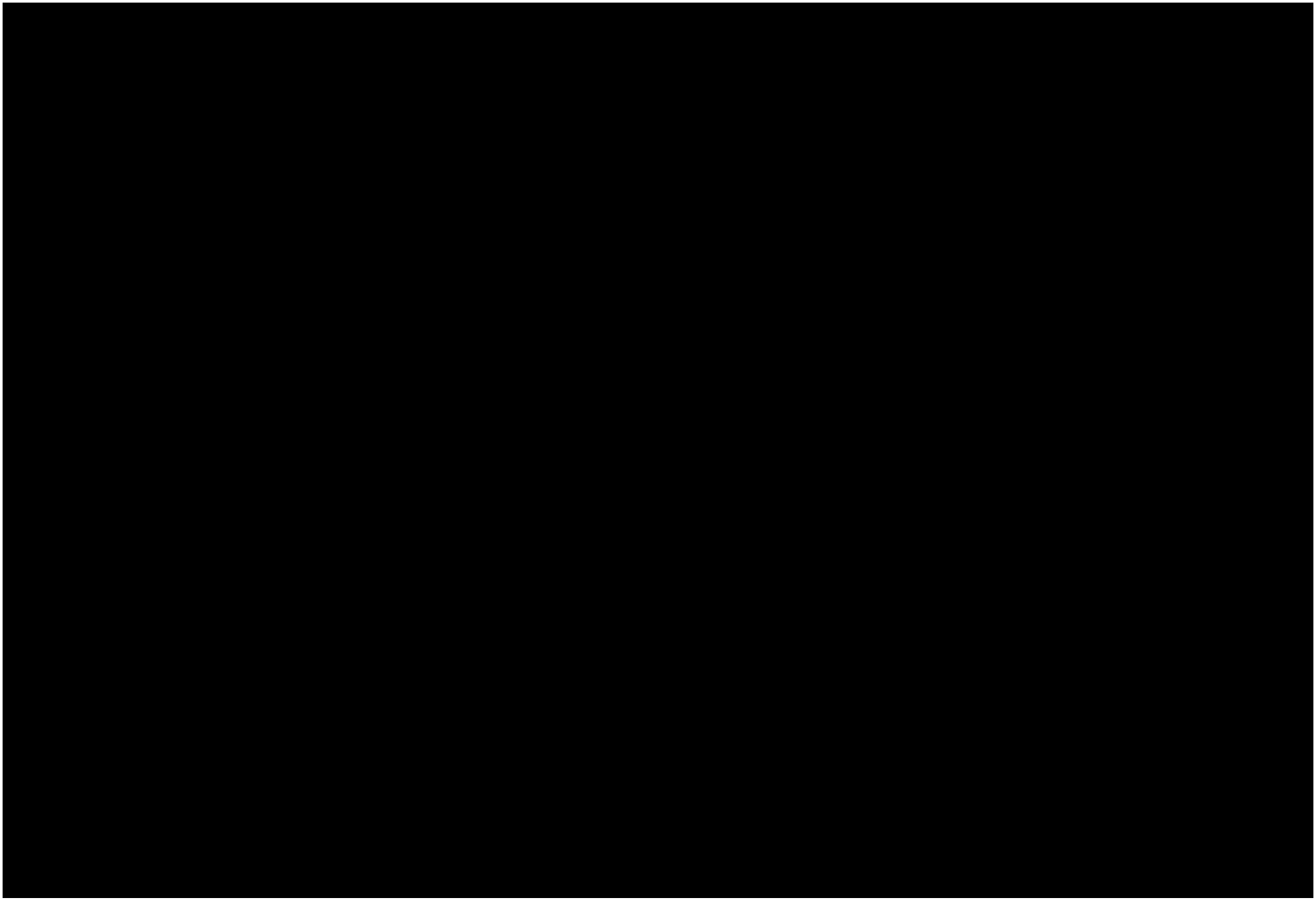
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

K.C. Electric Association, Inc.

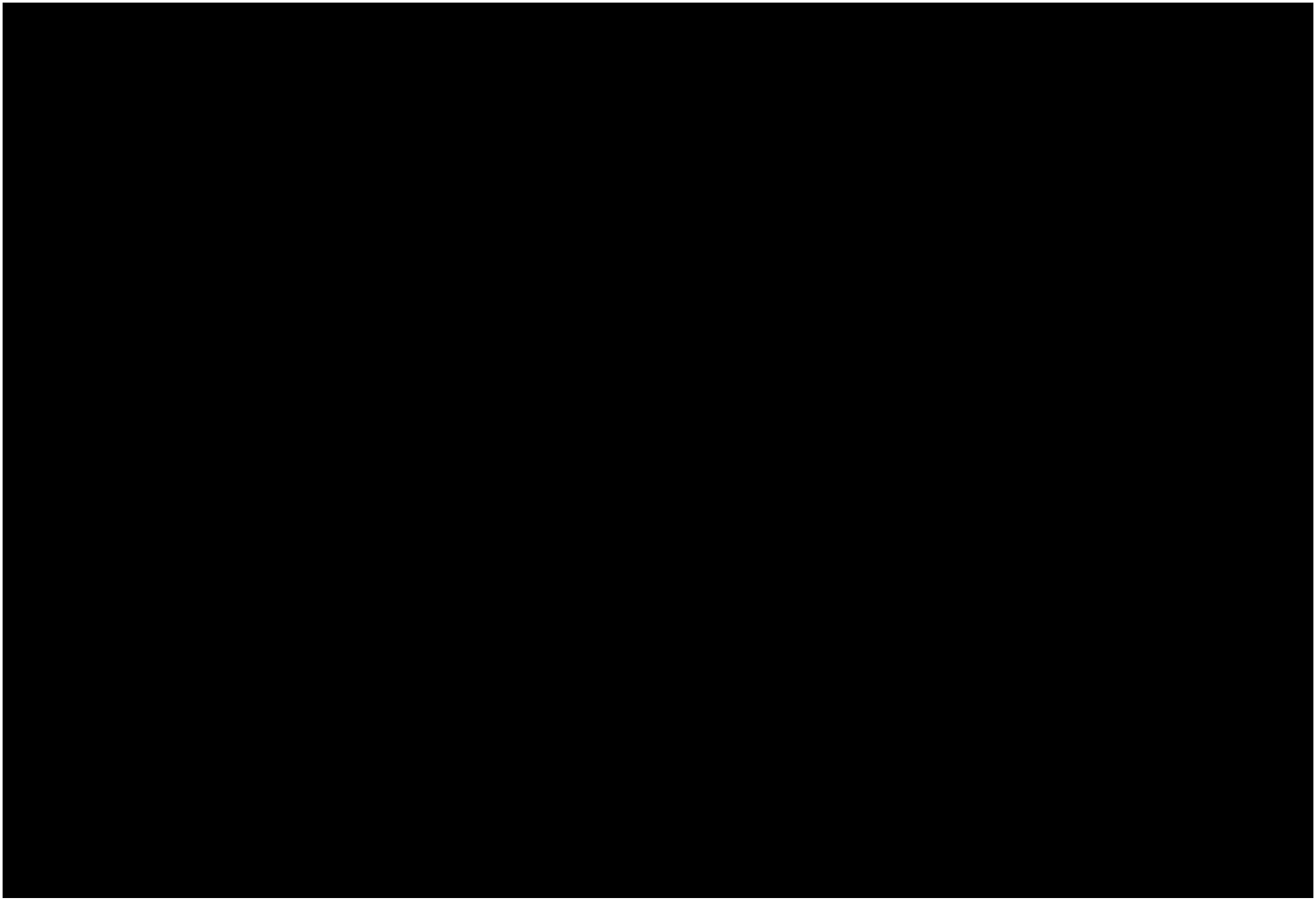
Date of Off Peak Day - 08/10/2021



Member Forecasted Off Peak Demand Day for September 2021

K.C. Electric Association, Inc.

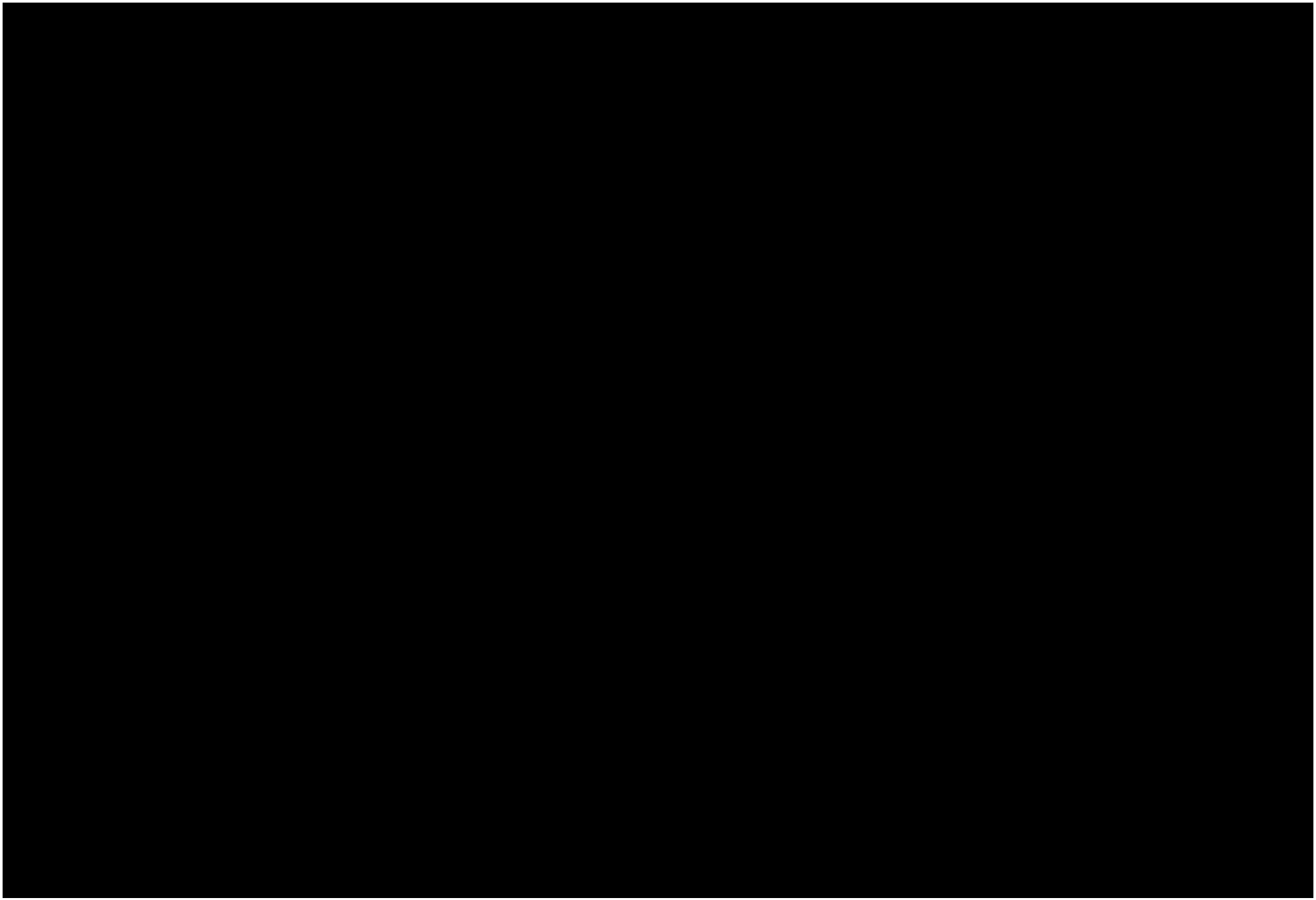
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

K.C. Electric Association, Inc.

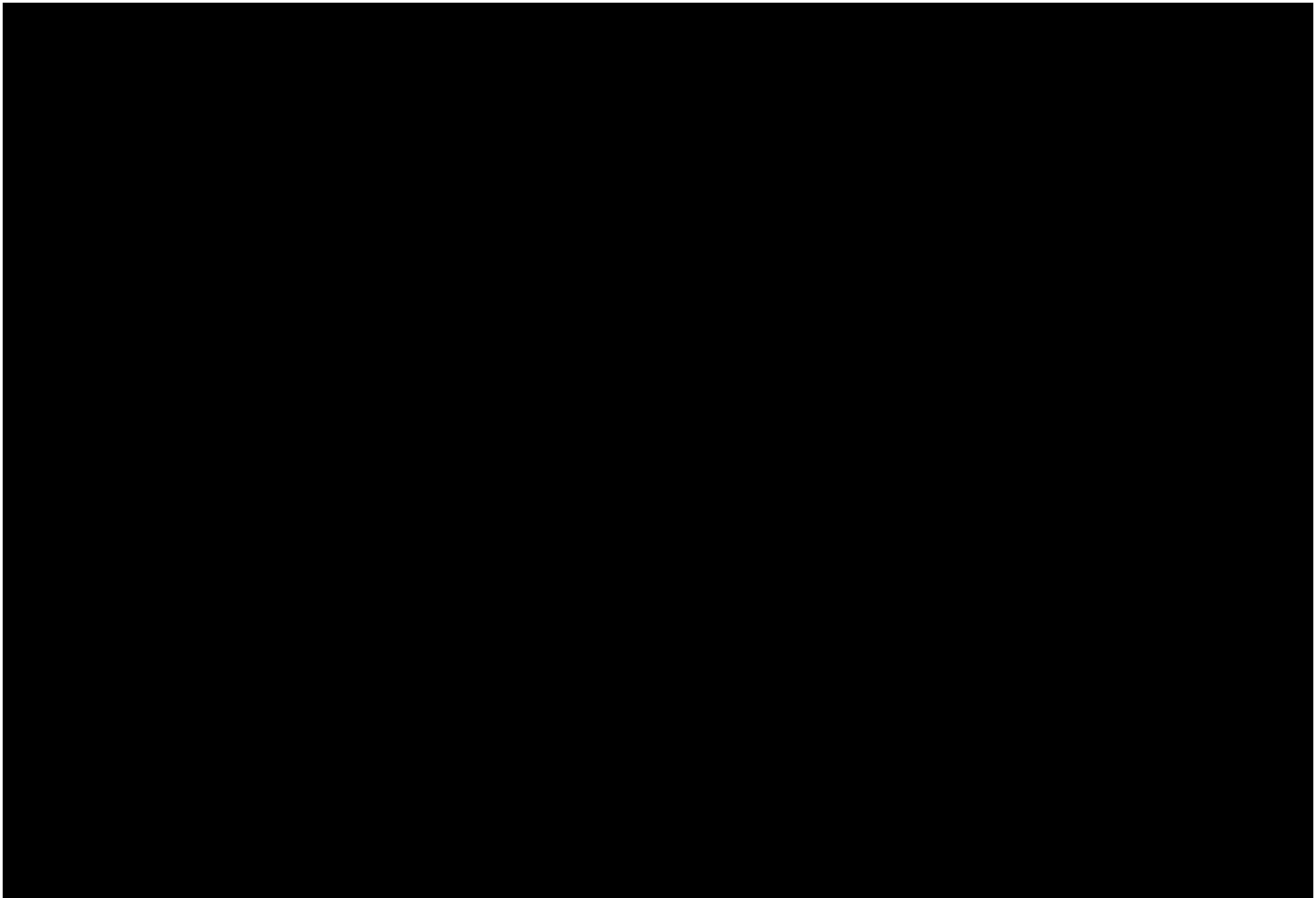
Date of Off Peak Day - 10/02/2021



Member Forecasted Off Peak Demand Day for November 2021

K.C. Electric Association, Inc.

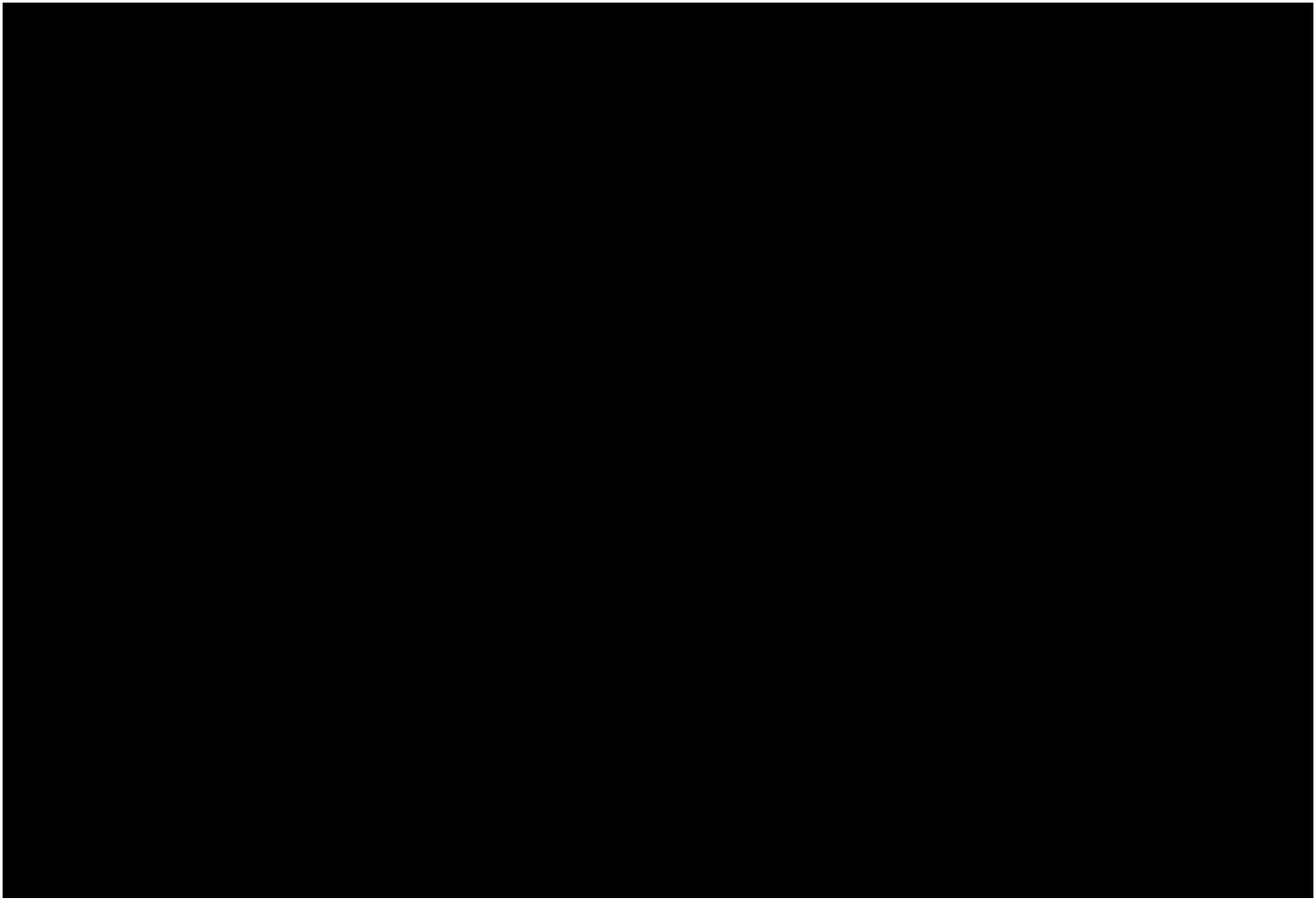
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

K.C. Electric Association, Inc.

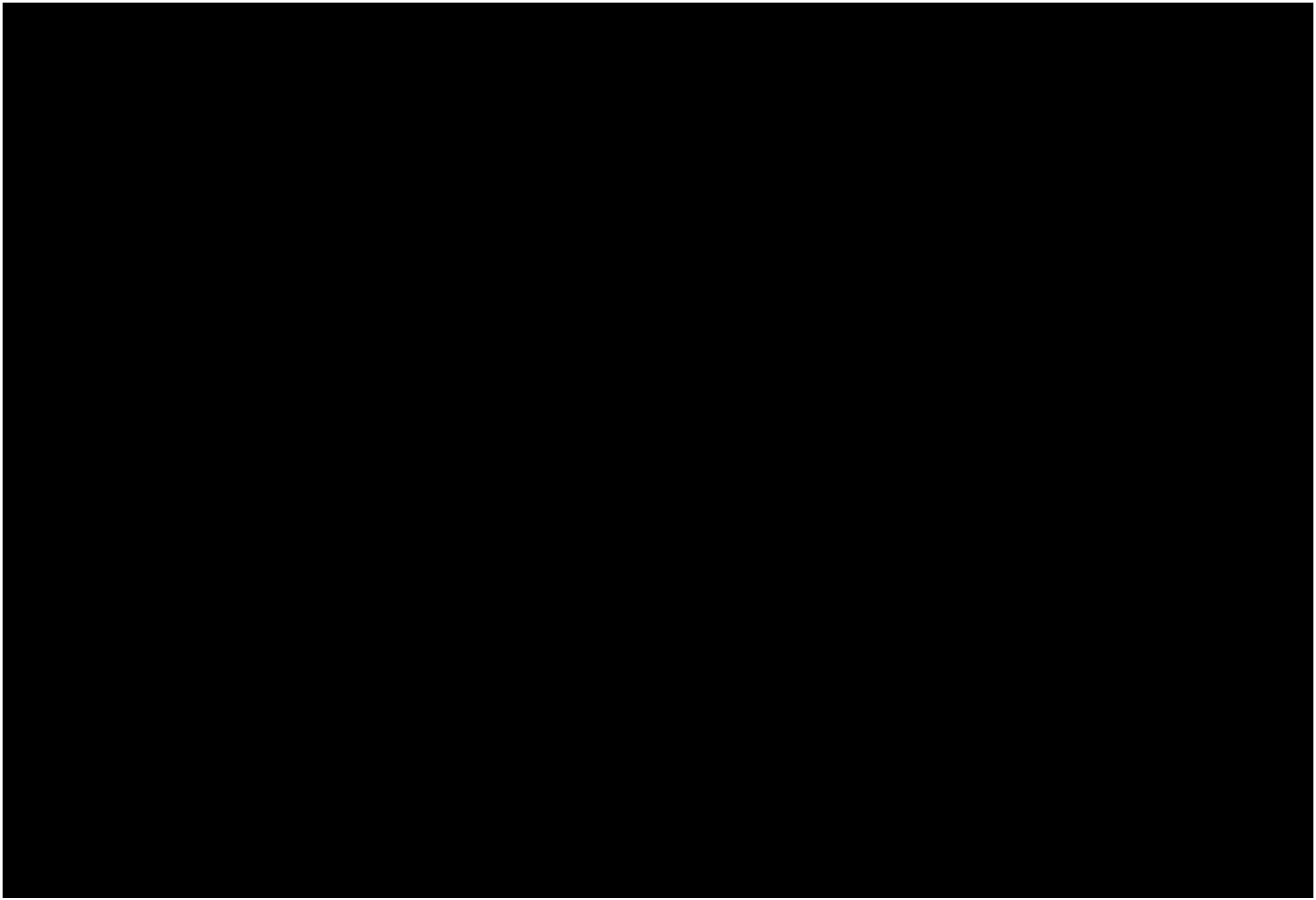
Date of Off Peak Day - 12/21/2021



Member Forecasted Off Peak Demand Day for January 2021

La Plata Electric Association, Inc.

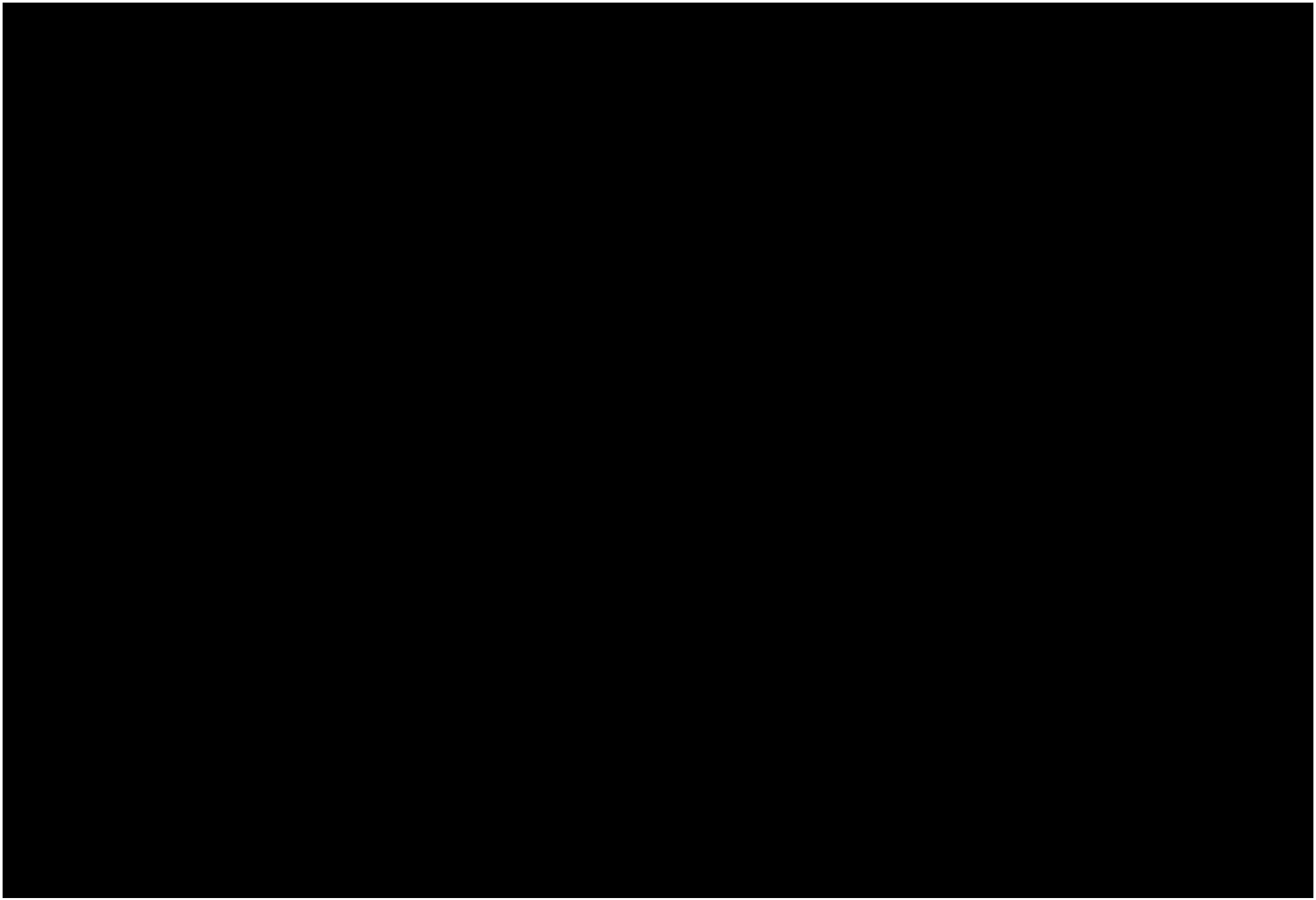
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

La Plata Electric Association, Inc.

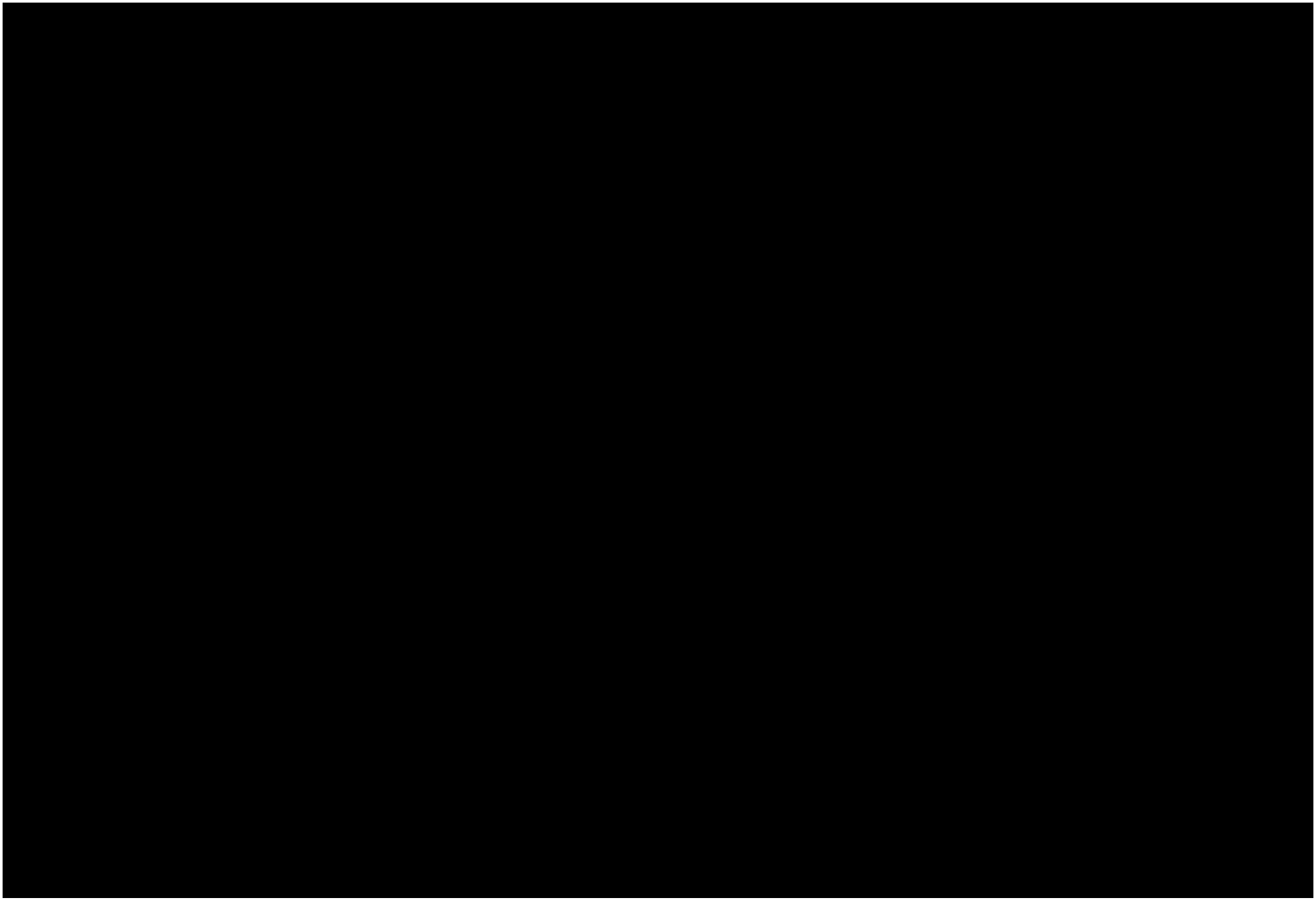
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

La Plata Electric Association, Inc.

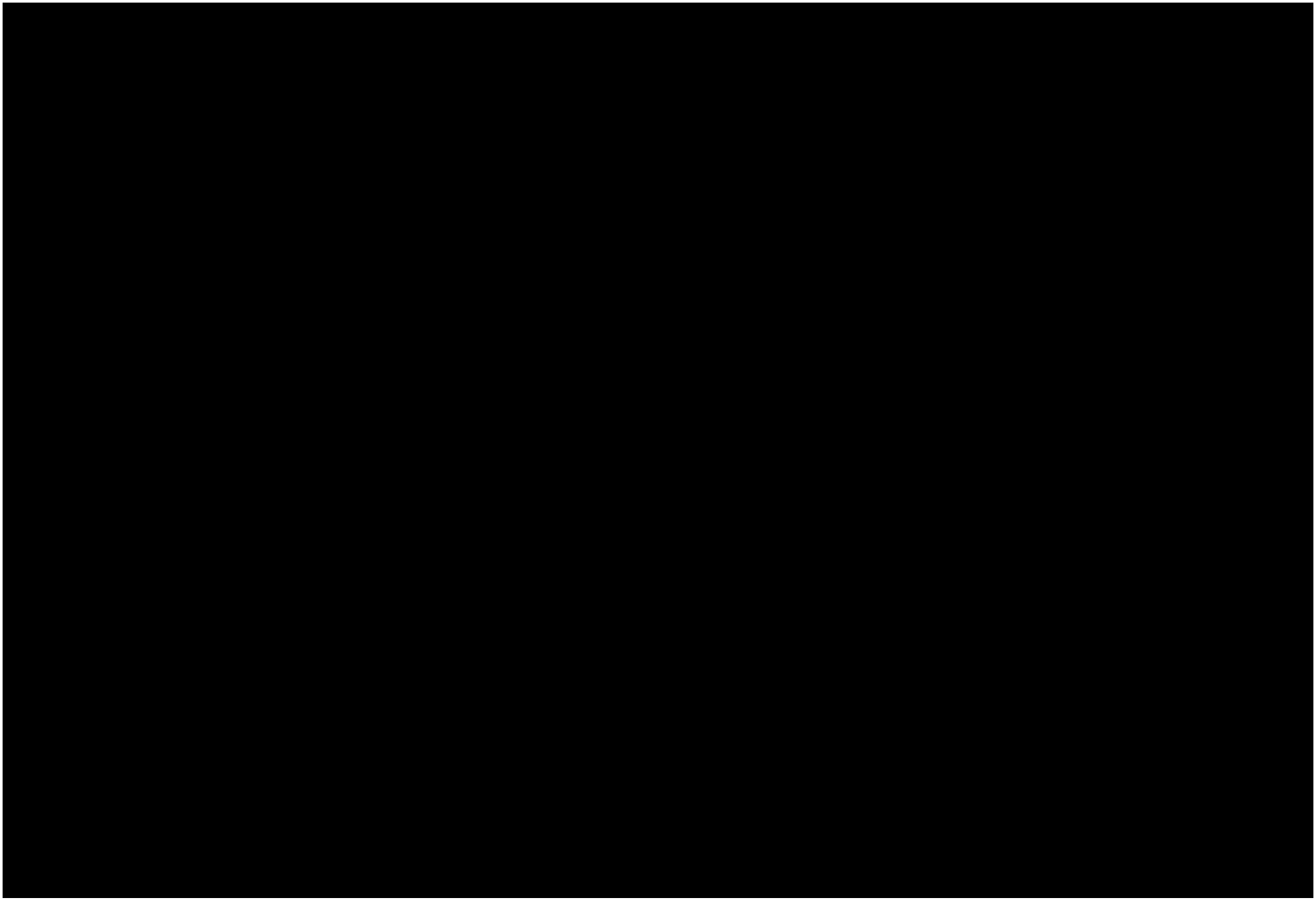
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

La Plata Electric Association, Inc.

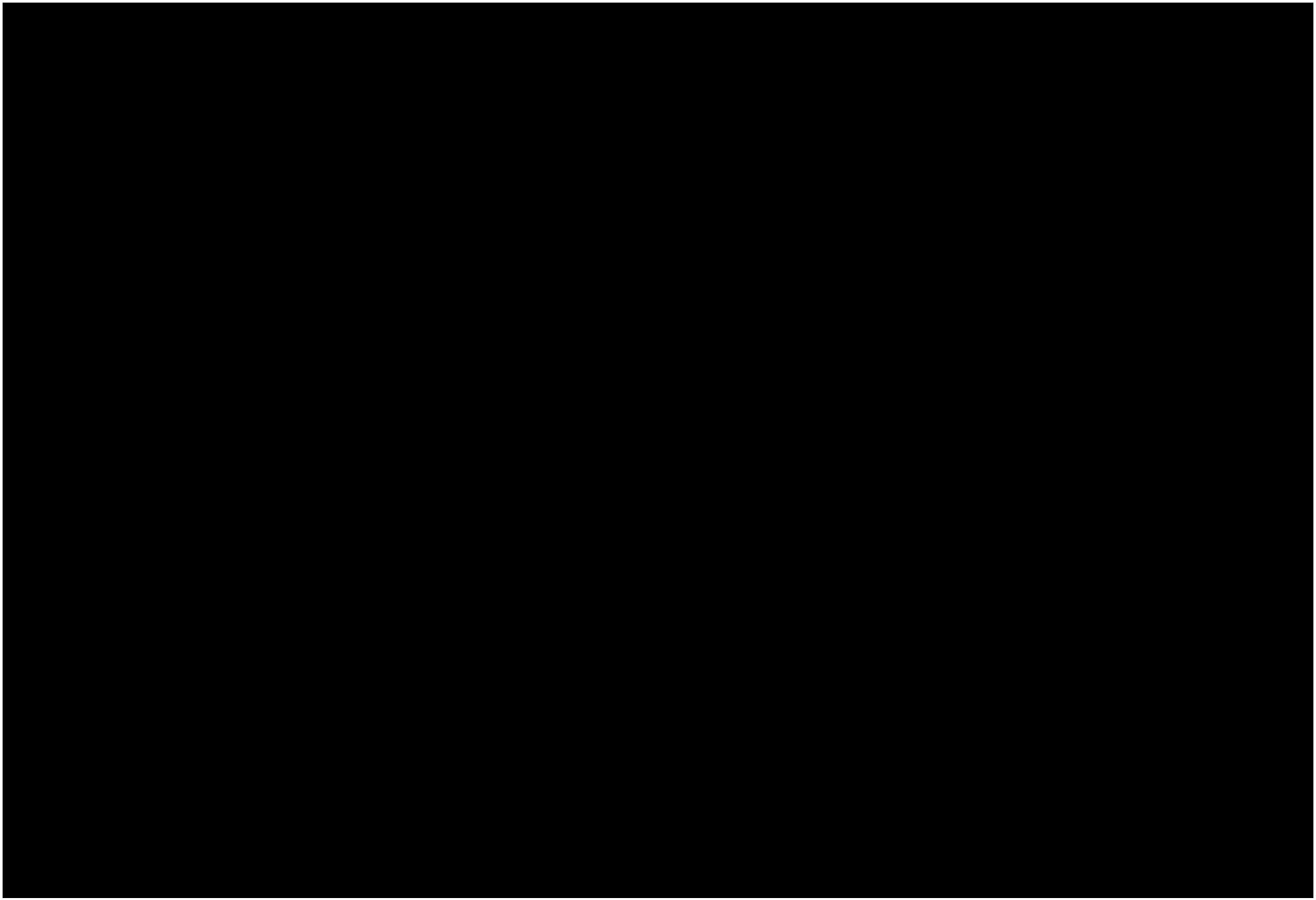
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

La Plata Electric Association, Inc.

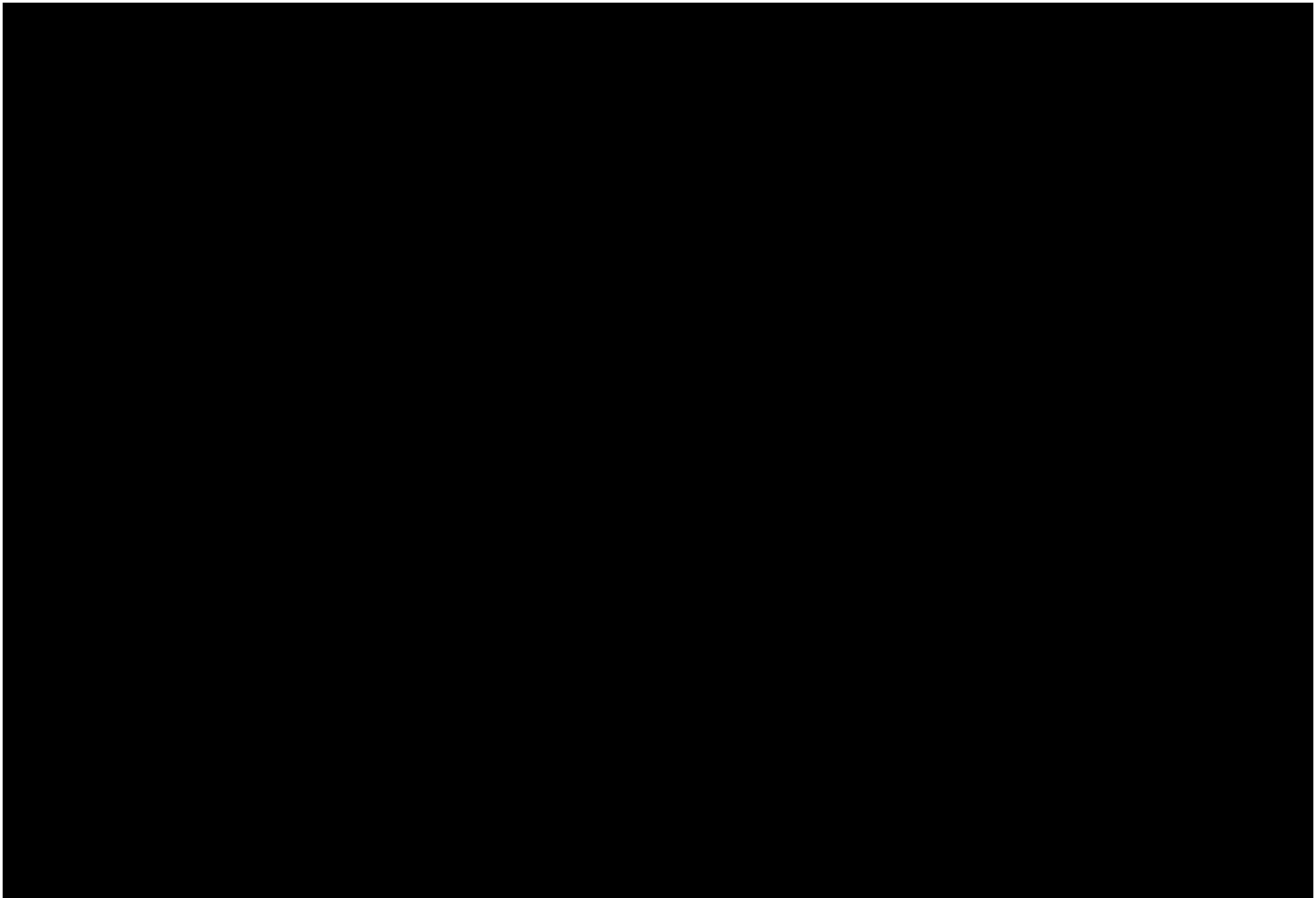
Date of Off Peak Day - 05/26/2021



Member Forecasted Off Peak Demand Day for June 2021

La Plata Electric Association, Inc.

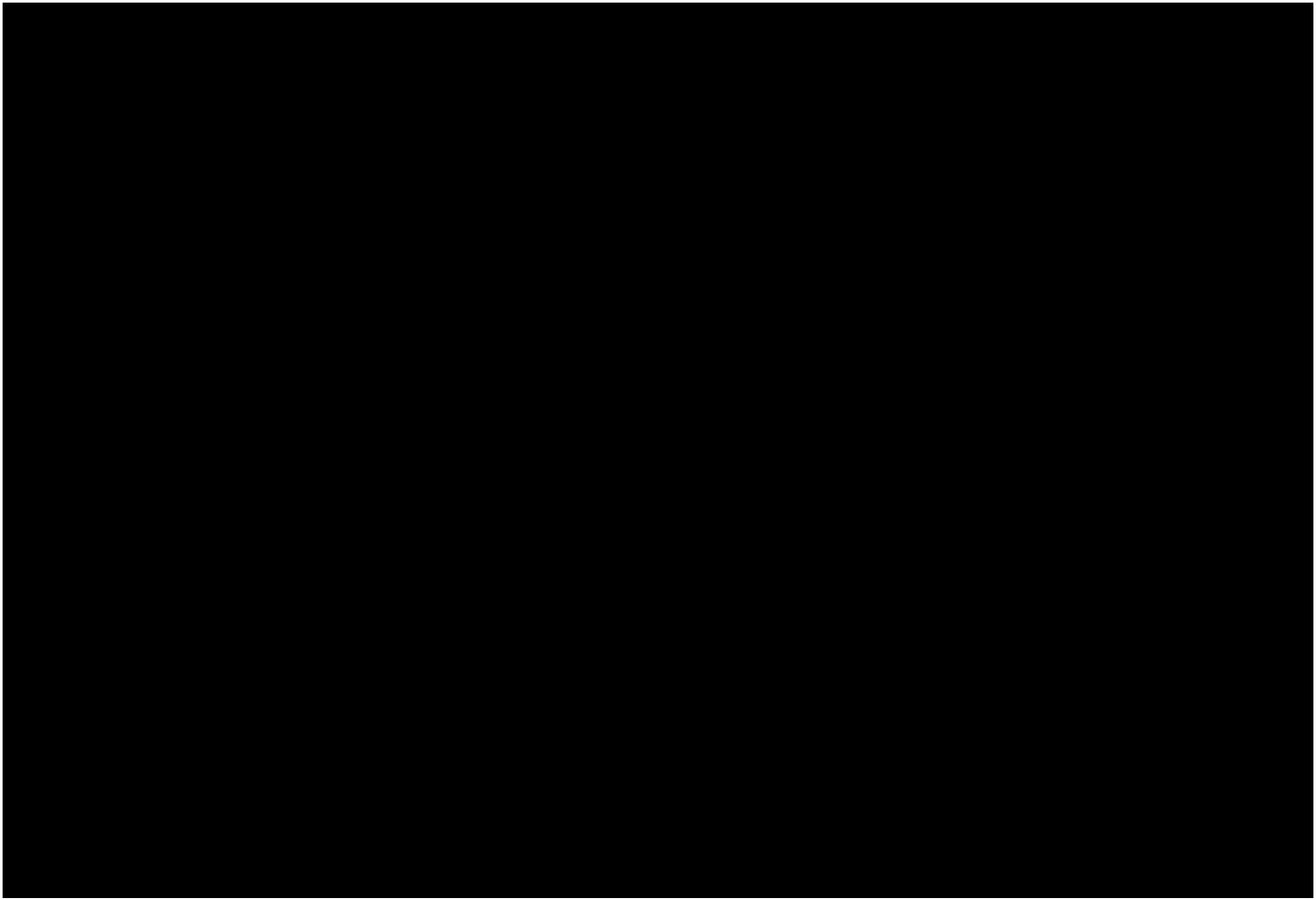
Date of Off Peak Day - 06/06/2021



Member Forecasted Off Peak Demand Day for July 2021

La Plata Electric Association, Inc.

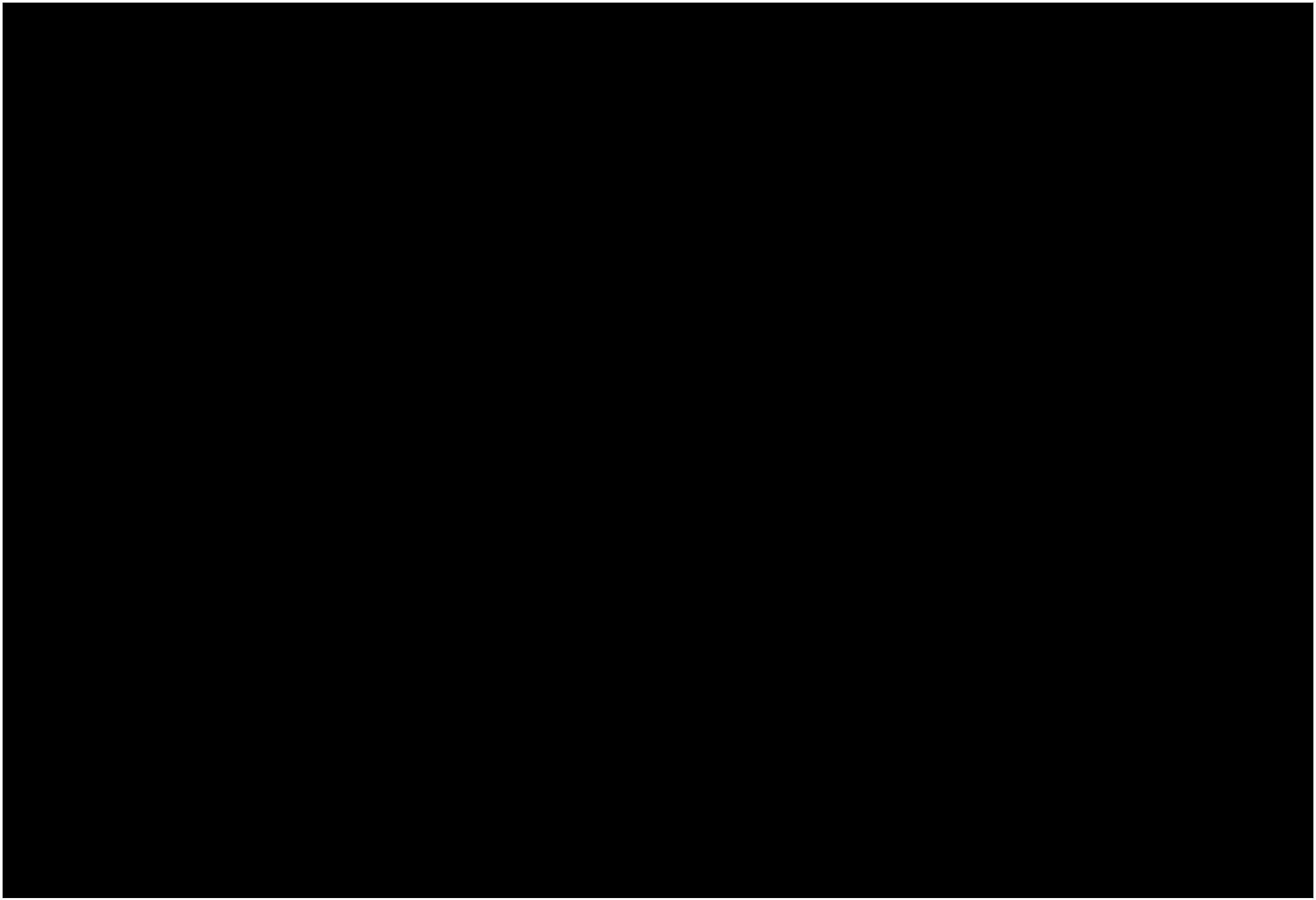
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

La Plata Electric Association, Inc.

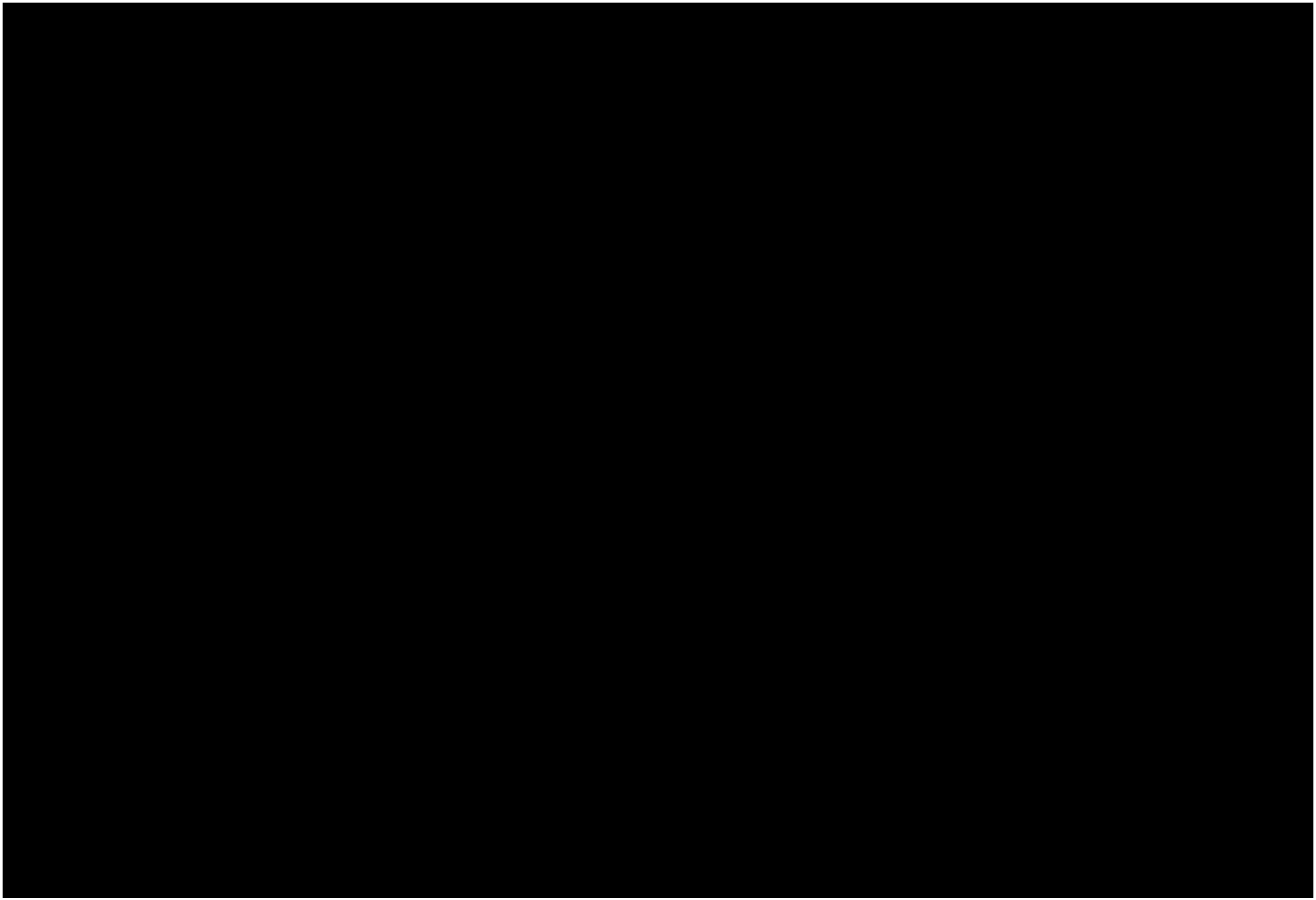
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

La Plata Electric Association, Inc.

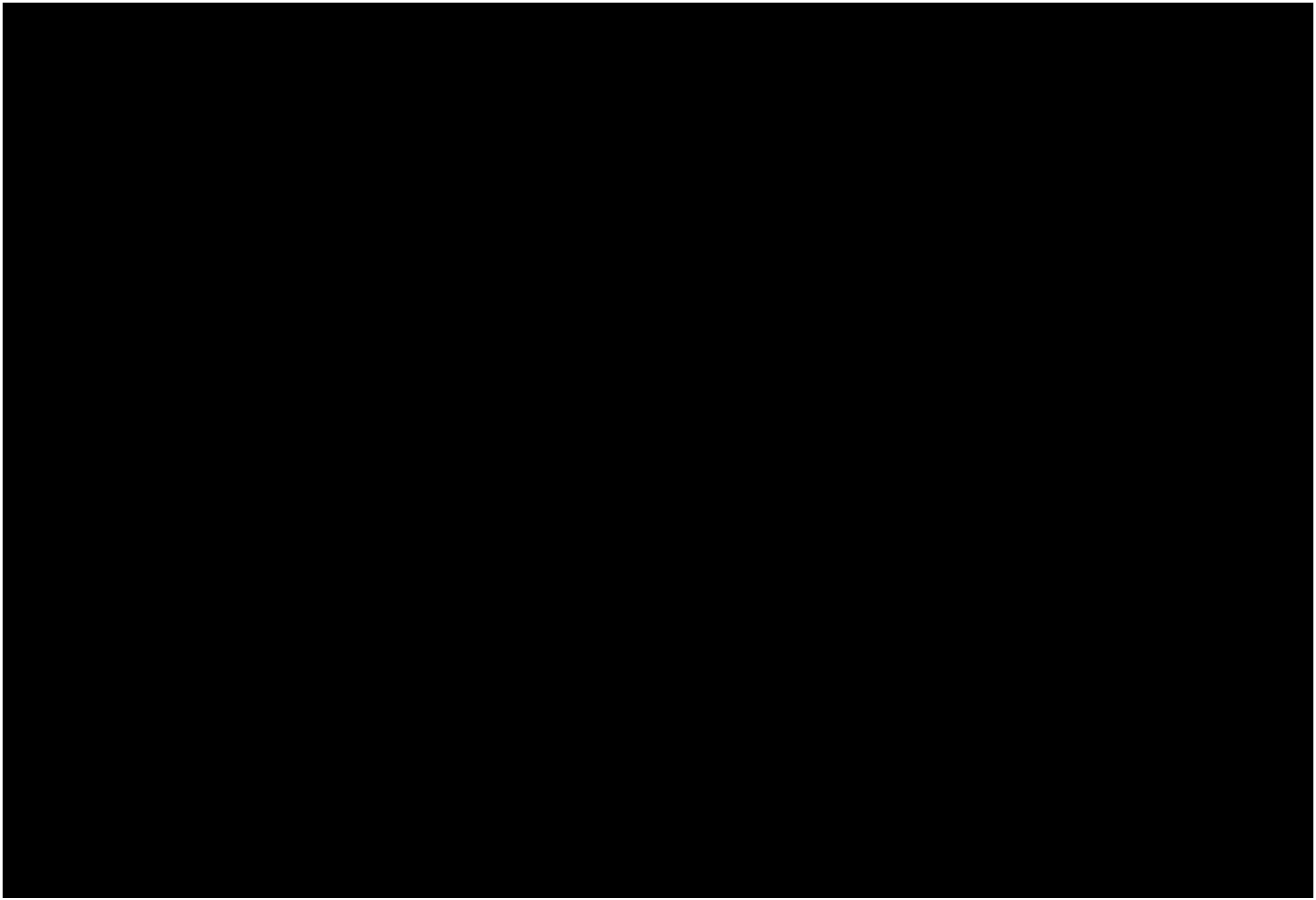
Date of Off Peak Day - 09/21/2021



Member Forecasted Off Peak Demand Day for October 2021

La Plata Electric Association, Inc.

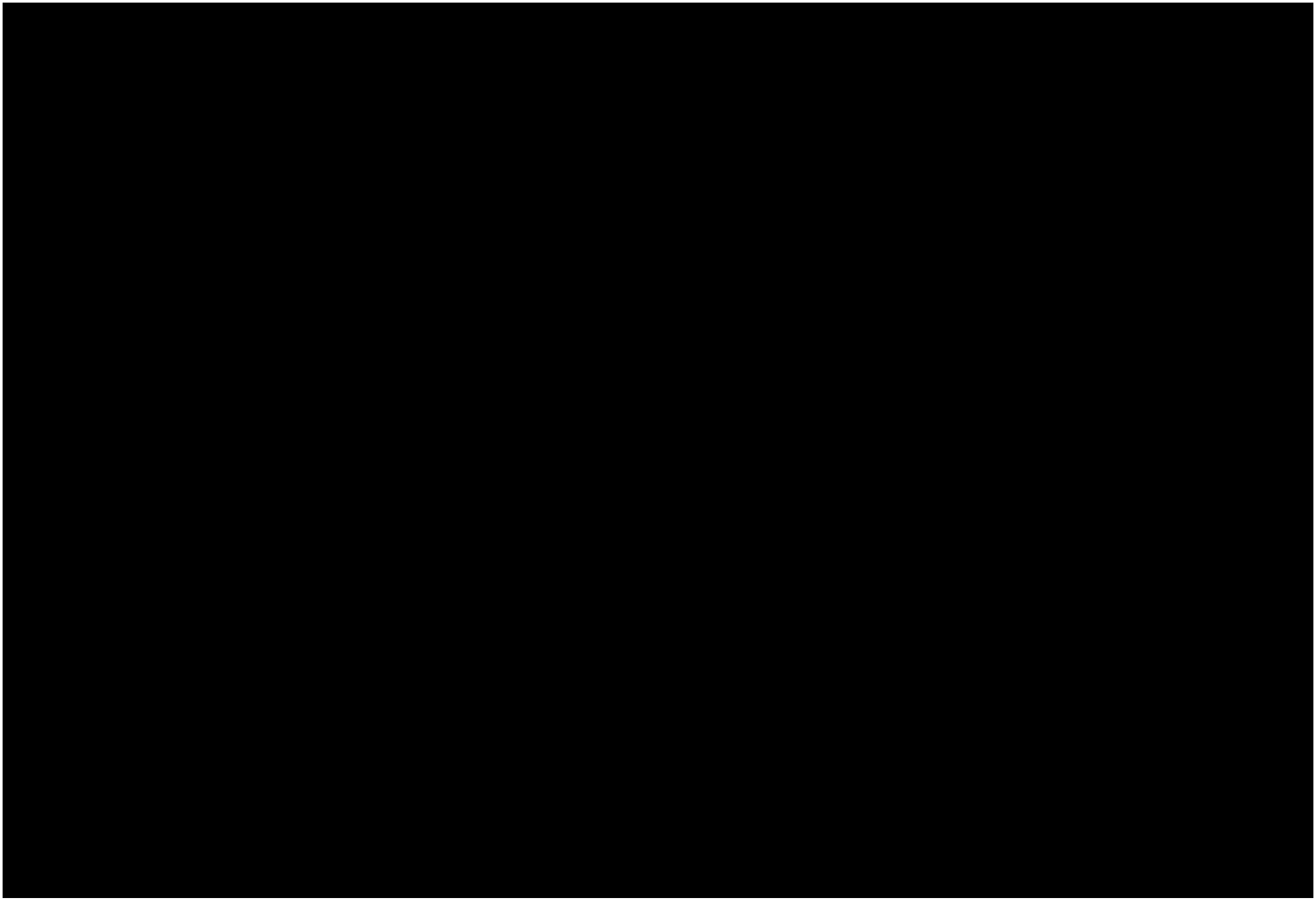
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

La Plata Electric Association, Inc.

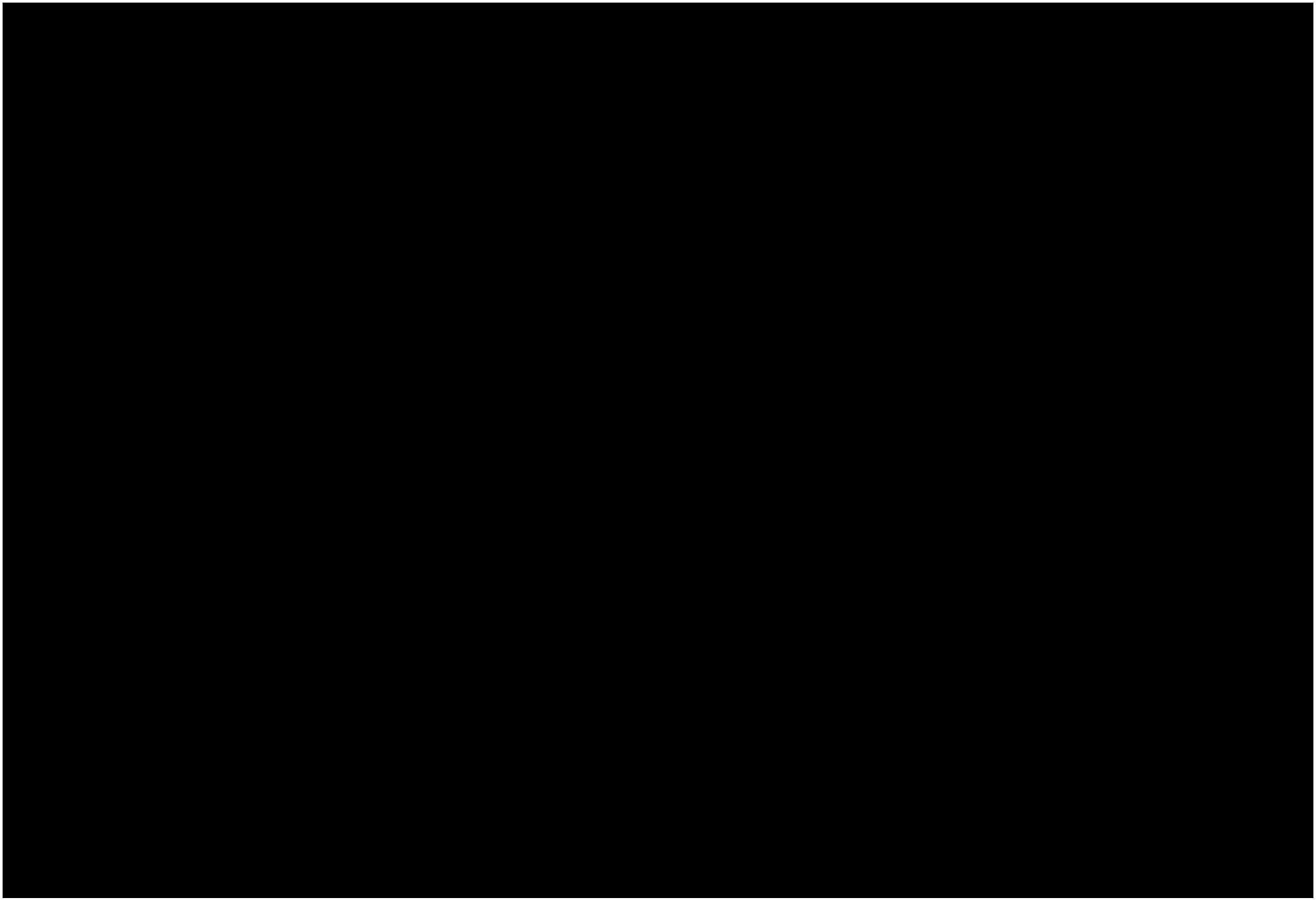
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

La Plata Electric Association, Inc.

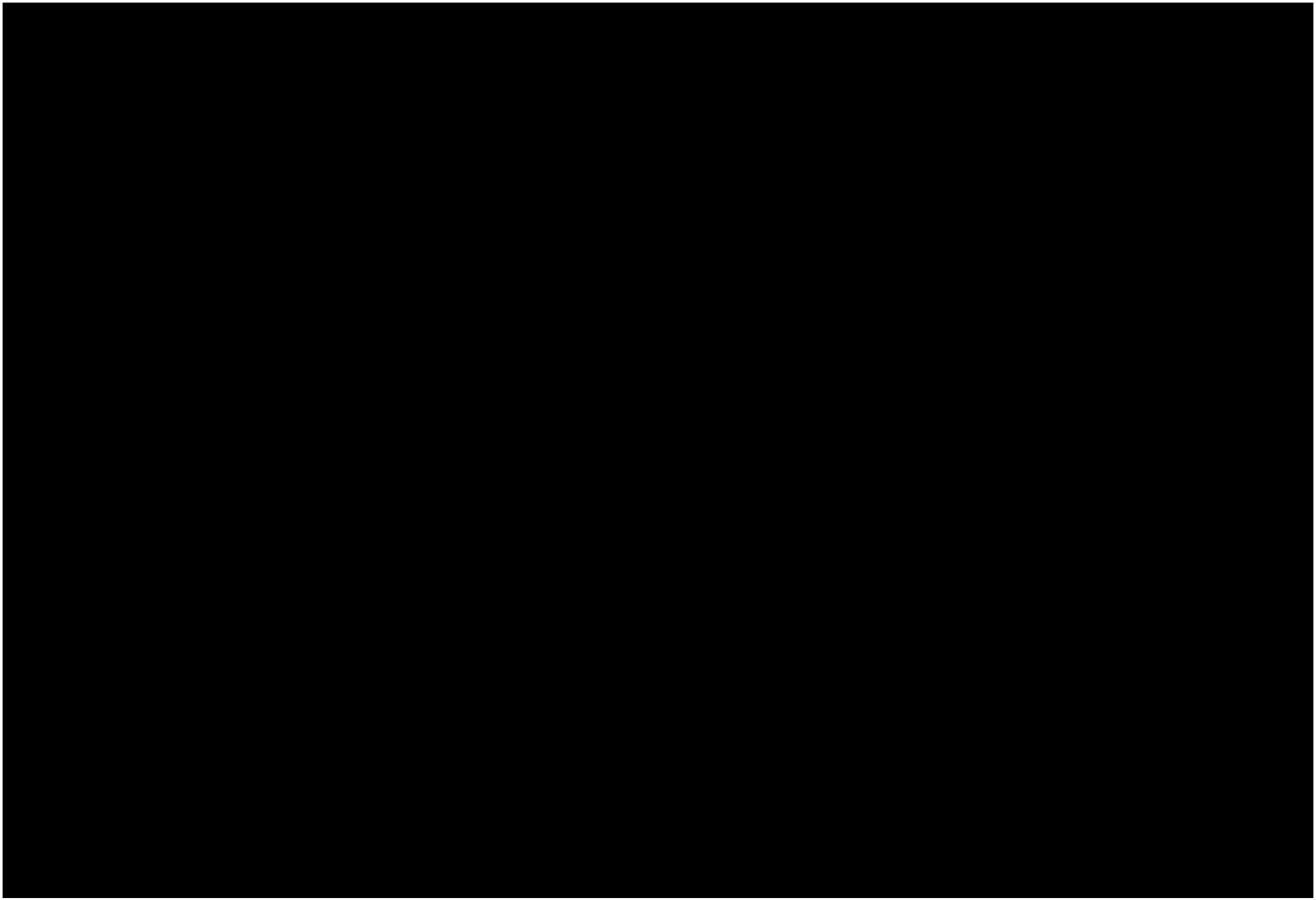
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Morgan County Rural Electric Association

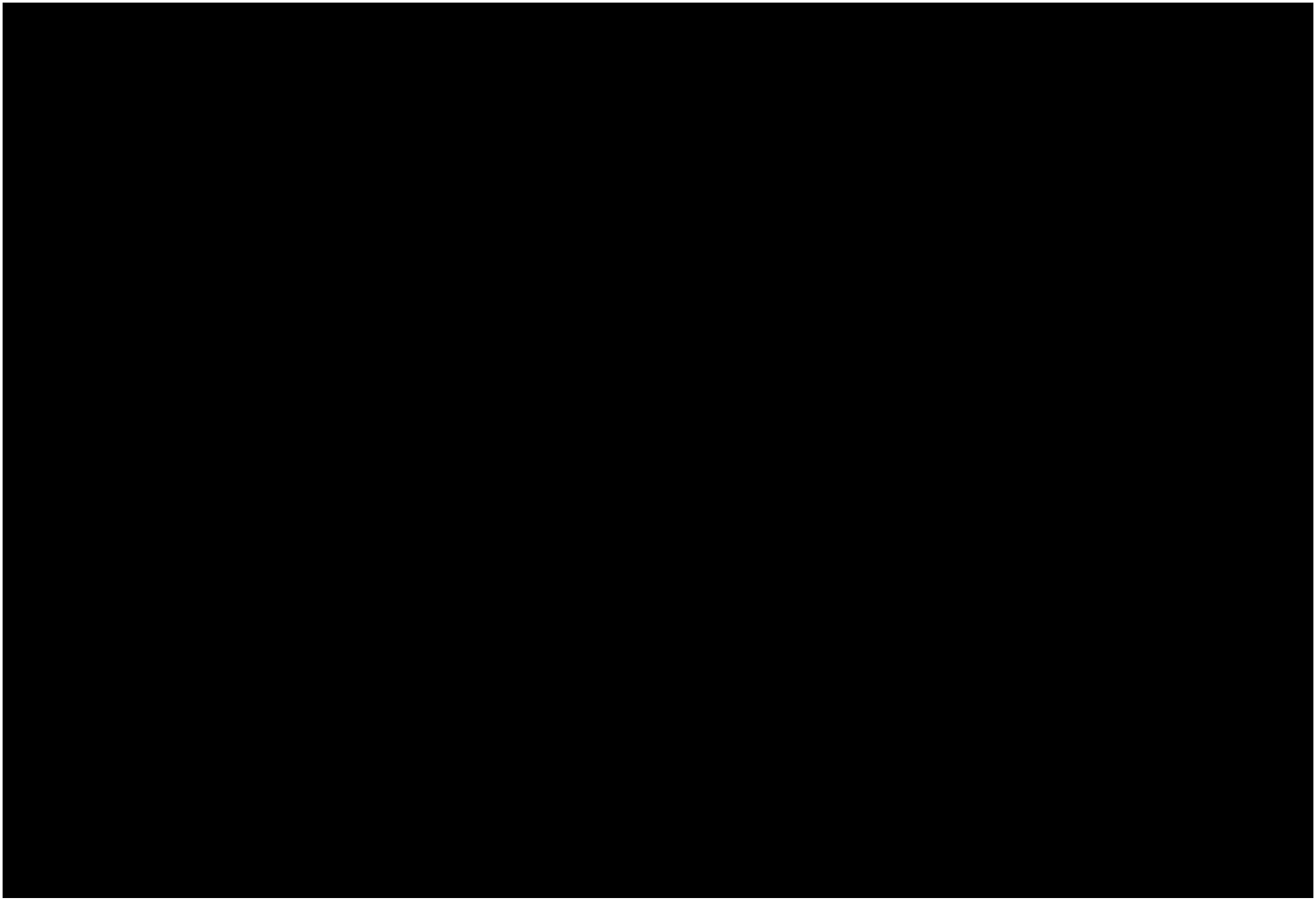
Date of Off Peak Day - 01/10/2021



Member Forecasted Off Peak Demand Day for February 2021

Morgan County Rural Electric Association

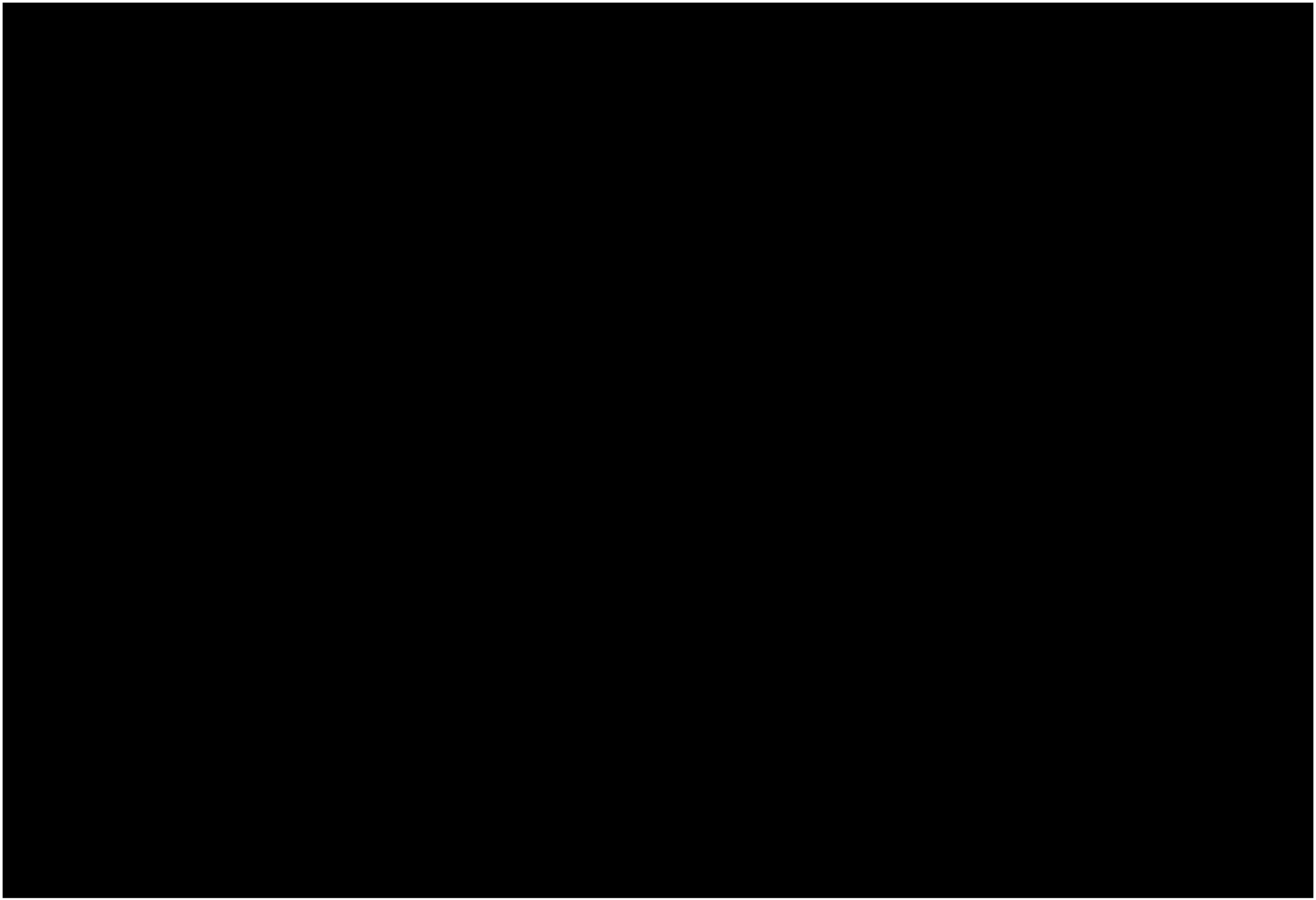
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Morgan County Rural Electric Association

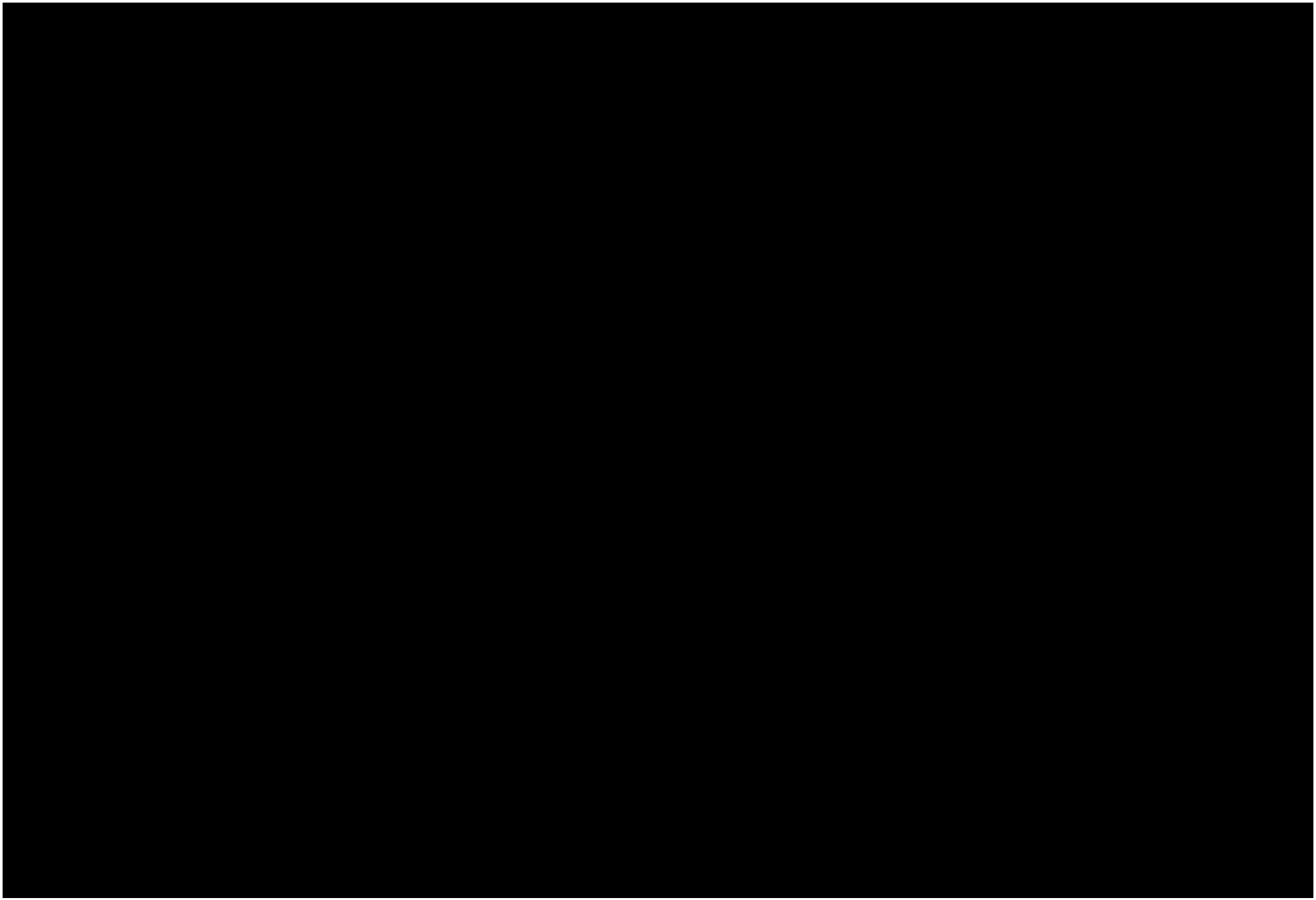
Date of Off Peak Day - 03/25/2021



Member Forecasted Off Peak Demand Day for April 2021

Morgan County Rural Electric Association

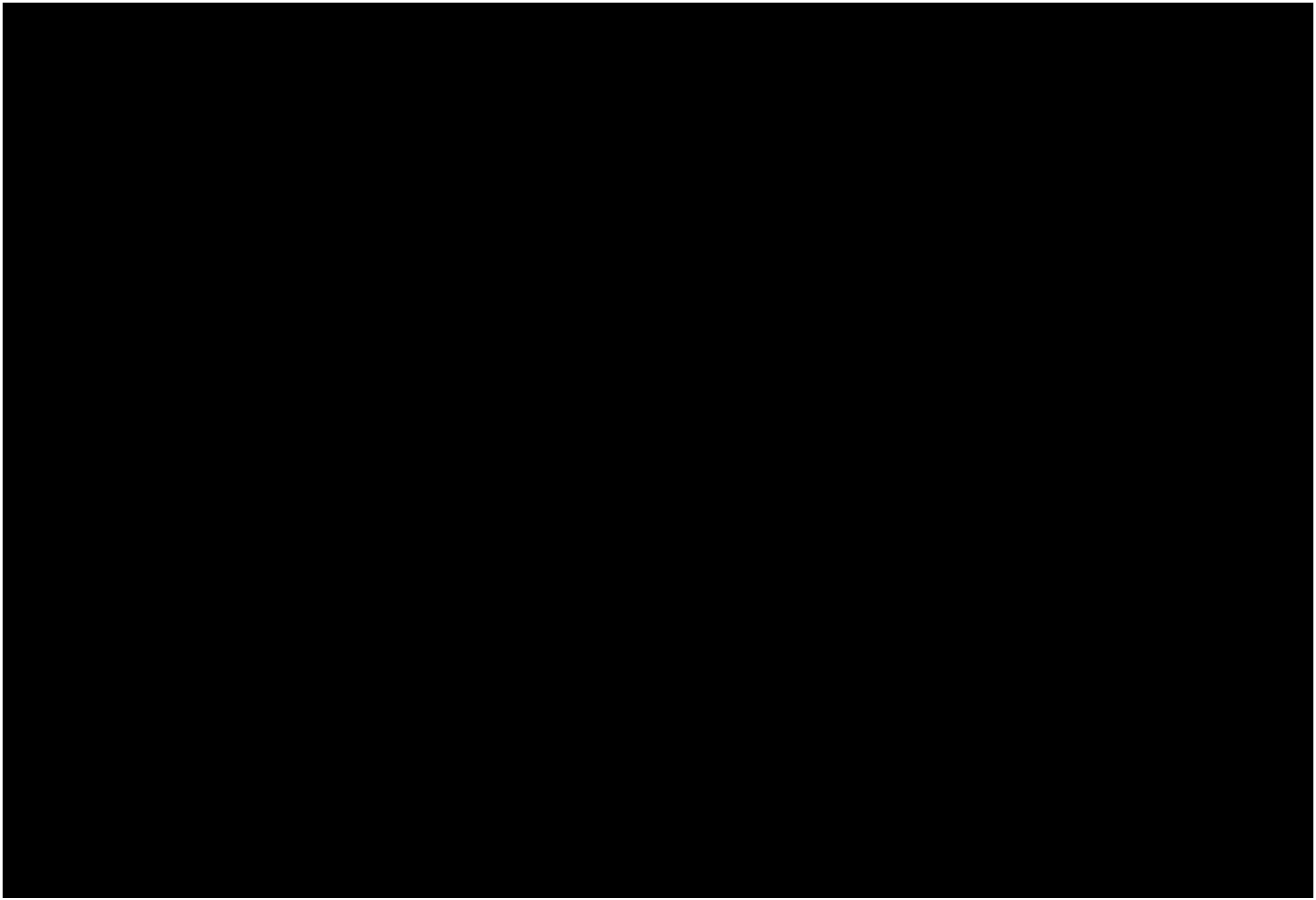
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Morgan County Rural Electric Association

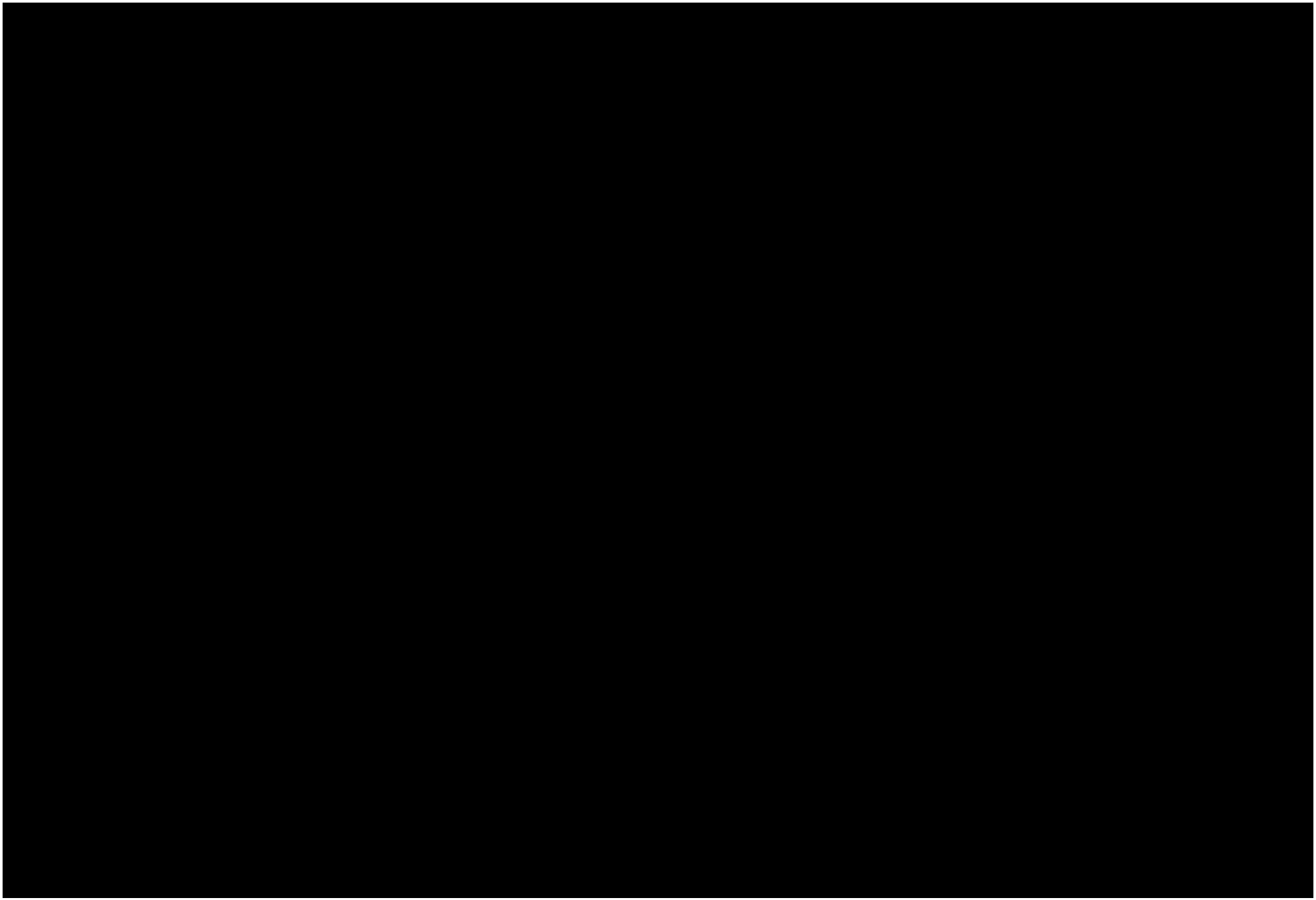
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Morgan County Rural Electric Association

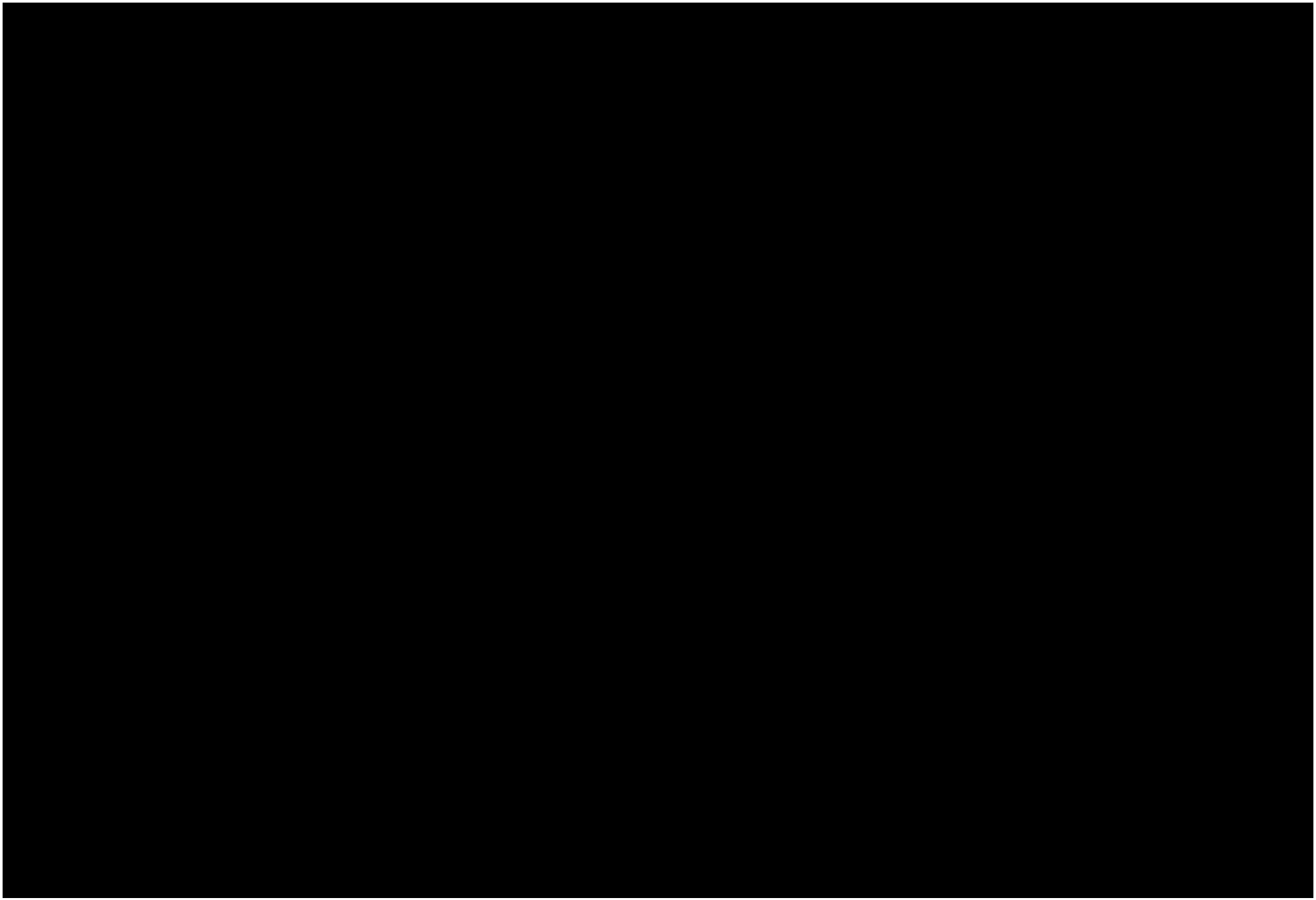
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Morgan County Rural Electric Association

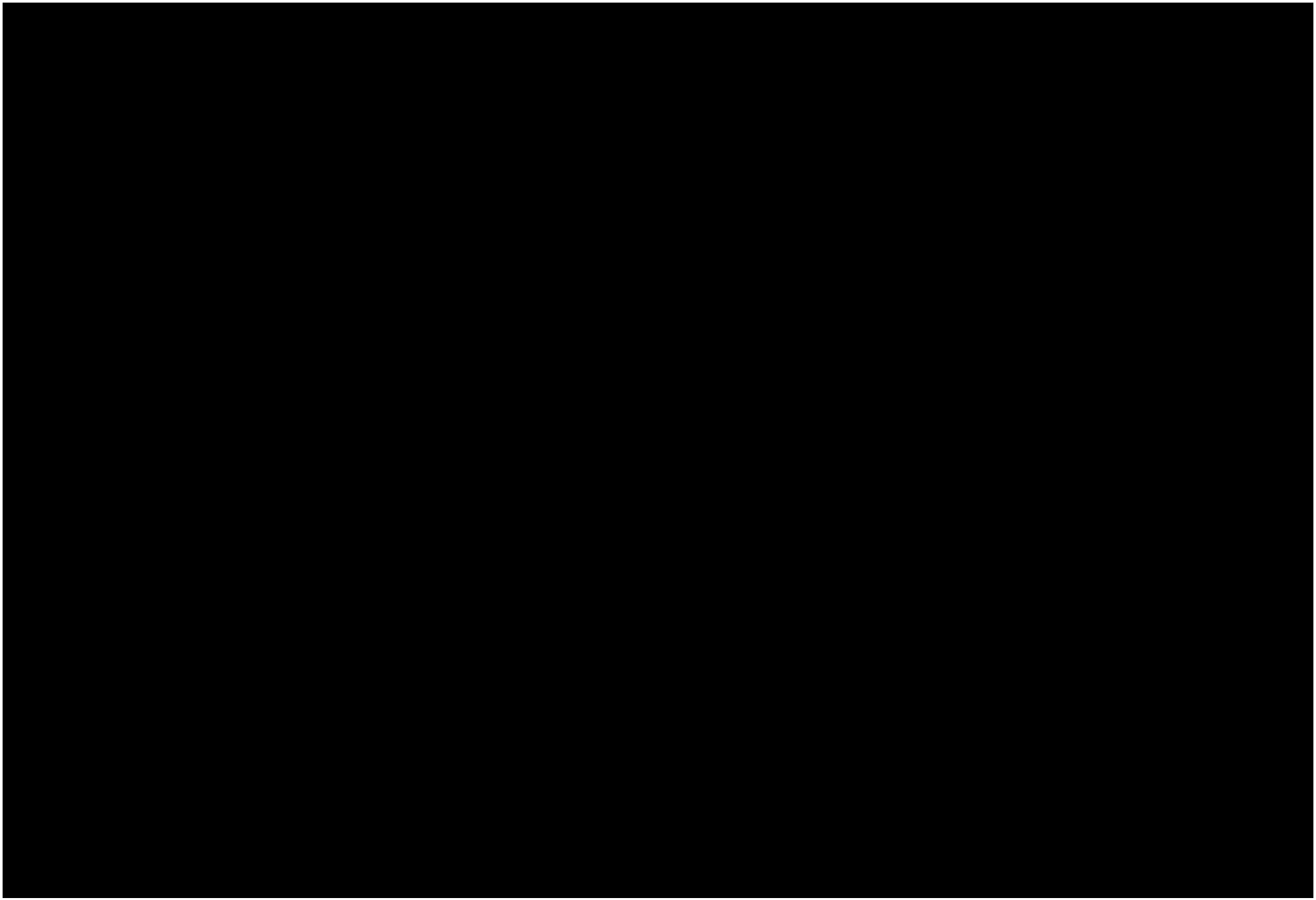
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Morgan County Rural Electric Association

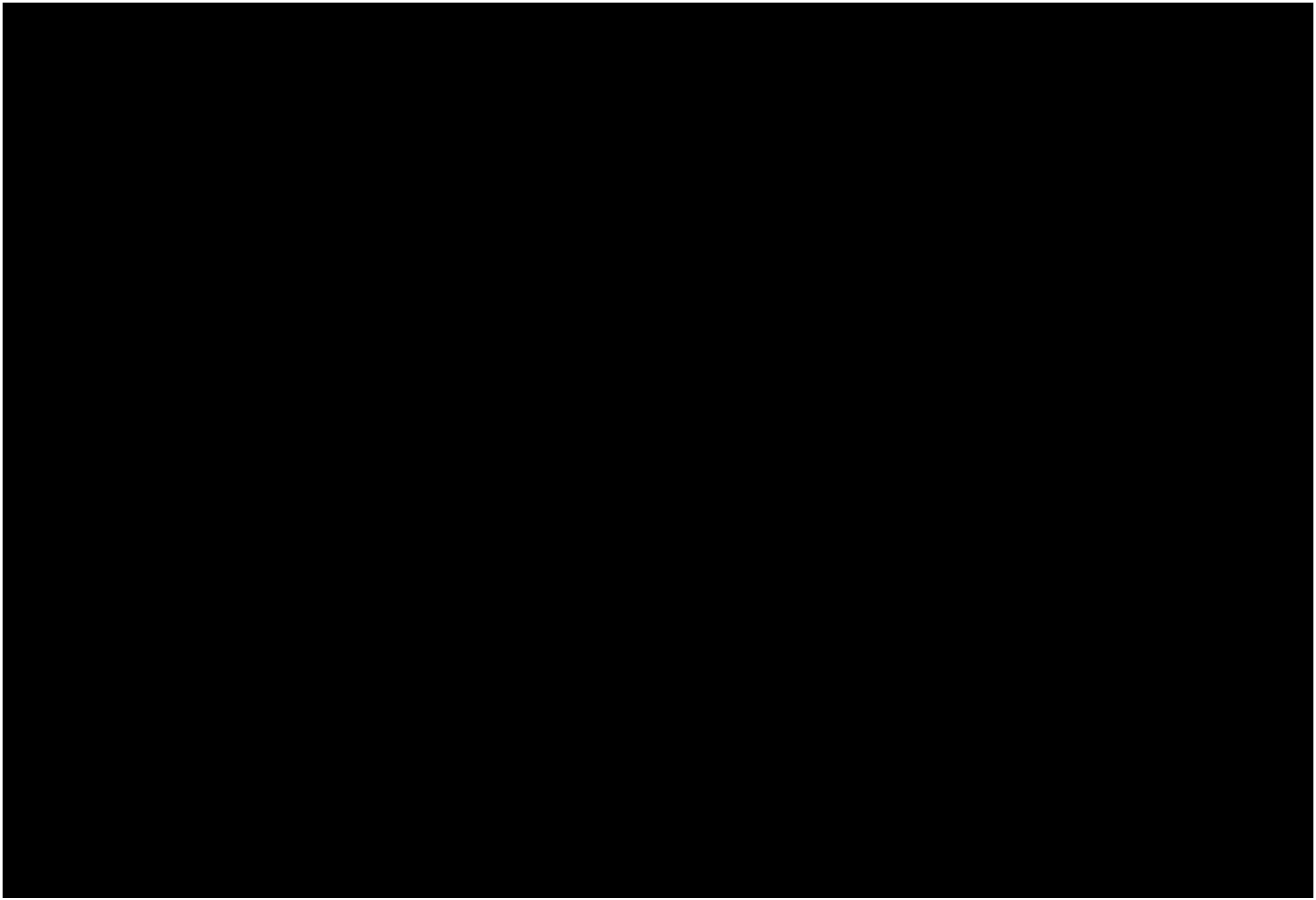
Date of Off Peak Day - 08/08/2021



Member Forecasted Off Peak Demand Day for September 2021

Morgan County Rural Electric Association

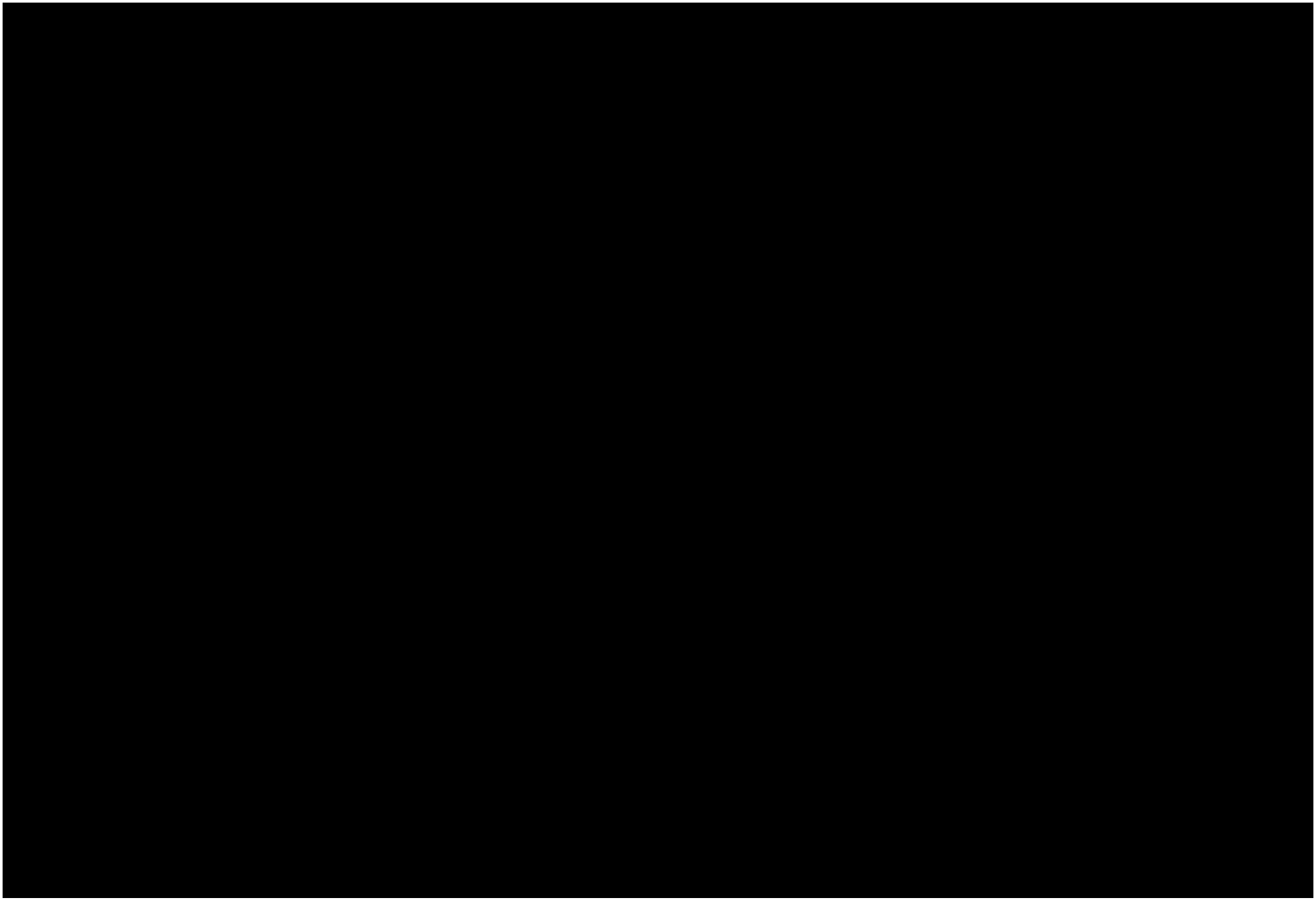
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Morgan County Rural Electric Association

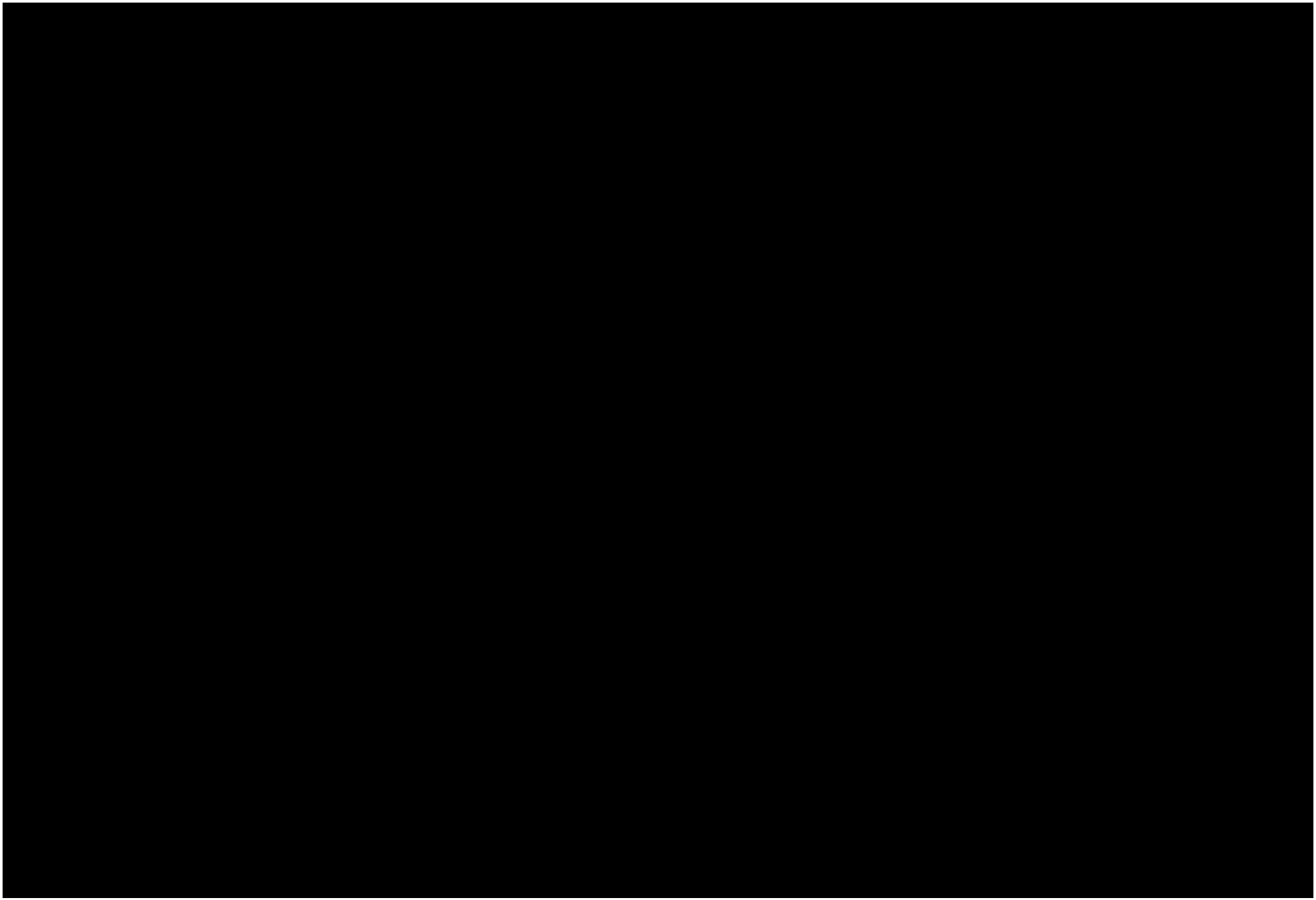
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Morgan County Rural Electric Association

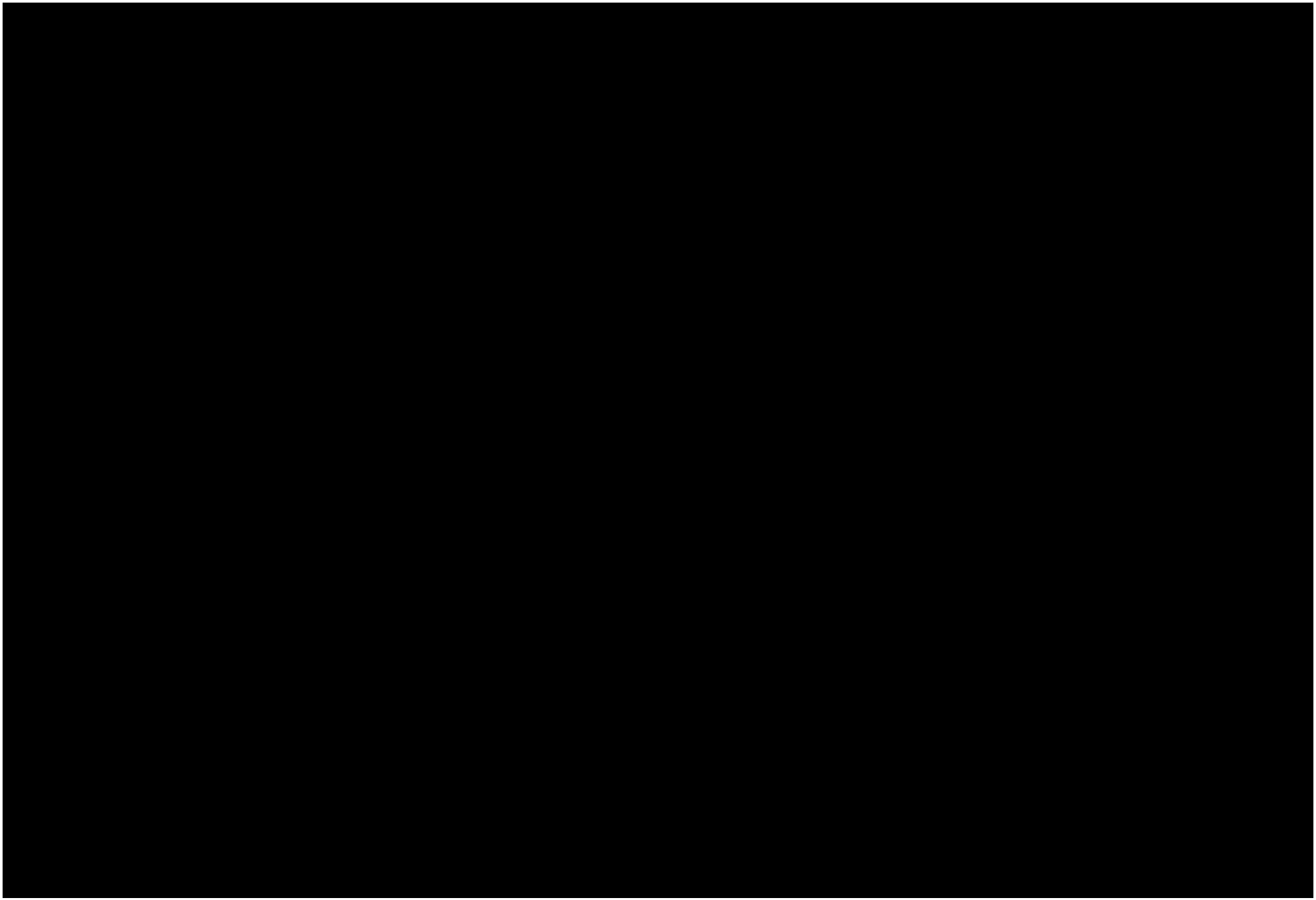
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Morgan County Rural Electric Association

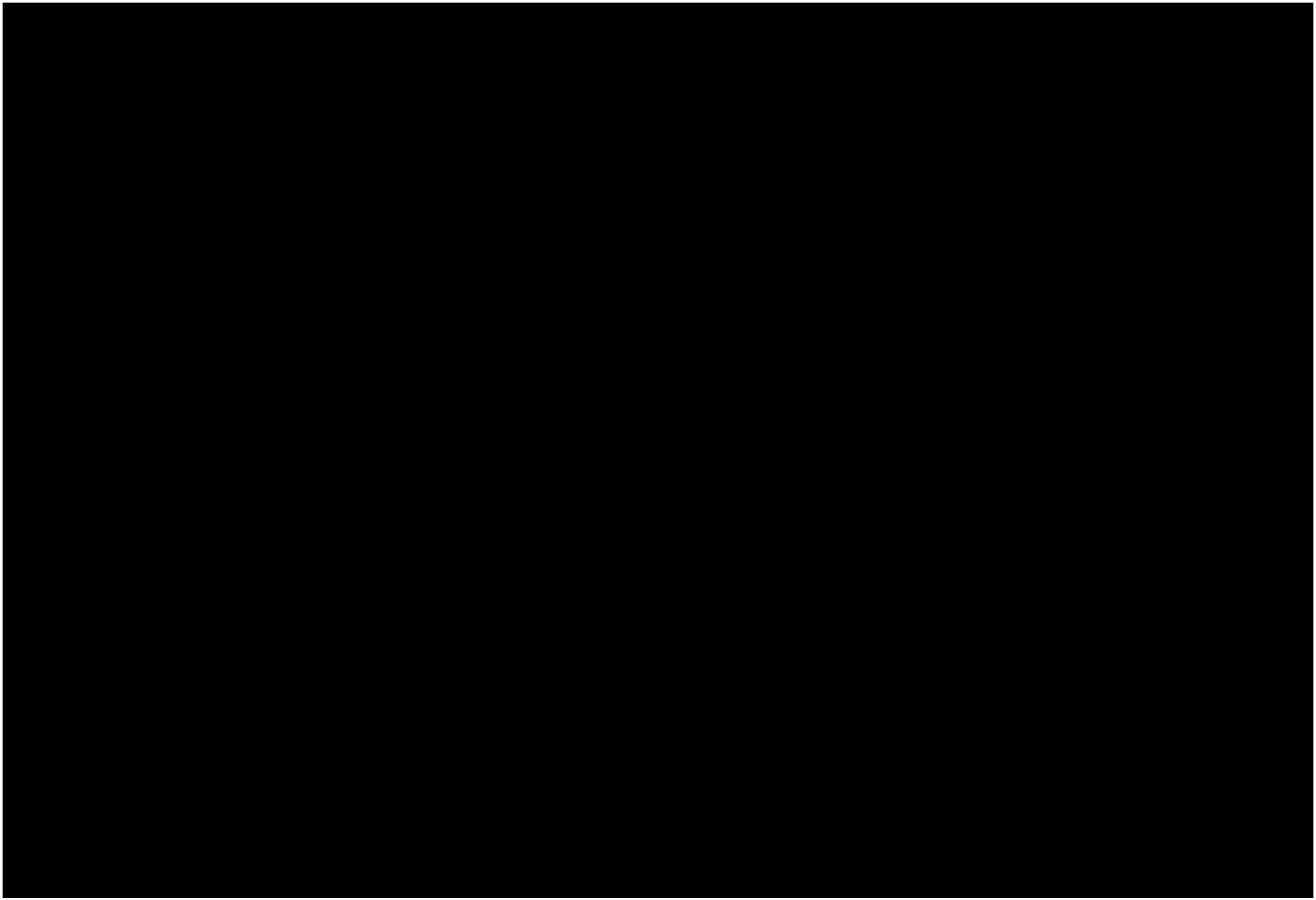
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Mountain Parks Electric, Inc.

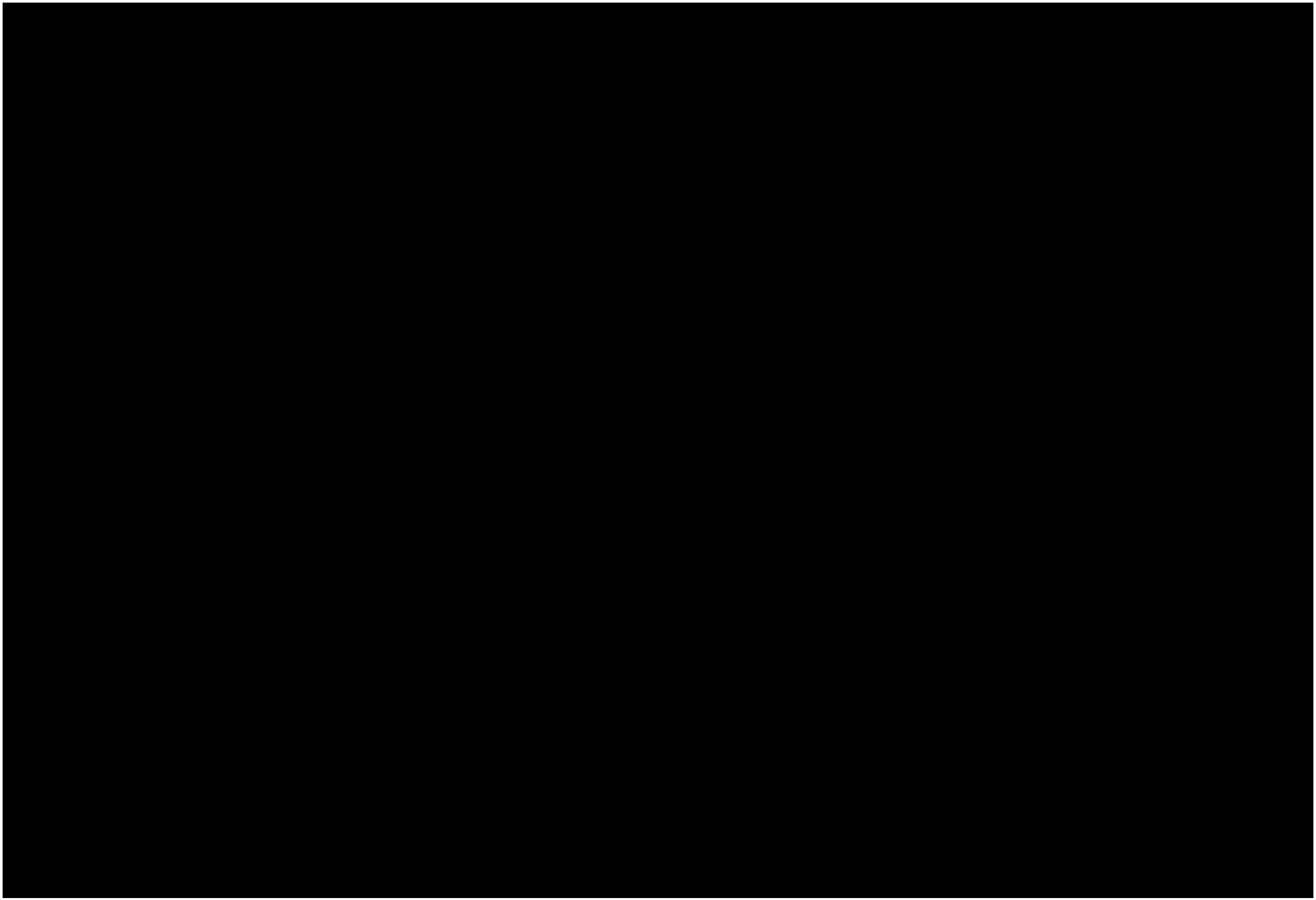
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Mountain Parks Electric, Inc.

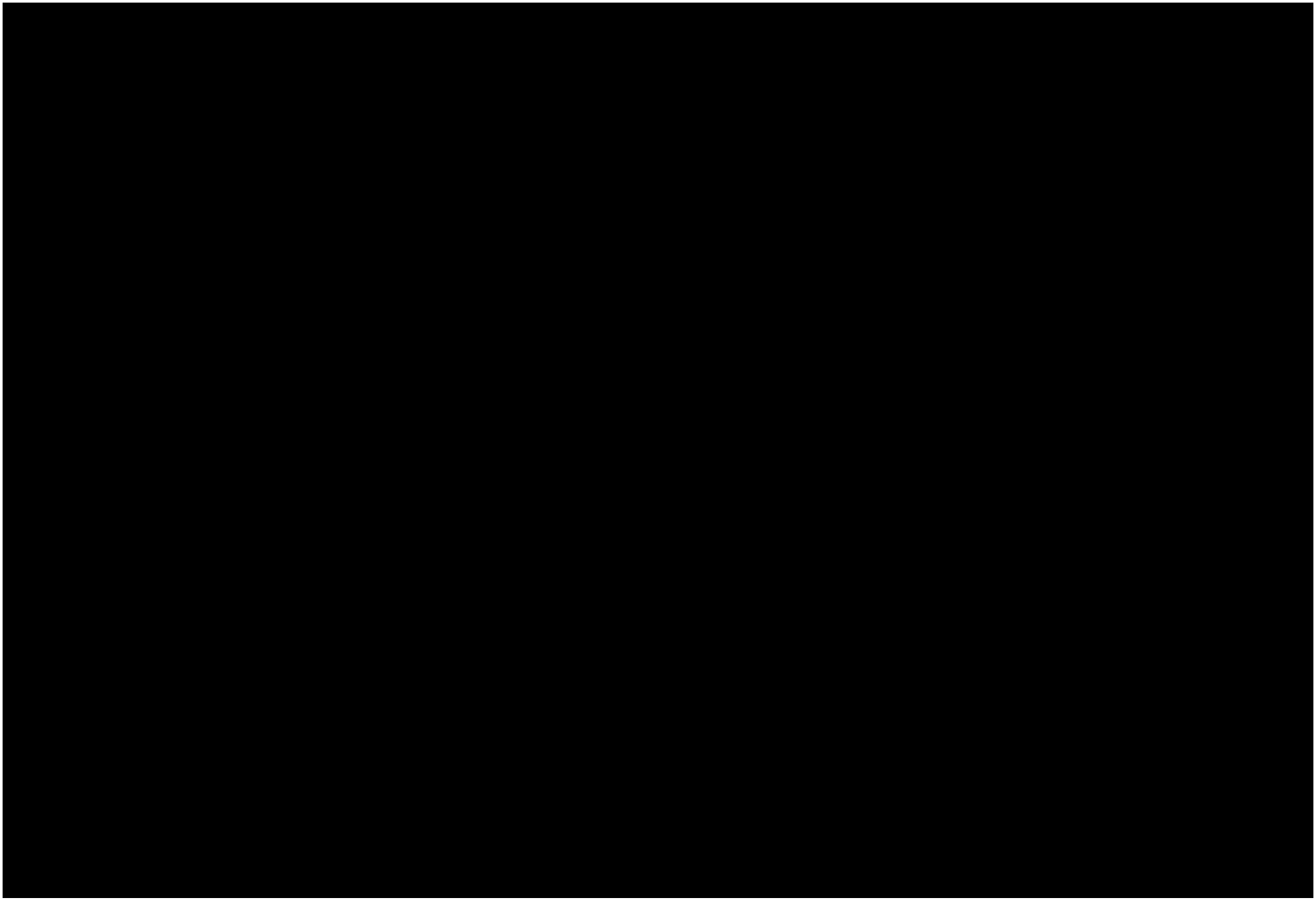
Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Mountain Parks Electric, Inc.

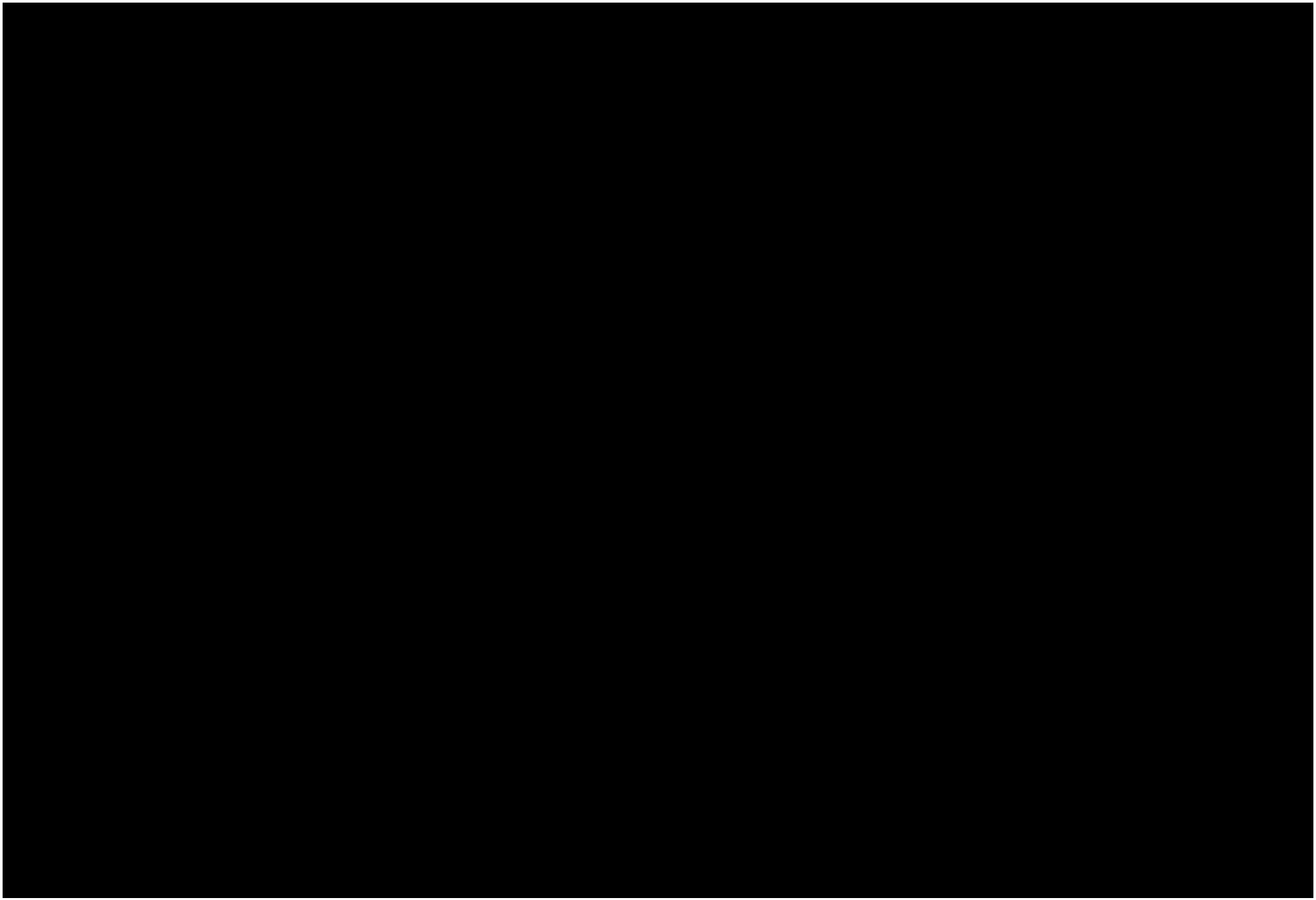
Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Mountain Parks Electric, Inc.

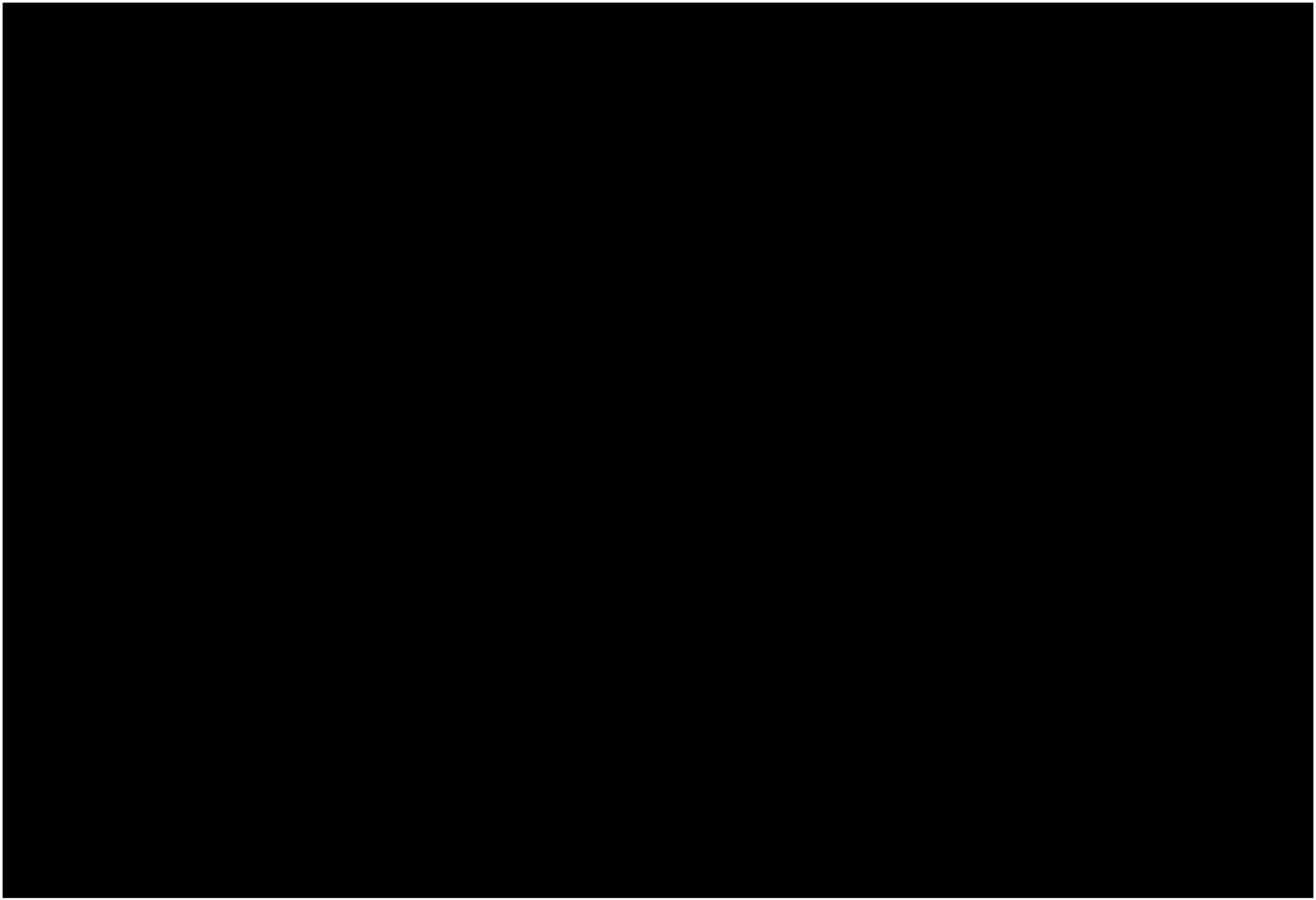
Date of Off Peak Day - 04/29/2021



Member Forecasted Off Peak Demand Day for May 2021

Mountain Parks Electric, Inc.

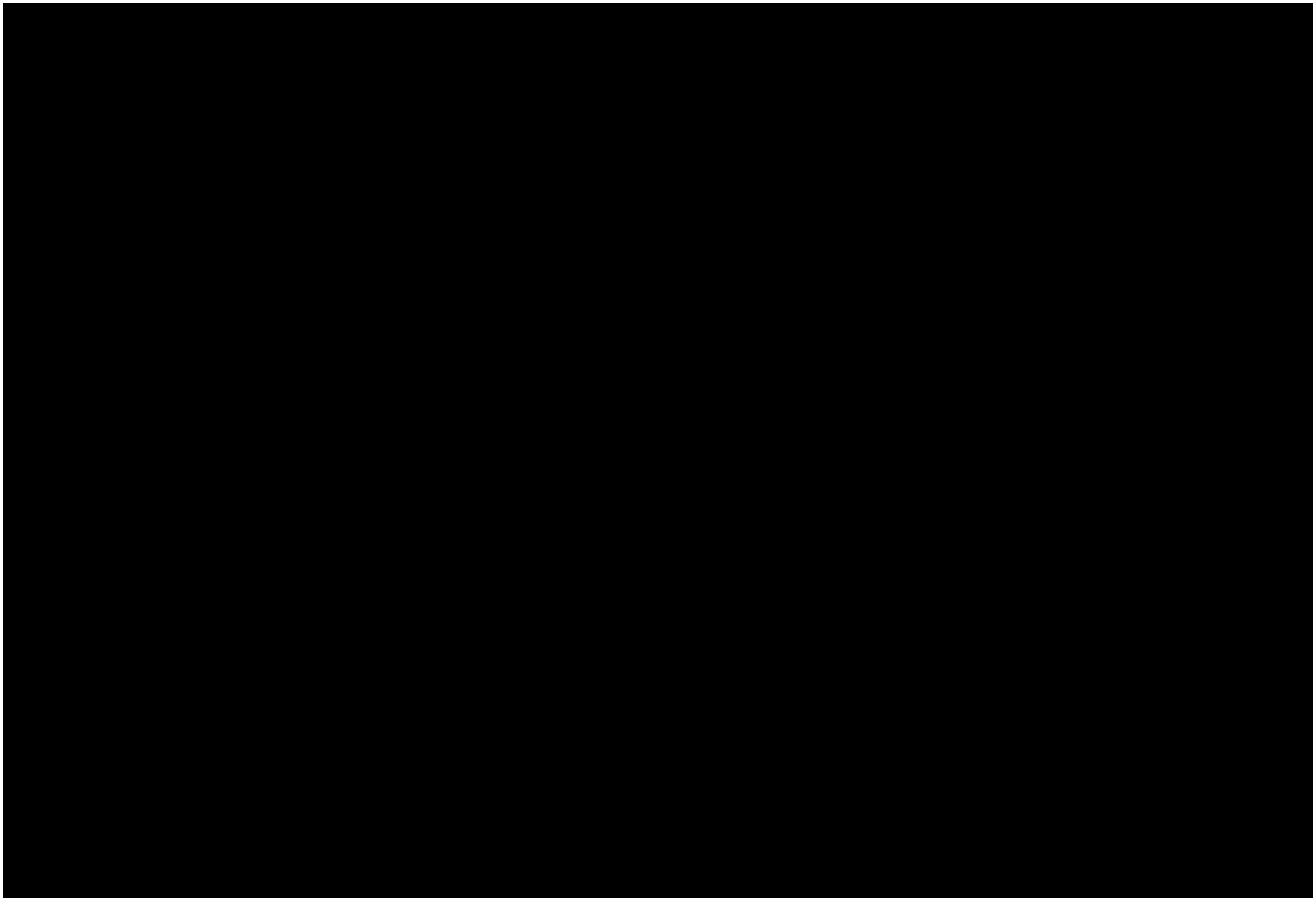
Date of Off Peak Day - 05/25/2021



Member Forecasted Off Peak Demand Day for June 2021

Mountain Parks Electric, Inc.

Date of Off Peak Day - 06/20/2021



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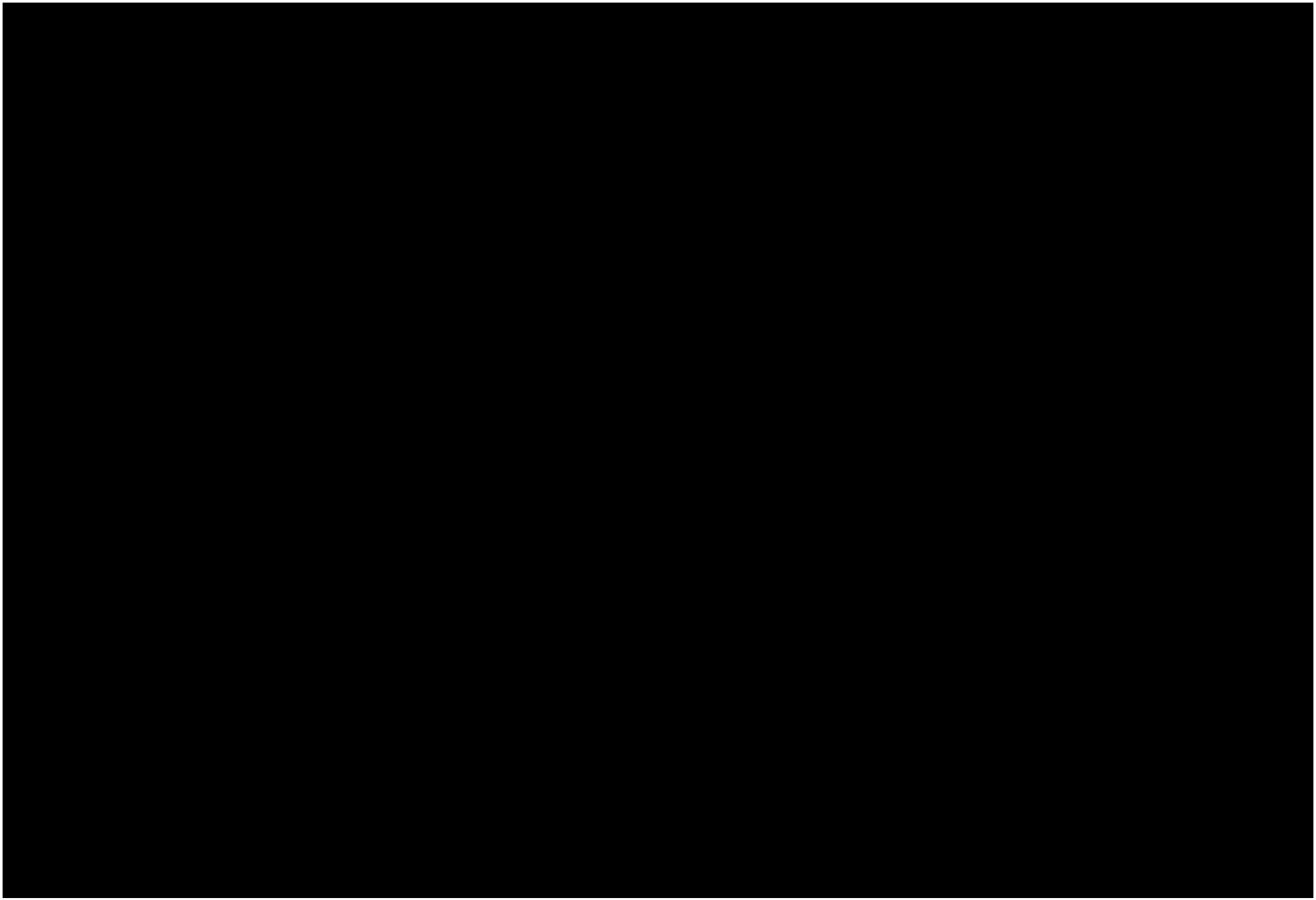
Member Forecasted Off Peak Demand Day for July 2021

Mountain Parks Electric, Inc.

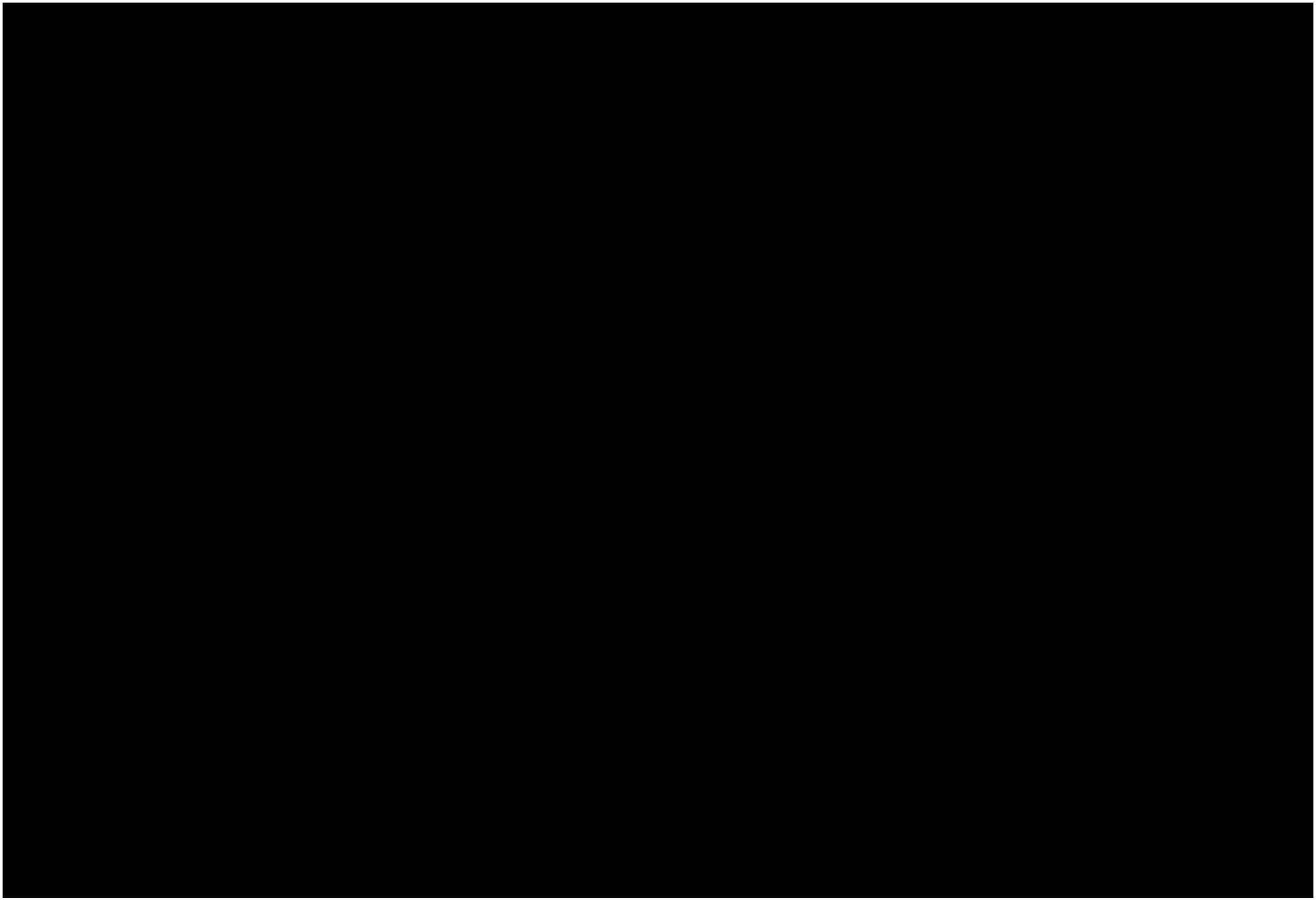
Date of Off Peak Day - 07/19/2021



Member Forecasted Off Peak Demand Day for August 2021

Mountain Parks Electric, Inc.

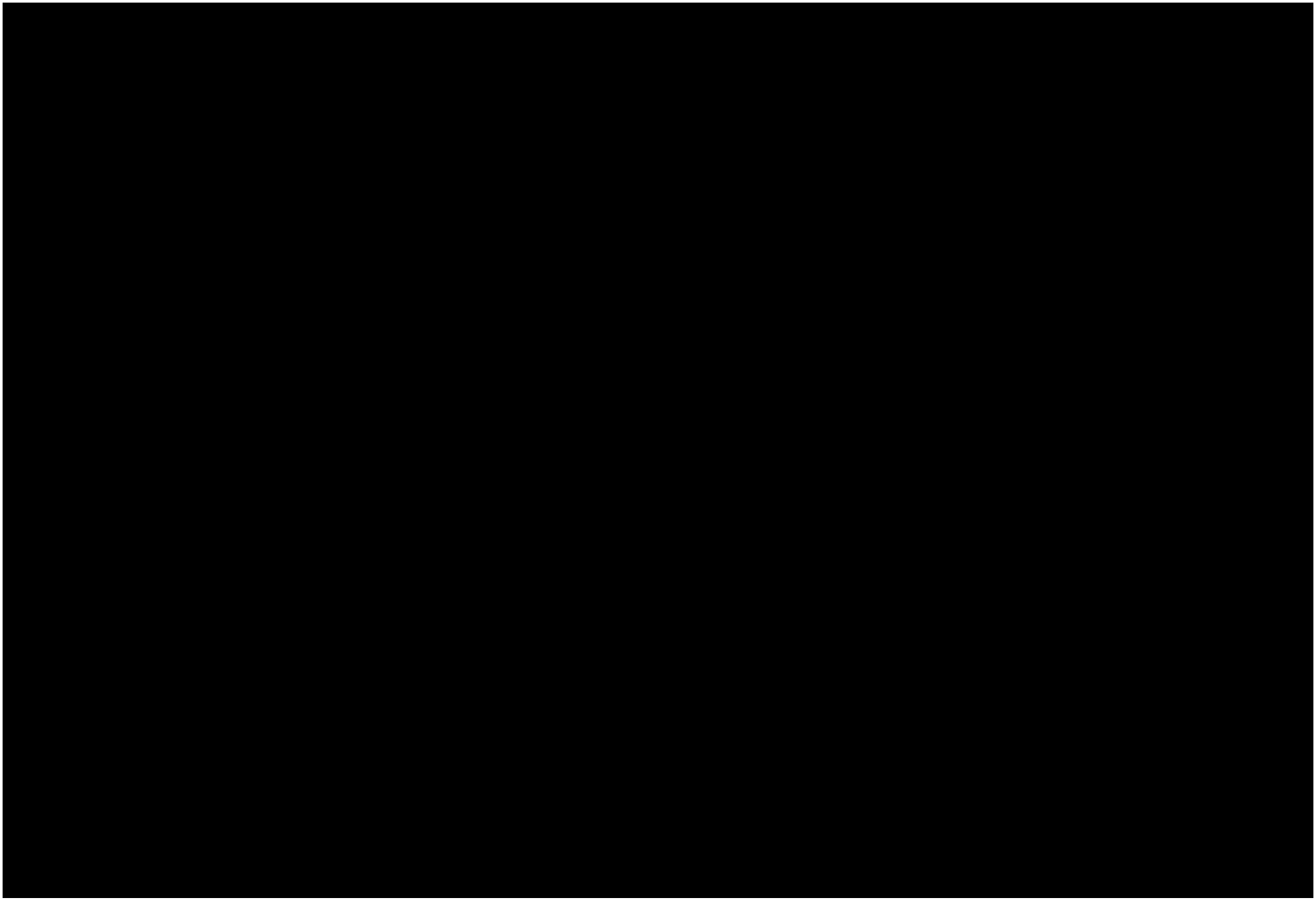
Date of Off Peak Day - 08/23/2021



Member Forecasted Off Peak Demand Day for September 2021

Mountain Parks Electric, Inc.

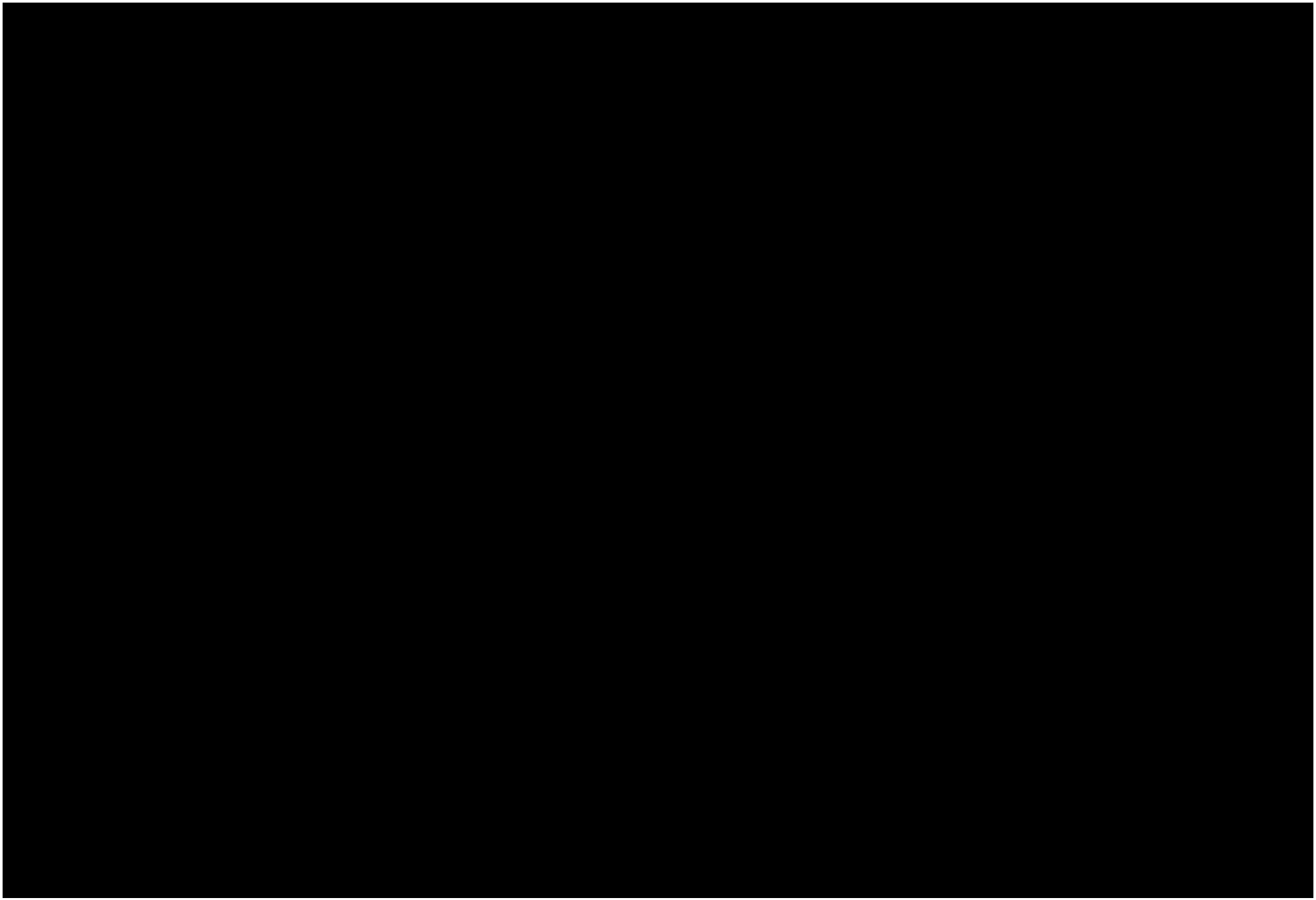
Date of Off Peak Day - 09/27/2021



Member Forecasted Off Peak Demand Day for October 2021

Mountain Parks Electric, Inc.

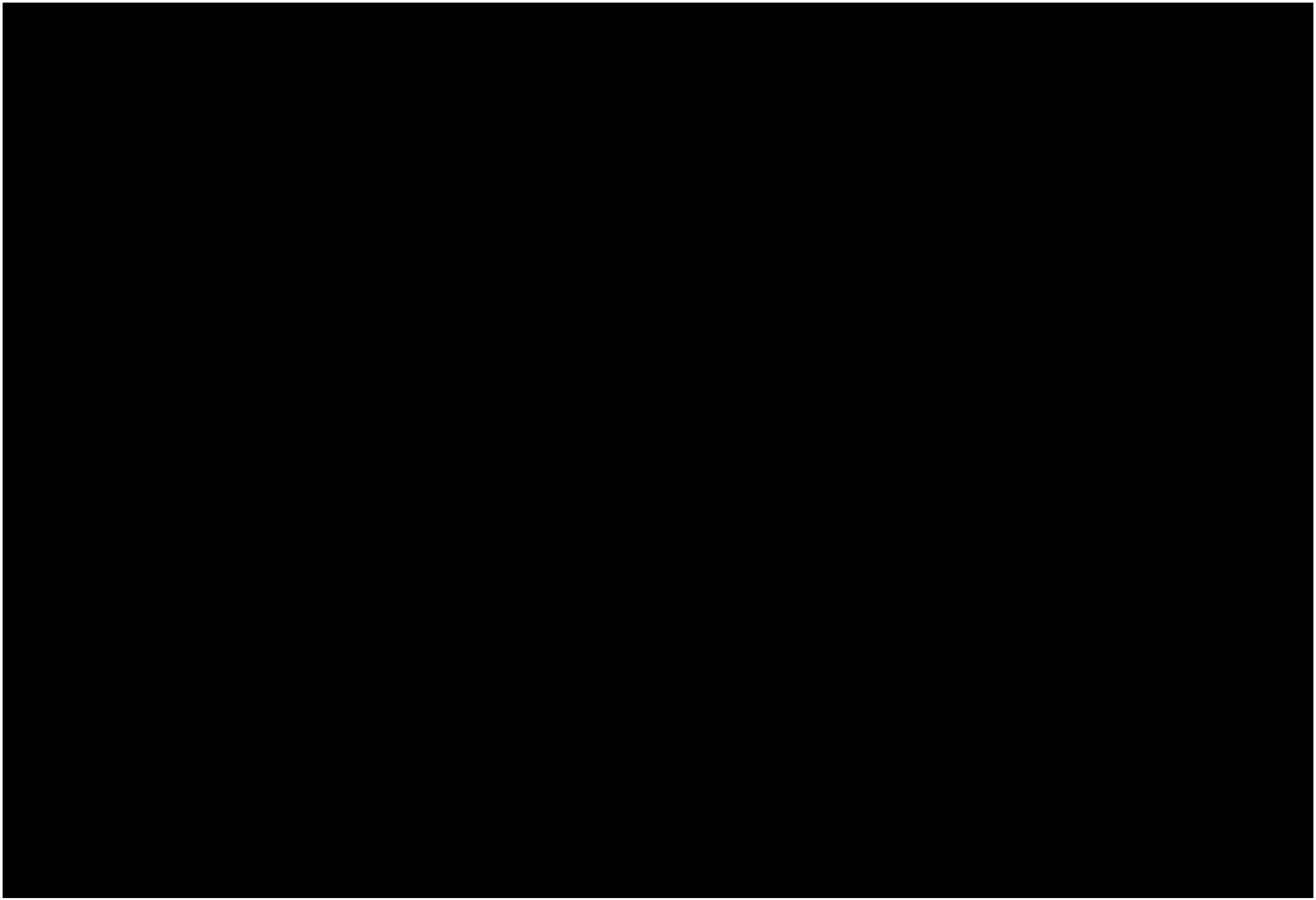
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Mountain Parks Electric, Inc.

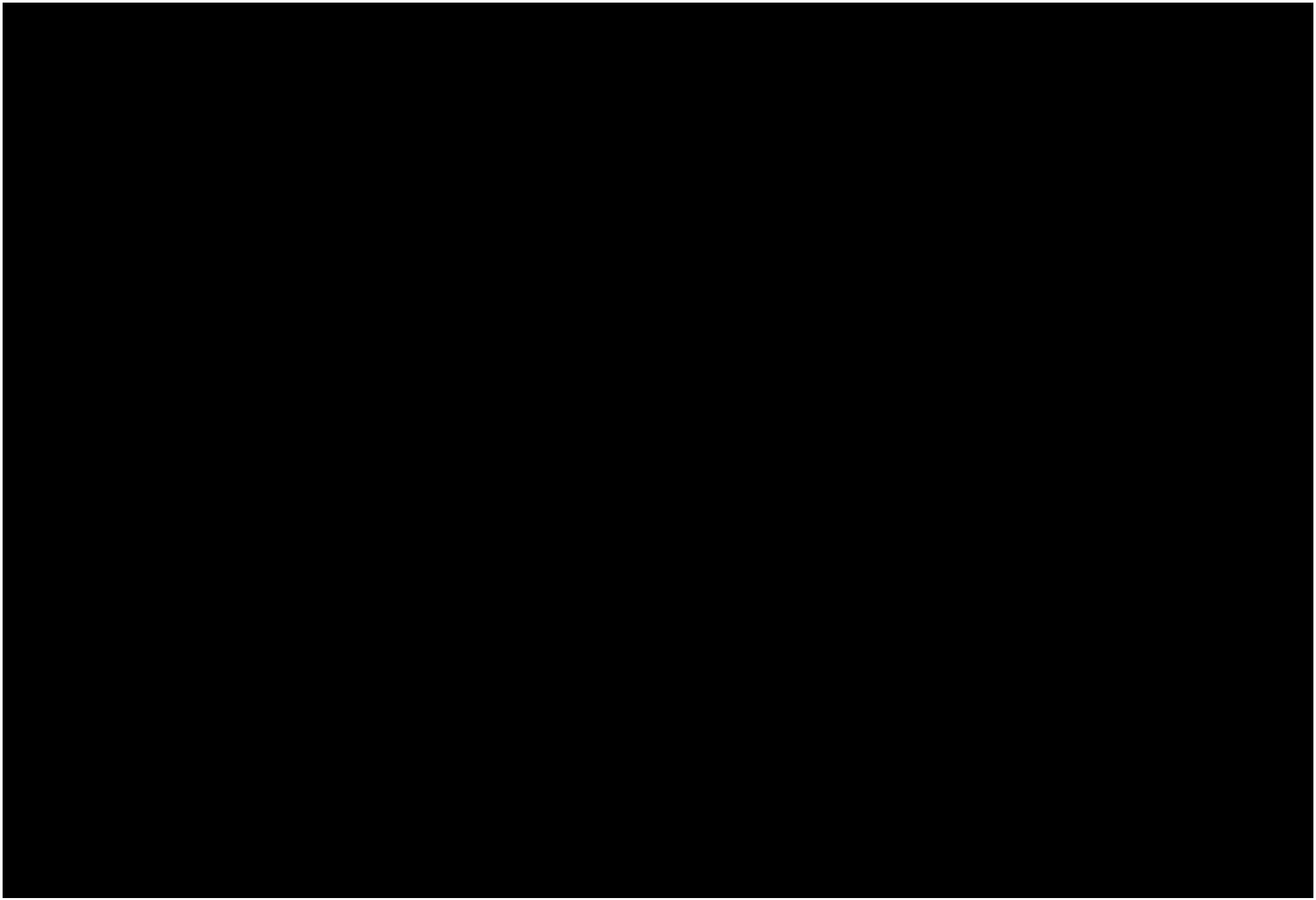
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Mountain Parks Electric, Inc.

Date of Off Peak Day - 12/11/2021



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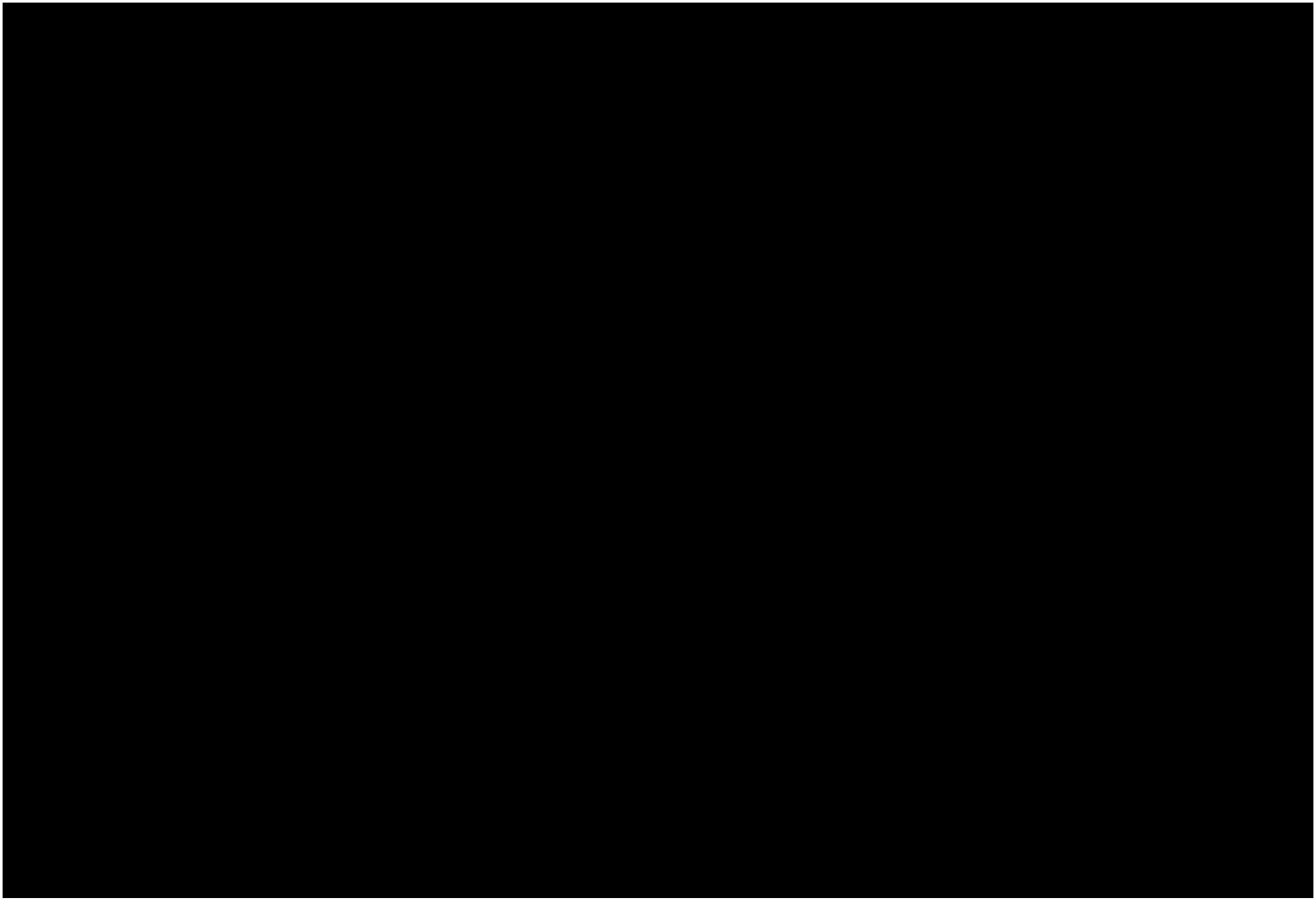
Member Forecasted Off Peak Demand Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

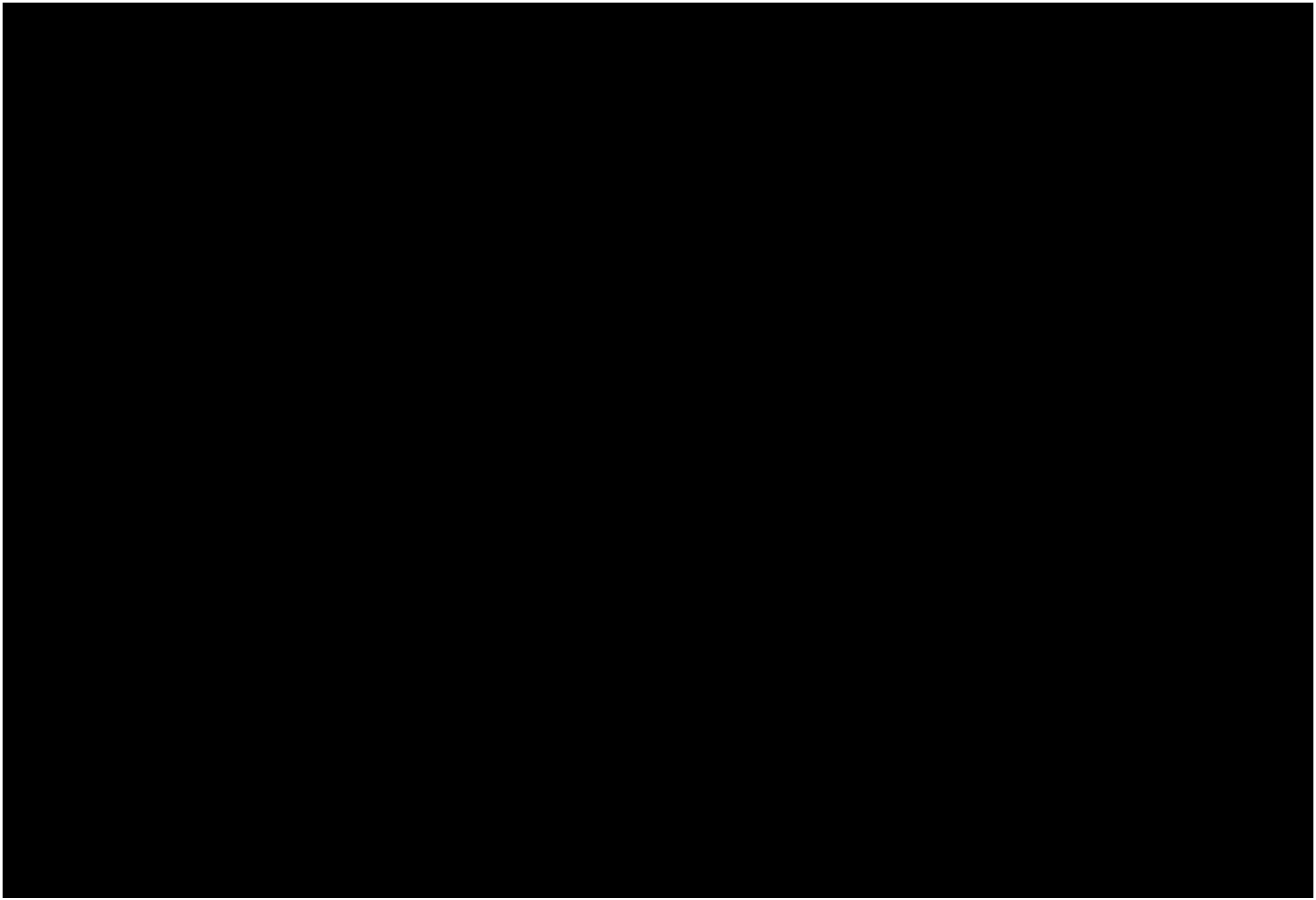
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

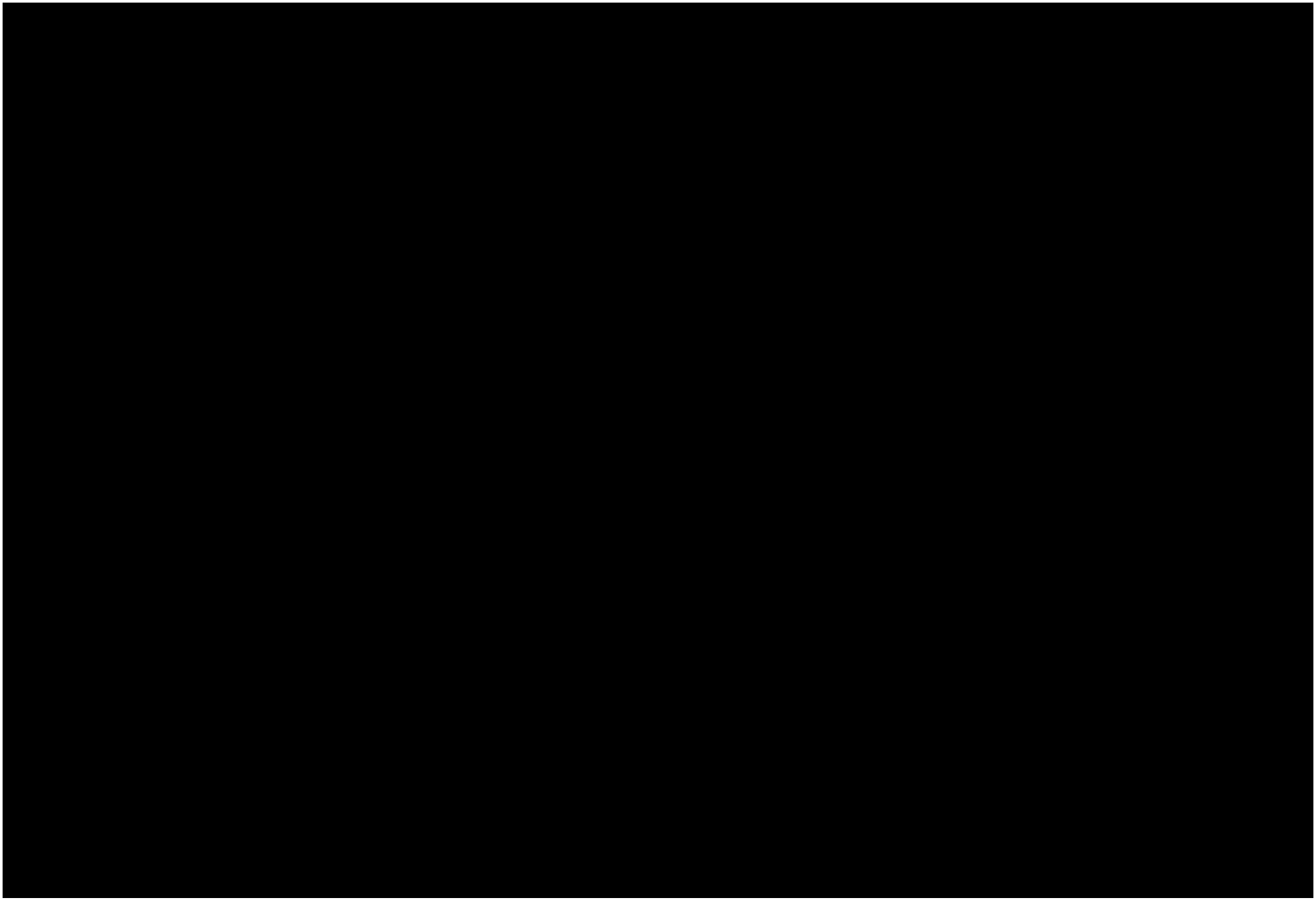
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.

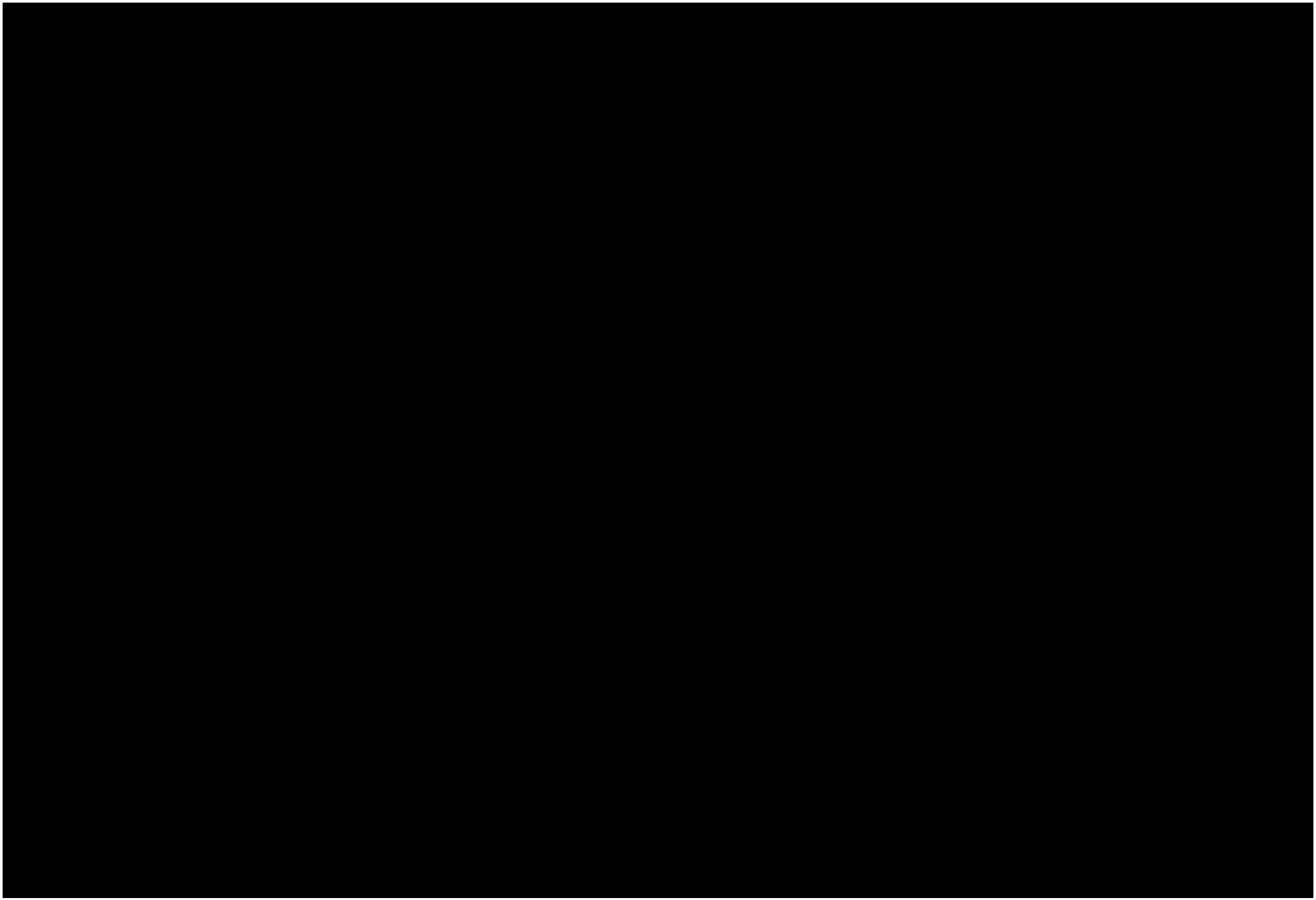
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

Date of Off Peak Day - 04/07/2021



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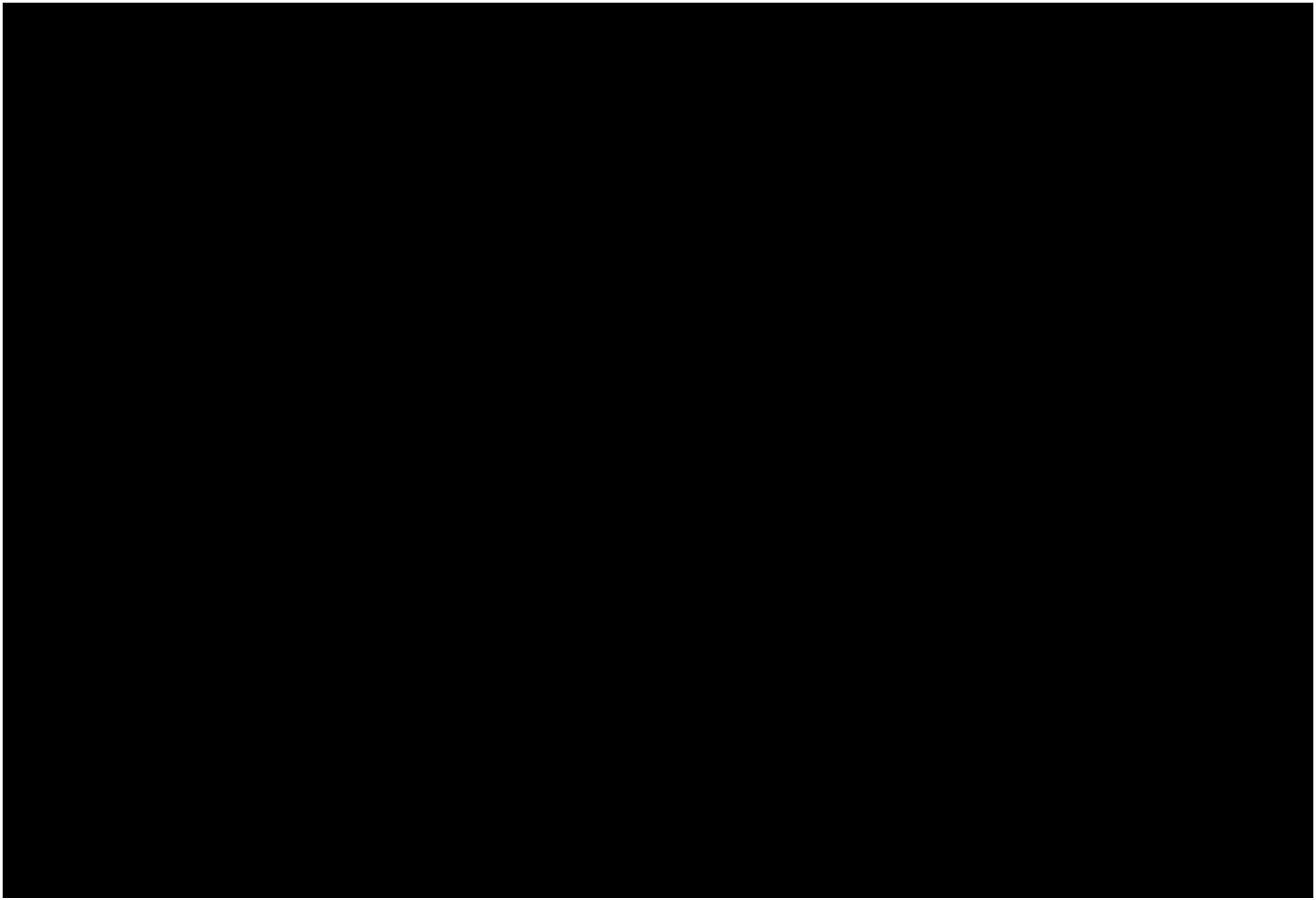
Member Forecasted Off Peak Demand Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

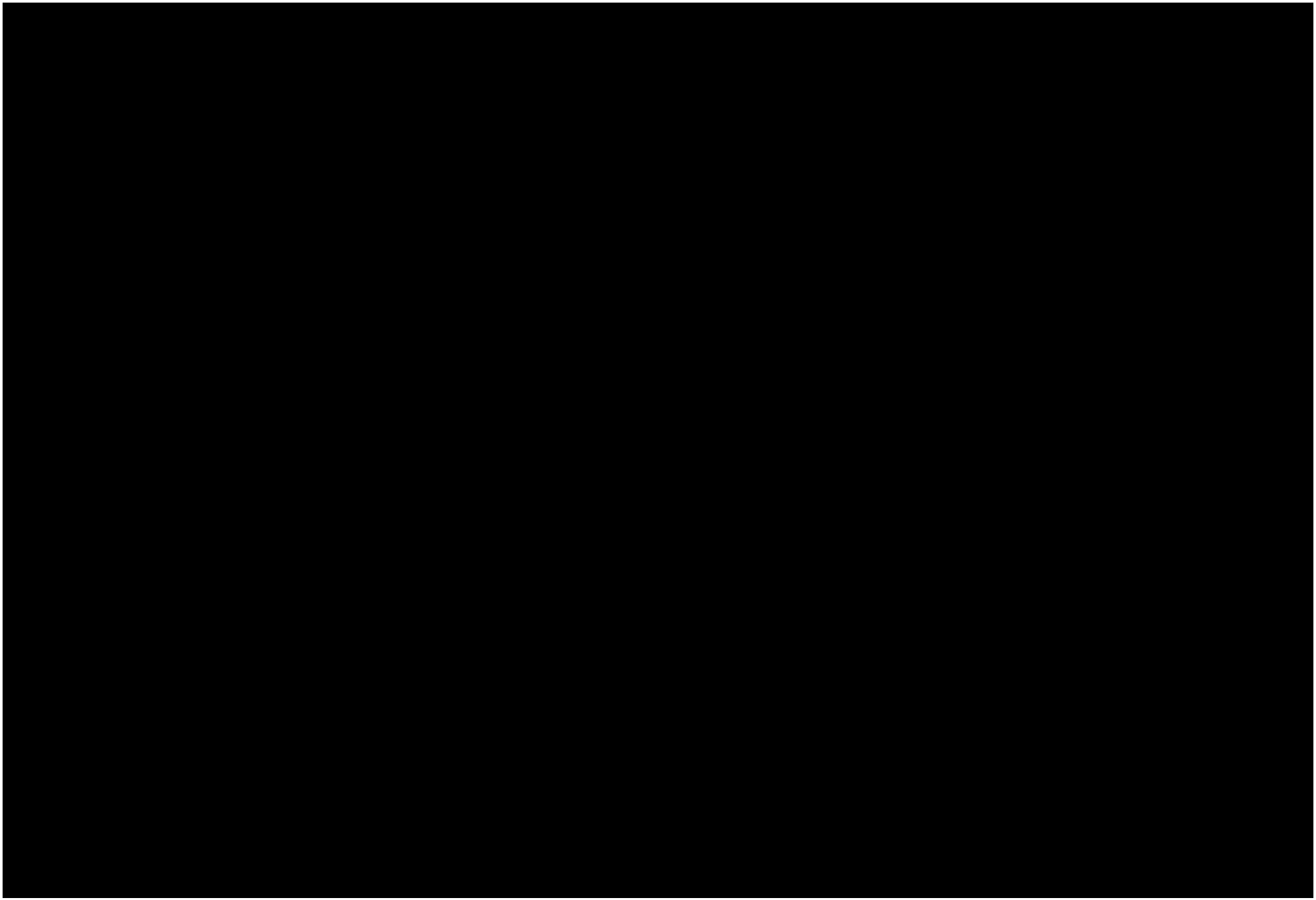
Date of Off Peak Day - 05/31/2021



Member Forecasted Off Peak Demand Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

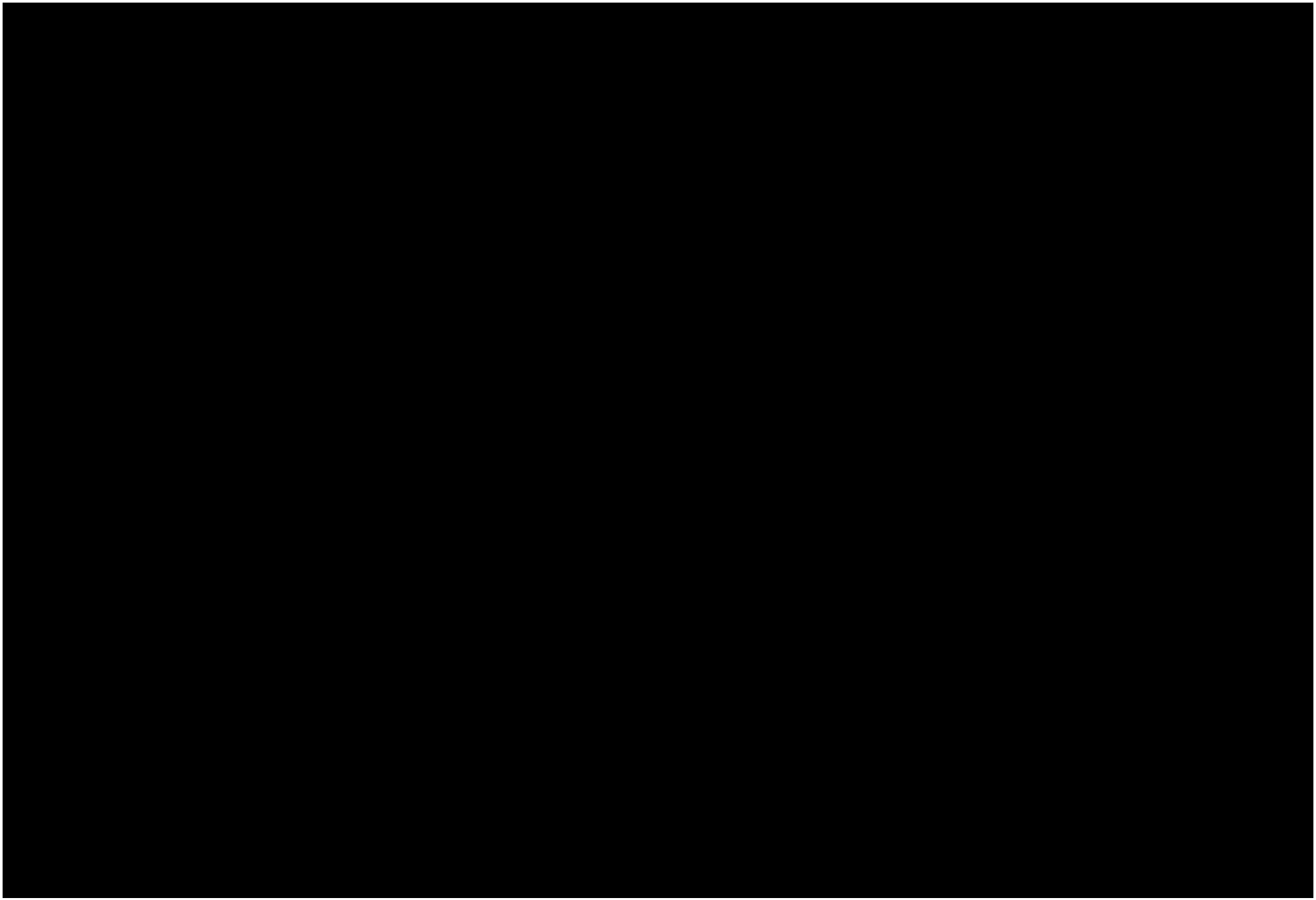
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

Date of Off Peak Day - 07/30/2021



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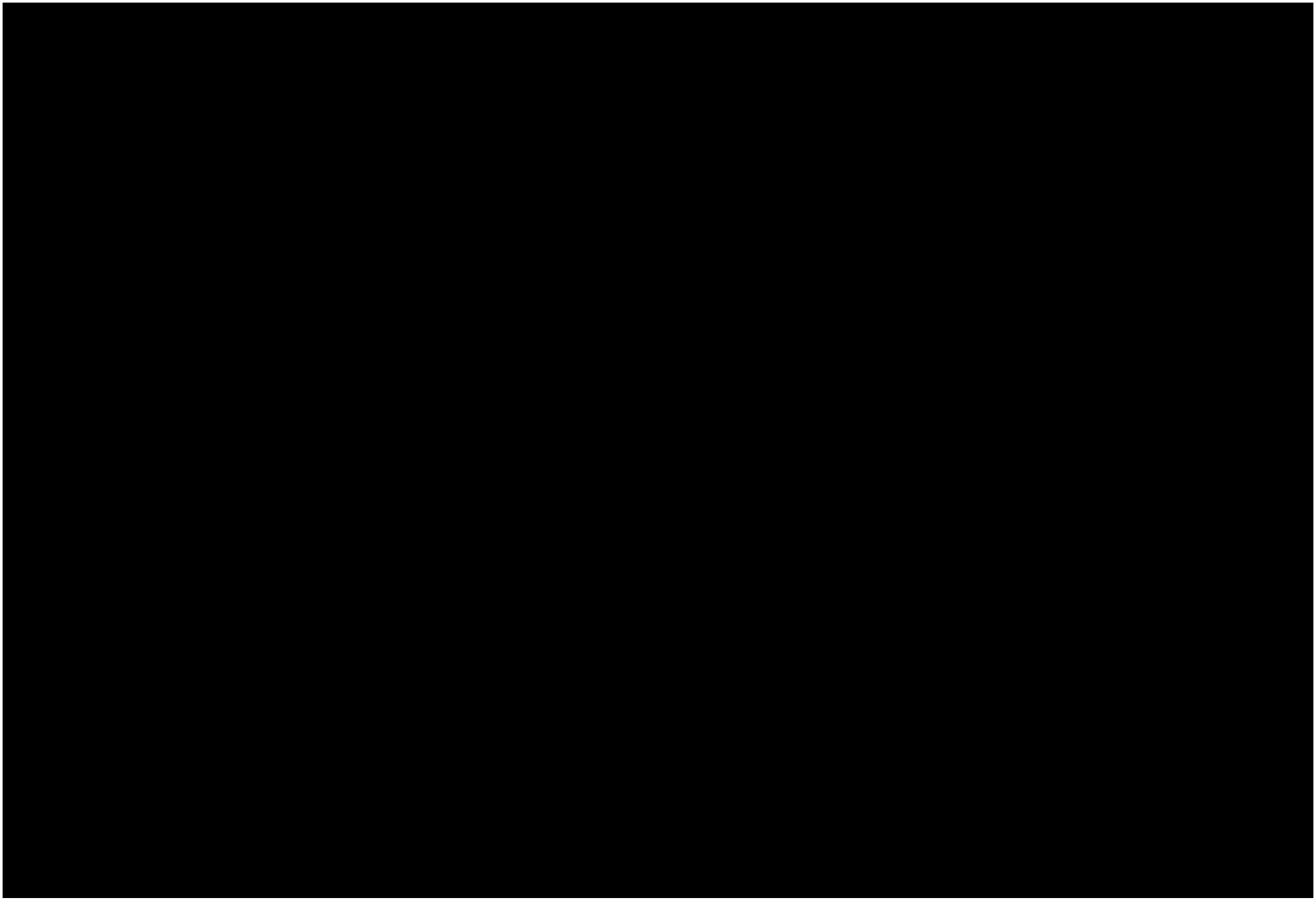
Member Forecasted Off Peak Demand Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

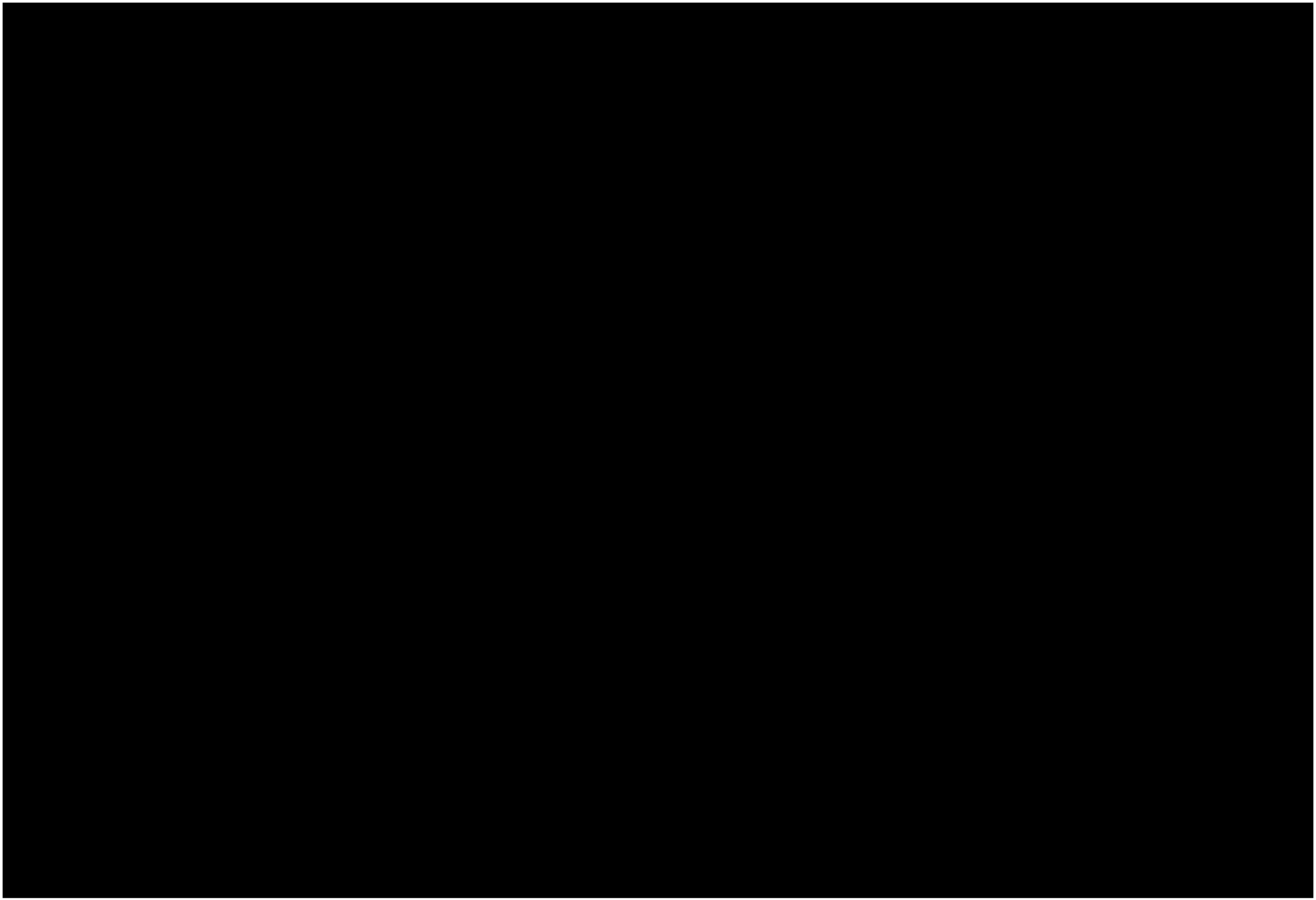
Date of Off Peak Day - 08/25/2021



Member Forecasted Off Peak Demand Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.

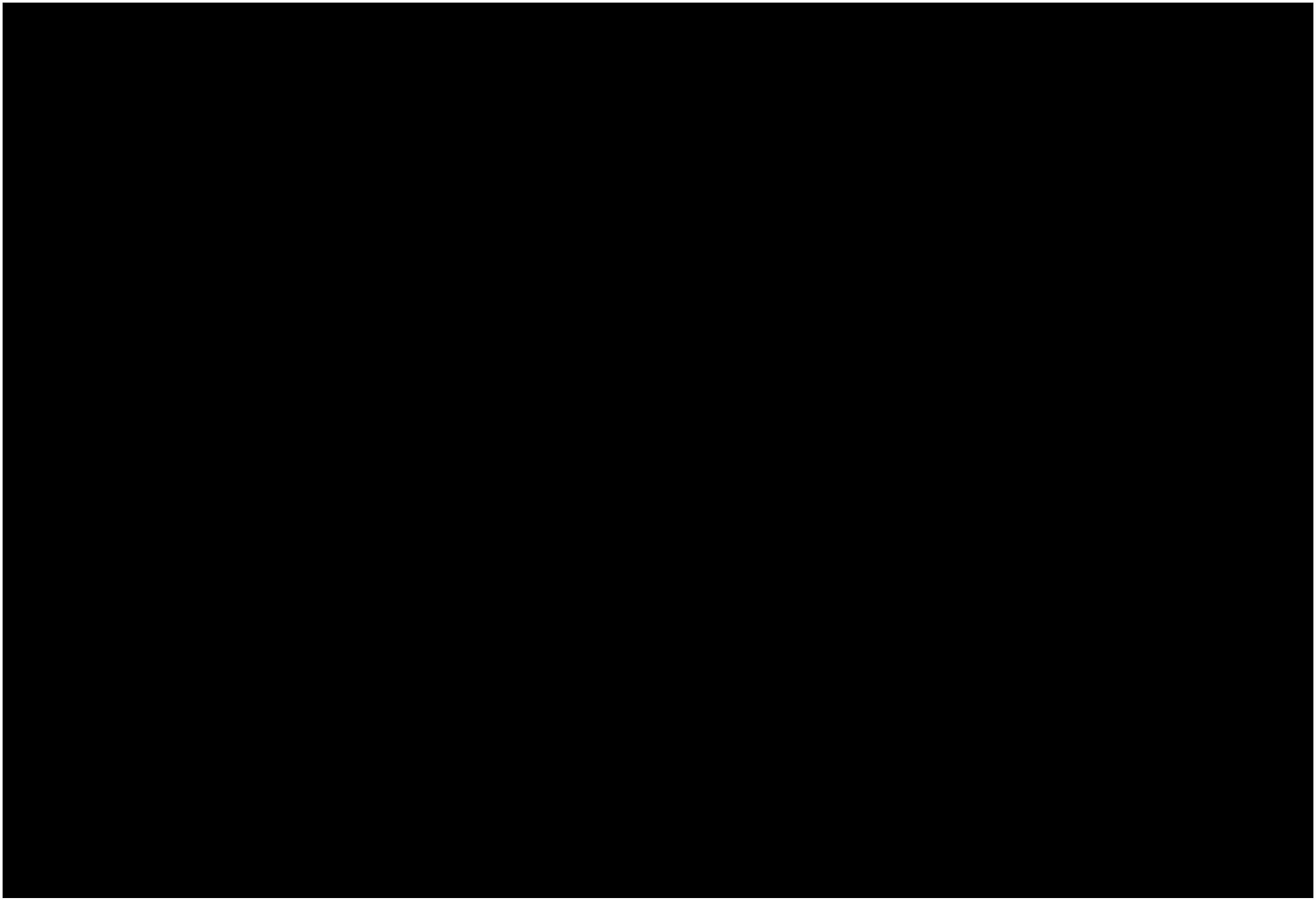
Date of Off Peak Day - 09/23/2021



Member Forecasted Off Peak Demand Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

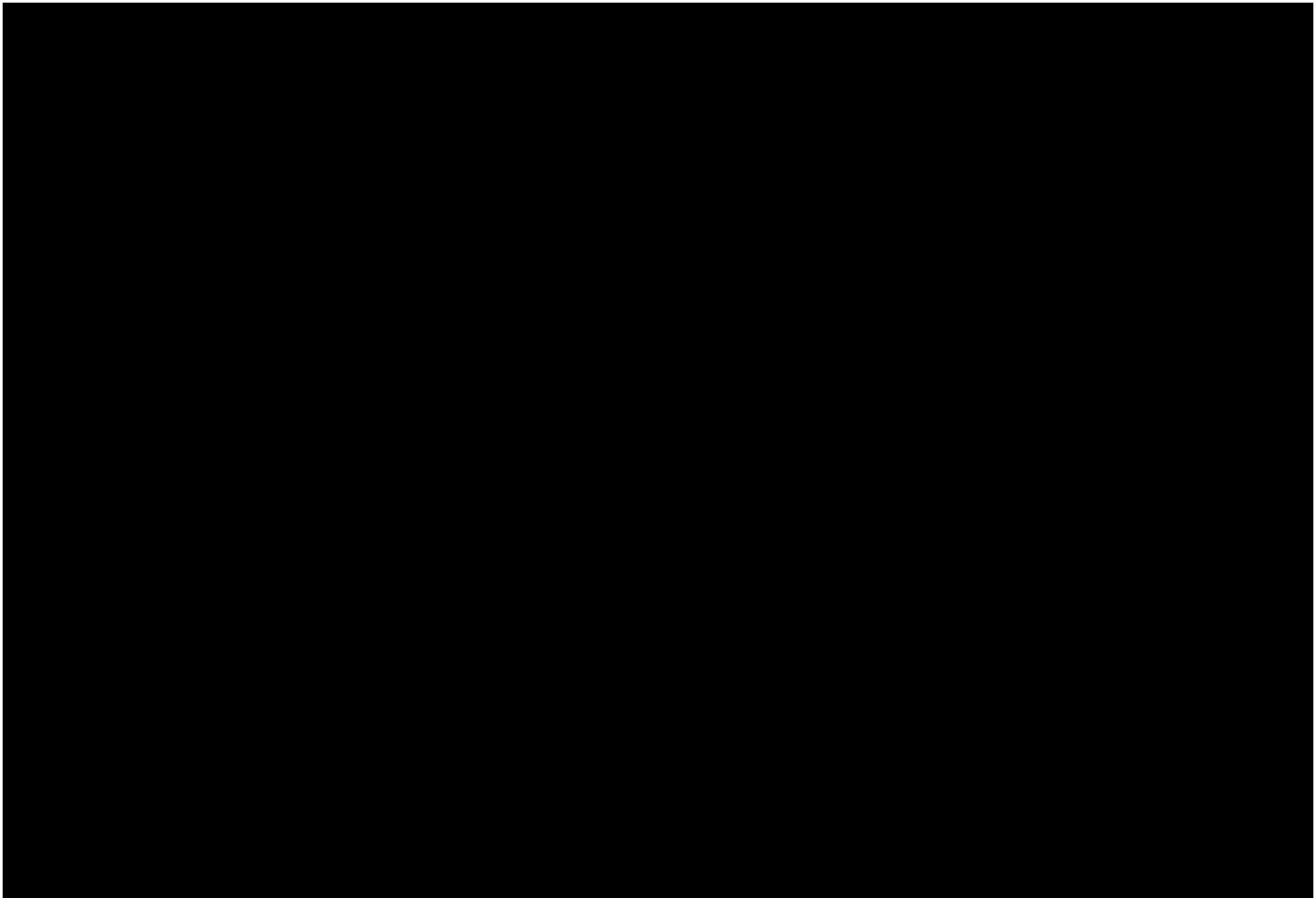
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

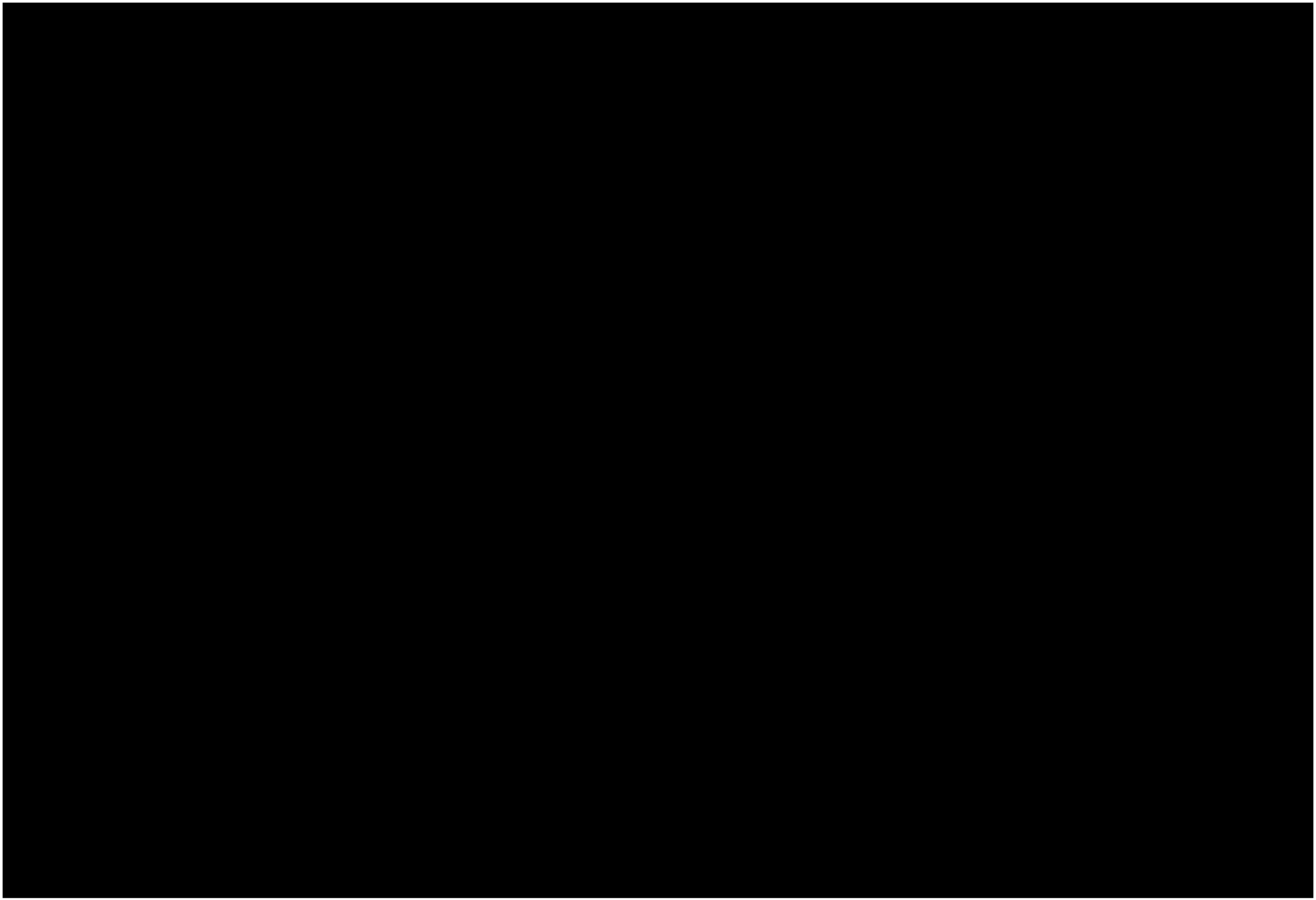
Date of Off Peak Day - 11/06/2021



Member Forecasted Off Peak Demand Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

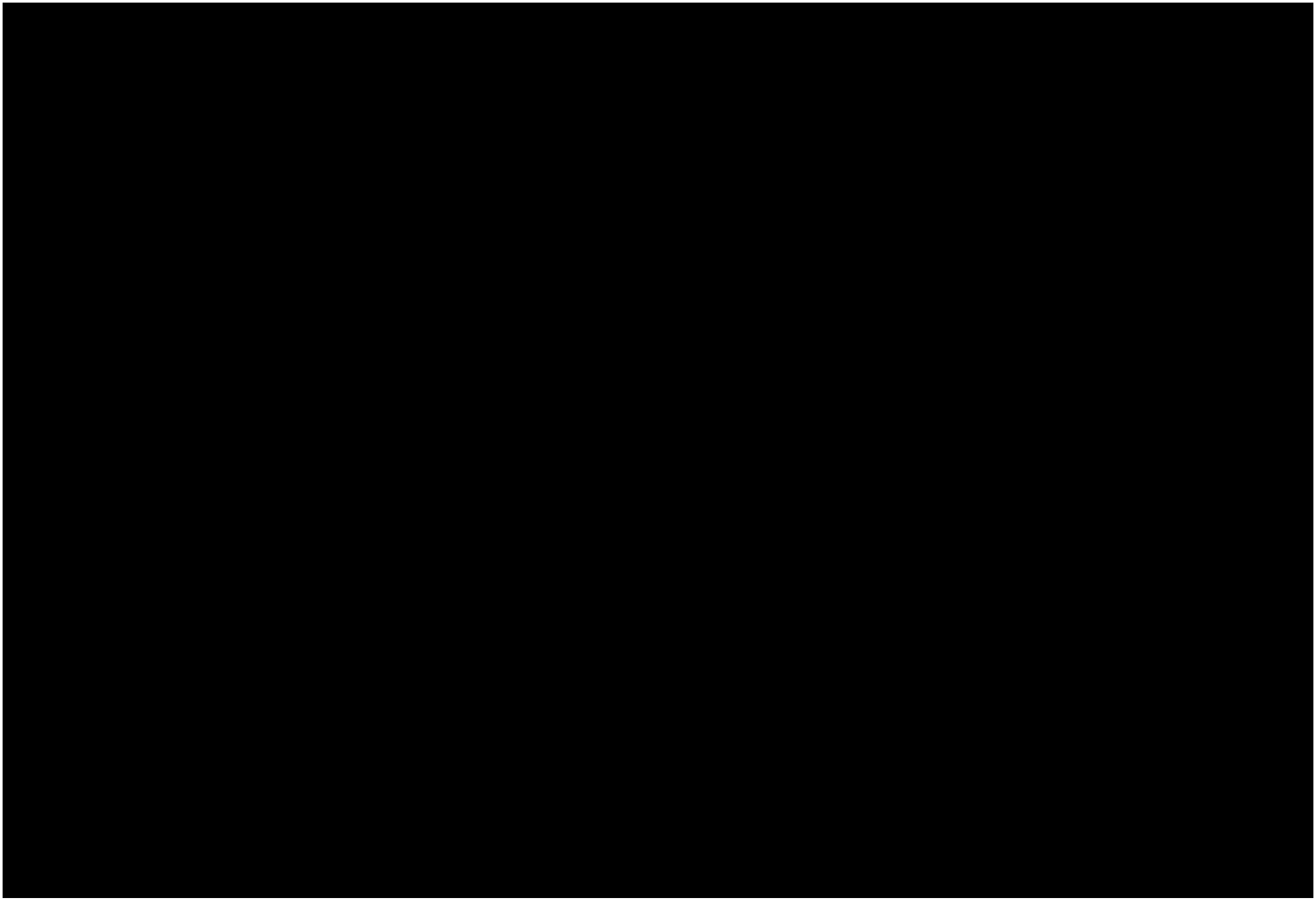
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Mountain View Electric Association, Inc.

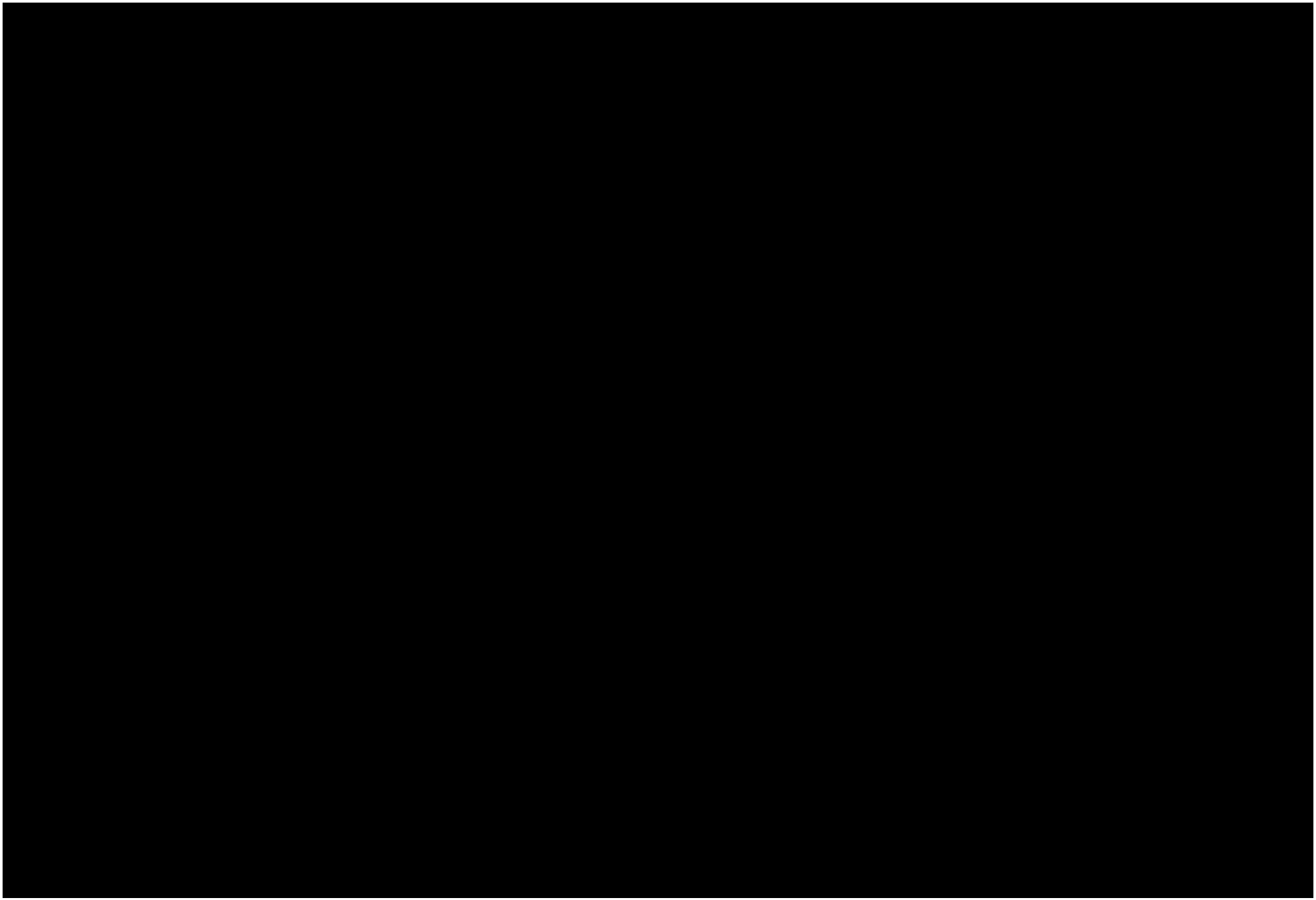
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

Mountain View Electric Association, Inc.

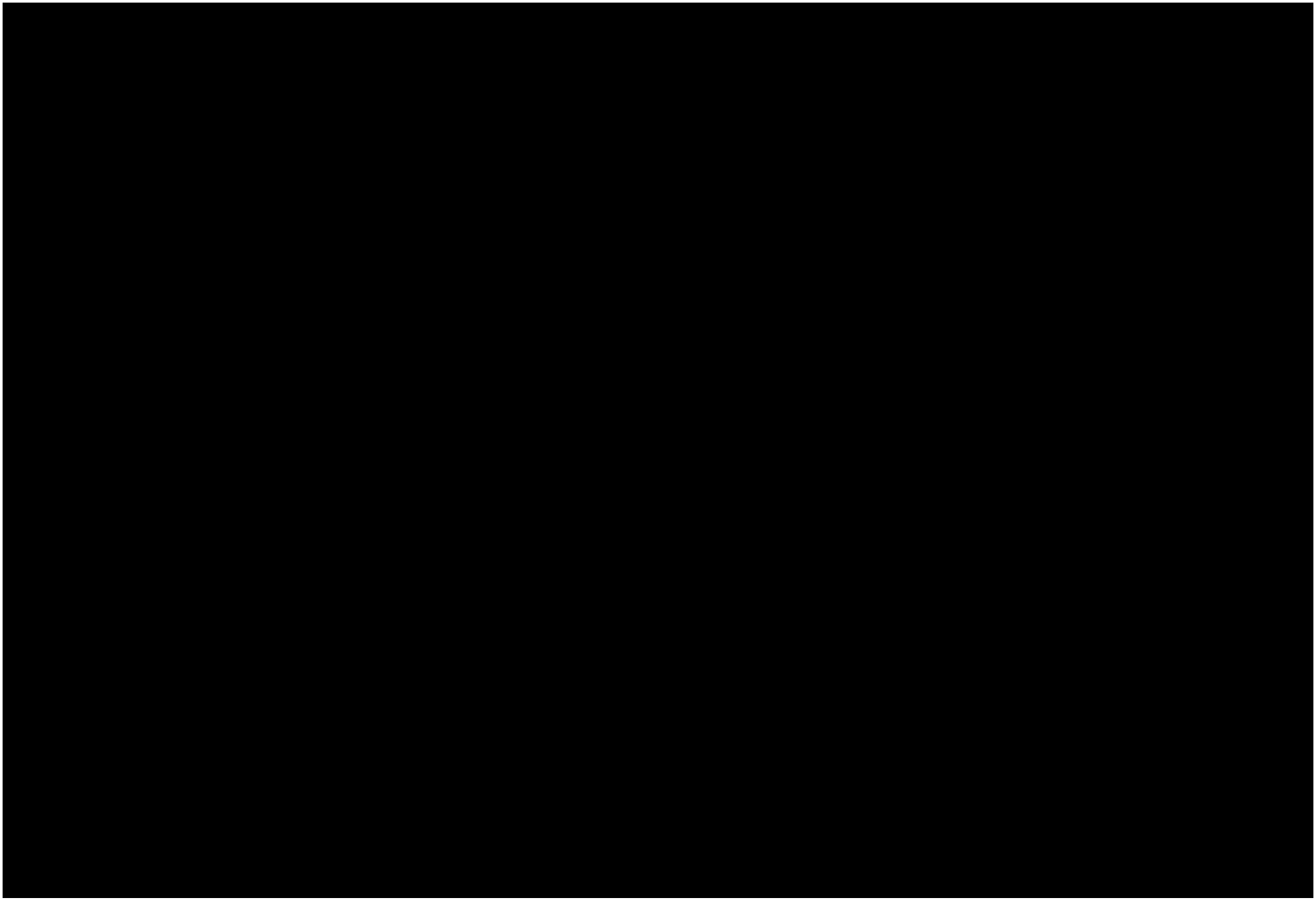
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 03/21/2021



Member Forecasted Off Peak Demand Day for April 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 04/07/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Mountain View Electric Association, Inc.

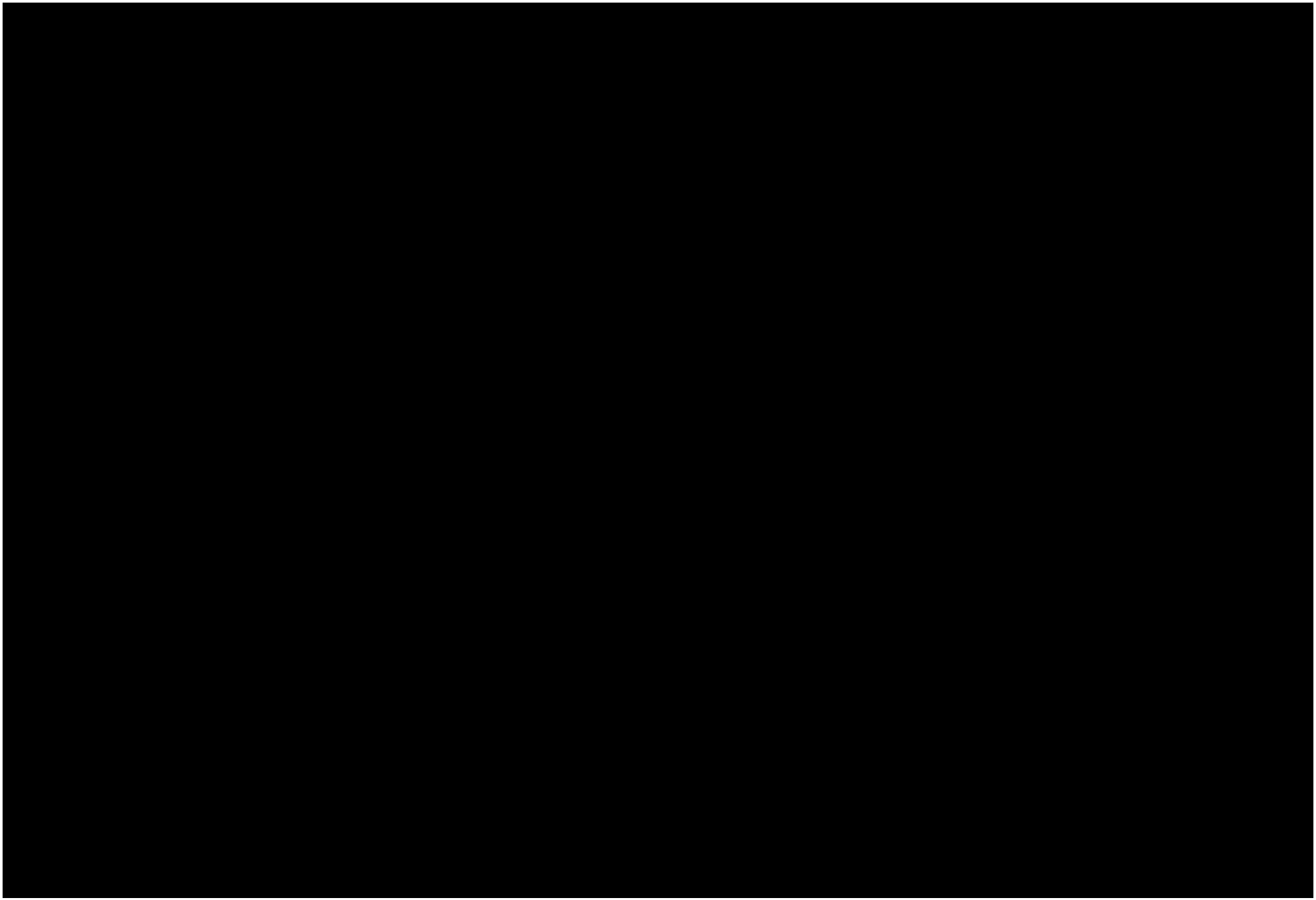
Date of Off Peak Day - 05/29/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Mountain View Electric Association, Inc.

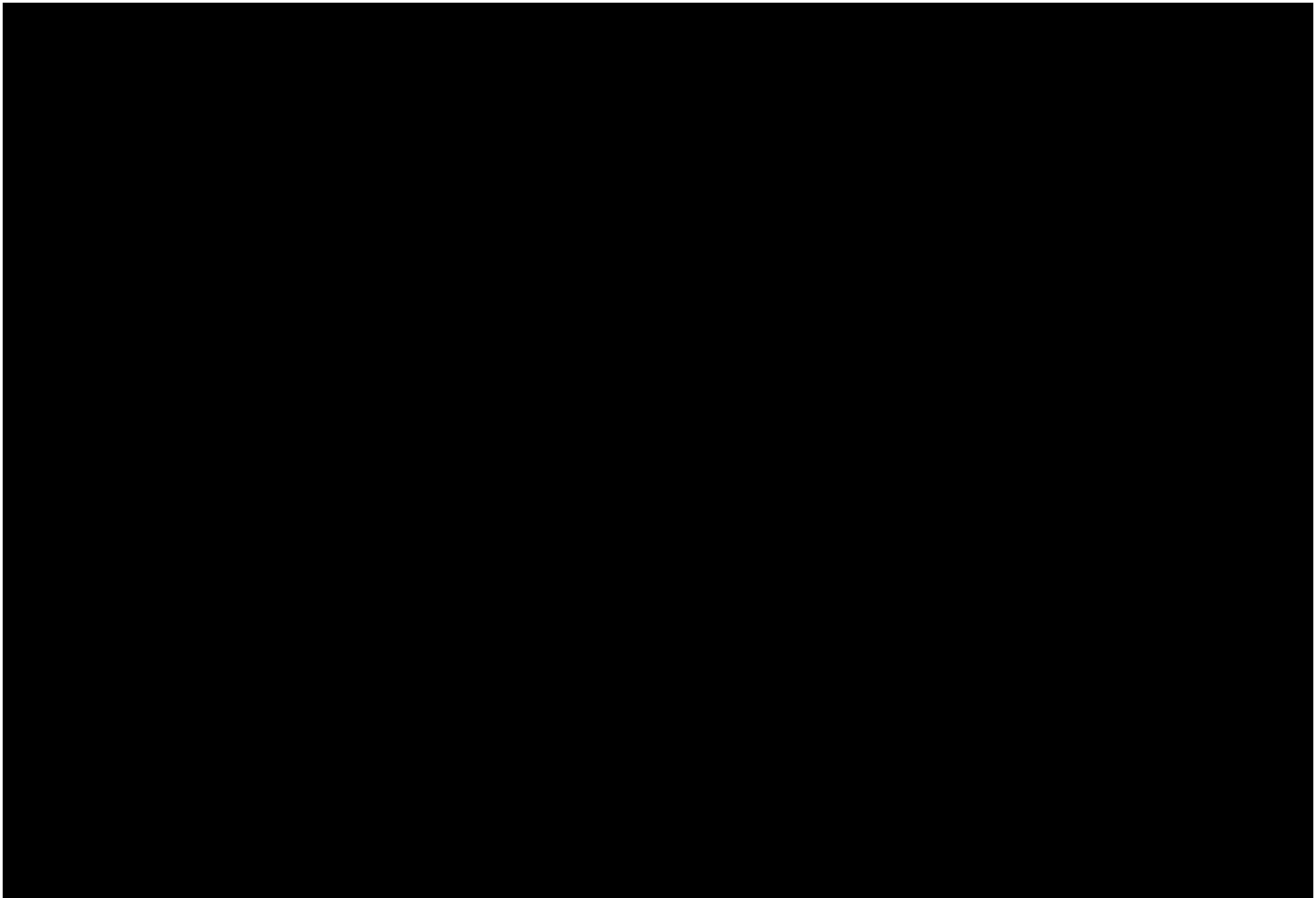
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Mountain View Electric Association, Inc.

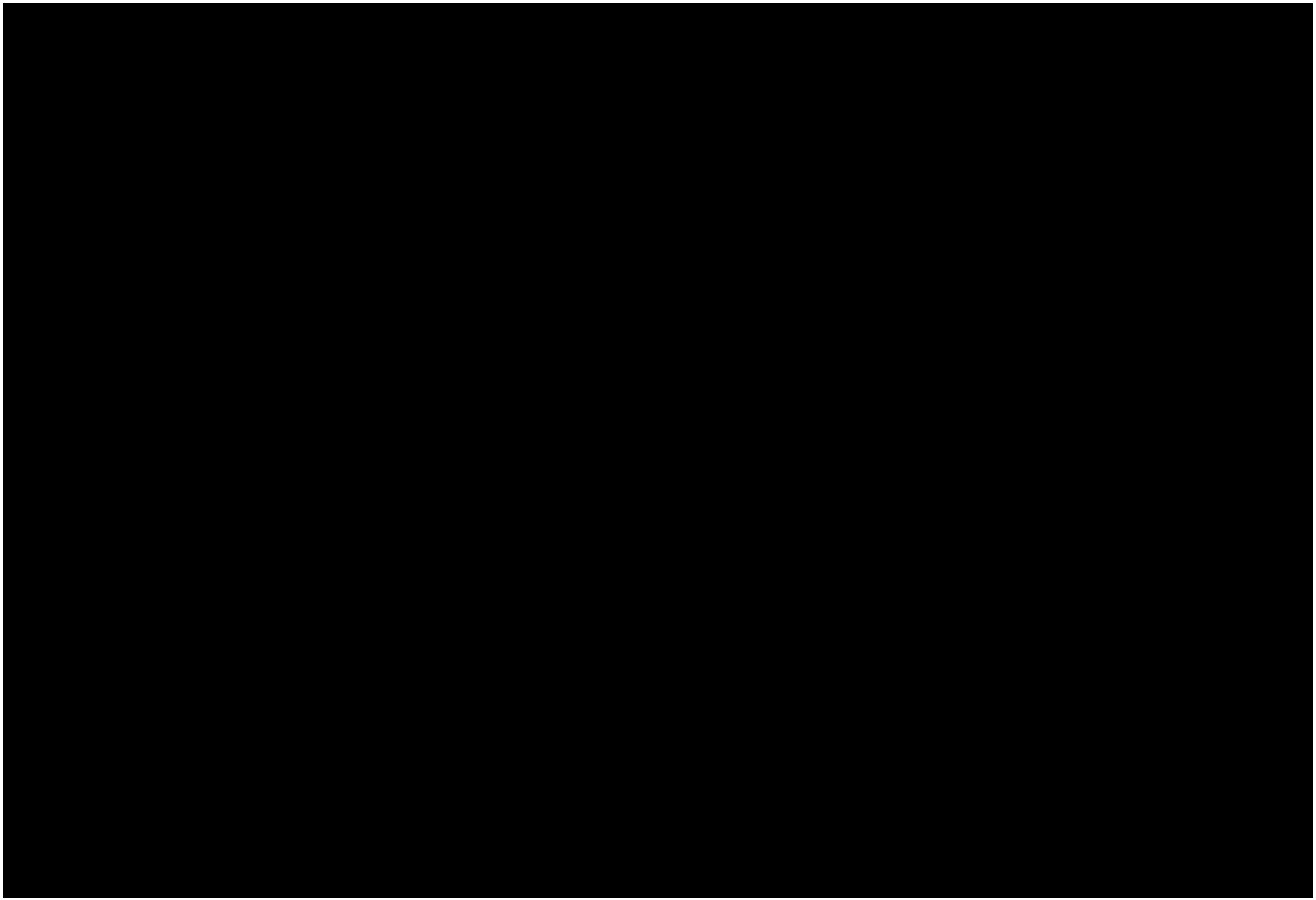
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

Mountain View Electric Association, Inc.

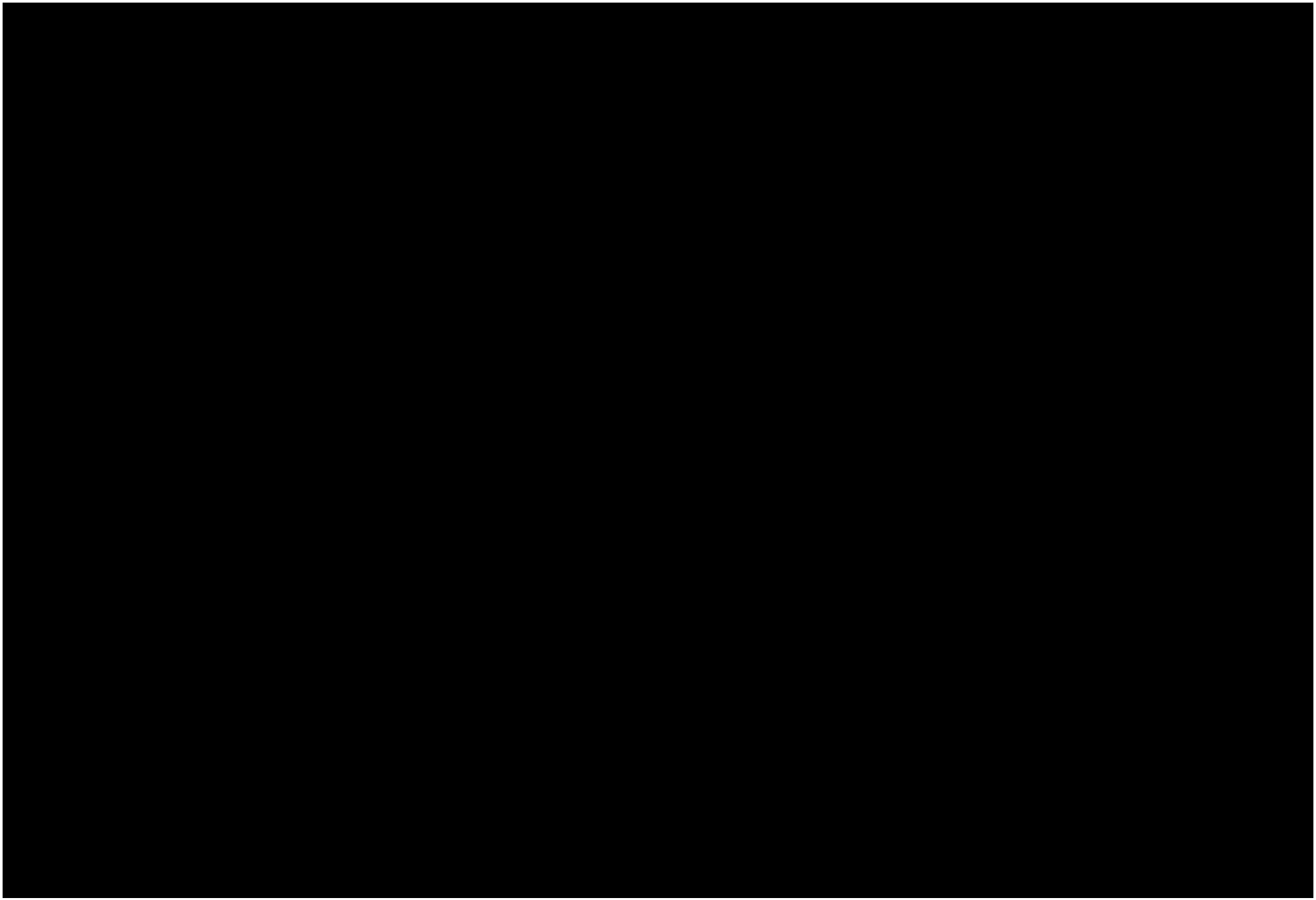
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Mountain View Electric Association, Inc.

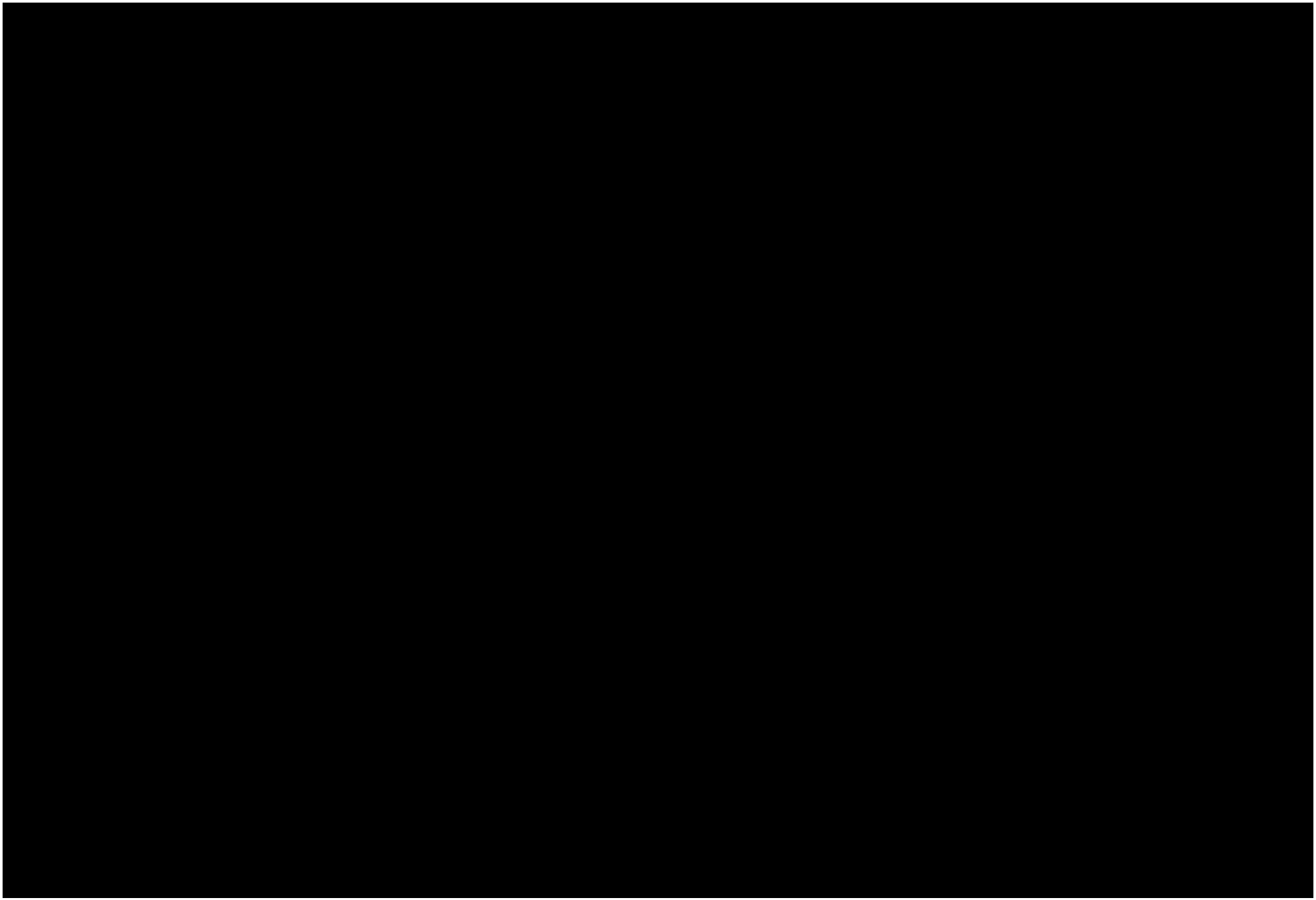
Date of Off Peak Day - 09/18/2021



Member Forecasted Off Peak Demand Day for October 2021

Mountain View Electric Association, Inc.

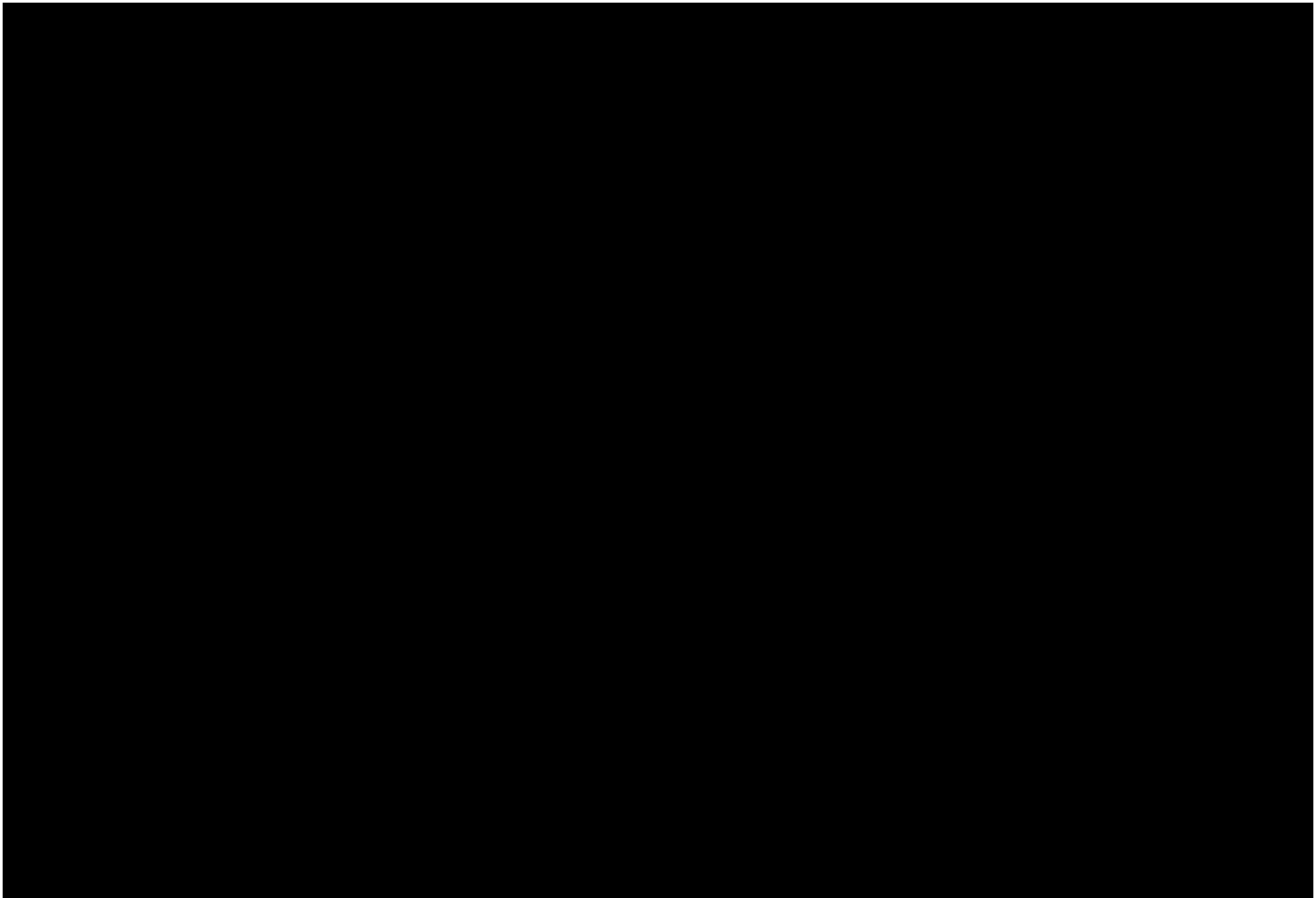
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Mountain View Electric Association, Inc.

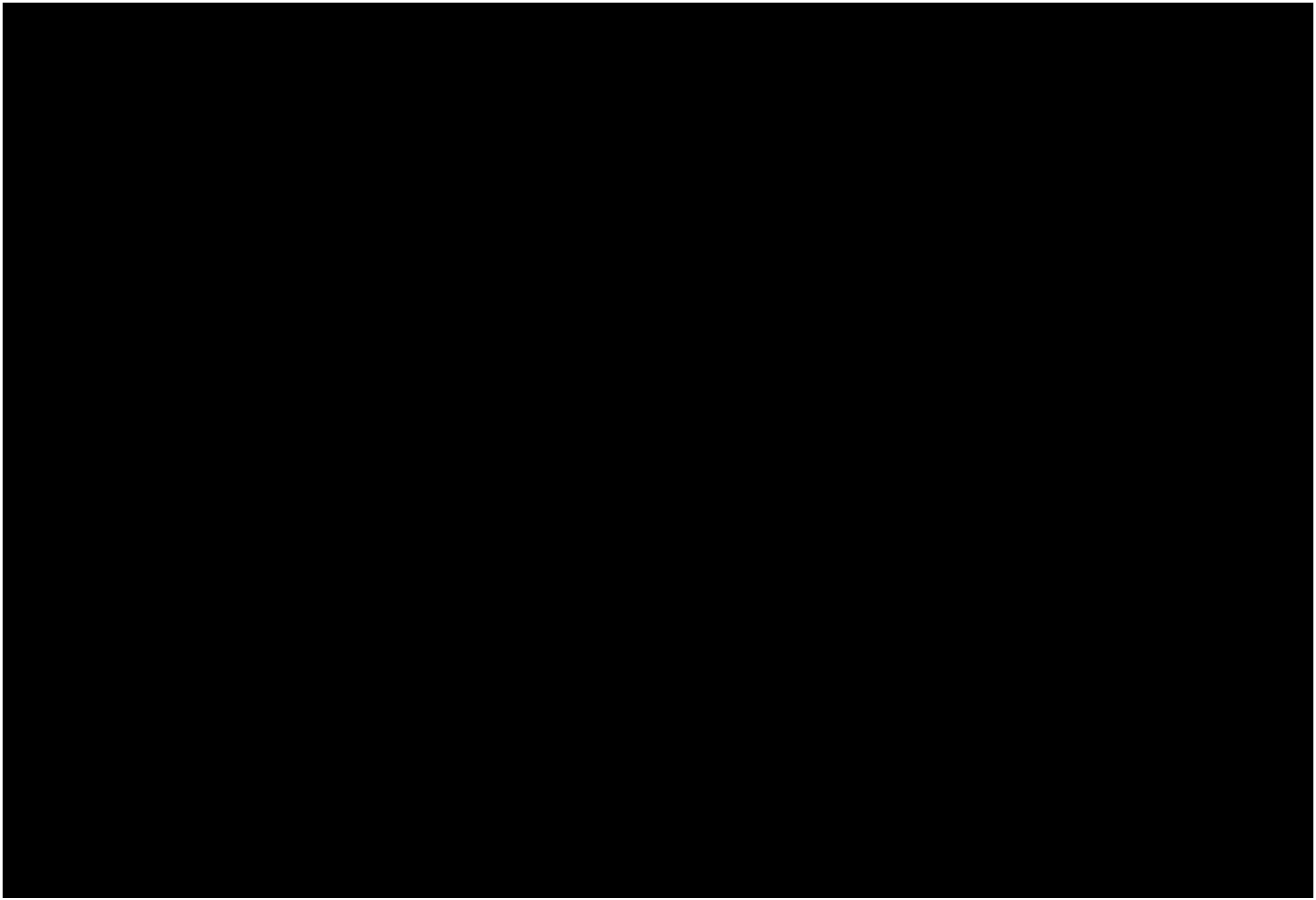
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Mountain View Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



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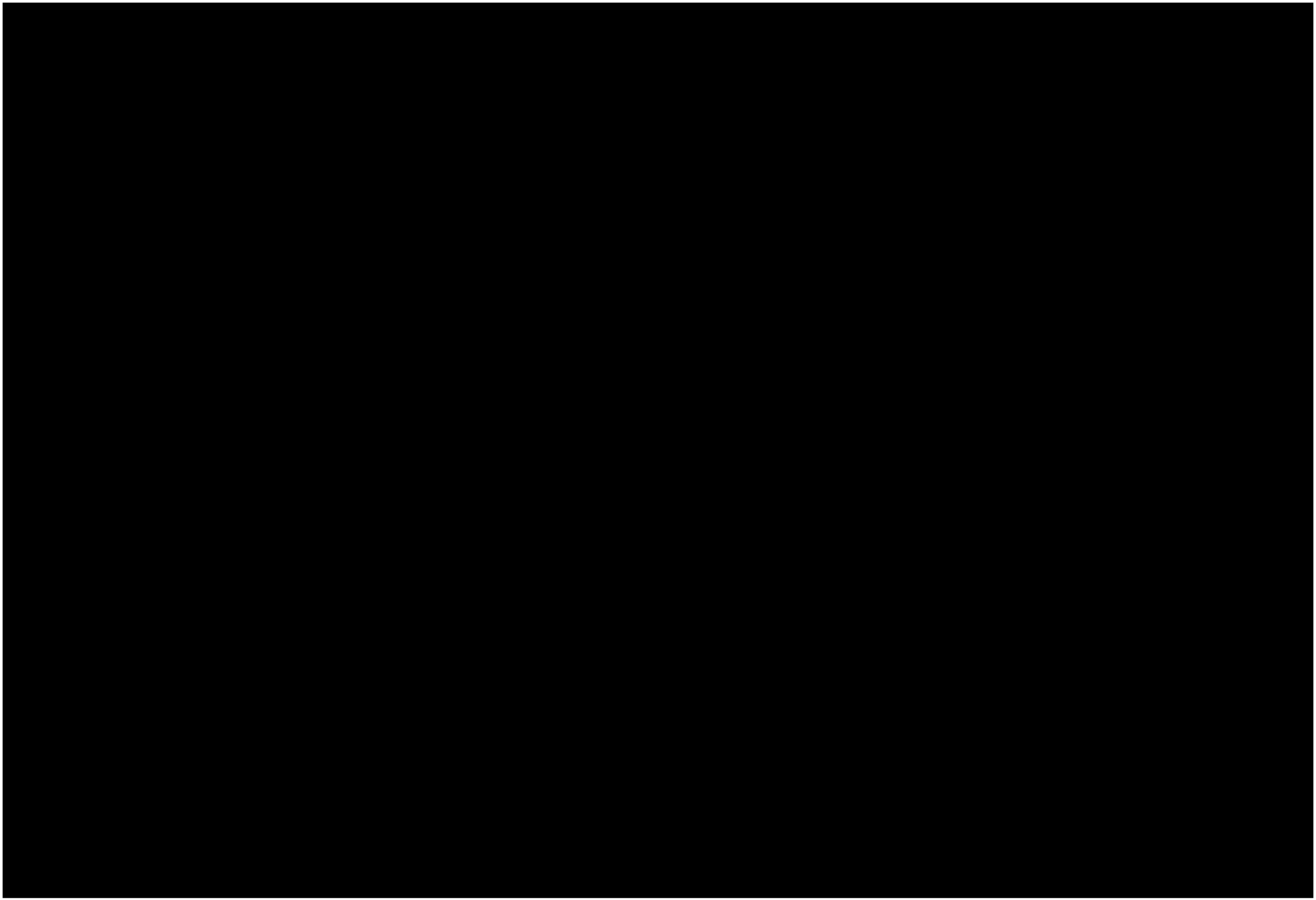
Member Forecasted Off Peak Demand Day for January 2021

Midwest Electric Cooperative Corporation

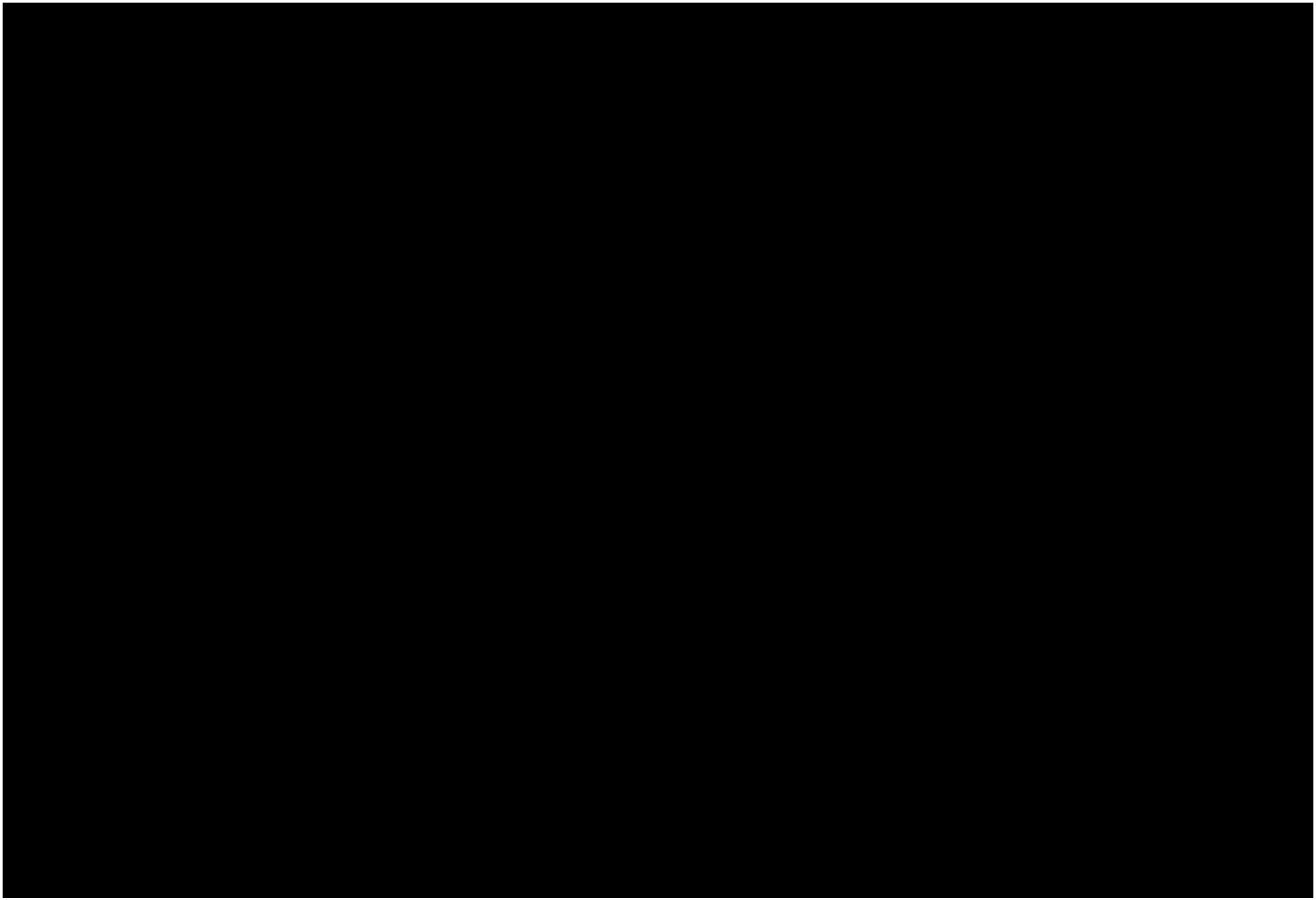
Date of Off Peak Day - 01/30/2021



Member Forecasted Off Peak Demand Day for February 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 02/16/2021



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Member Forecasted Off Peak Demand Day for March 2021

Midwest Electric Cooperative Corporation

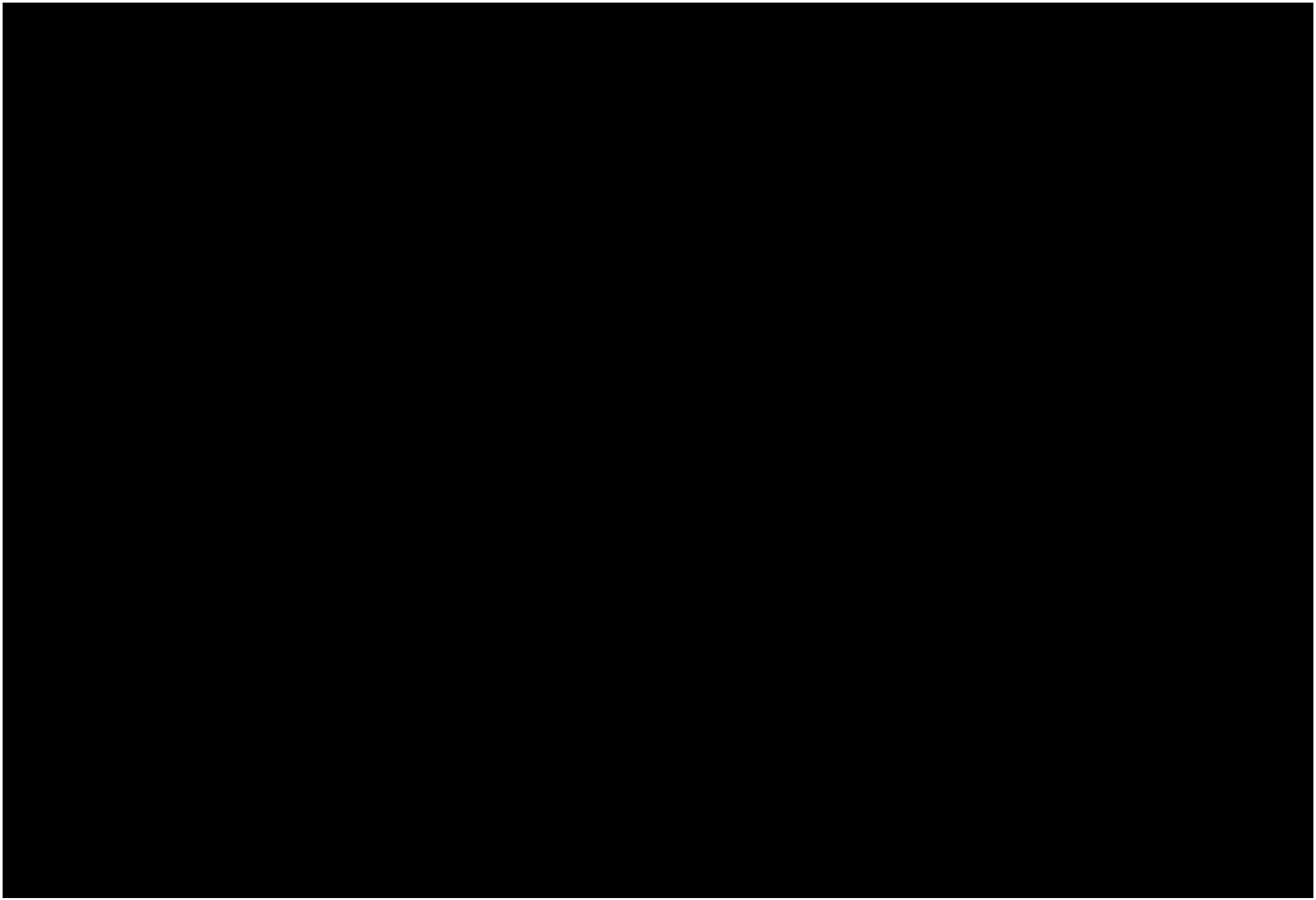
Date of Off Peak Day - 03/29/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 04/23/2021



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Member Forecasted Off Peak Demand Day for May 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 05/02/2021

[redacted]

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Member Forecasted Off Peak Demand Day for June 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 06/08/2021

[redacted]

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Member Forecasted Off Peak Demand Day for July 2021

Midwest Electric Cooperative Corporation

Date of Off Peak Day - 07/03/2021

[redacted]

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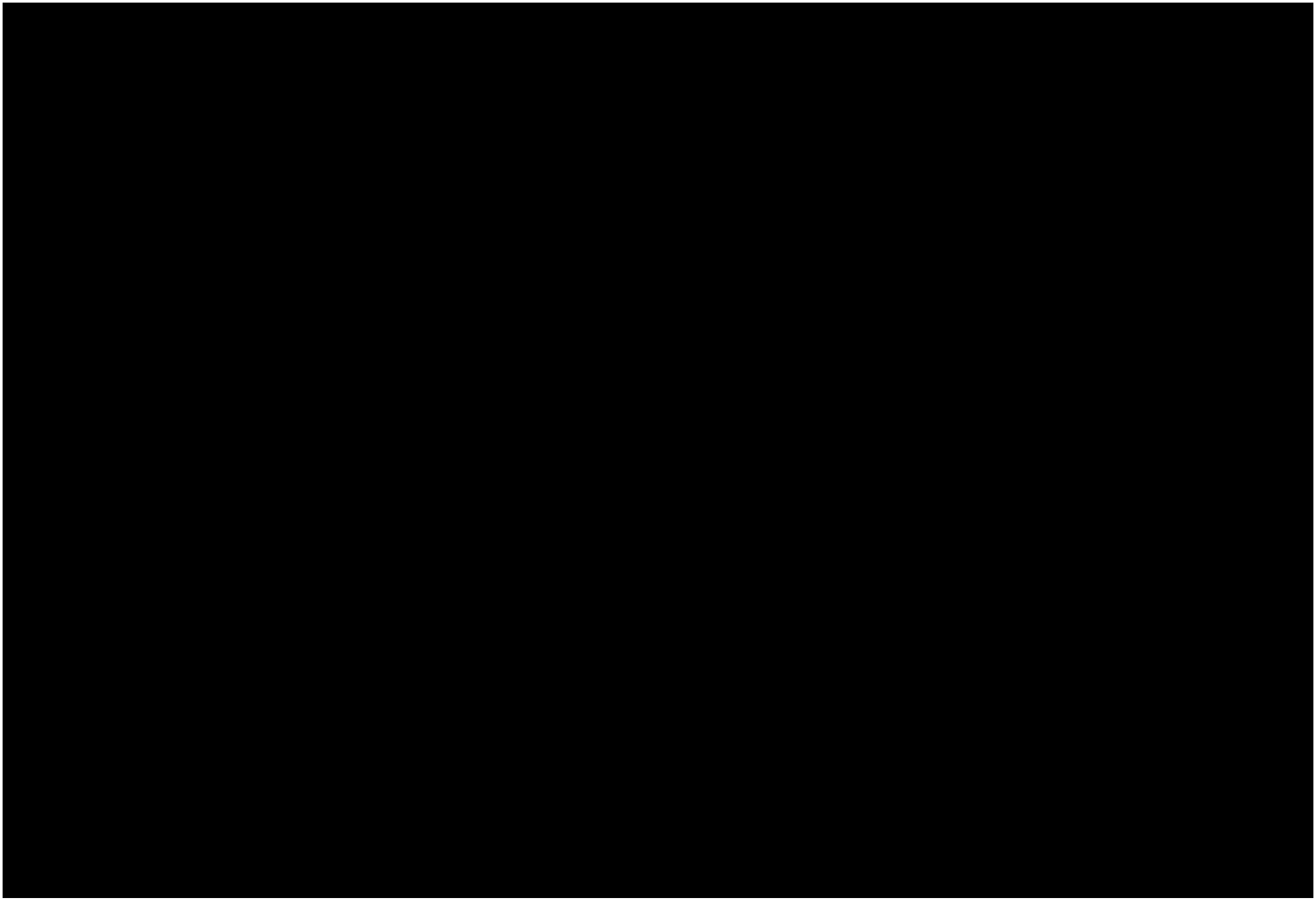
Member Forecasted Off Peak Demand Day for August 2021

Midwest Electric Cooperative Corporation

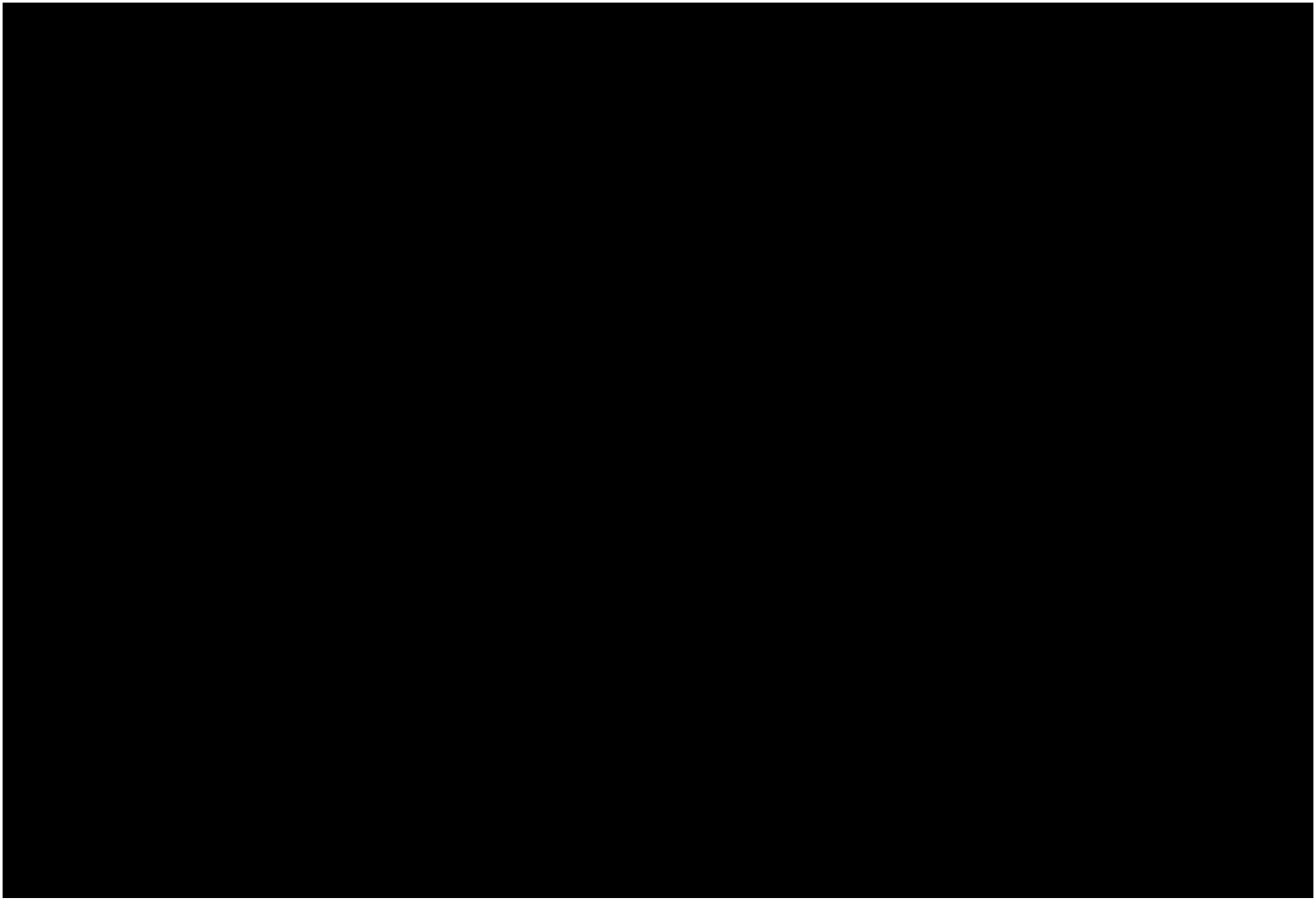
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

Midwest Electric Cooperative Corporation

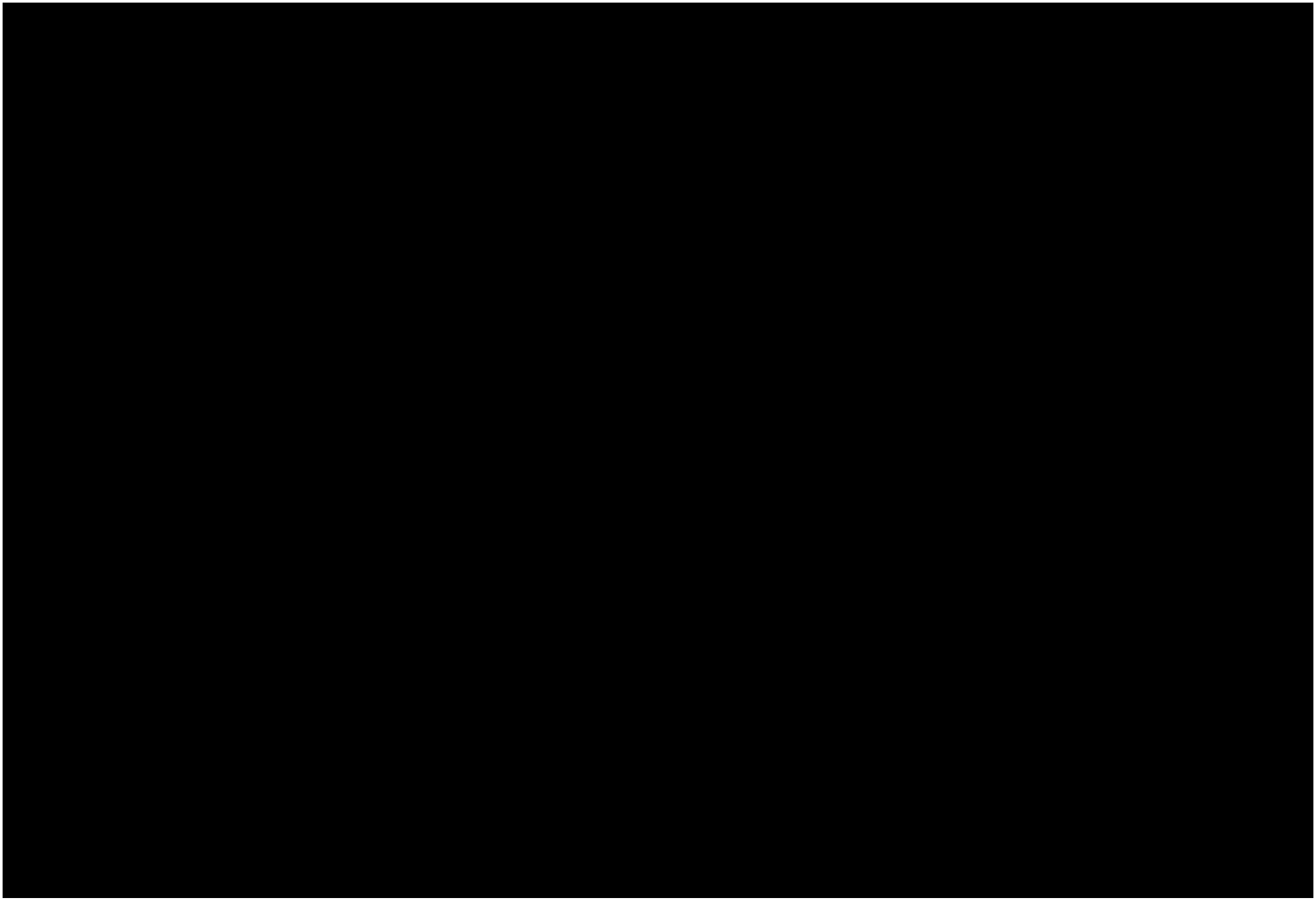
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Midwest Electric Cooperative Corporation

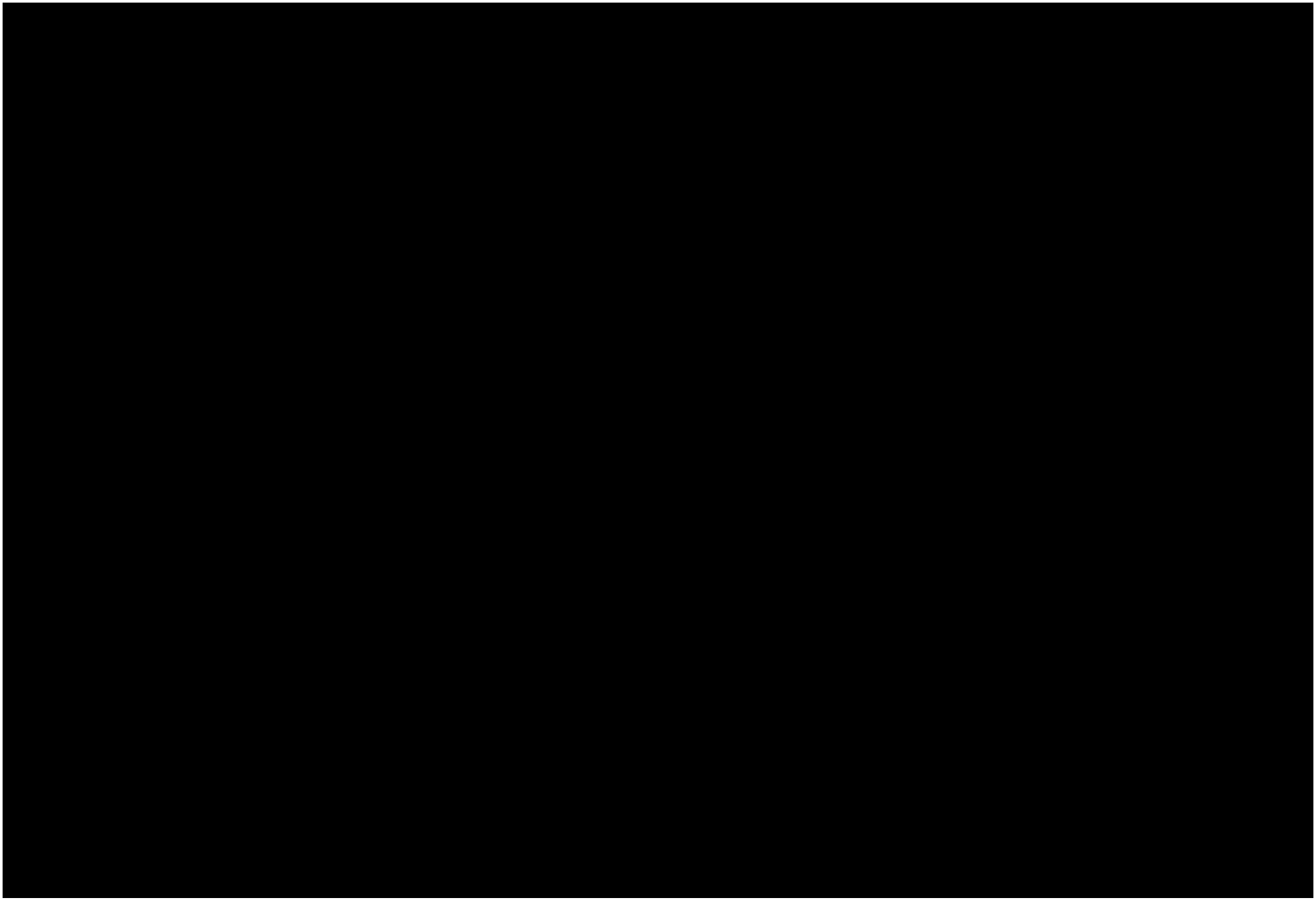
Date of Off Peak Day - 10/07/2021



Member Forecasted Off Peak Demand Day for November 2021

Midwest Electric Cooperative Corporation

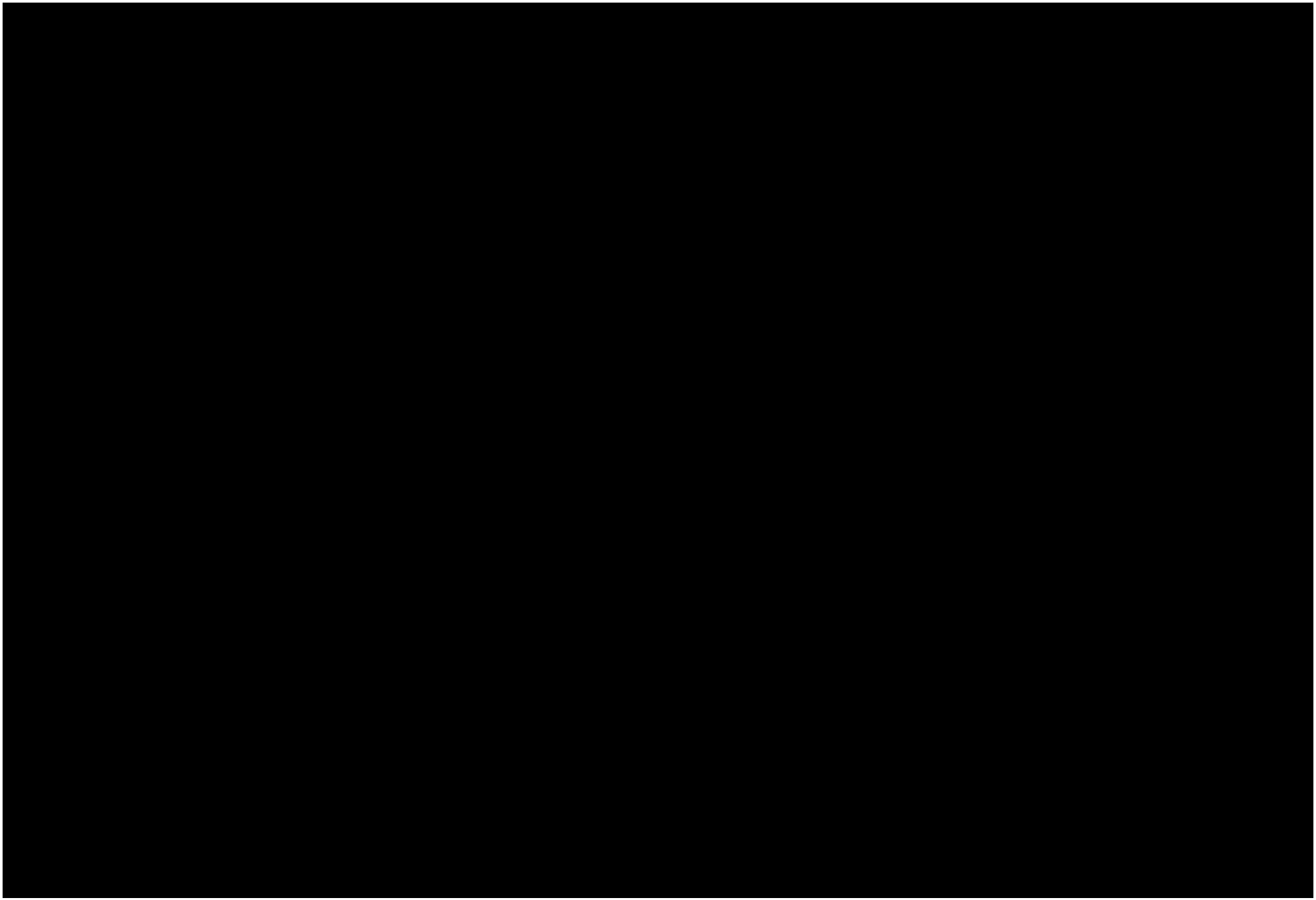
Date of Off Peak Day - 11/30/2021



Member Forecasted Off Peak Demand Day for December 2021

Midwest Electric Cooperative Corporation

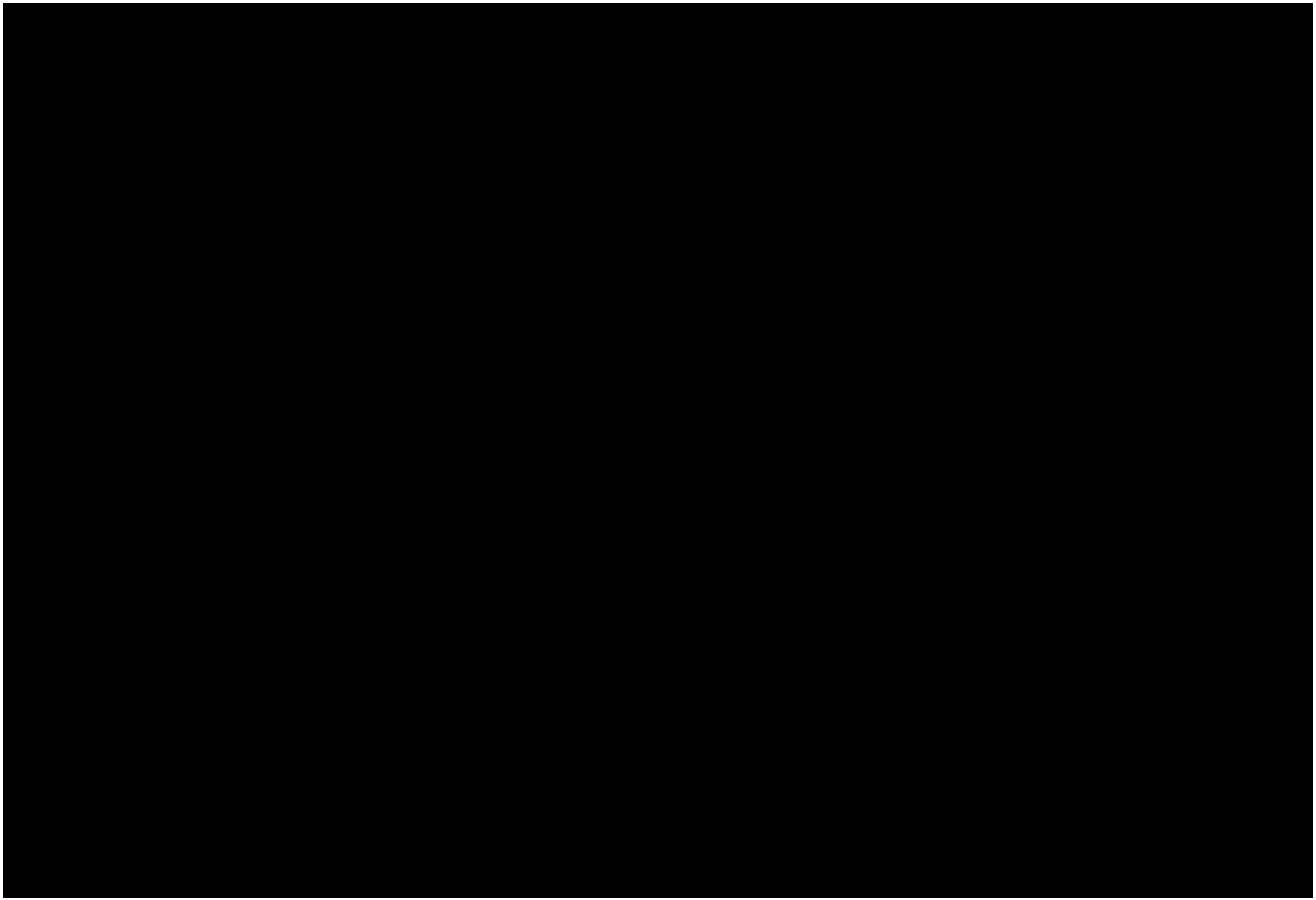
Date of Off Peak Day - 12/06/2021



Member Forecasted Off Peak Demand Day for January 2021

Niobrara Electric Association, Inc.

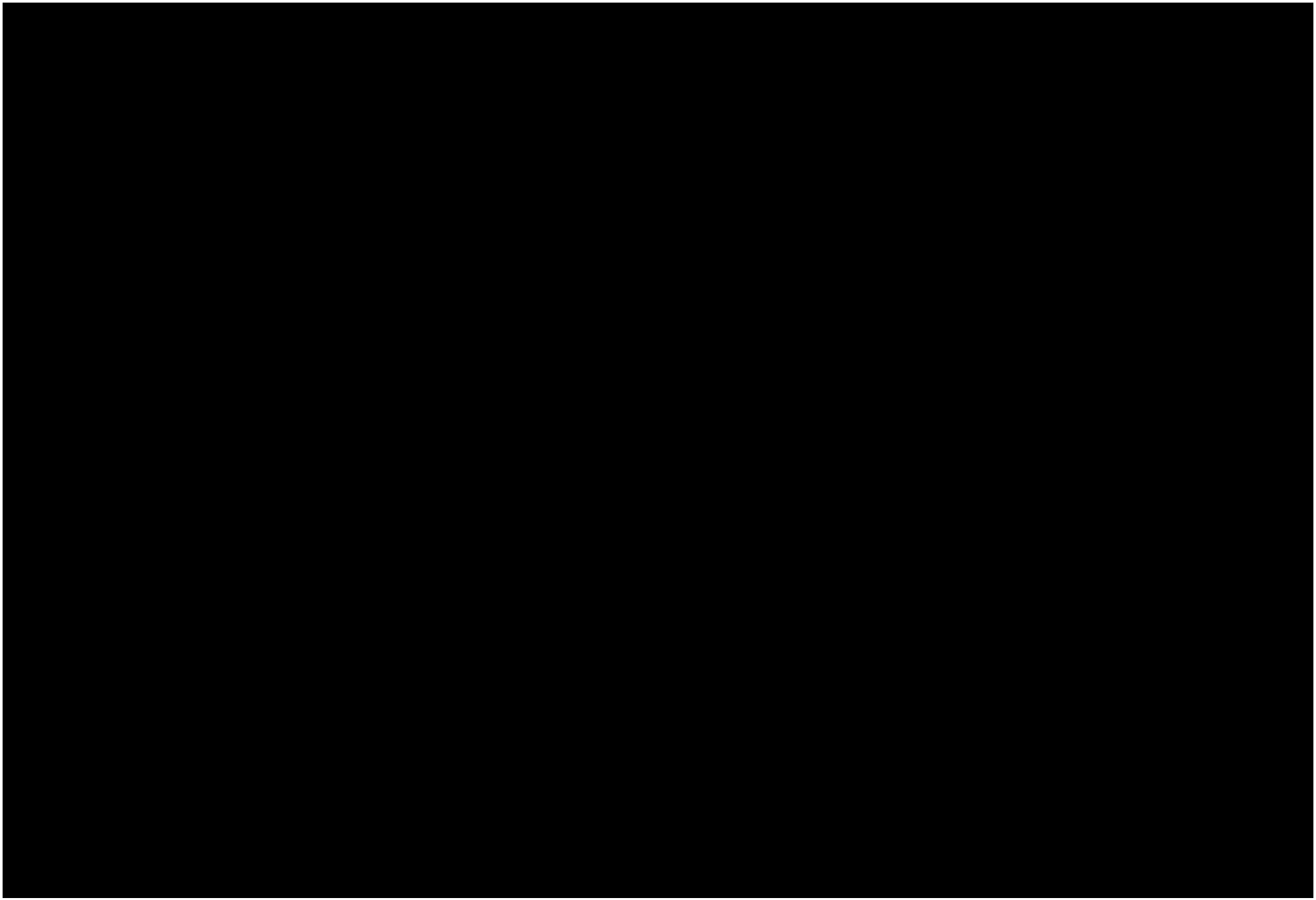
Date of Off Peak Day - 01/10/2021



Member Forecasted Off Peak Demand Day for February 2021

Niobrara Electric Association, Inc.

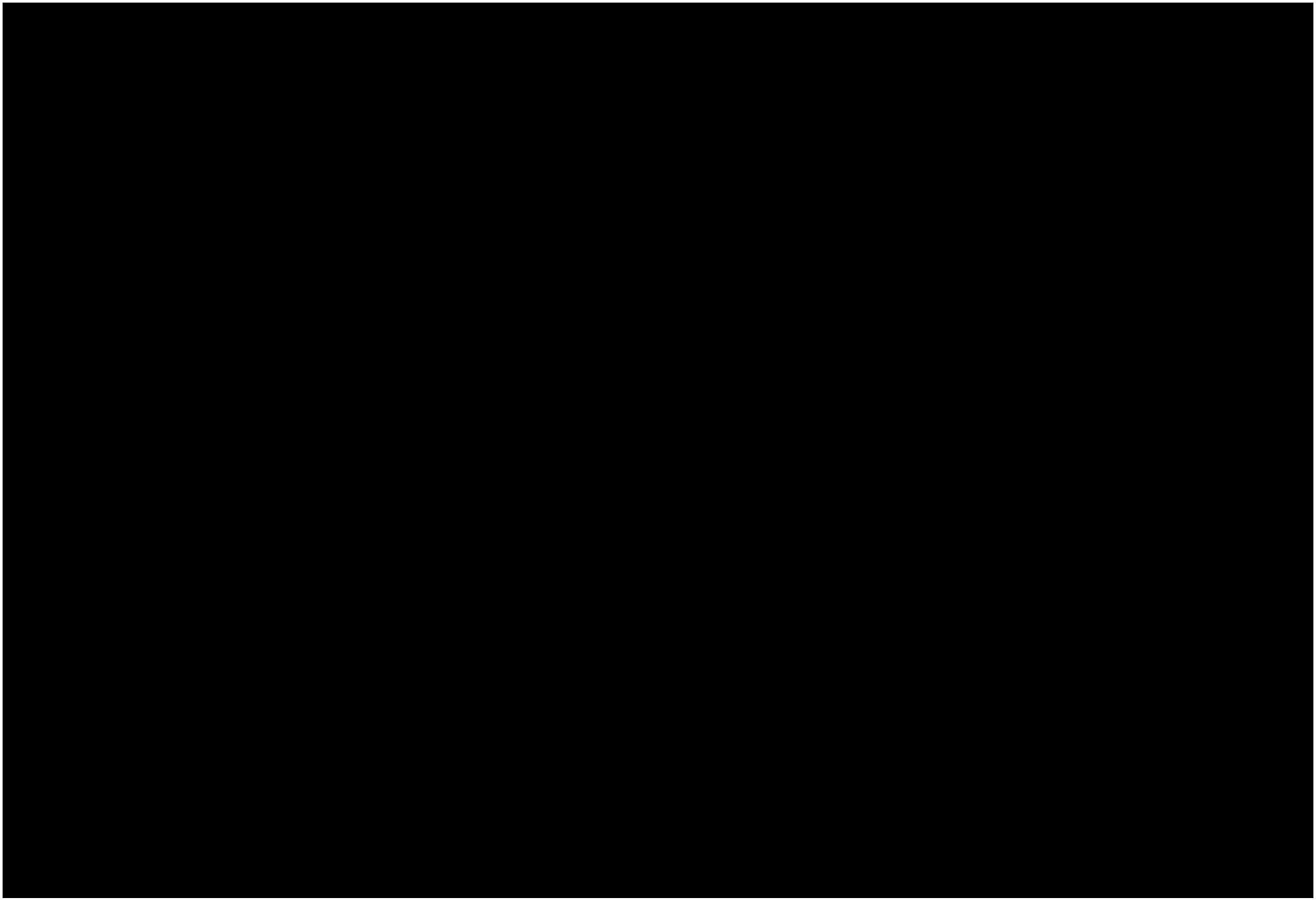
Date of Off Peak Day - 02/21/2021



Member Forecasted Off Peak Demand Day for March 2021

Niobrara Electric Association, Inc.

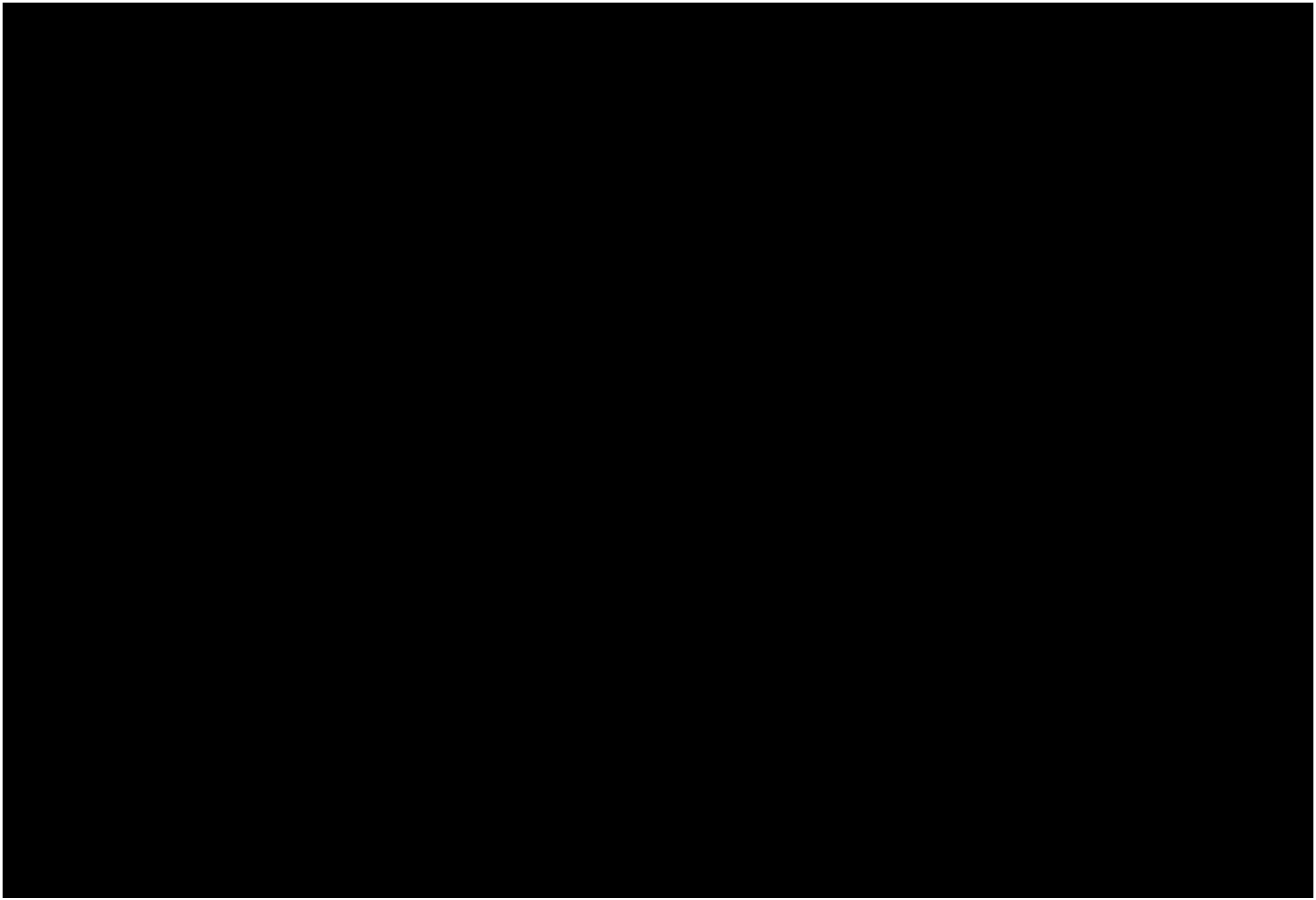
Date of Off Peak Day - 03/15/2021



Member Forecasted Off Peak Demand Day for April 2021

Niobrara Electric Association, Inc.

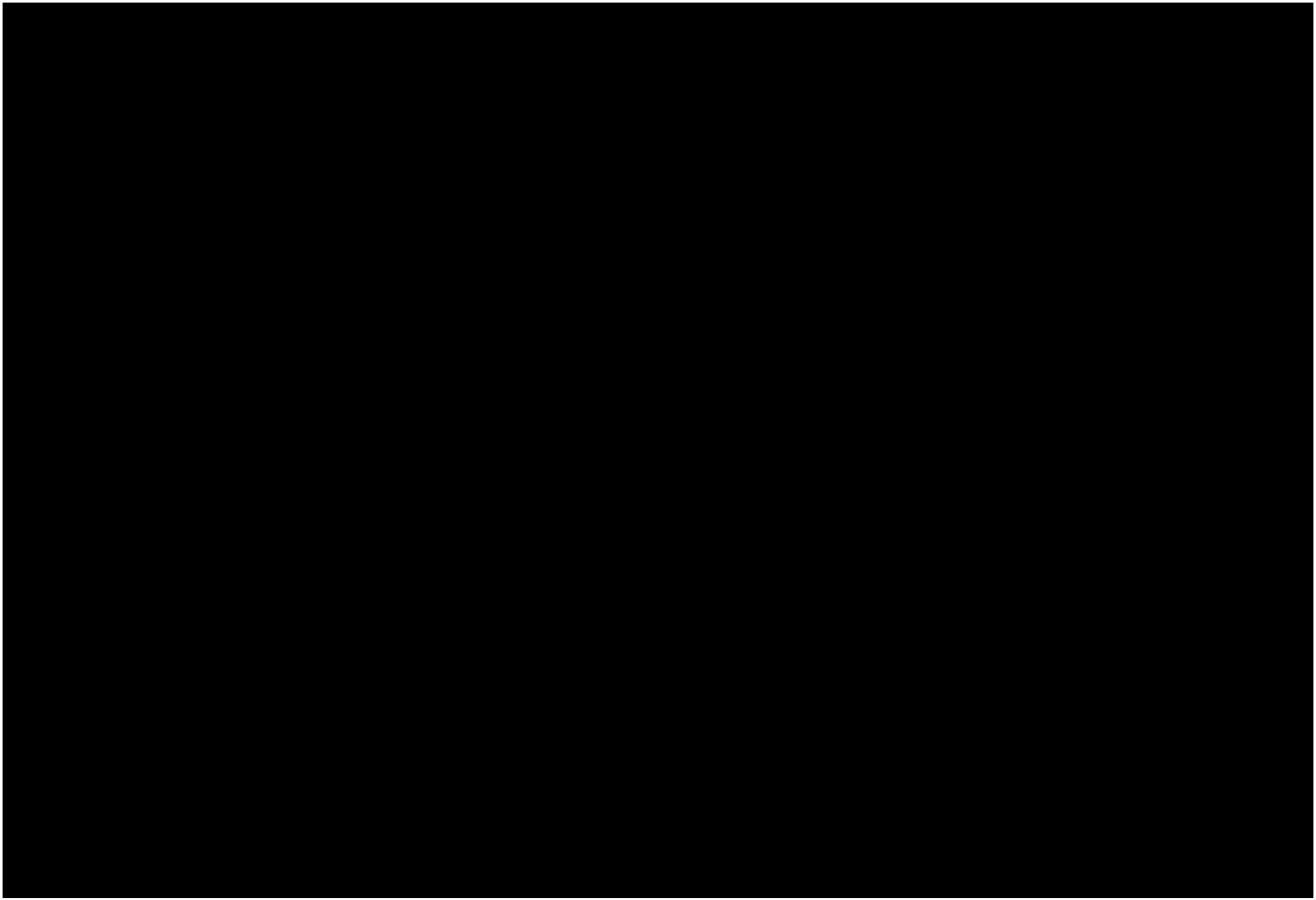
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Niobrara Electric Association, Inc.

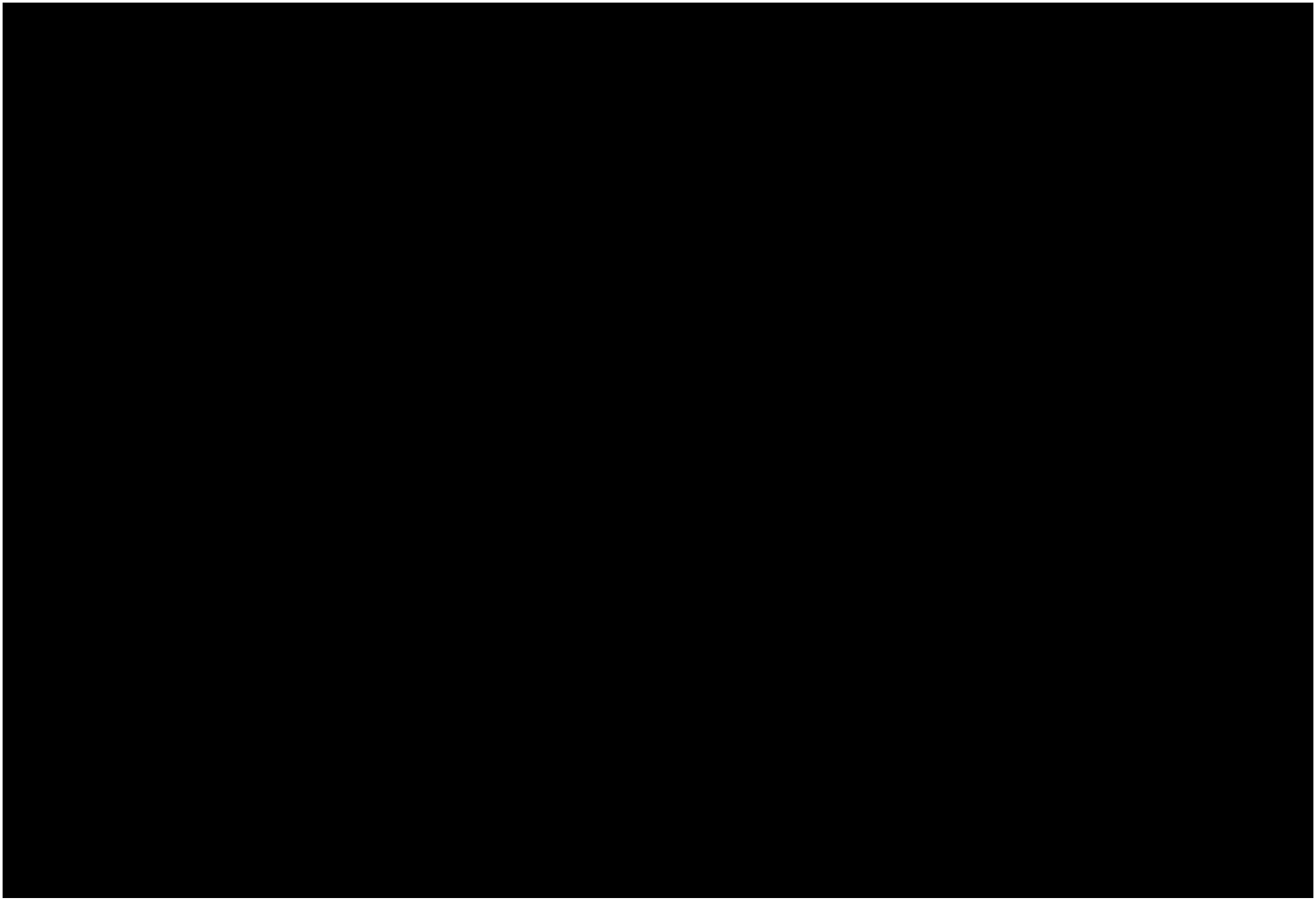
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Niobrara Electric Association, Inc.

Date of Off Peak Day - 06/19/2021



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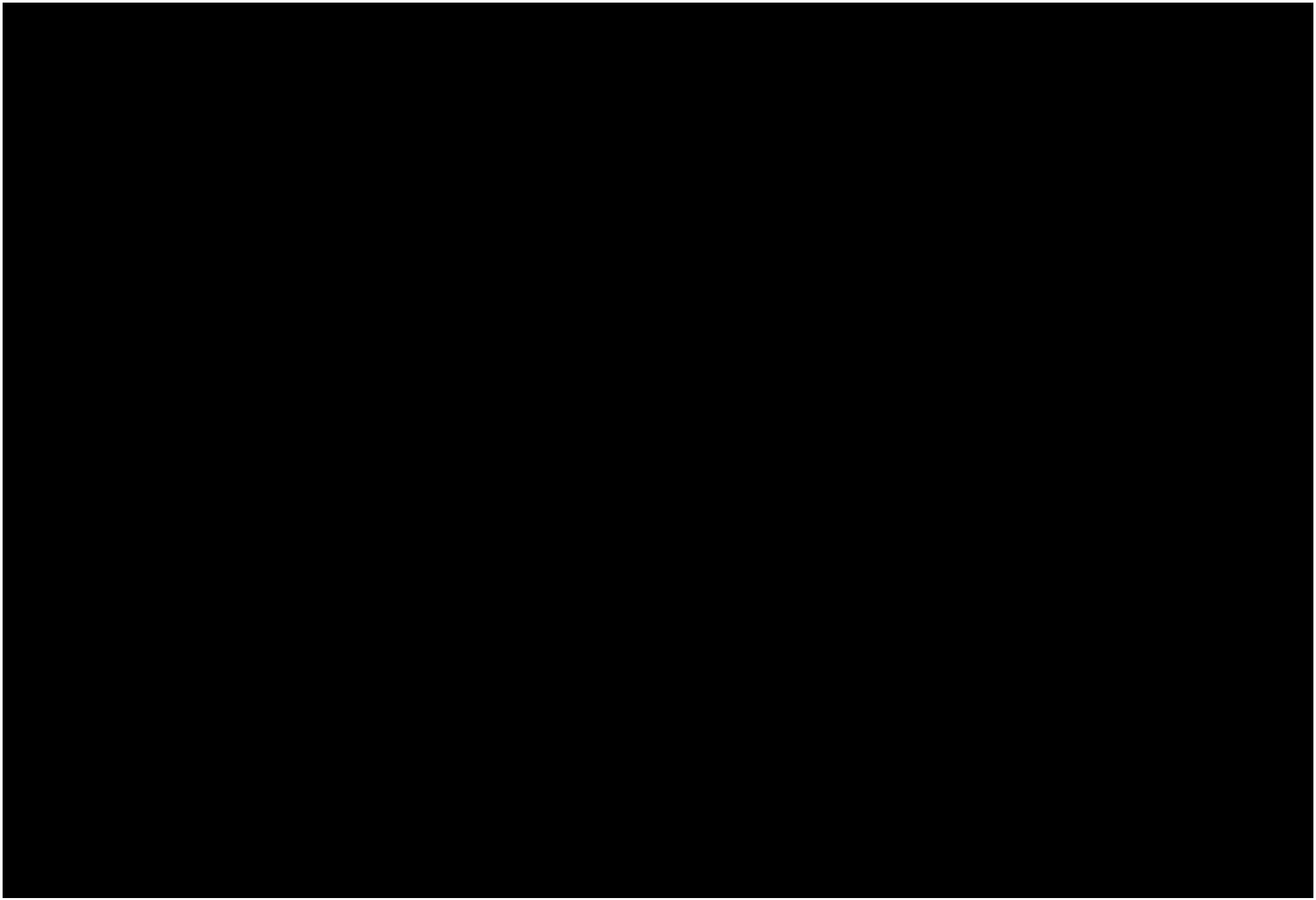
Member Forecasted Off Peak Demand Day for July 2021

Niobrara Electric Association, Inc.

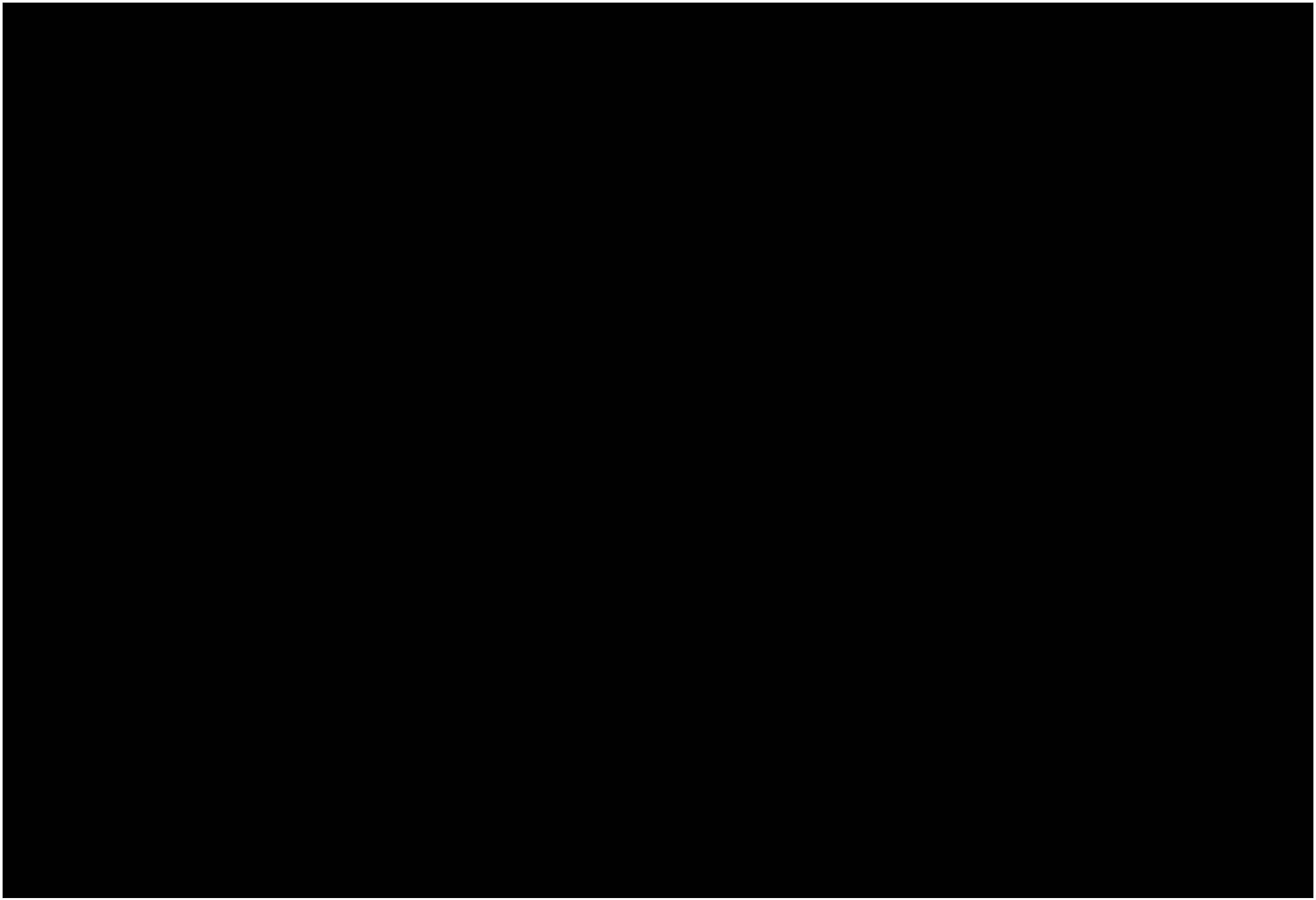
Date of Off Peak Day - 07/29/2021



Member Forecasted Off Peak Demand Day for August 2021

Niobrara Electric Association, Inc.

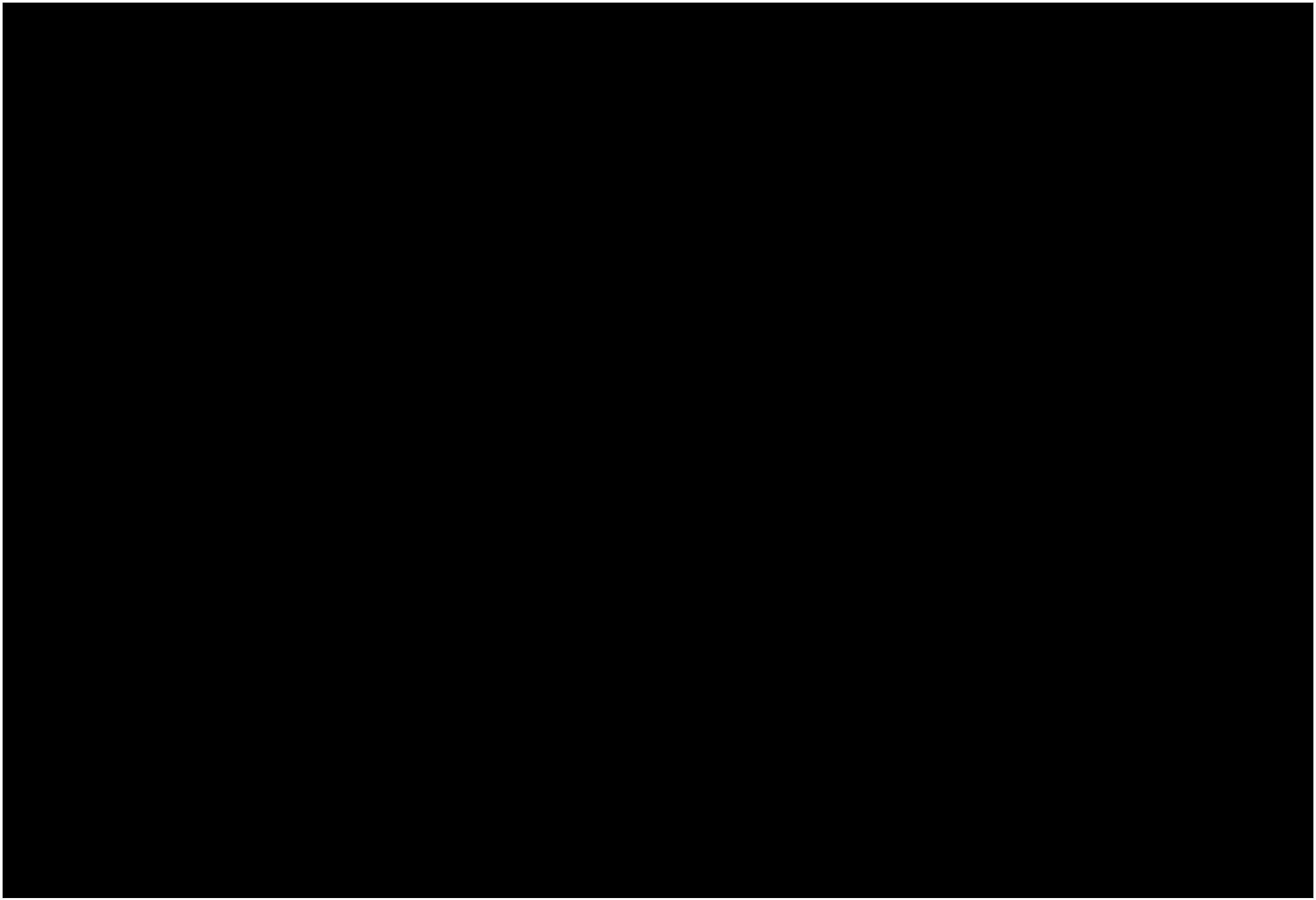
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Niobrara Electric Association, Inc.

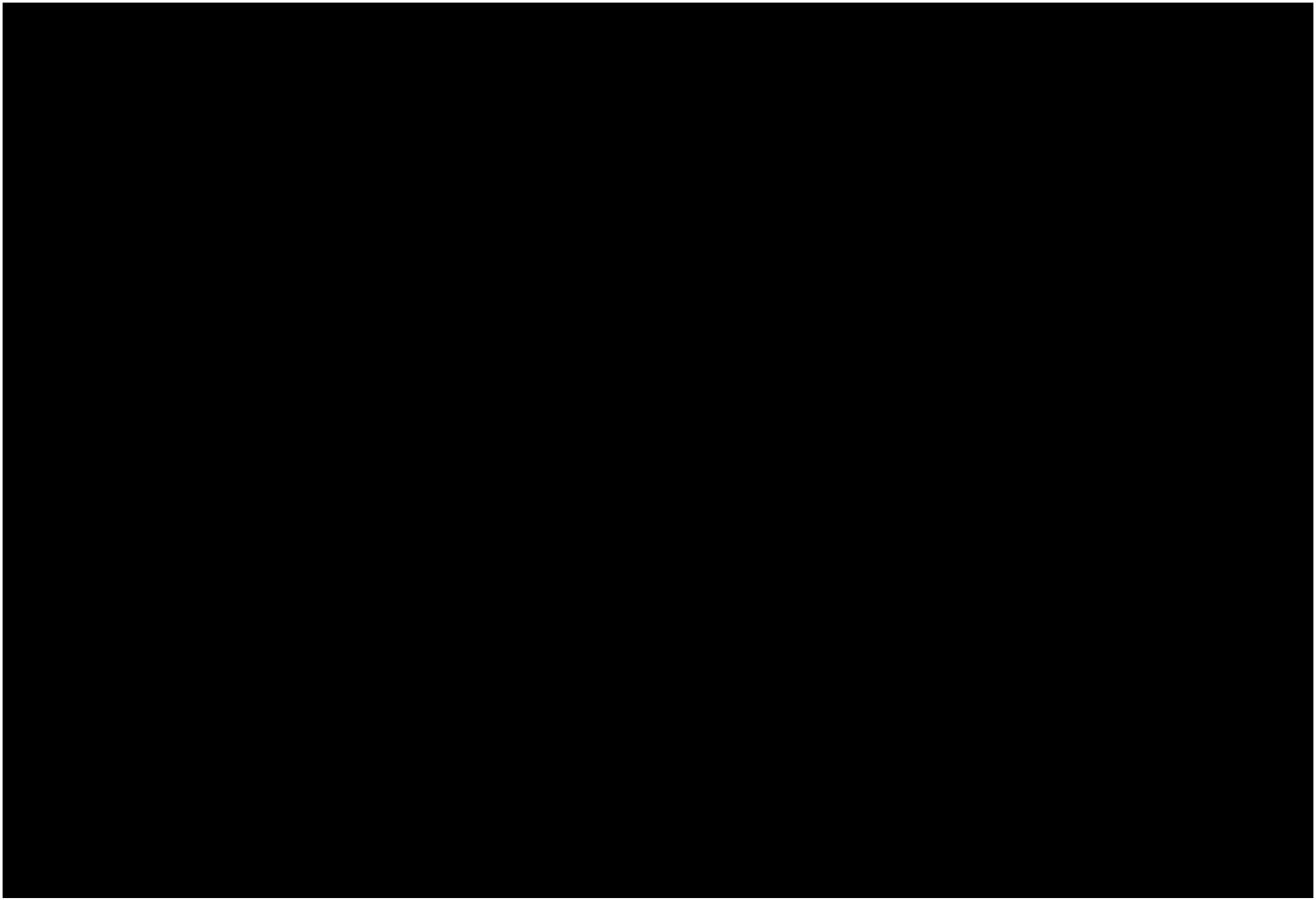
Date of Off Peak Day - 09/01/2021



Member Forecasted Off Peak Demand Day for October 2021

Niobrara Electric Association, Inc.

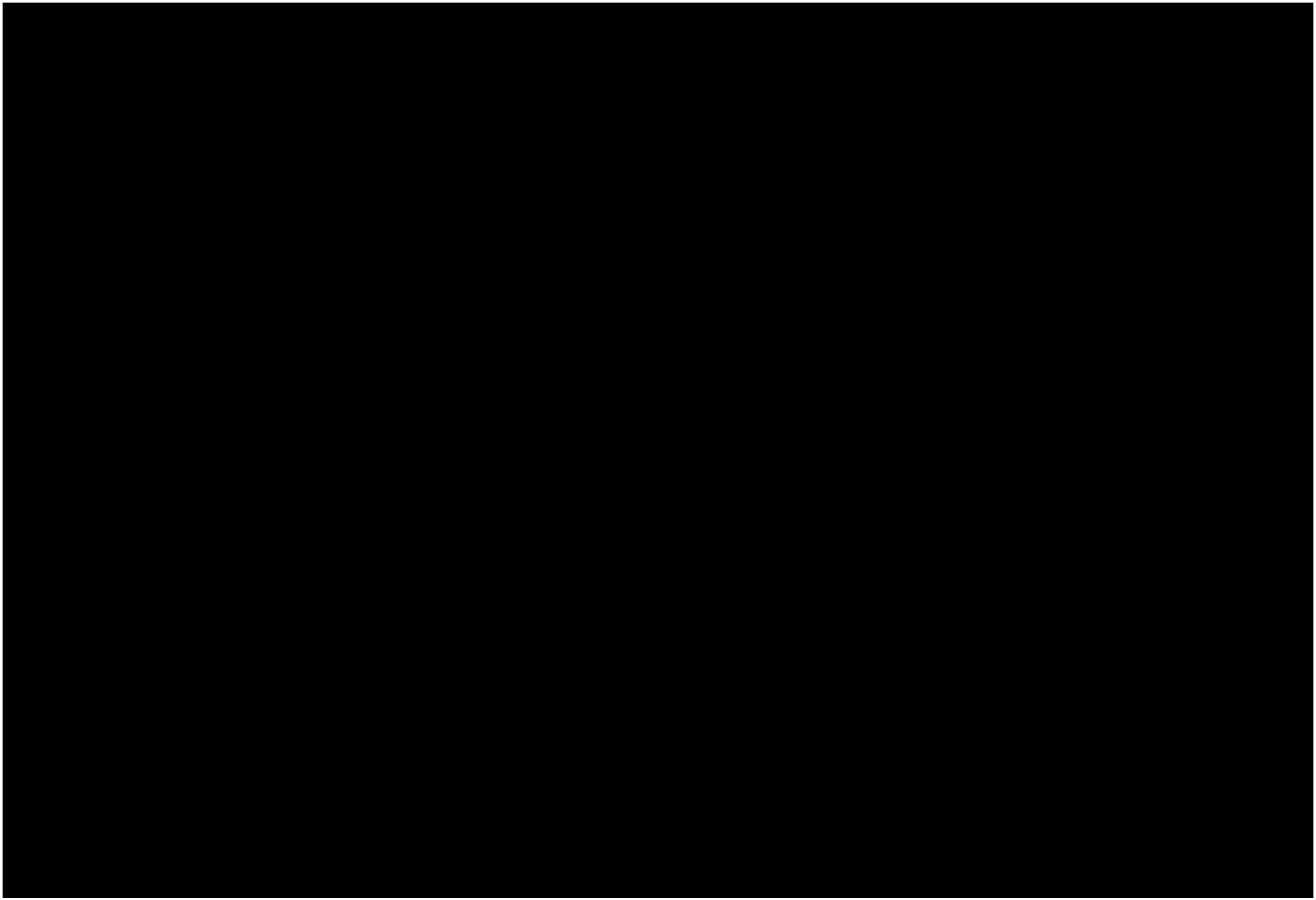
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Niobrara Electric Association, Inc.

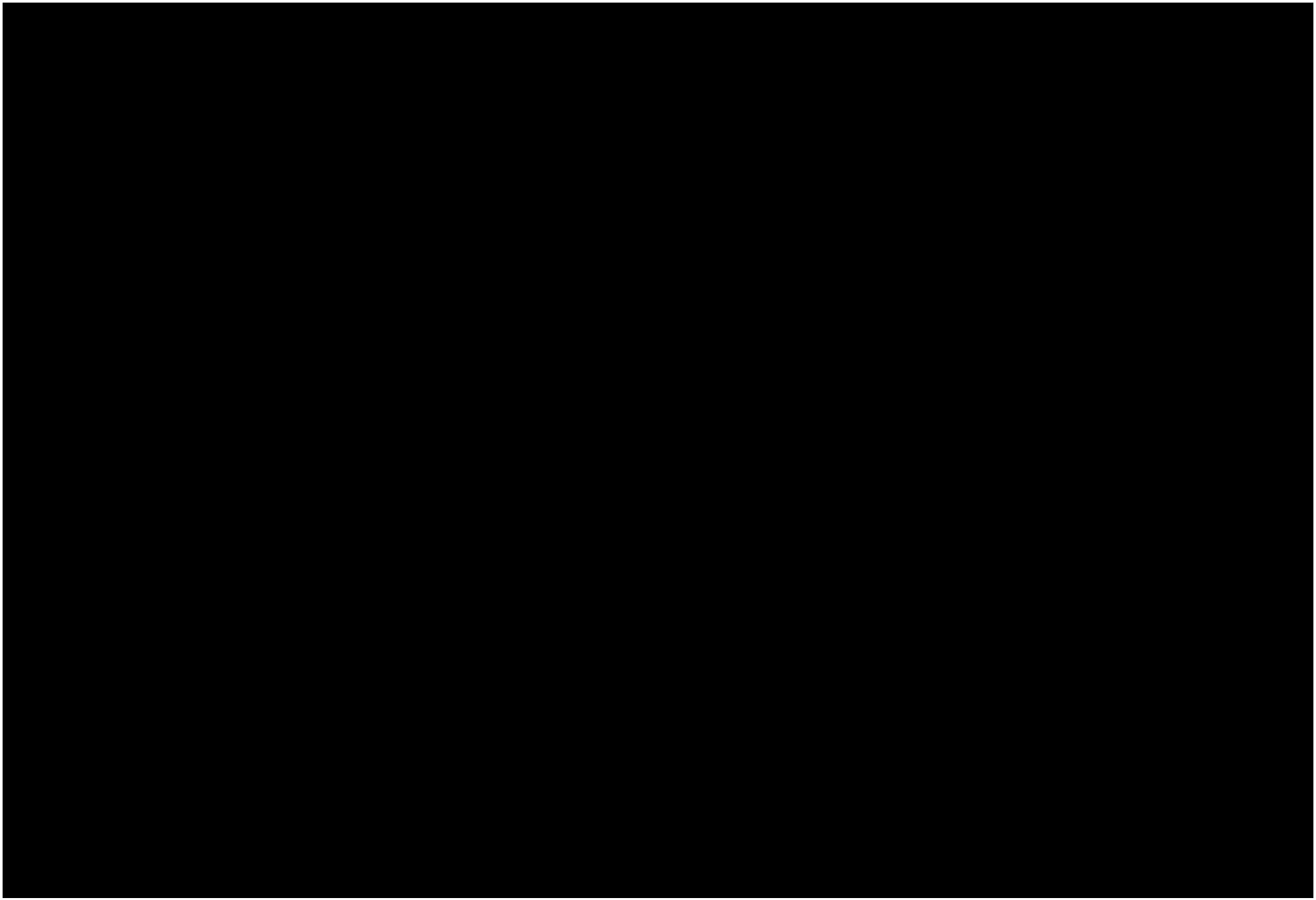
Date of Off Peak Day - 11/15/2021



Member Forecasted Off Peak Demand Day for December 2021

Niobrara Electric Association, Inc.

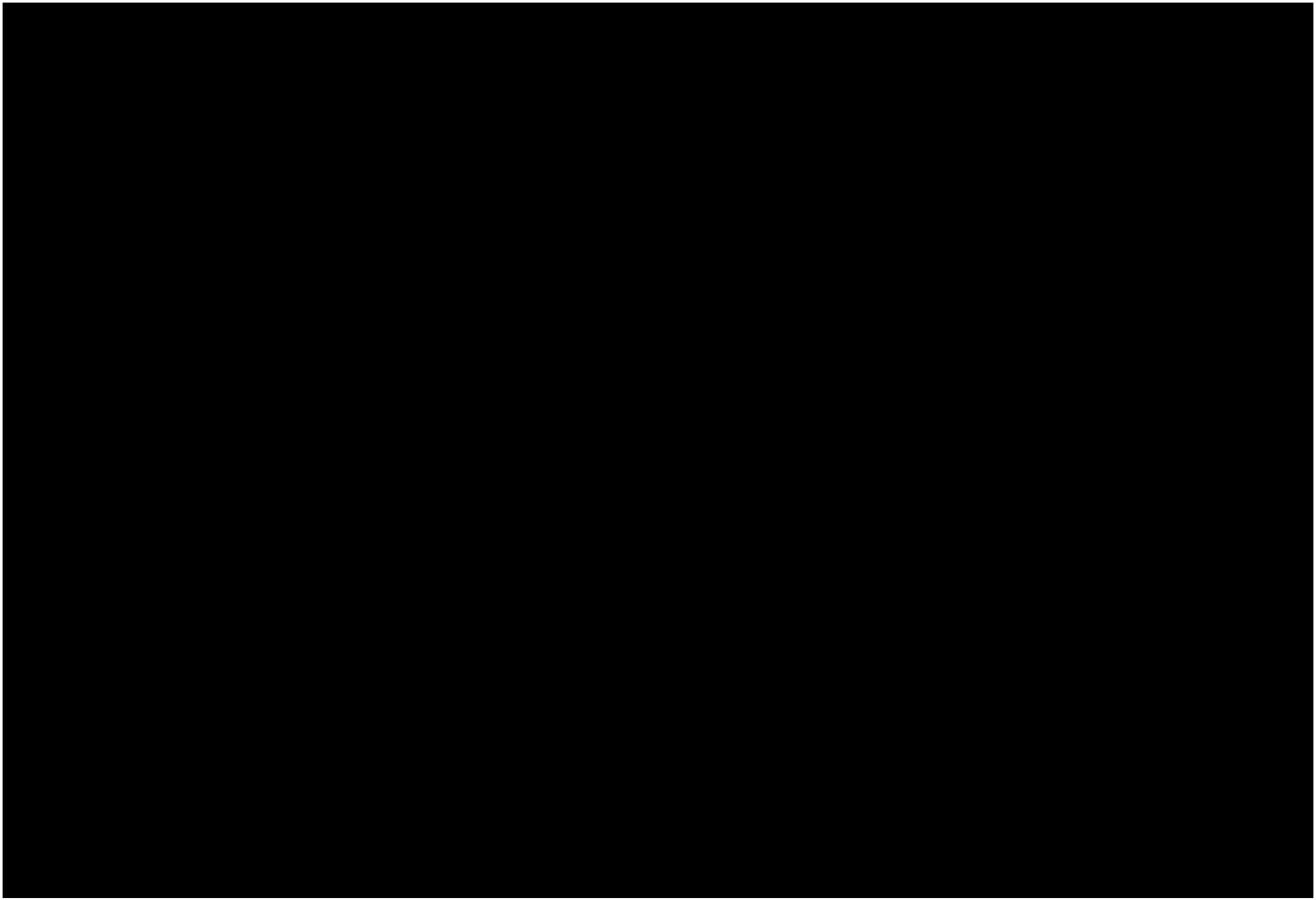
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Northwest Rural Public Power District

Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Northwest Rural Public Power District

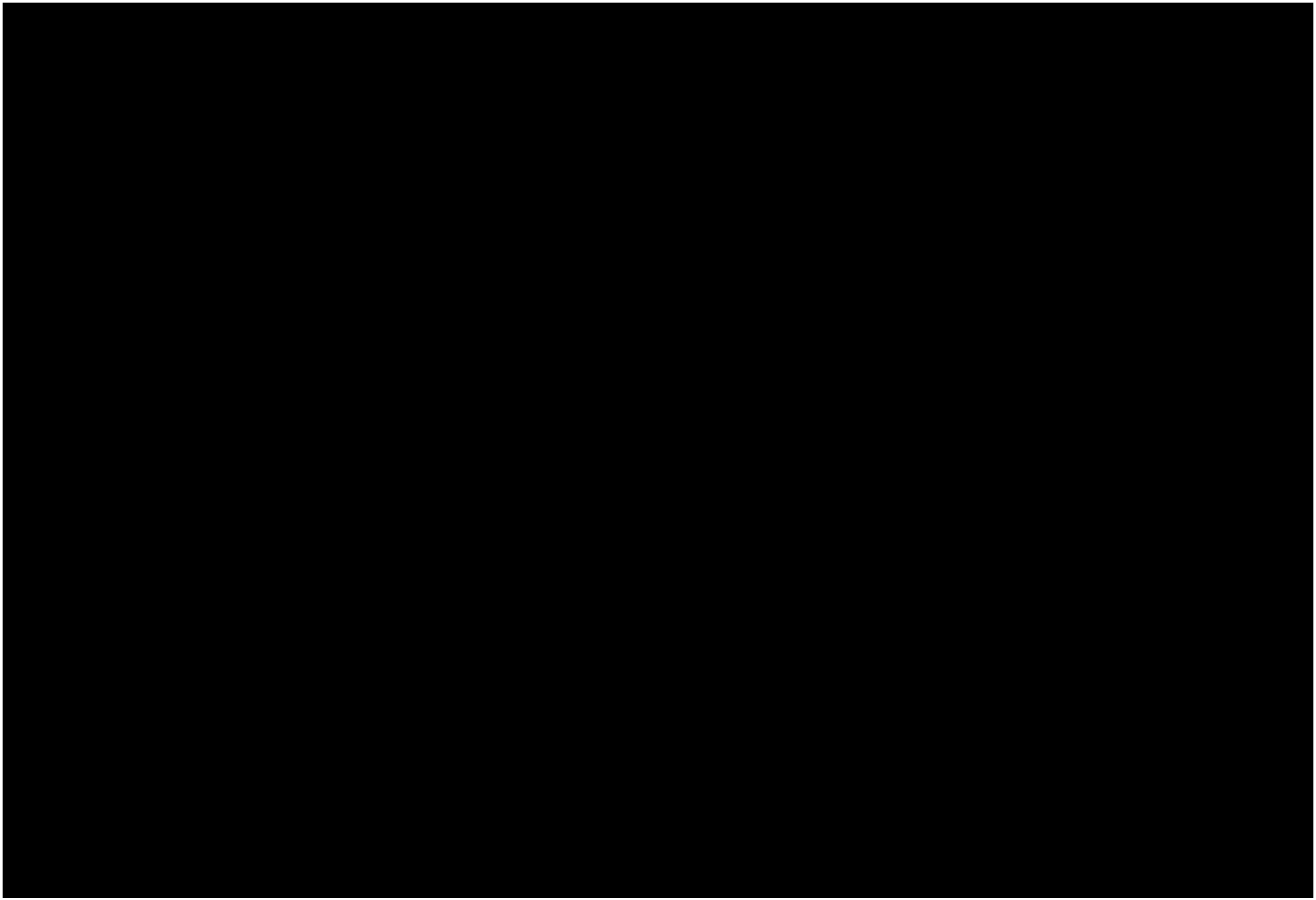
Date of Off Peak Day - 02/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for March 2021

Northwest Rural Public Power District

Date of Off Peak Day - 03/27/2021



Member Forecasted Off Peak Demand Day for April 2021

Northwest Rural Public Power District

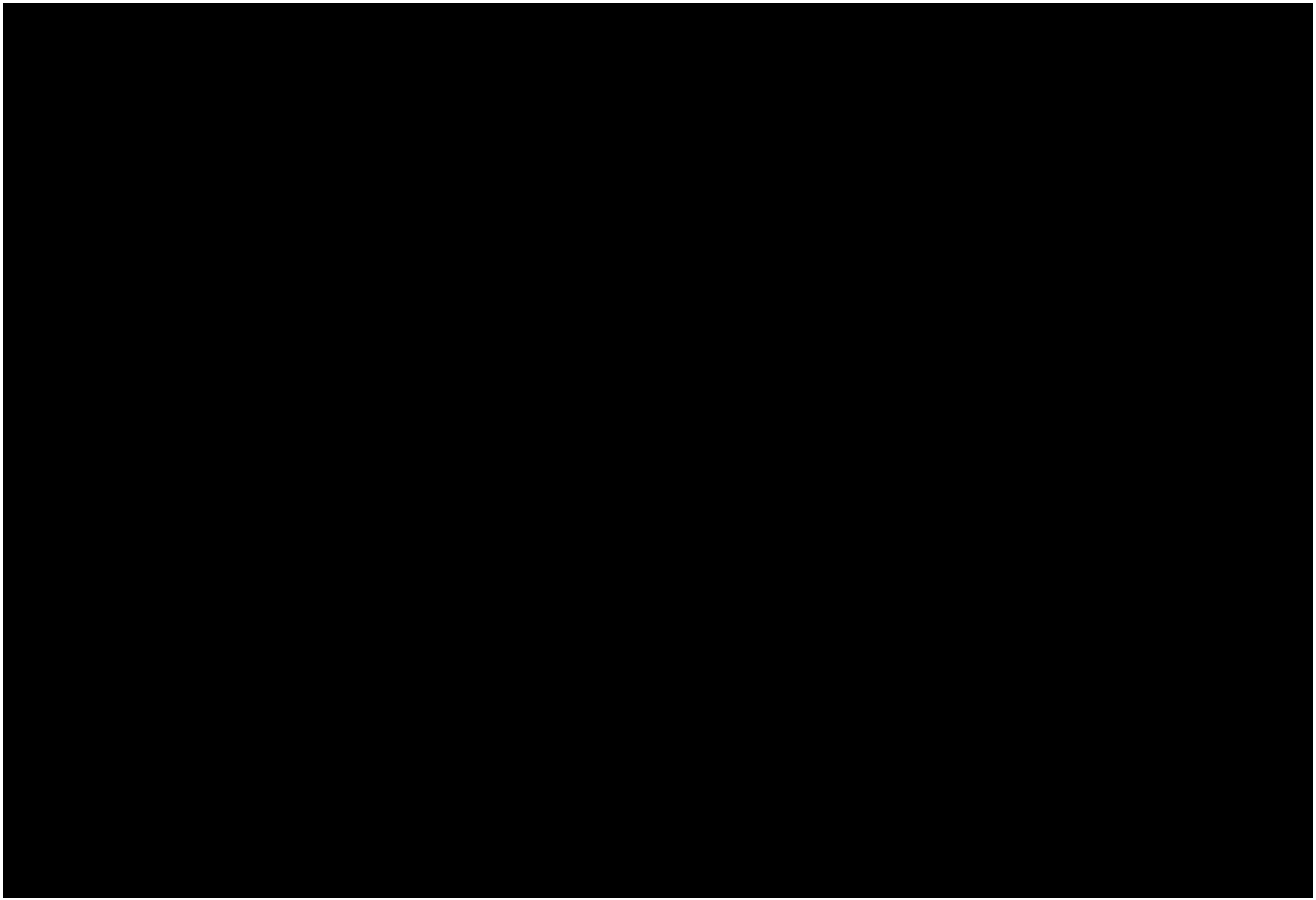
Date of Off Peak Day - 04/23/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Northwest Rural Public Power District

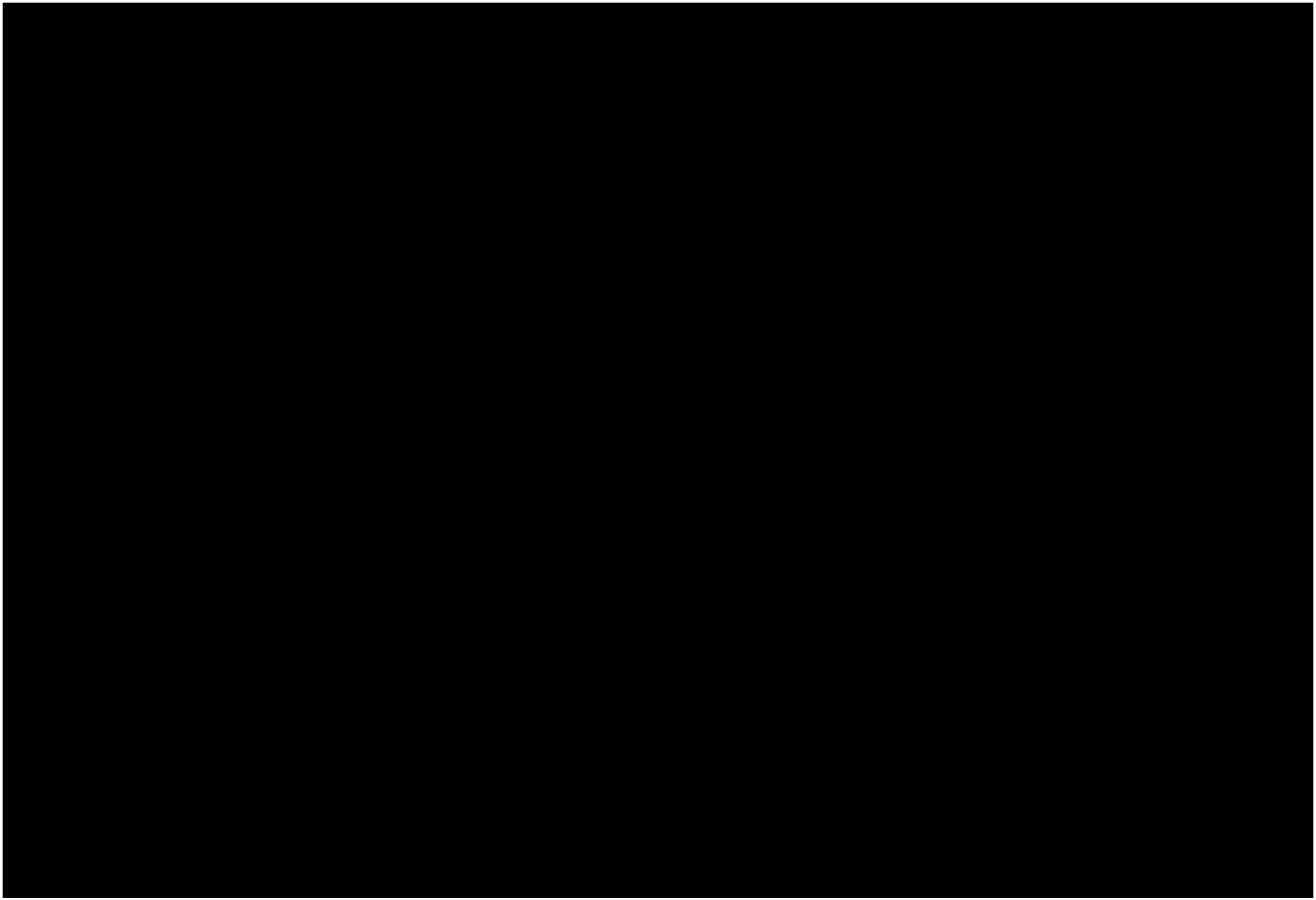
Date of Off Peak Day - 05/22/2021



Member Forecasted Off Peak Demand Day for June 2021

Northwest Rural Public Power District

Date of Off Peak Day - 06/21/2021



Member Forecasted Off Peak Demand Day for July 2021

Northwest Rural Public Power District

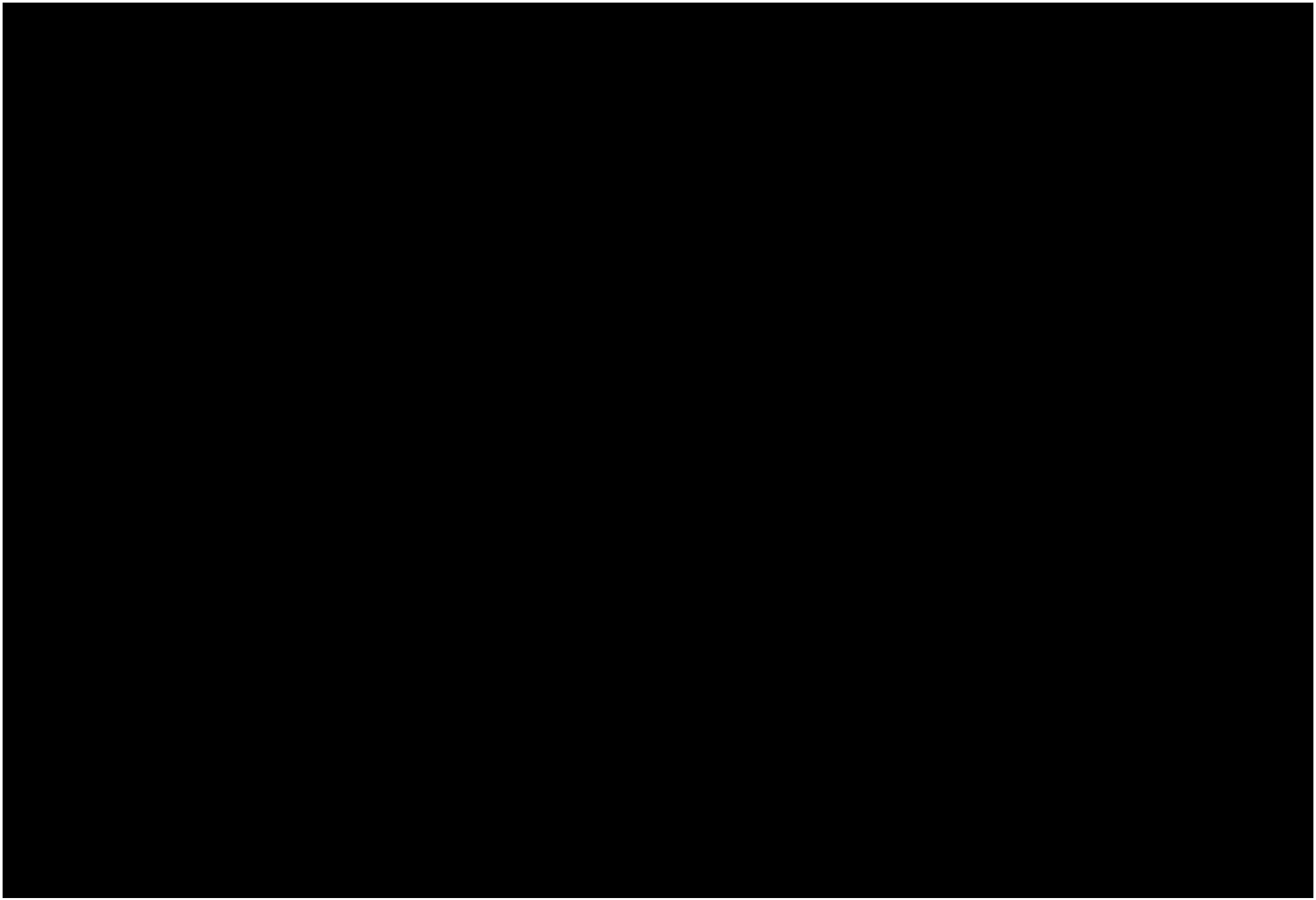
Date of Off Peak Day - 07/03/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Northwest Rural Public Power District

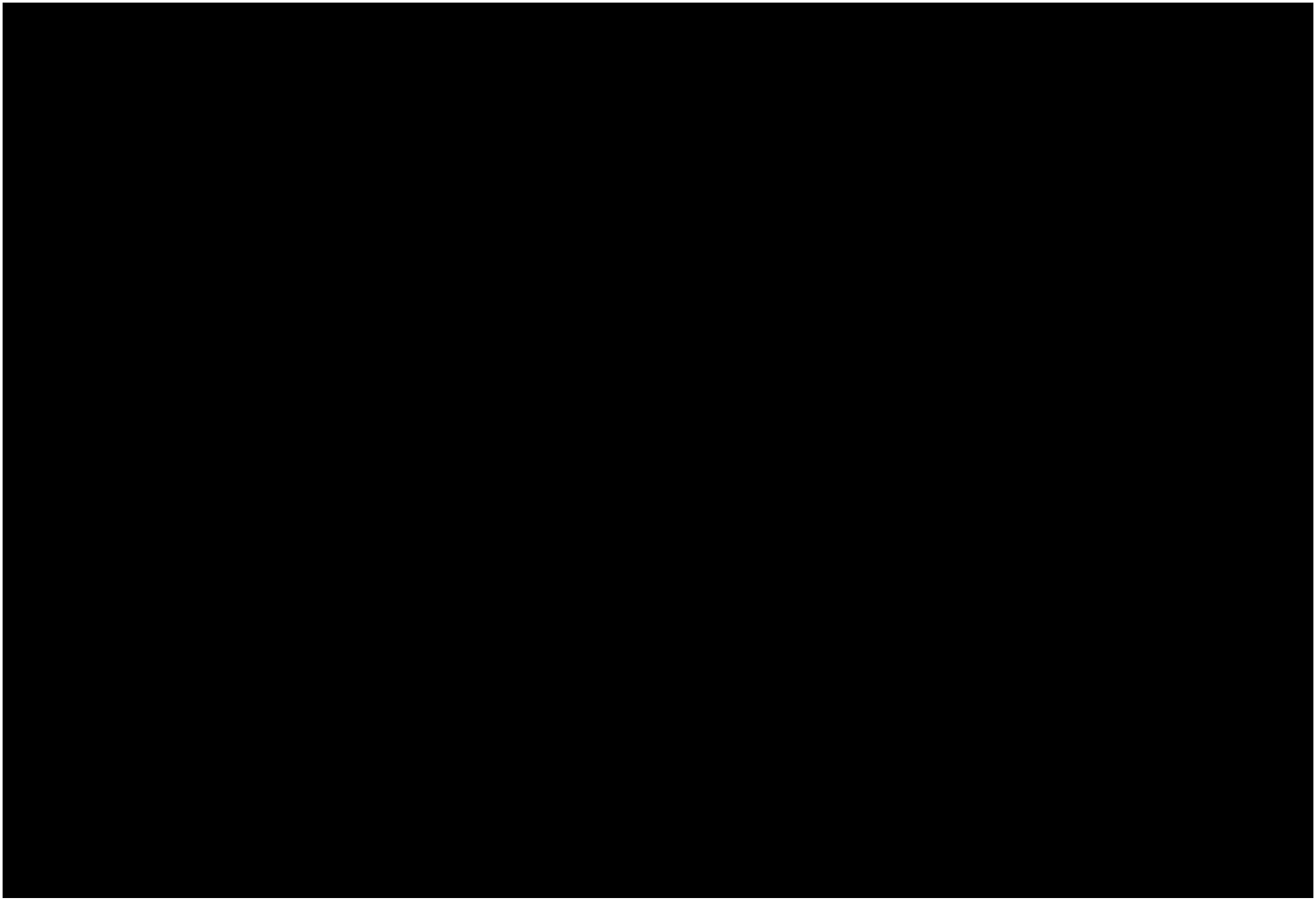
Date of Off Peak Day - 08/09/2021



Member Forecasted Off Peak Demand Day for September 2021

Northwest Rural Public Power District

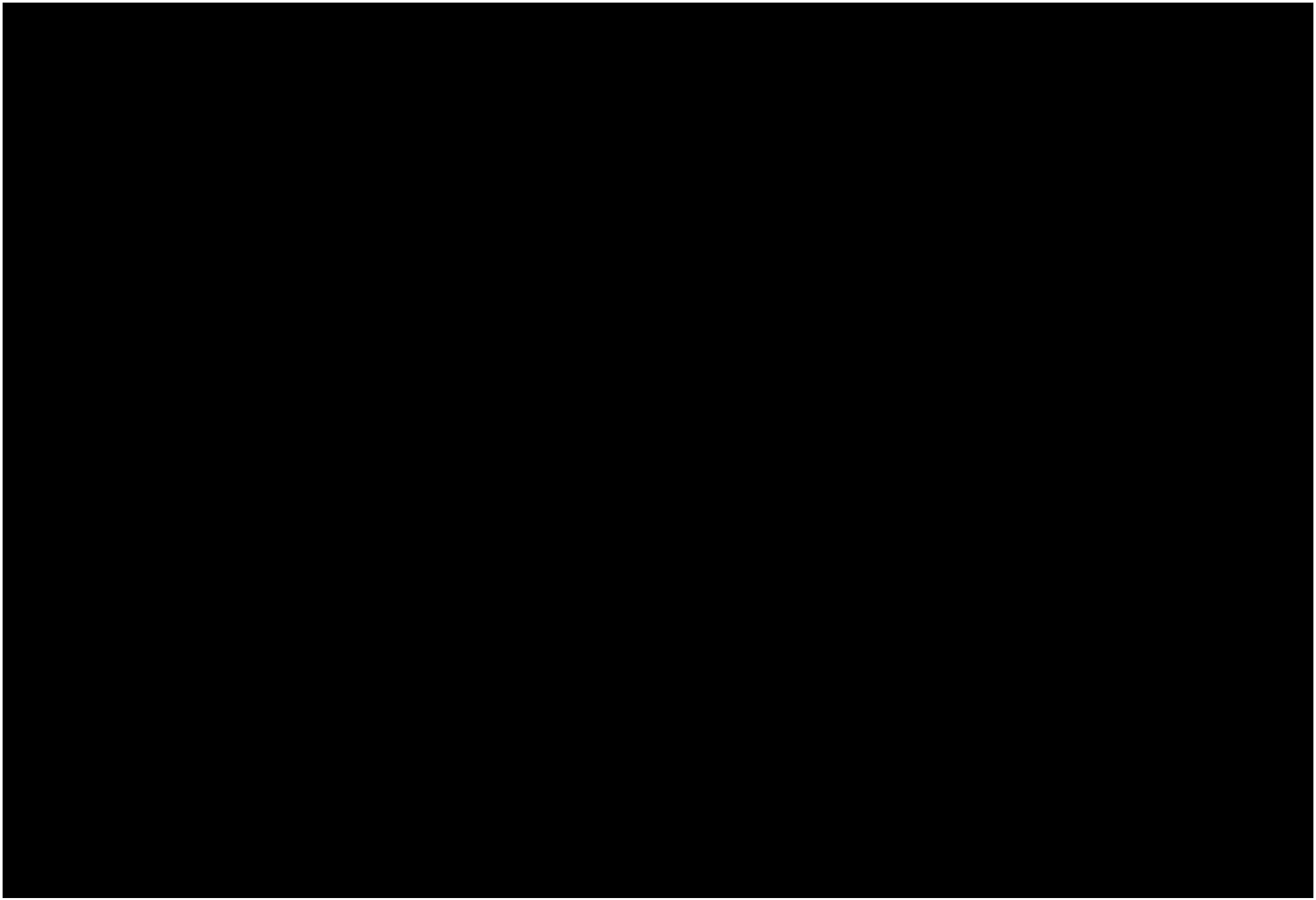
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Northwest Rural Public Power District

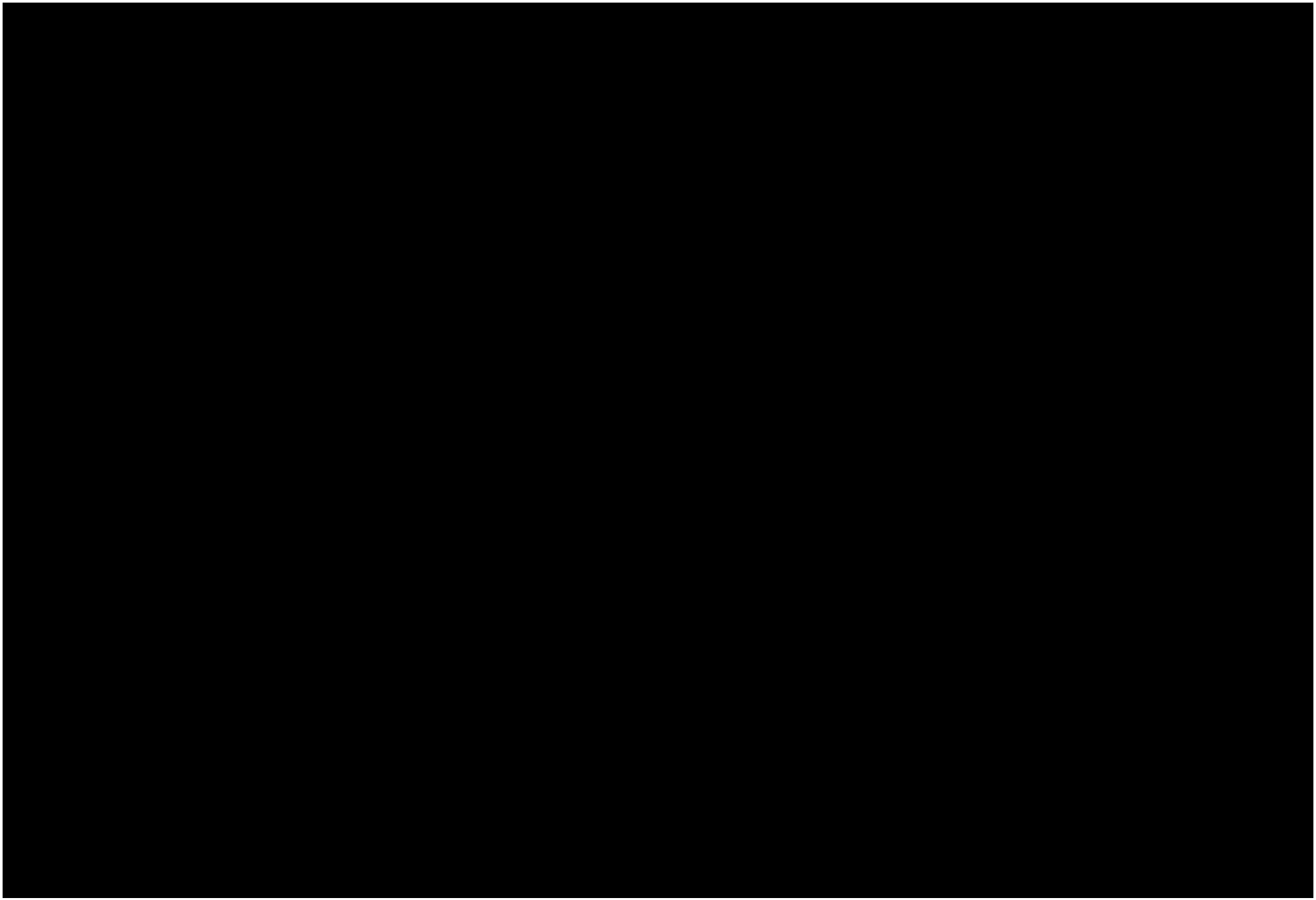
Date of Off Peak Day - 10/22/2021



Member Forecasted Off Peak Demand Day for November 2021

Northwest Rural Public Power District

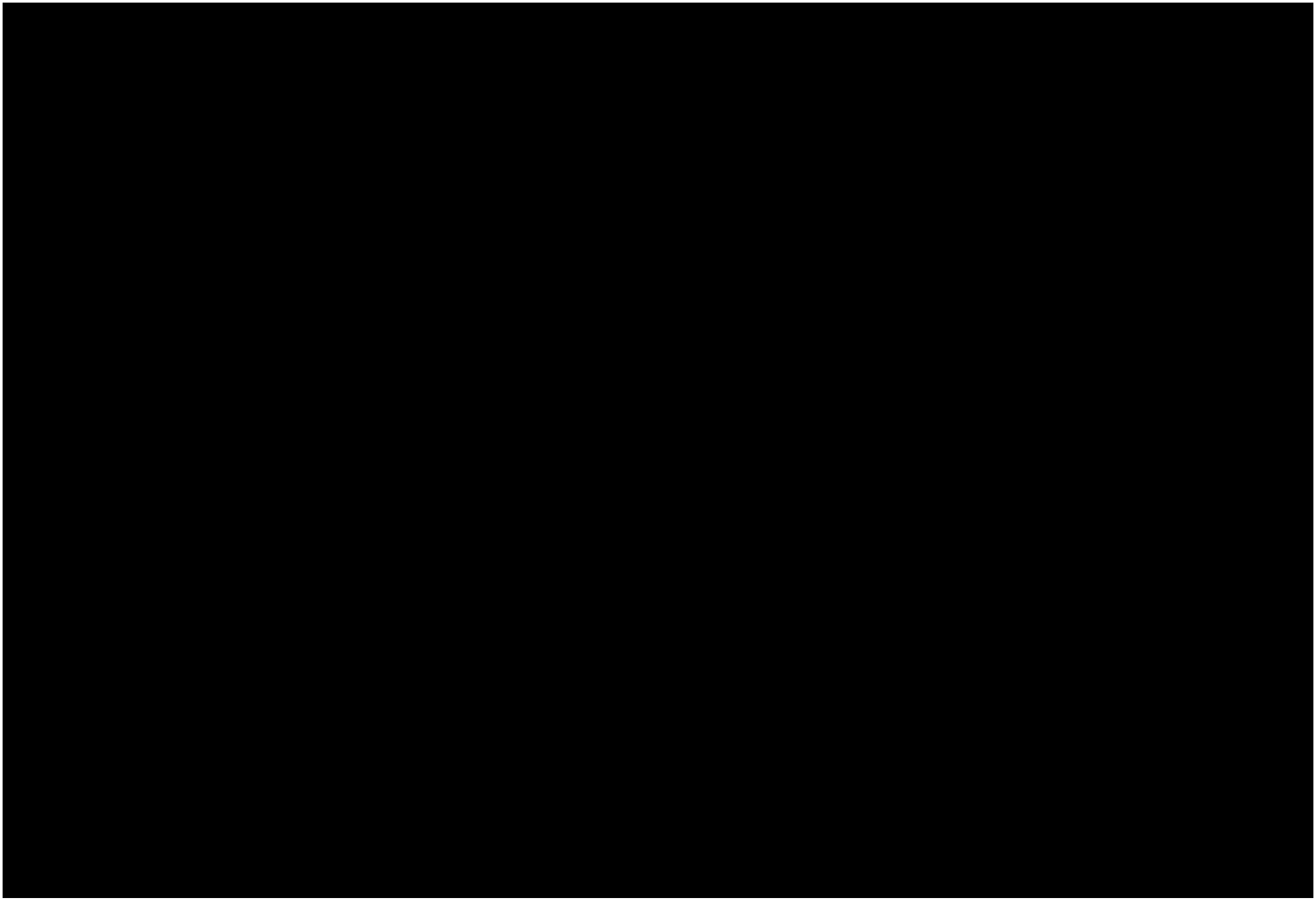
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Northwest Rural Public Power District

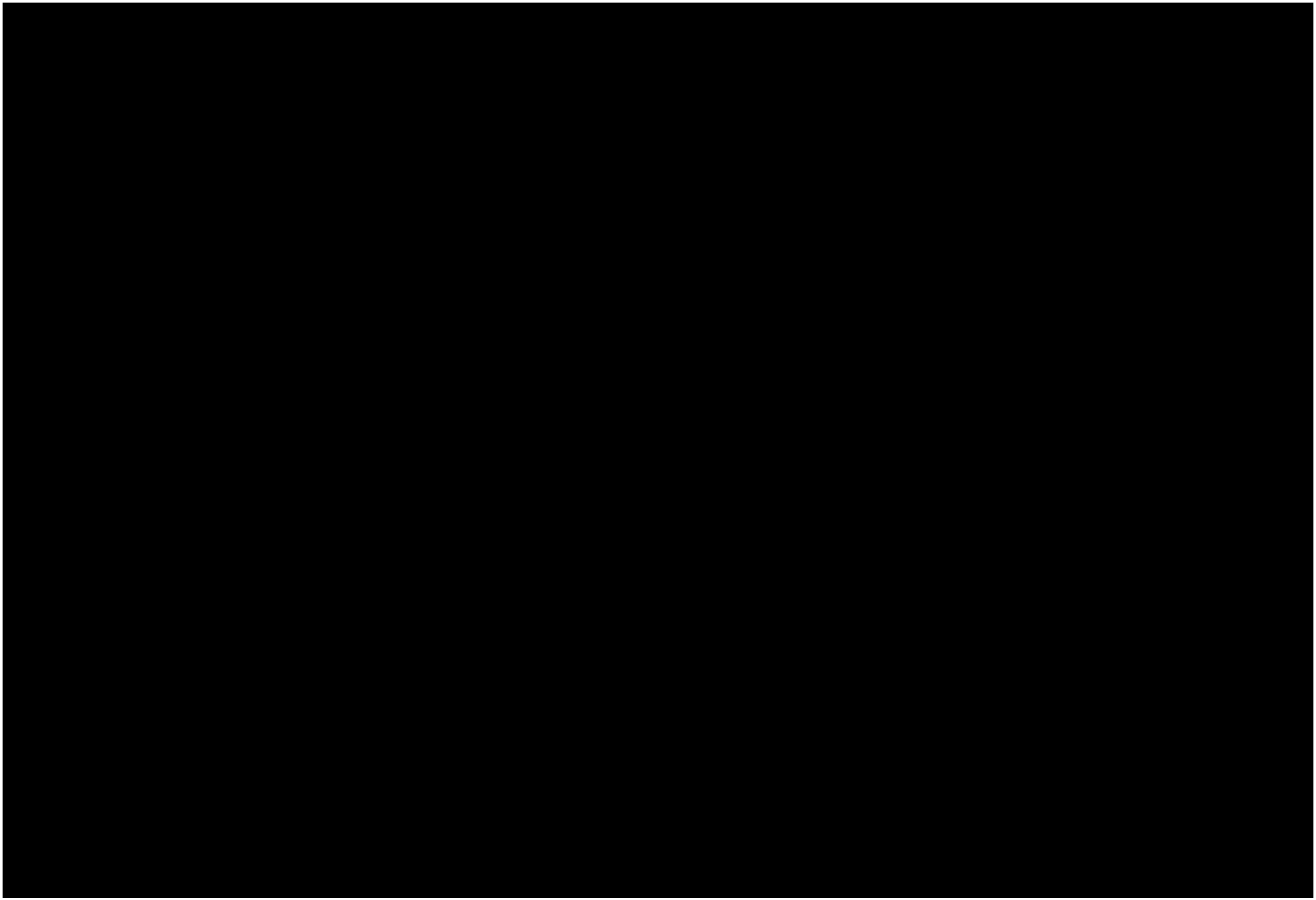
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Otero County Electric Cooperative, Inc.

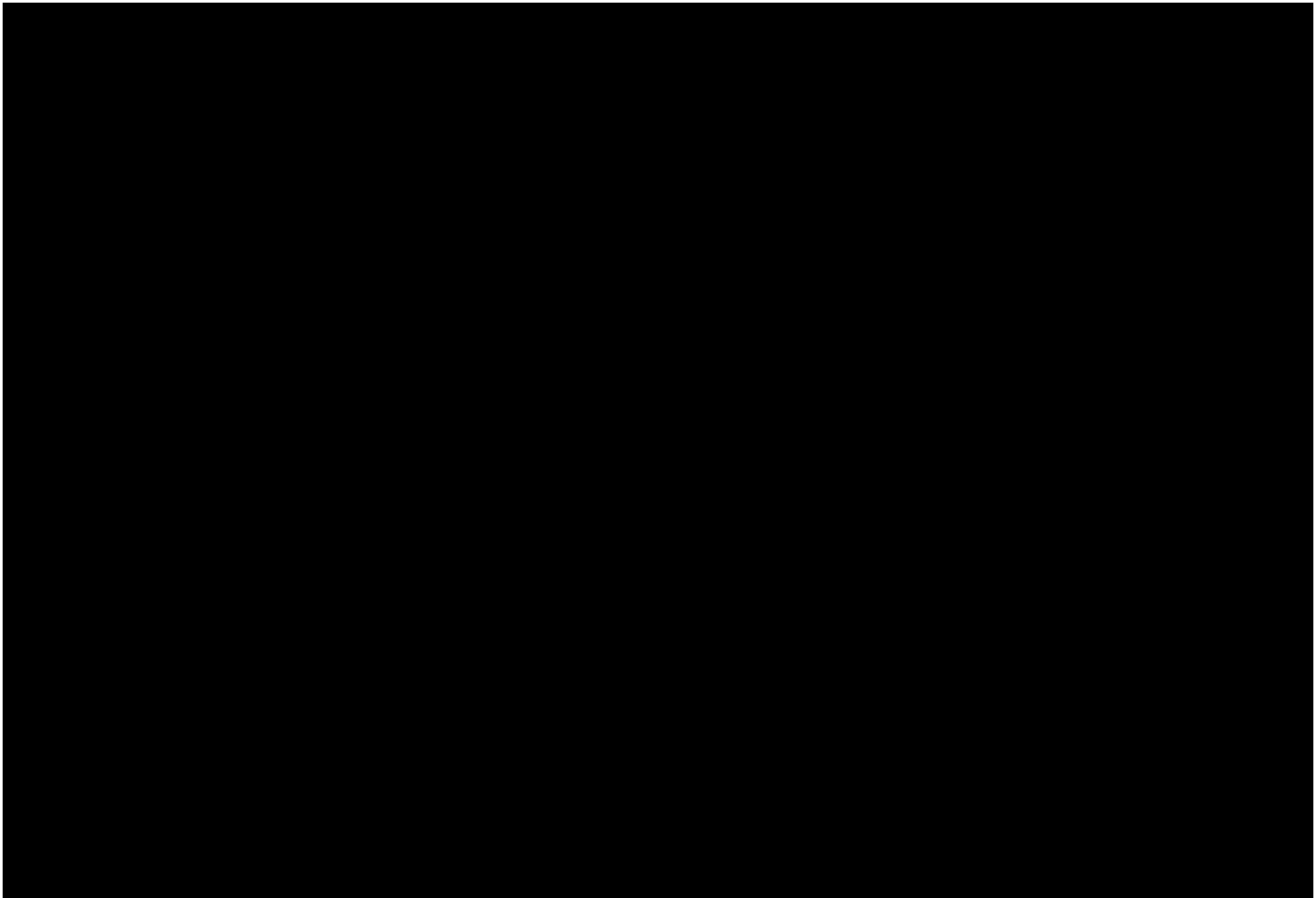
Date of Off Peak Day - 01/12/2021



Member Forecasted Off Peak Demand Day for February 2021

Otero County Electric Cooperative, Inc.

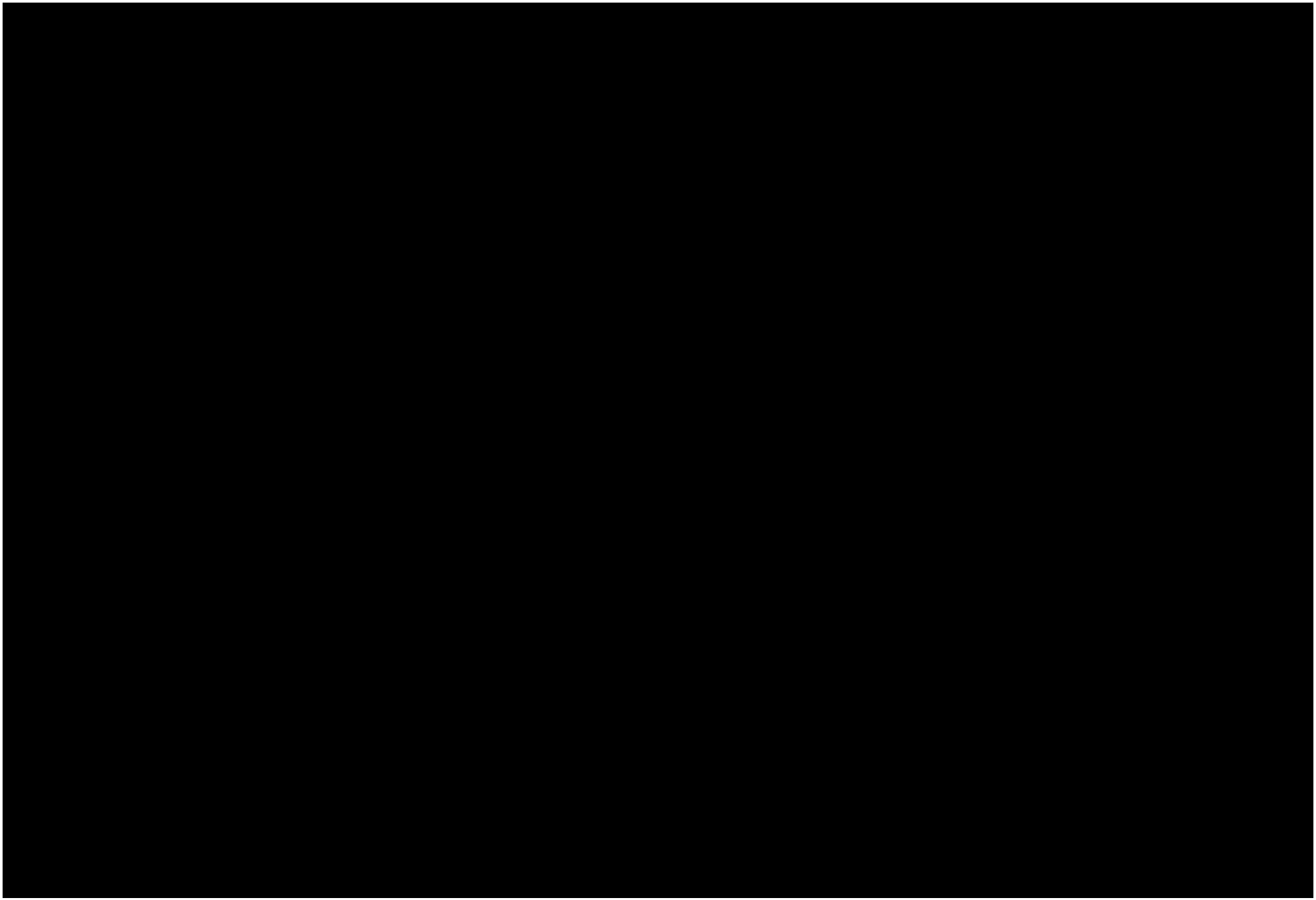
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Otero County Electric Cooperative, Inc.

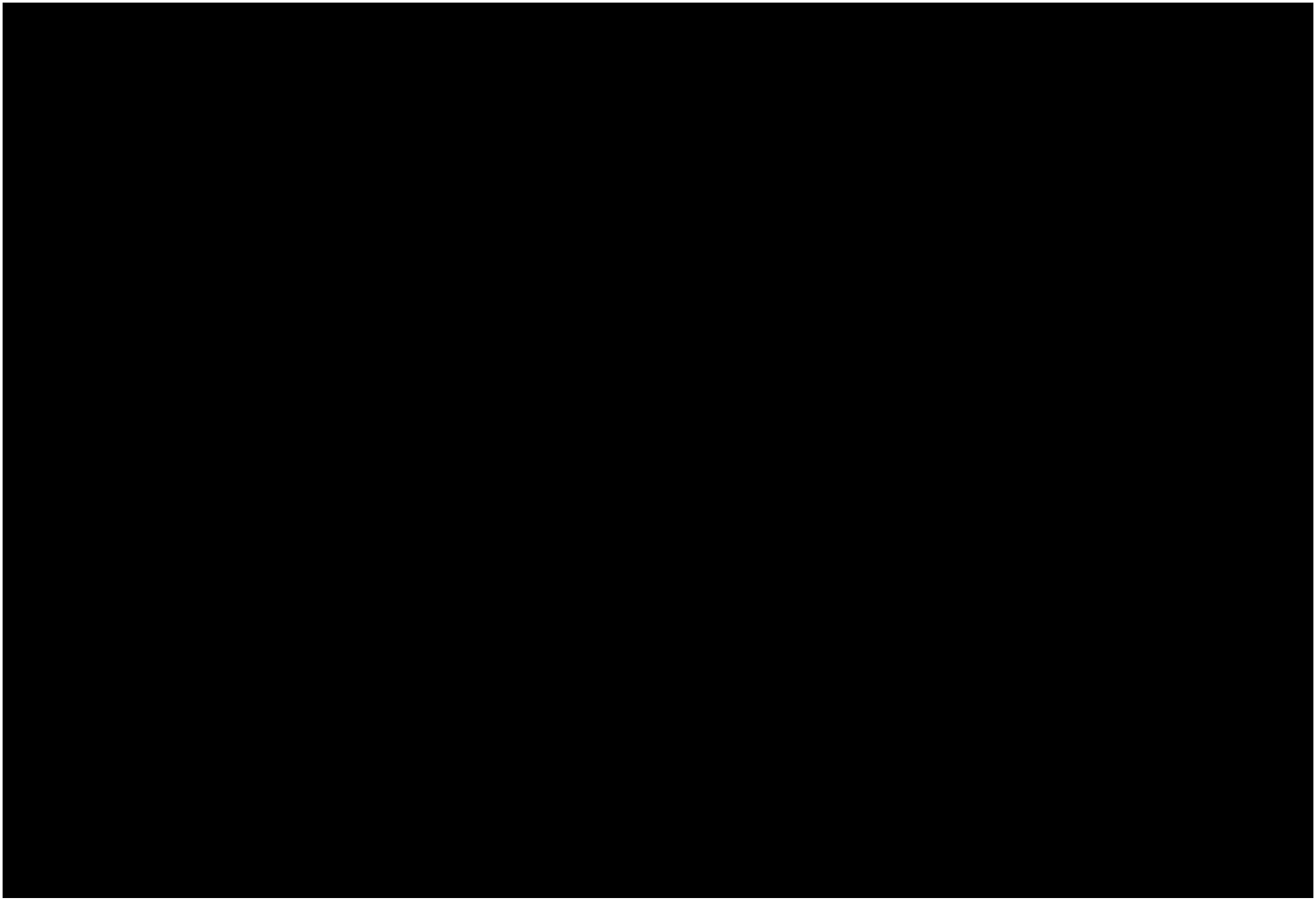
Date of Off Peak Day - 03/22/2021



Member Forecasted Off Peak Demand Day for April 2021

Otero County Electric Cooperative, Inc.

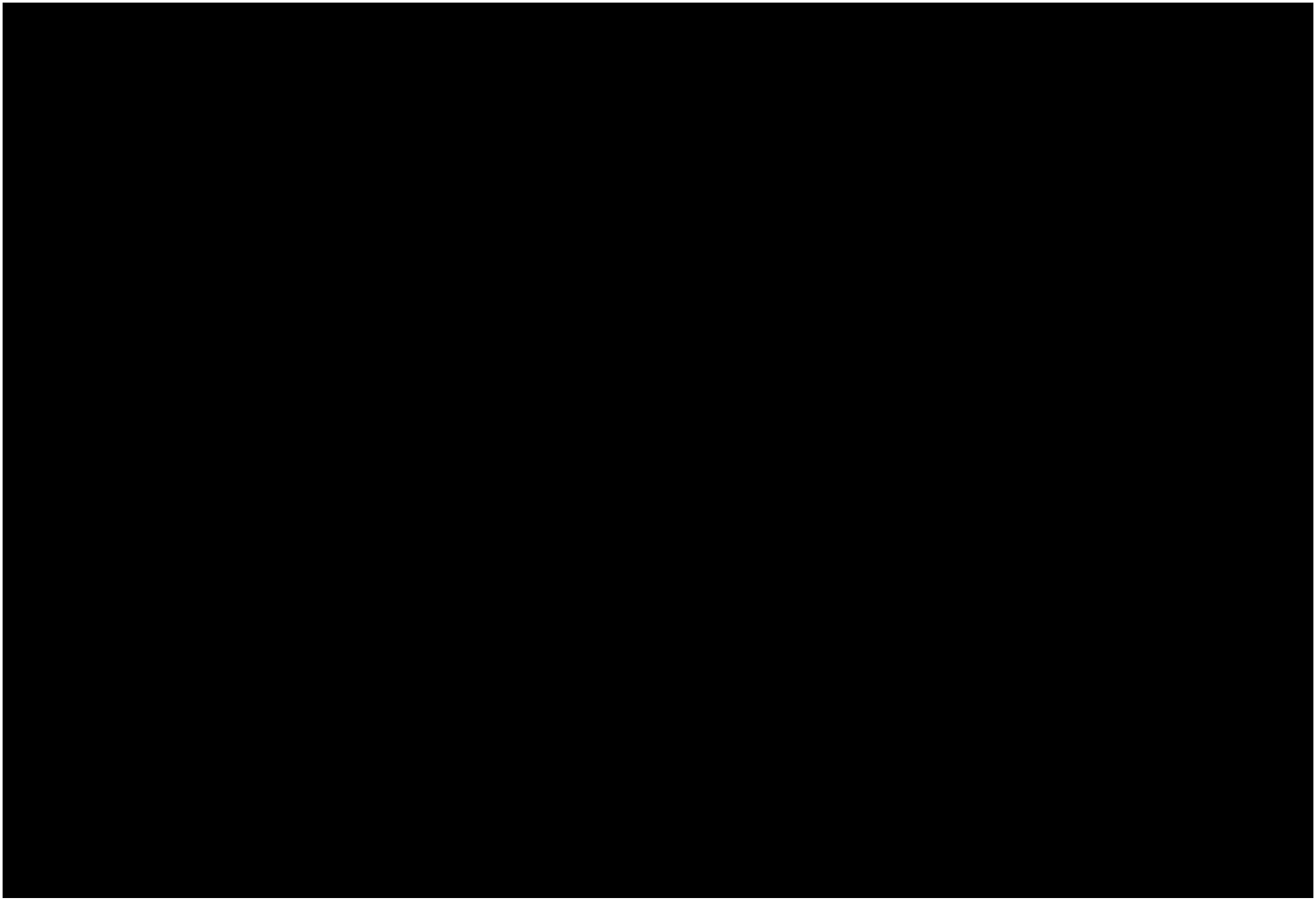
Date of Off Peak Day - 04/21/2021



Member Forecasted Off Peak Demand Day for May 2021

Otero County Electric Cooperative, Inc.

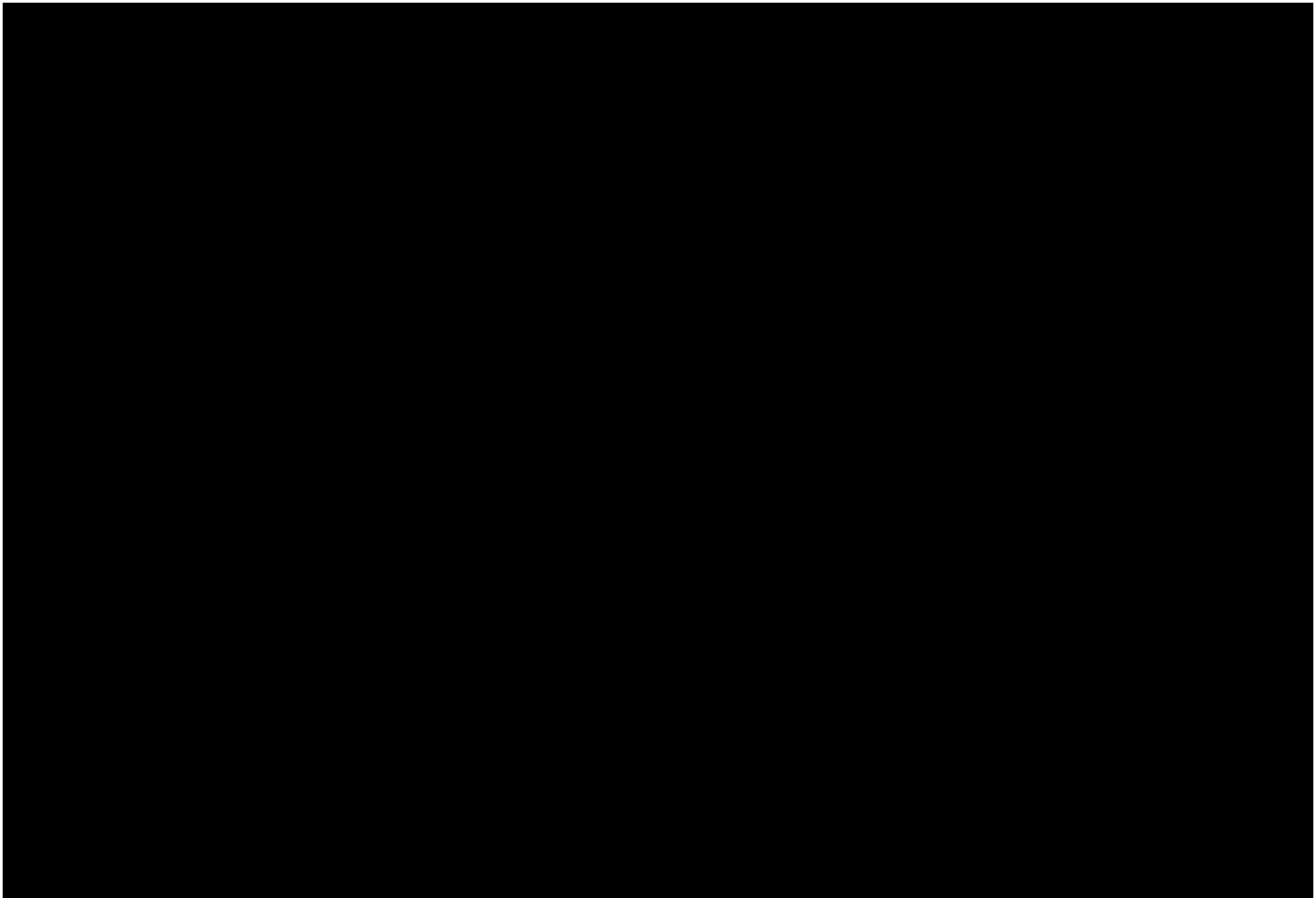
Date of Off Peak Day - 05/03/2021



Member Forecasted Off Peak Demand Day for June 2021

Otero County Electric Cooperative, Inc.

Date of Off Peak Day - 06/20/2021



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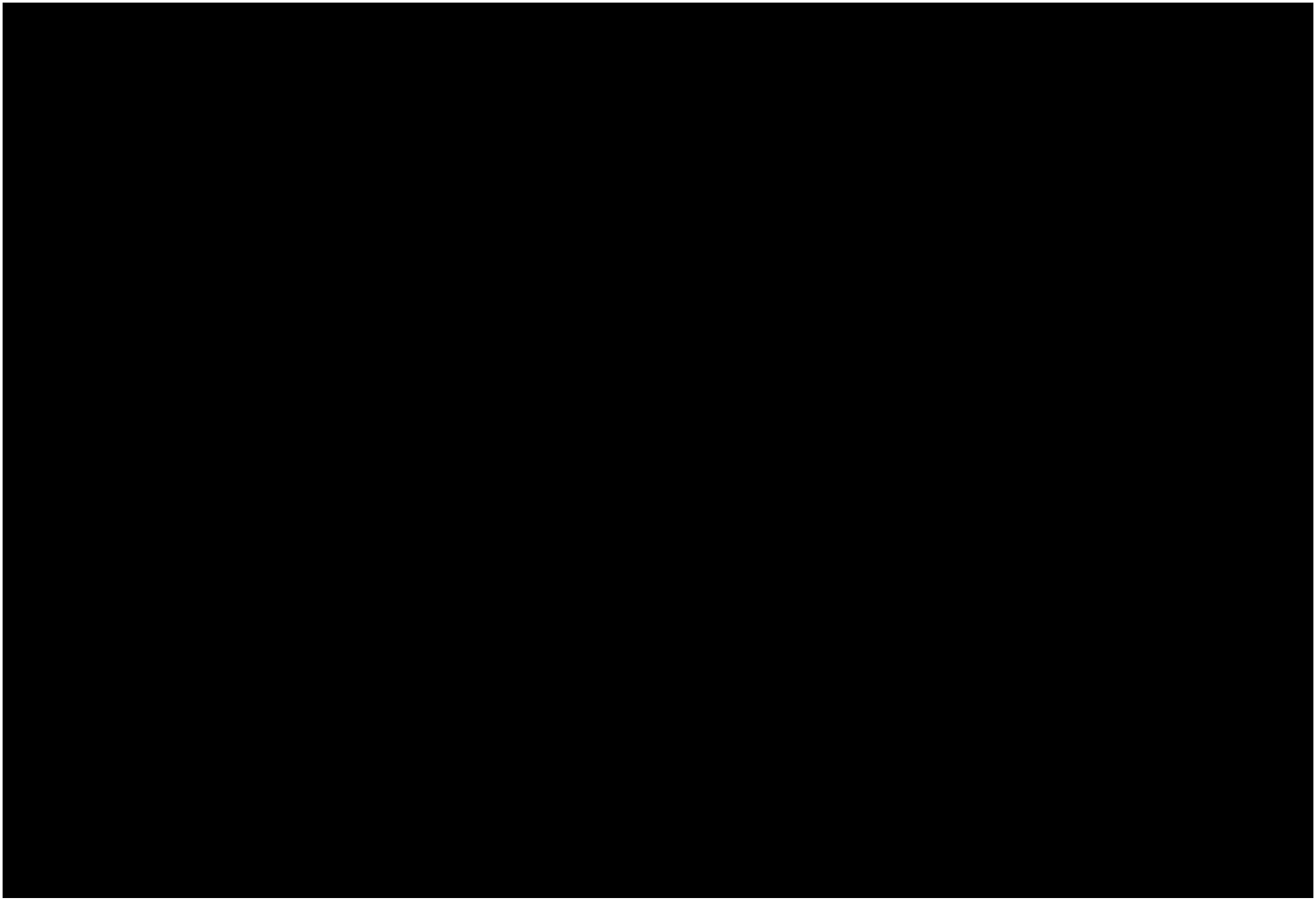
Member Forecasted Off Peak Demand Day for July 2021

Otero County Electric Cooperative, Inc.

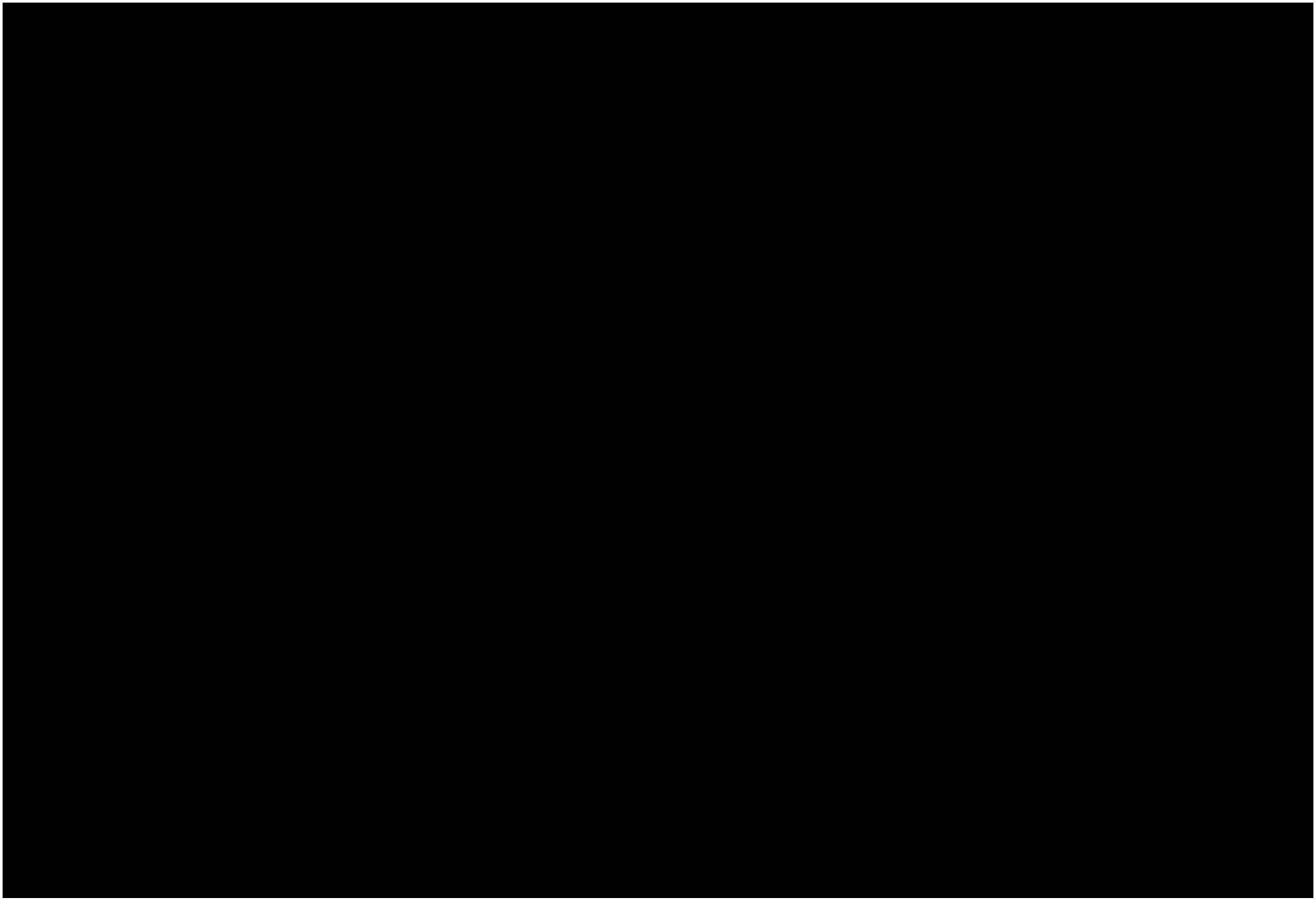
Date of Off Peak Day - 07/02/2021



Member Forecasted Off Peak Demand Day for August 2021

Otero County Electric Cooperative, Inc.

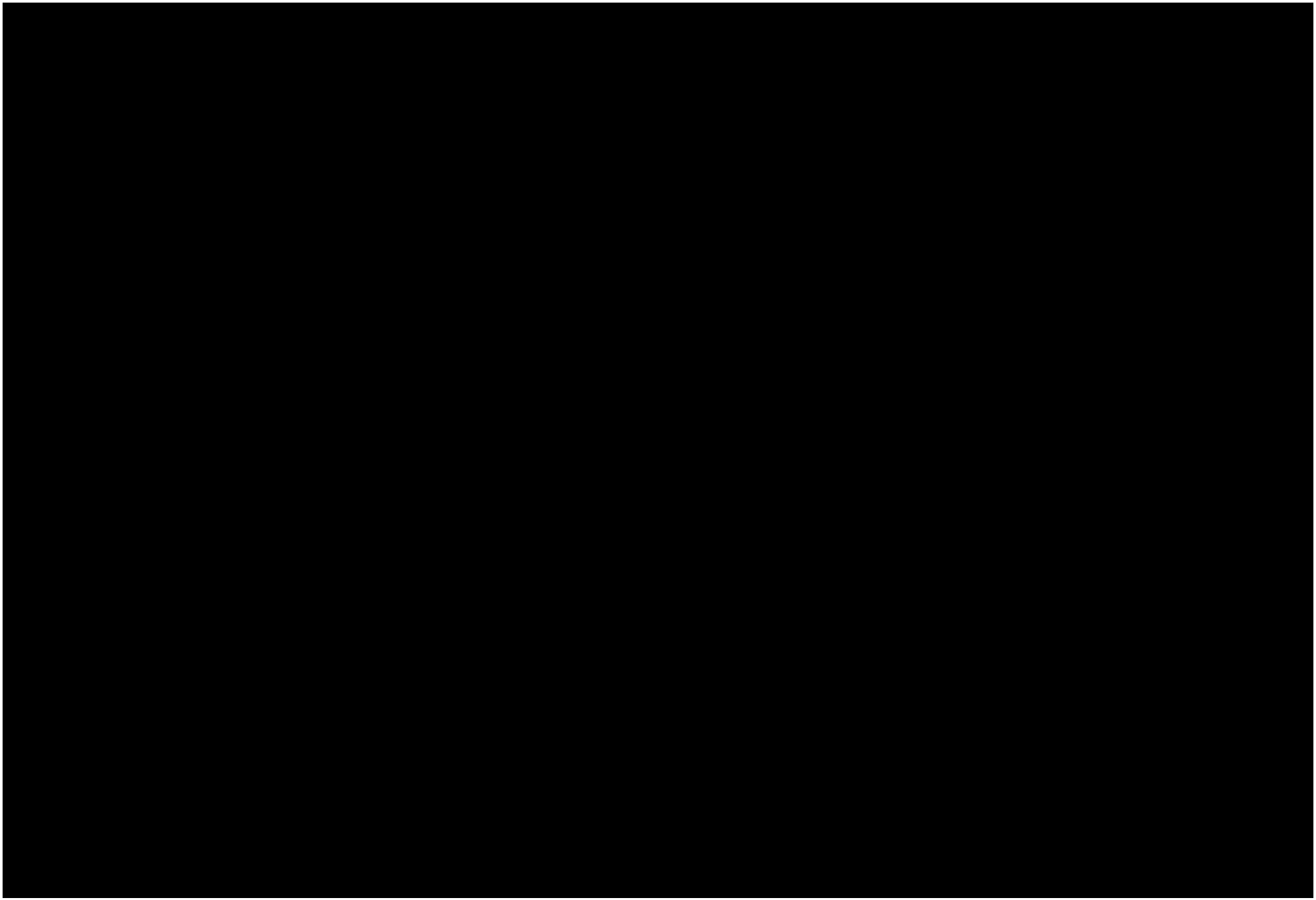
Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Otero County Electric Cooperative, Inc.

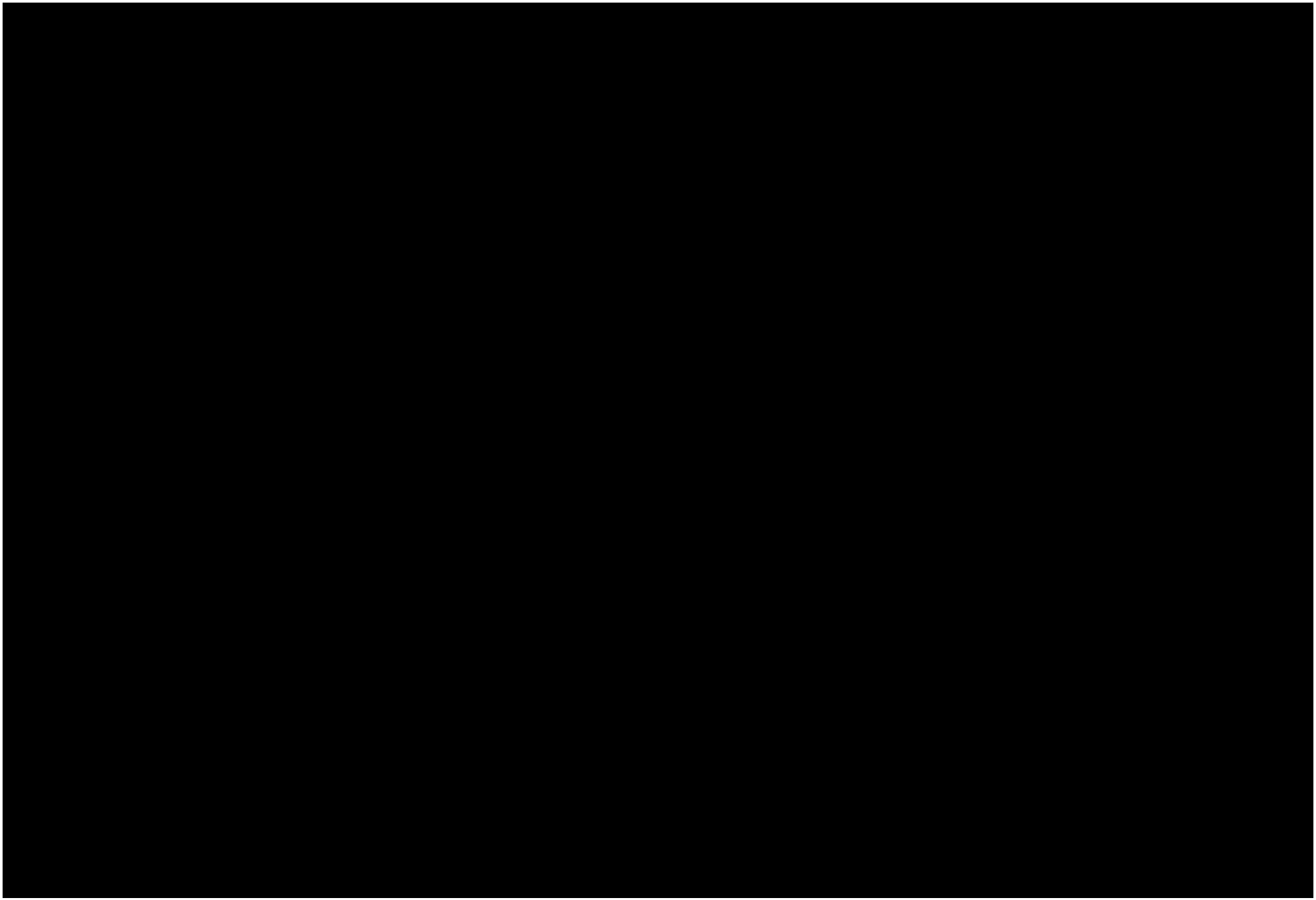
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Otero County Electric Cooperative, Inc.

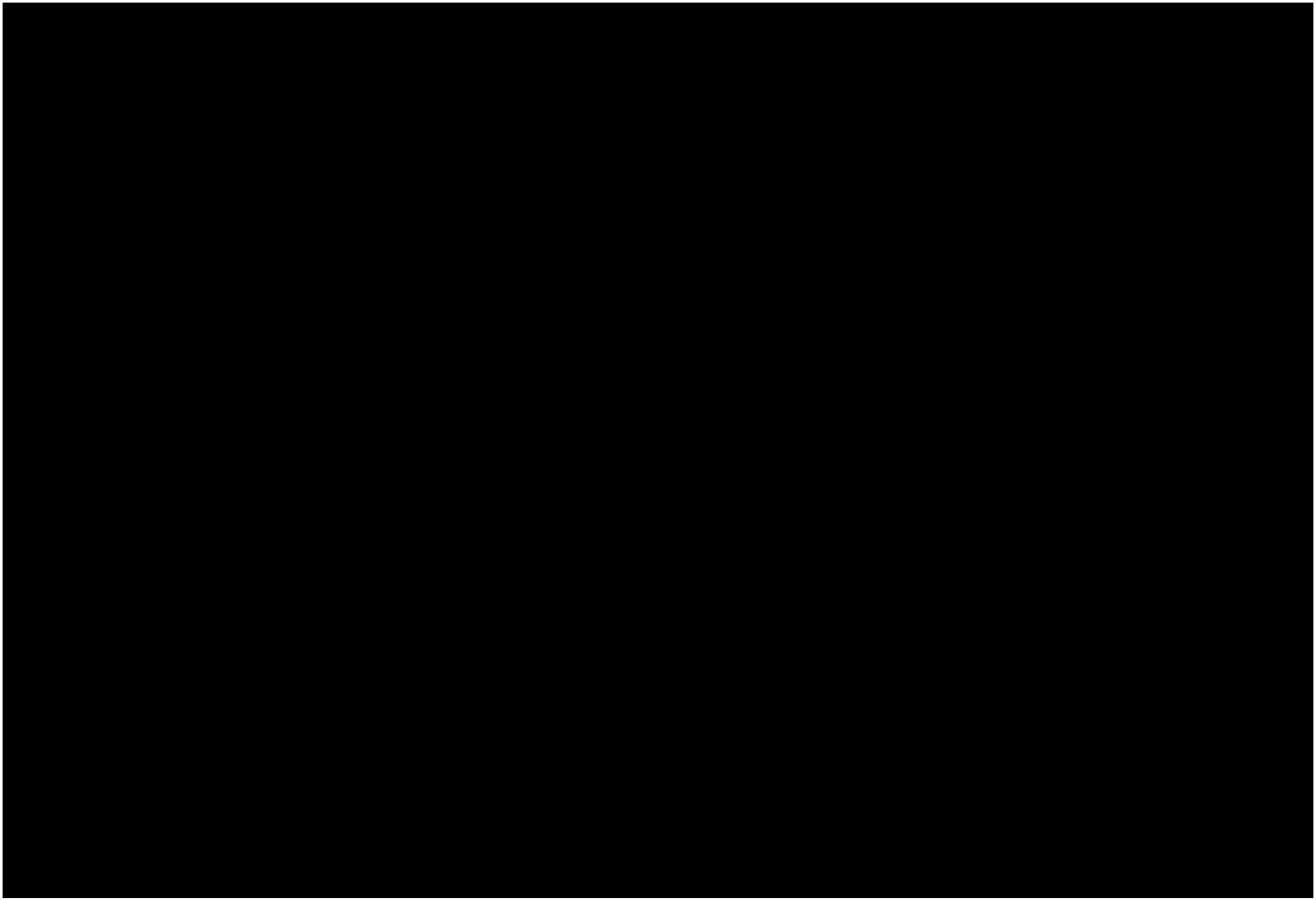
Date of Off Peak Day - 10/04/2021



Member Forecasted Off Peak Demand Day for November 2021

Otero County Electric Cooperative, Inc.

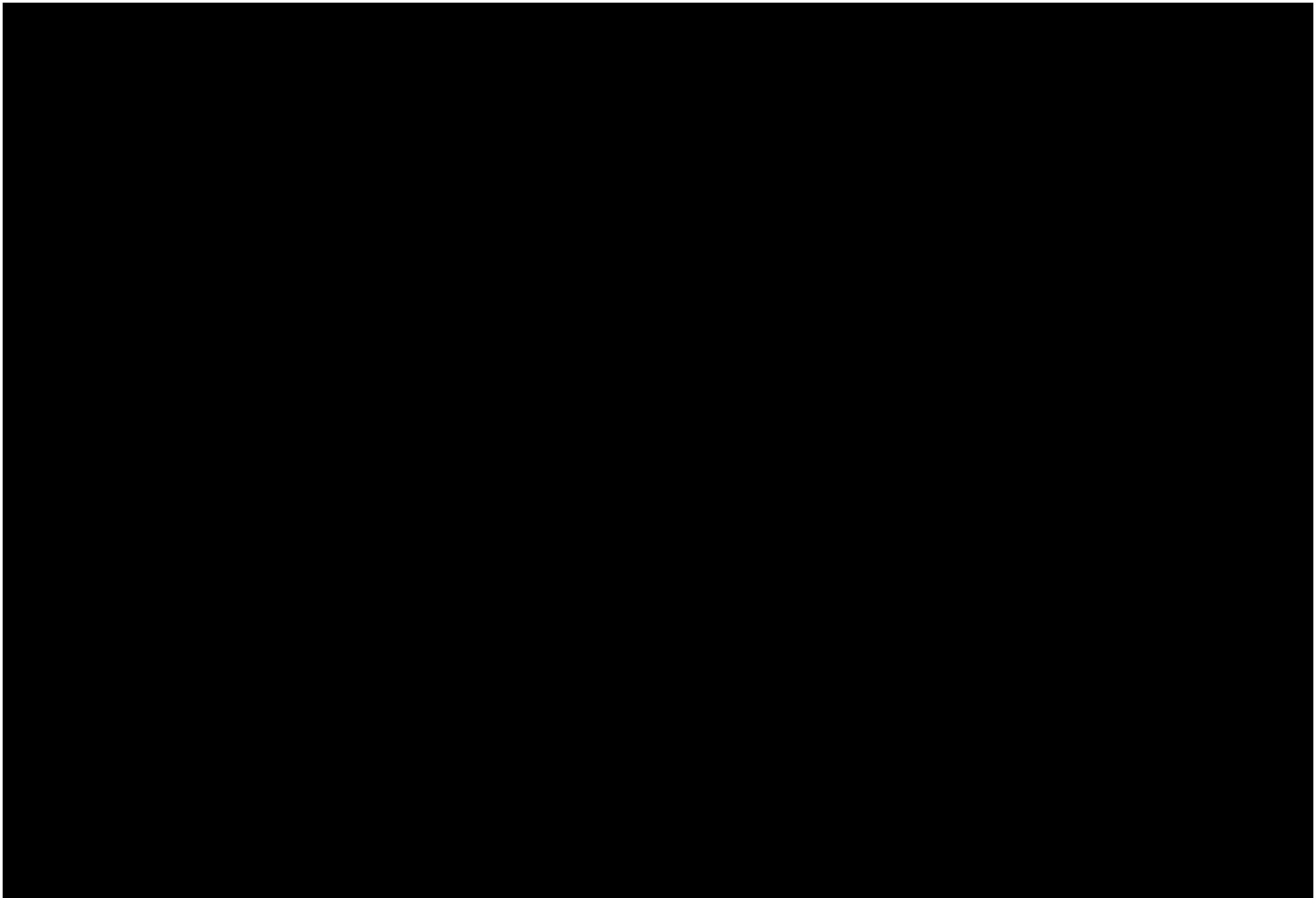
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Otero County Electric Cooperative, Inc.

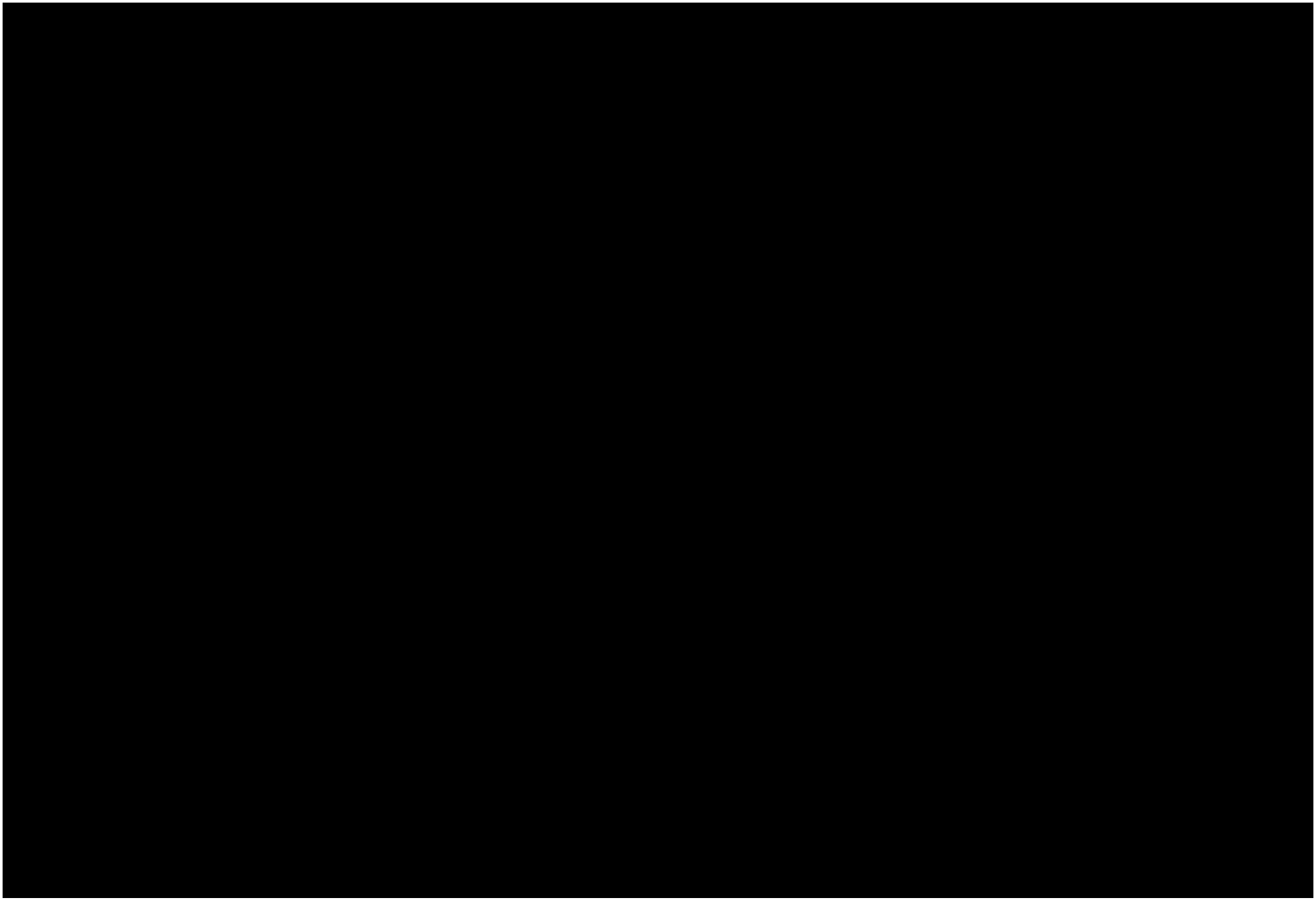
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Panhandle Rural Electric Membership Association

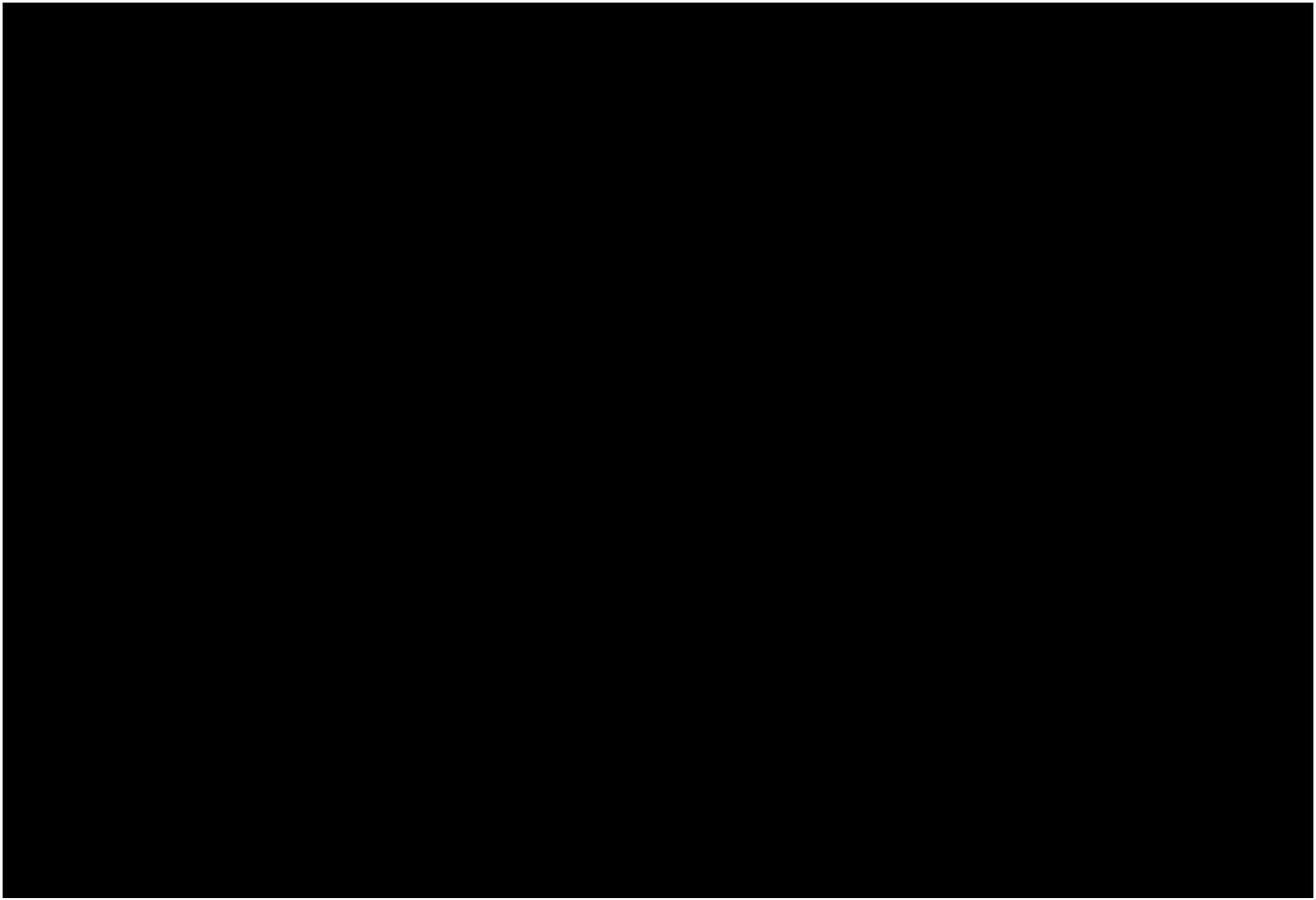
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Panhandle Rural Electric Membership Association

Date of Off Peak Day - 02/22/2021



Member Forecasted Off Peak Demand Day for March 2021

Panhandle Rural Electric Membership Association

Date of Off Peak Day - 03/27/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Panhandle Rural Electric Membership Association

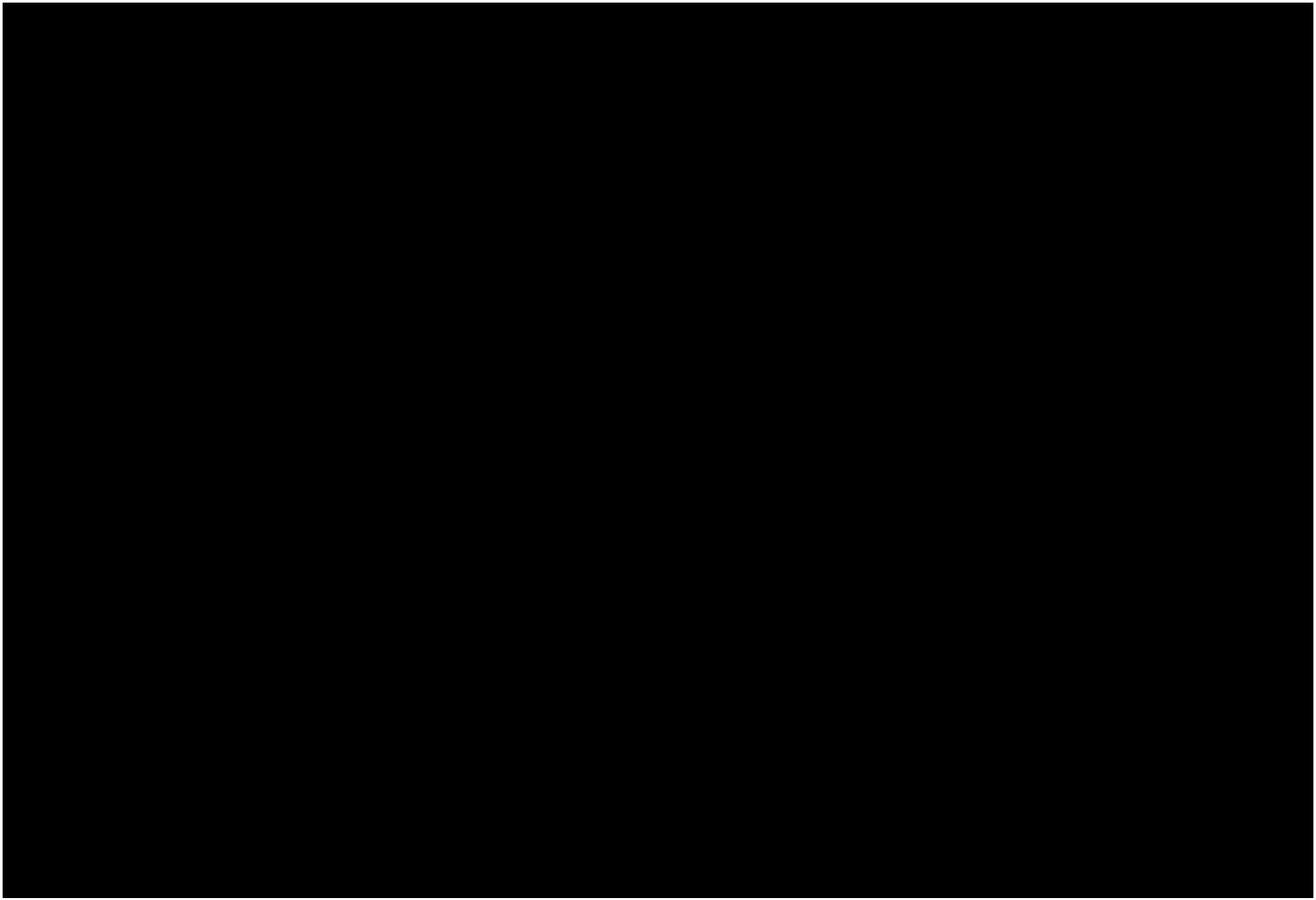
Date of Off Peak Day - 04/18/2021

[redacted]

Member Forecasted Off Peak Demand Day for May 2021

Panhandle Rural Electric Membership Association

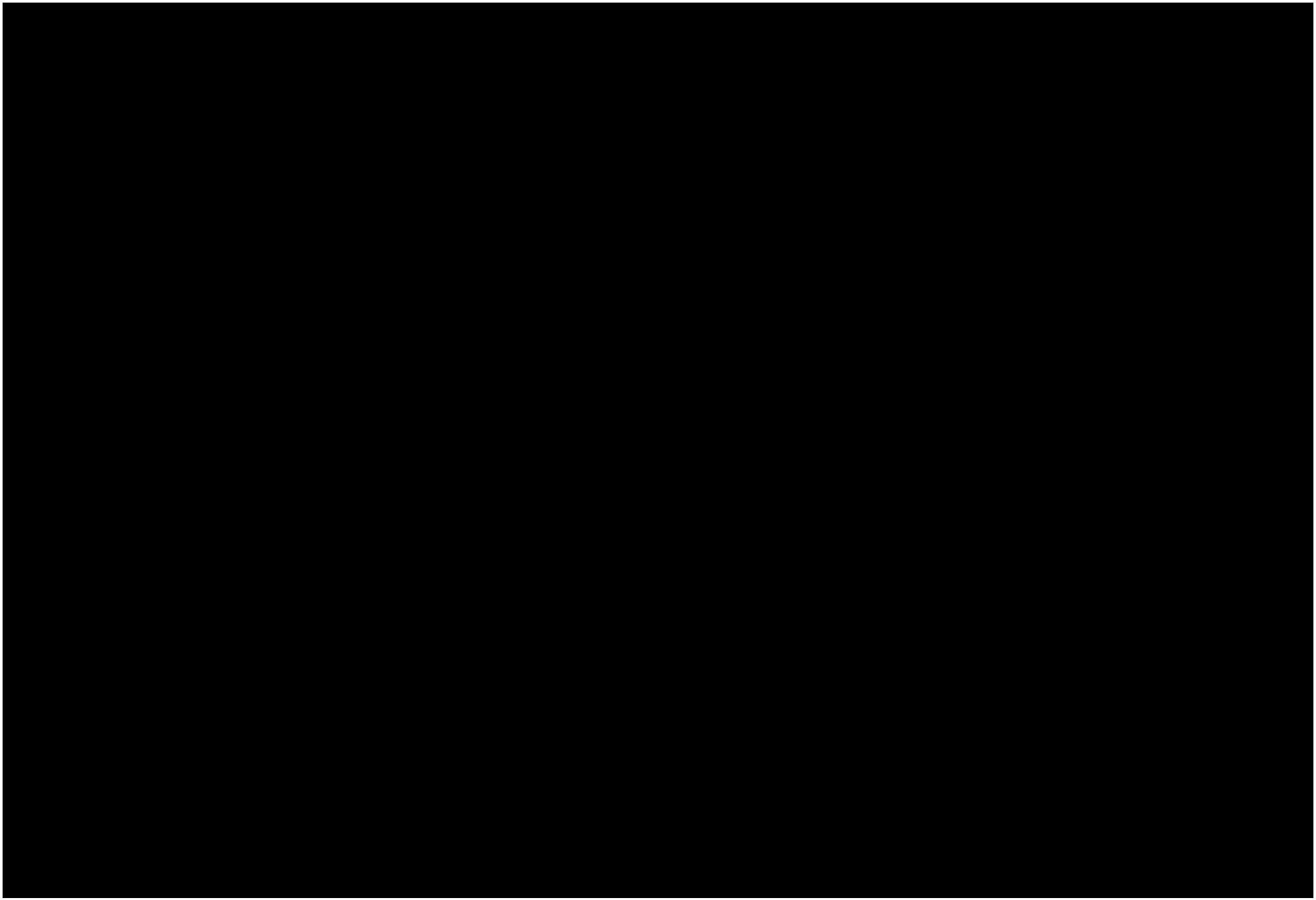
Date of Off Peak Day - 05/28/2021



Member Forecasted Off Peak Demand Day for June 2021

Panhandle Rural Electric Membership Association

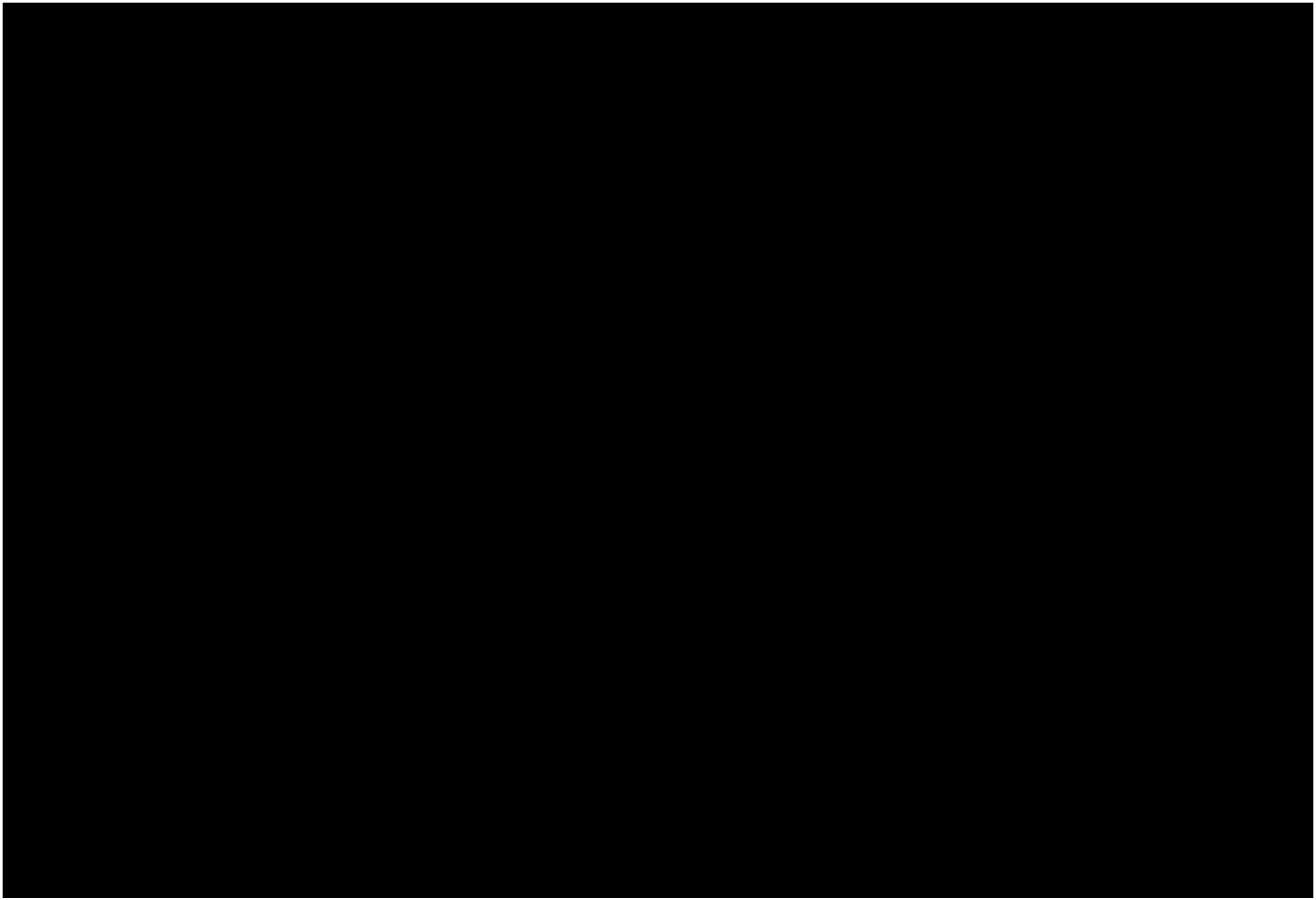
Date of Off Peak Day - 06/21/2021



Member Forecasted Off Peak Demand Day for July 2021

Panhandle Rural Electric Membership Association

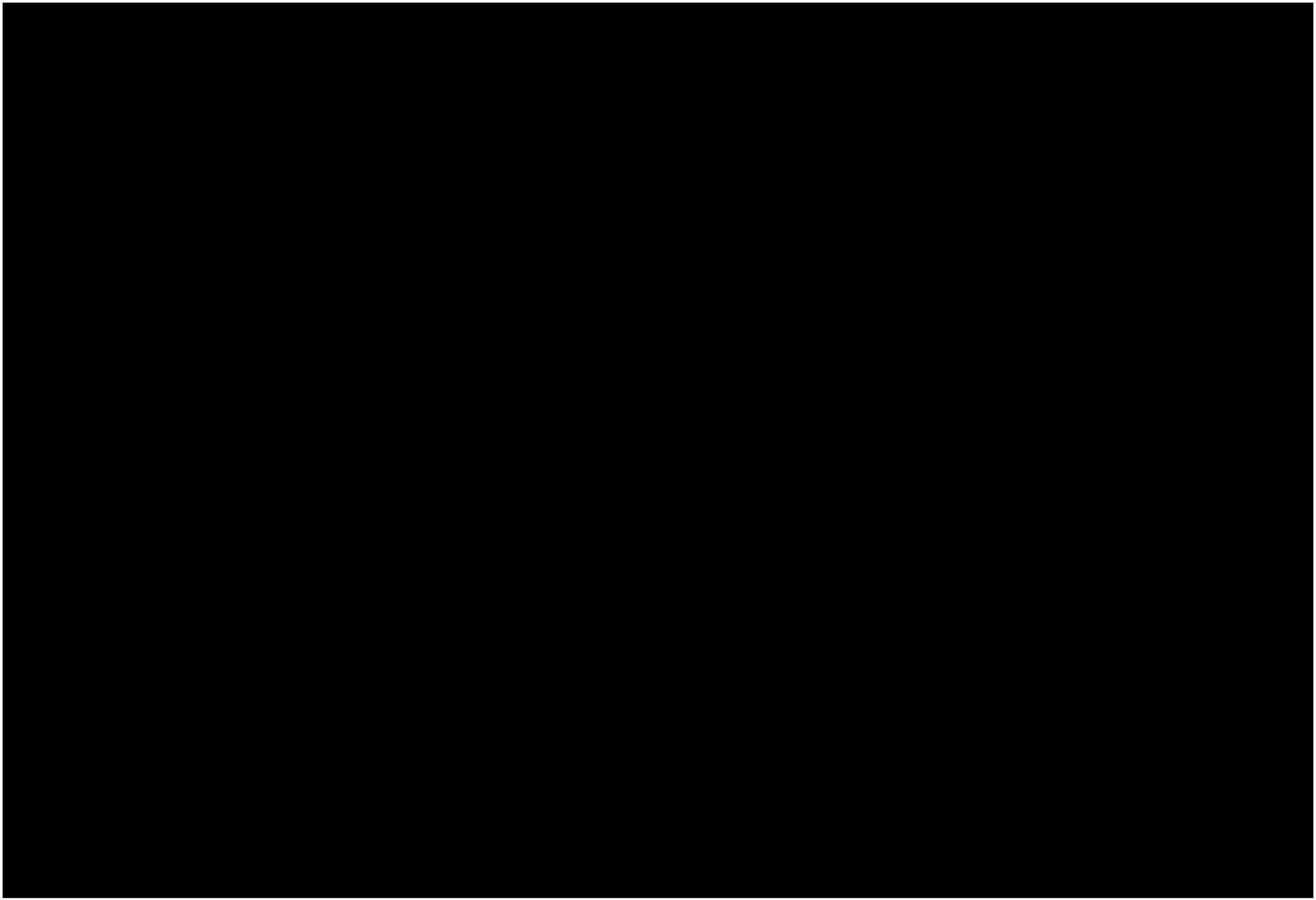
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

Panhandle Rural Electric Membership Association

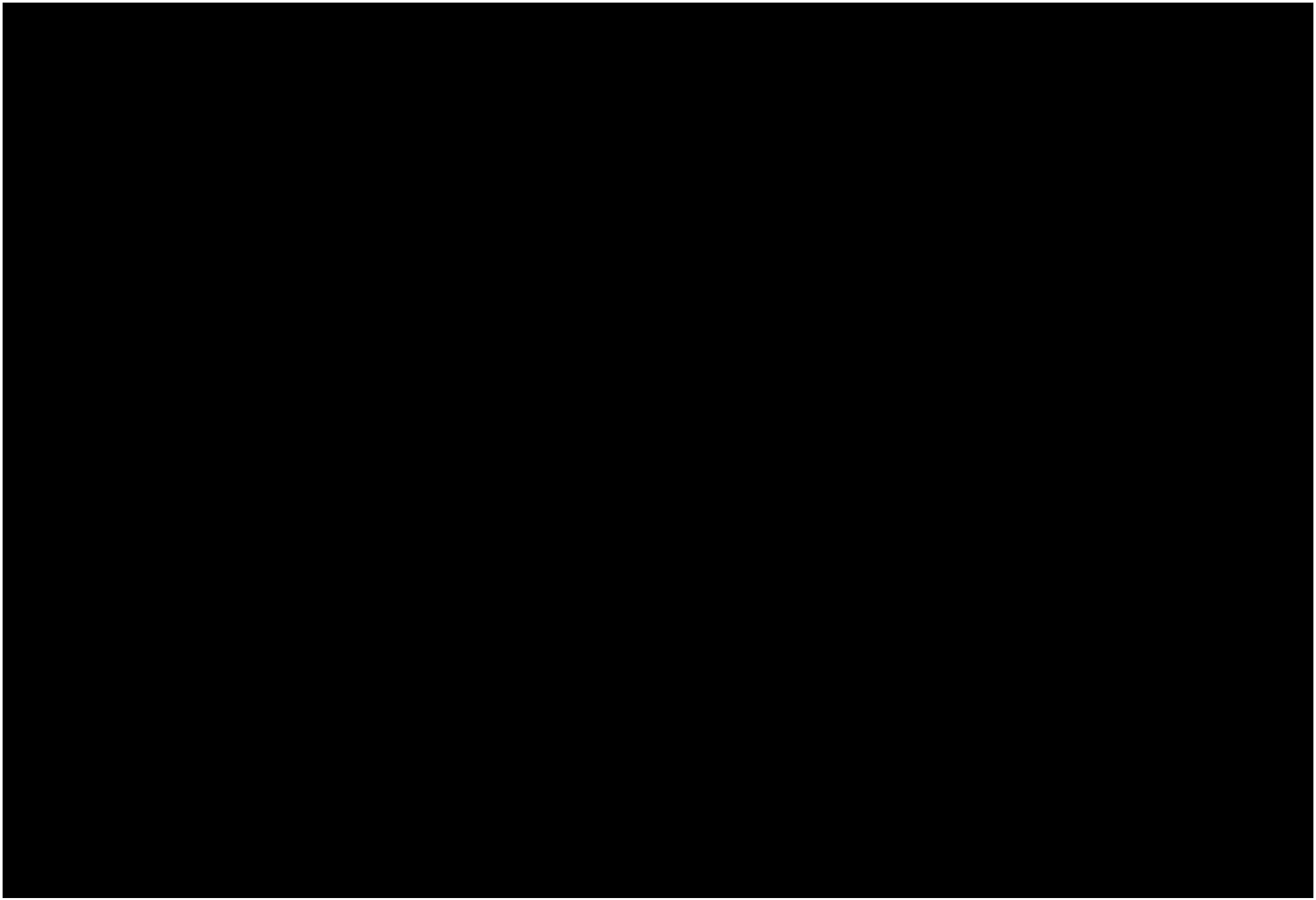
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Panhandle Rural Electric Membership Association

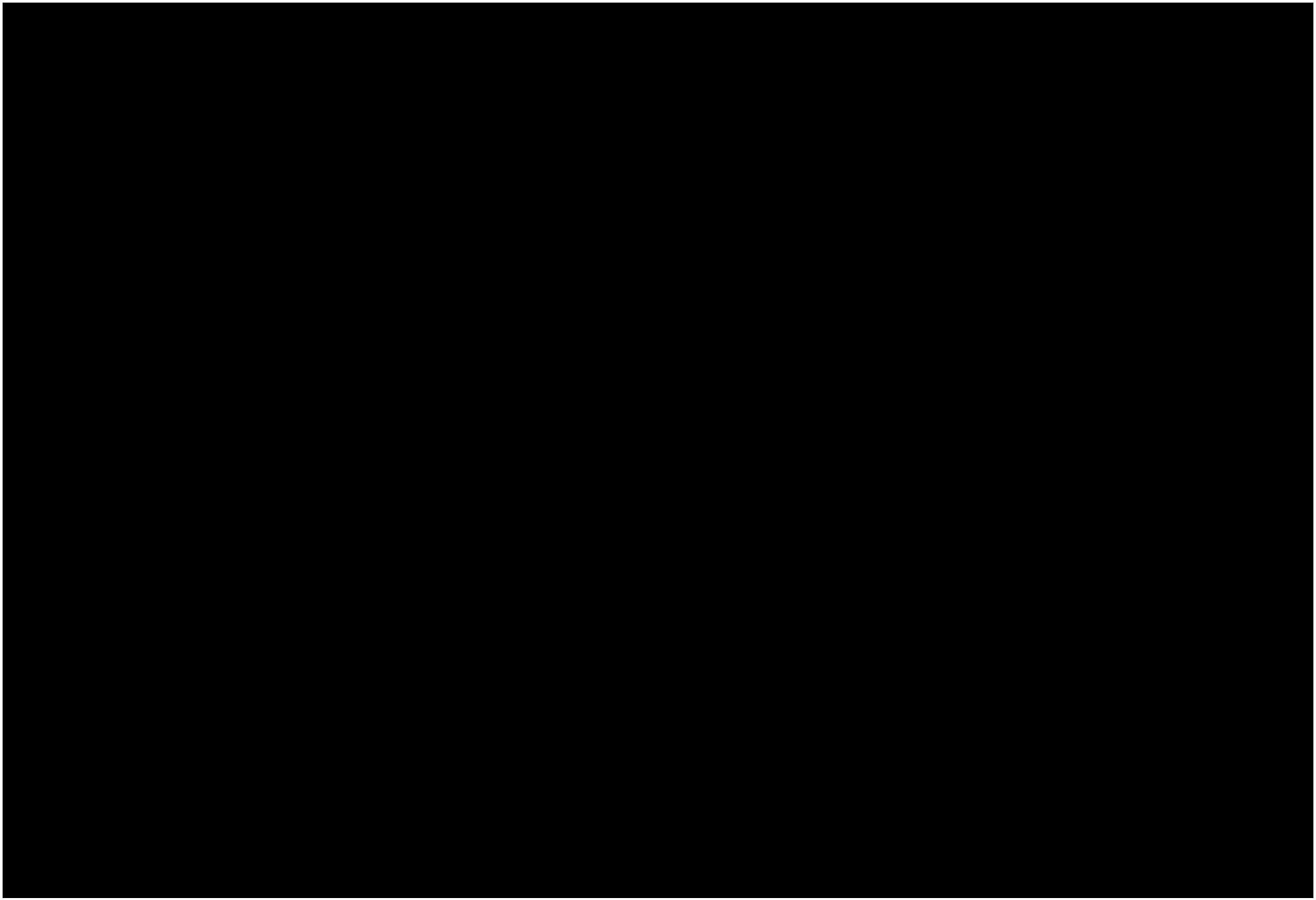
Date of Off Peak Day - 09/19/2021



Member Forecasted Off Peak Demand Day for October 2021

Panhandle Rural Electric Membership Association

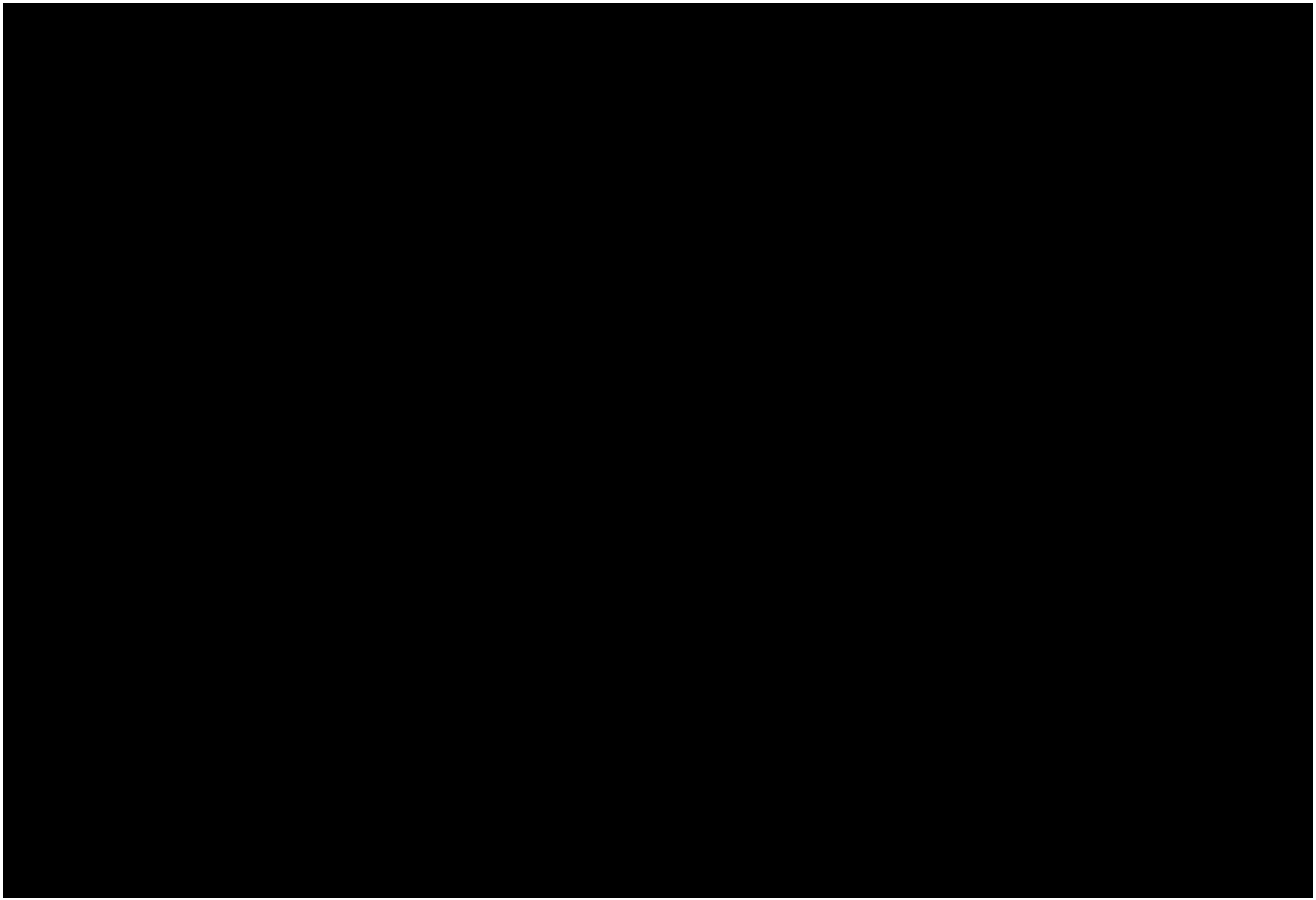
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

Panhandle Rural Electric Membership Association

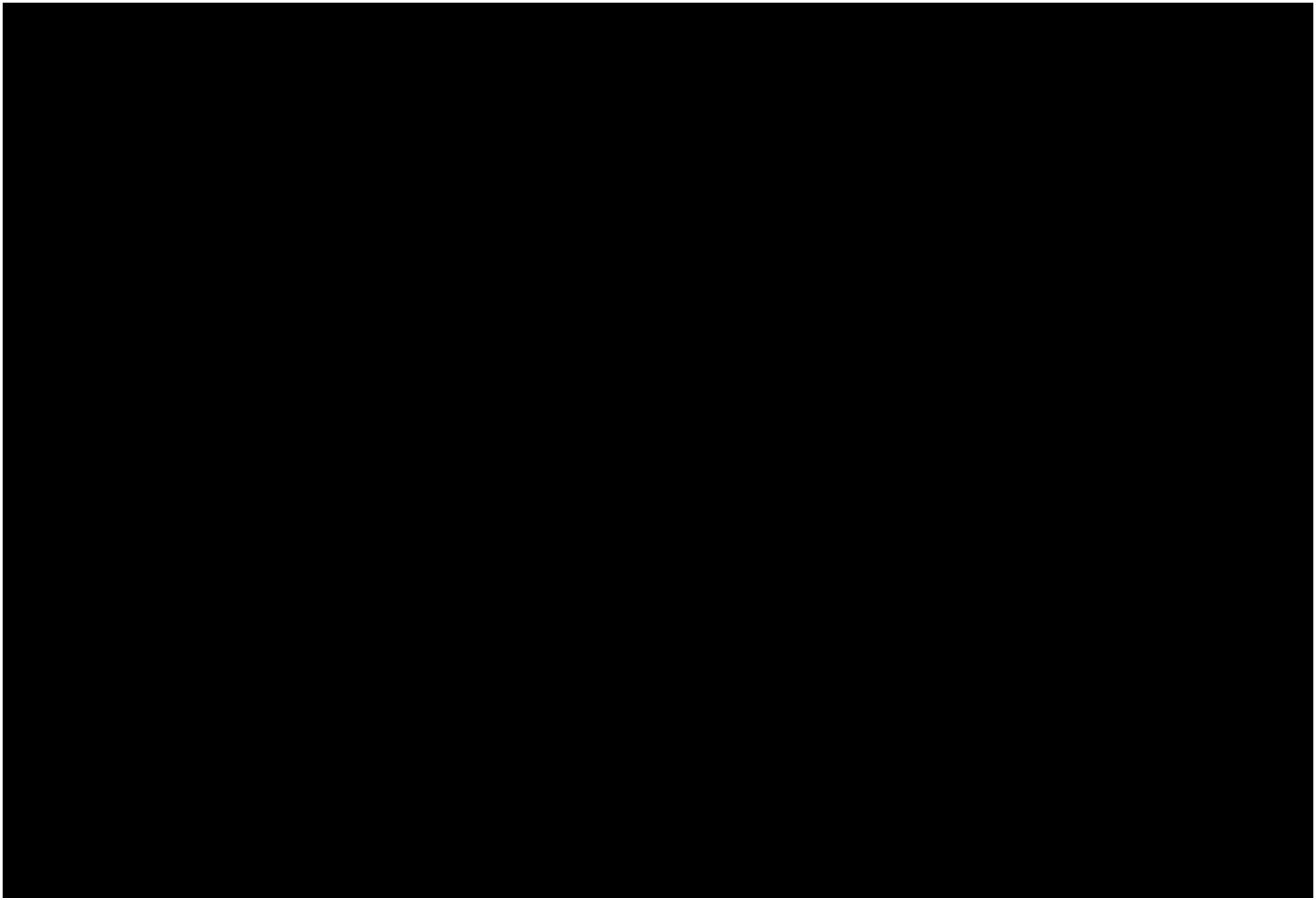
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Panhandle Rural Electric Membership Association

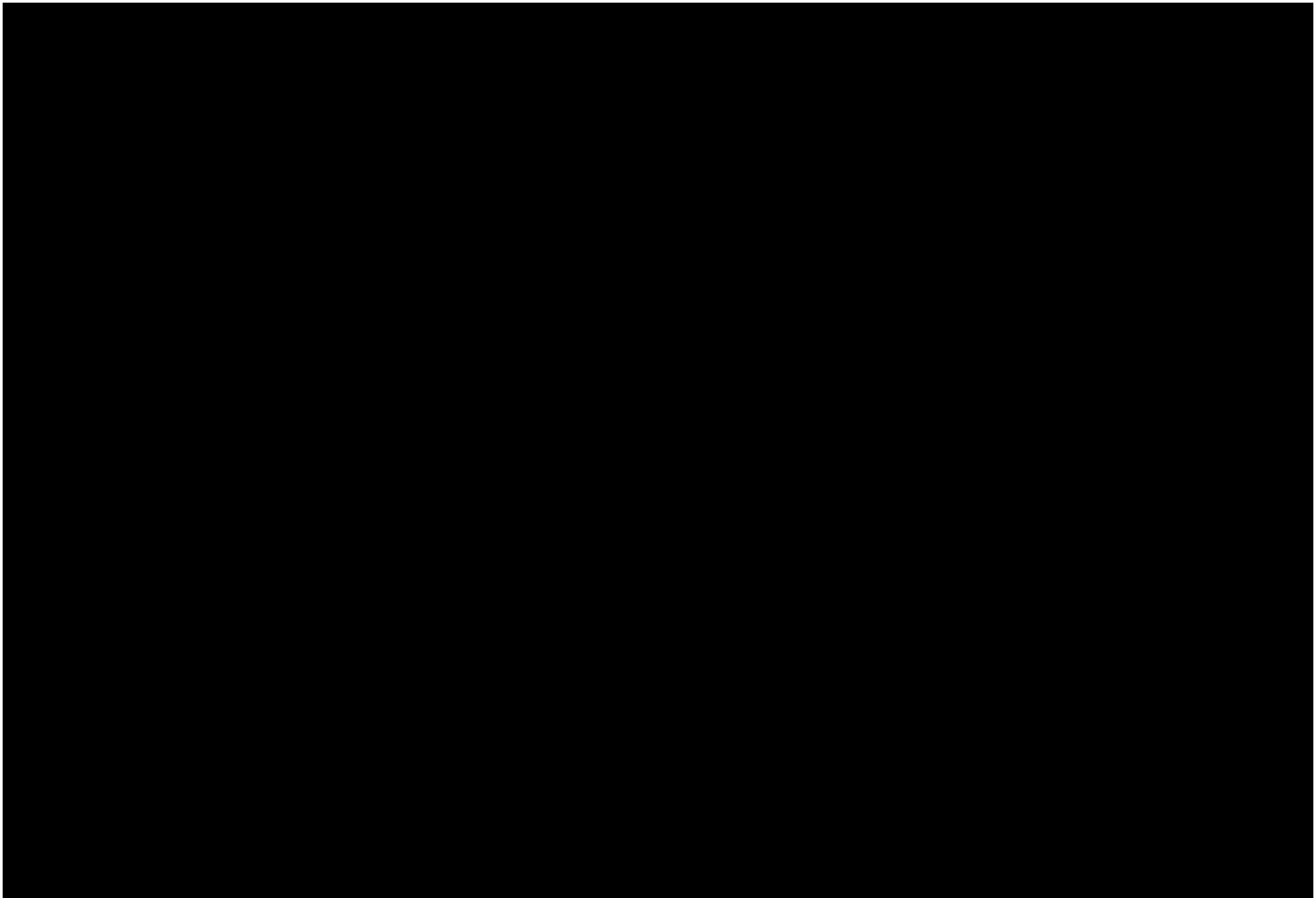
Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Poudre Valley Electric Association, Inc.

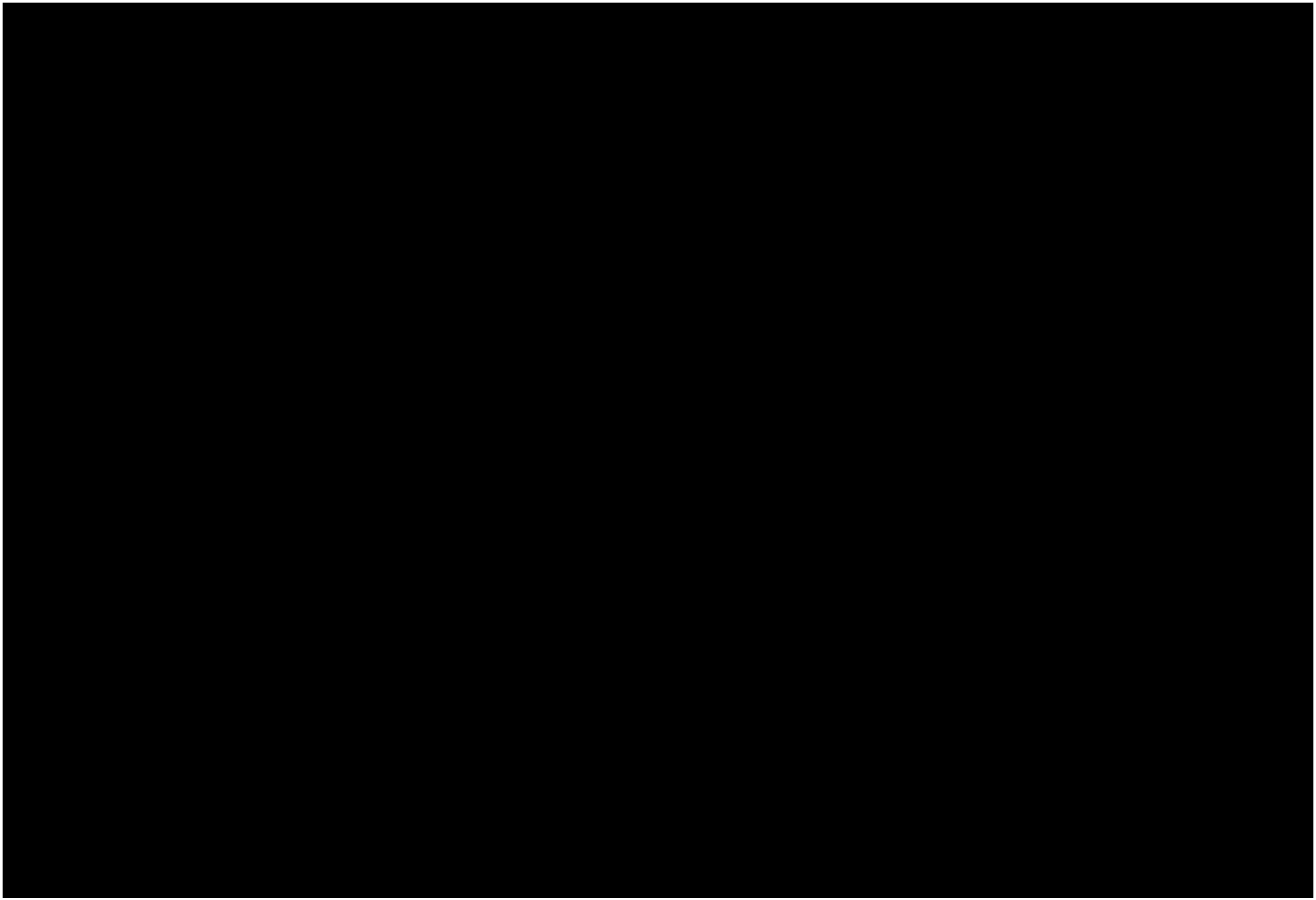
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 02/17/2021



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Member Forecasted Off Peak Demand Day for March 2021

Poudre Valley Electric Association, Inc.

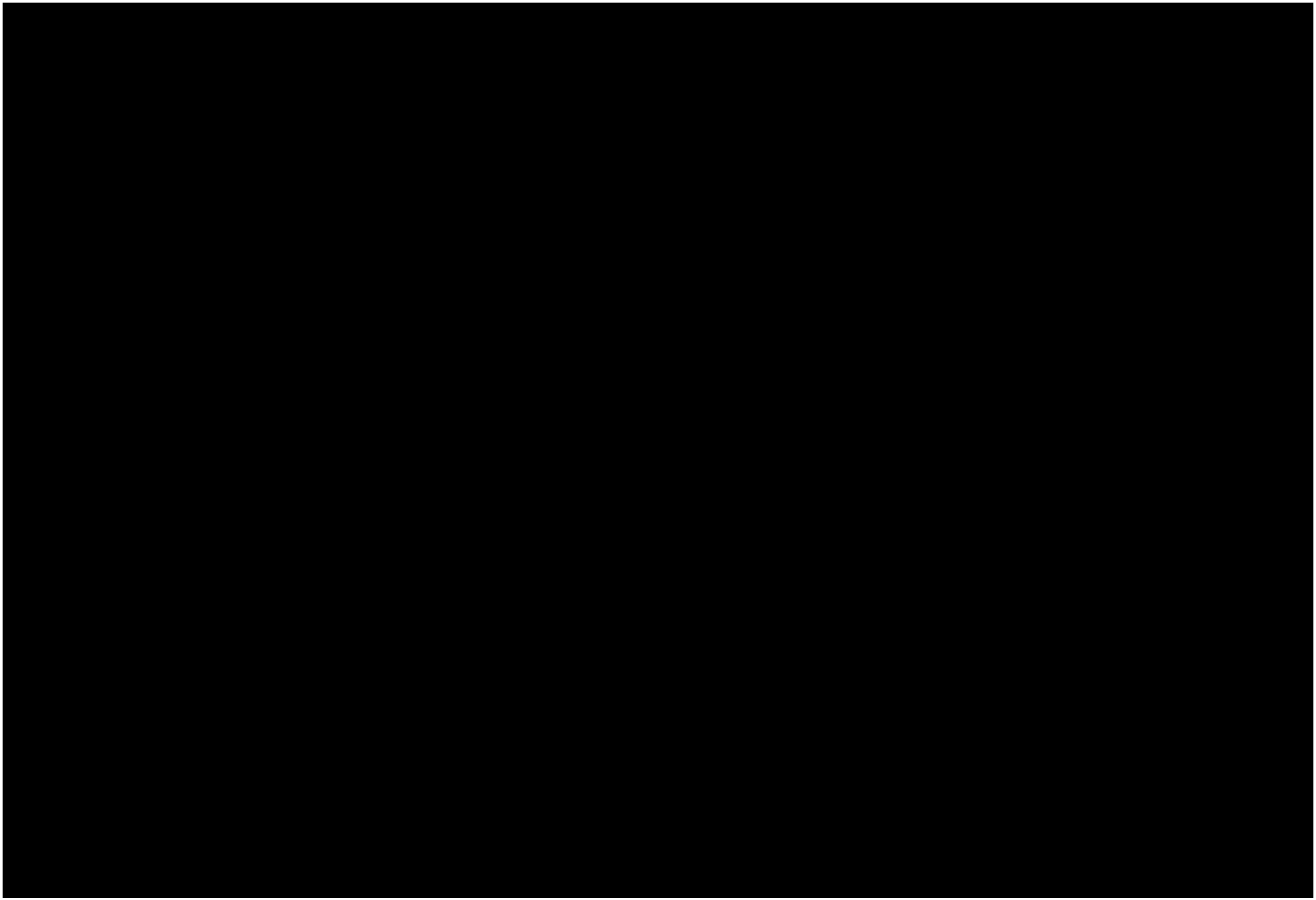
Date of Off Peak Day - 03/21/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Poudre Valley Electric Association, Inc.

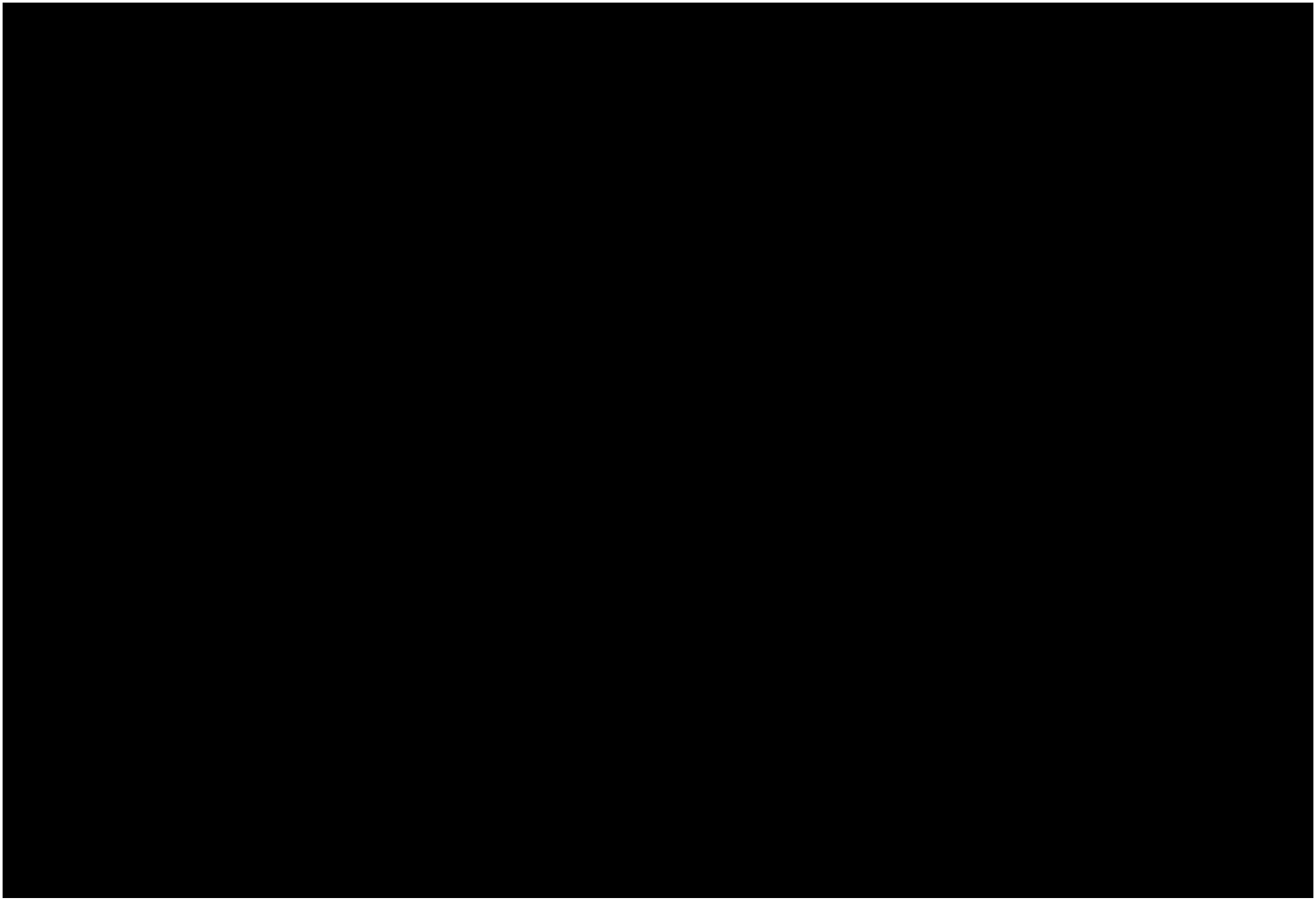
Date of Off Peak Day - 04/19/2021



Member Forecasted Off Peak Demand Day for May 2021

Poudre Valley Electric Association, Inc.

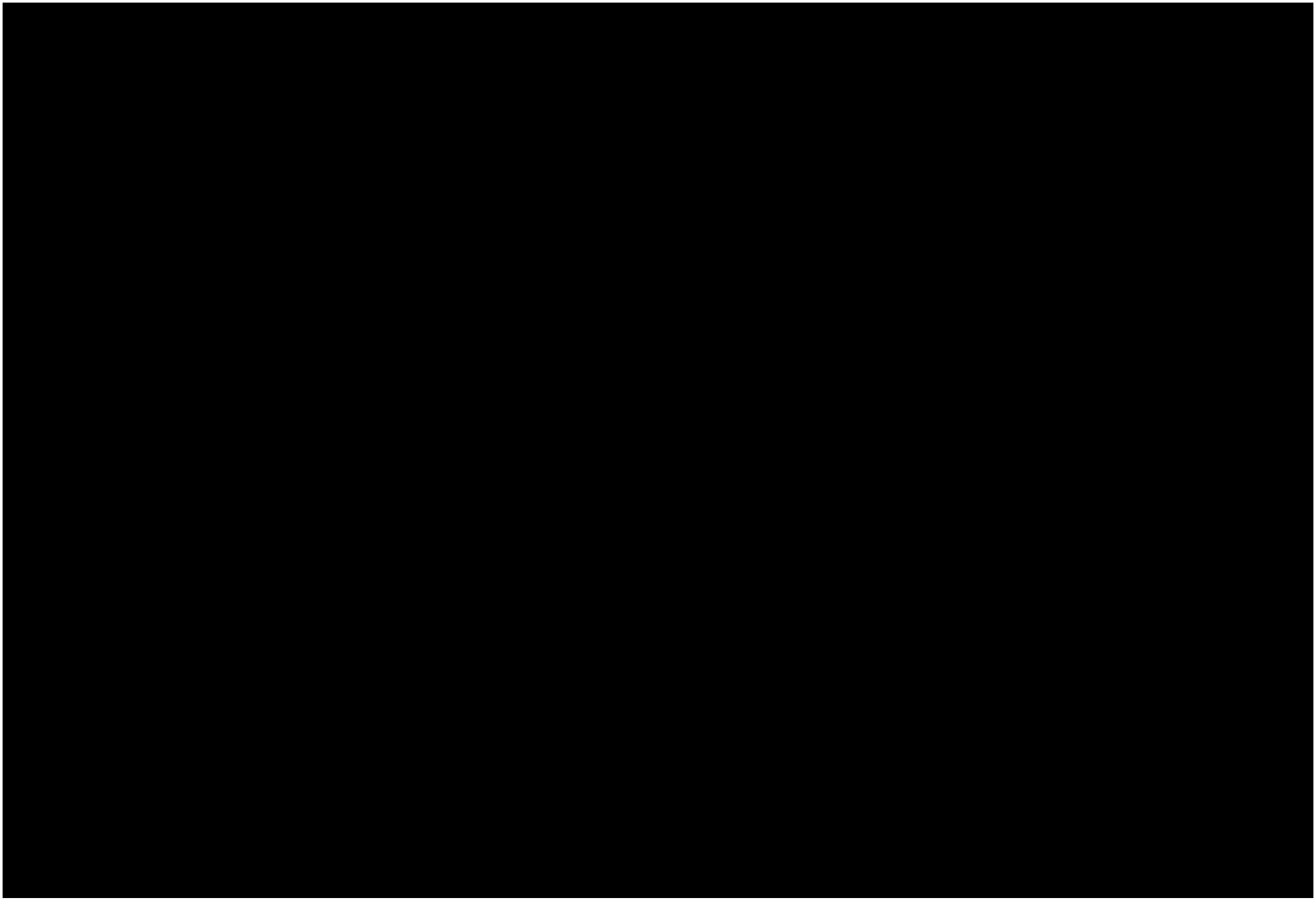
Date of Off Peak Day - 05/31/2021



Member Forecasted Off Peak Demand Day for June 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 06/21/2021



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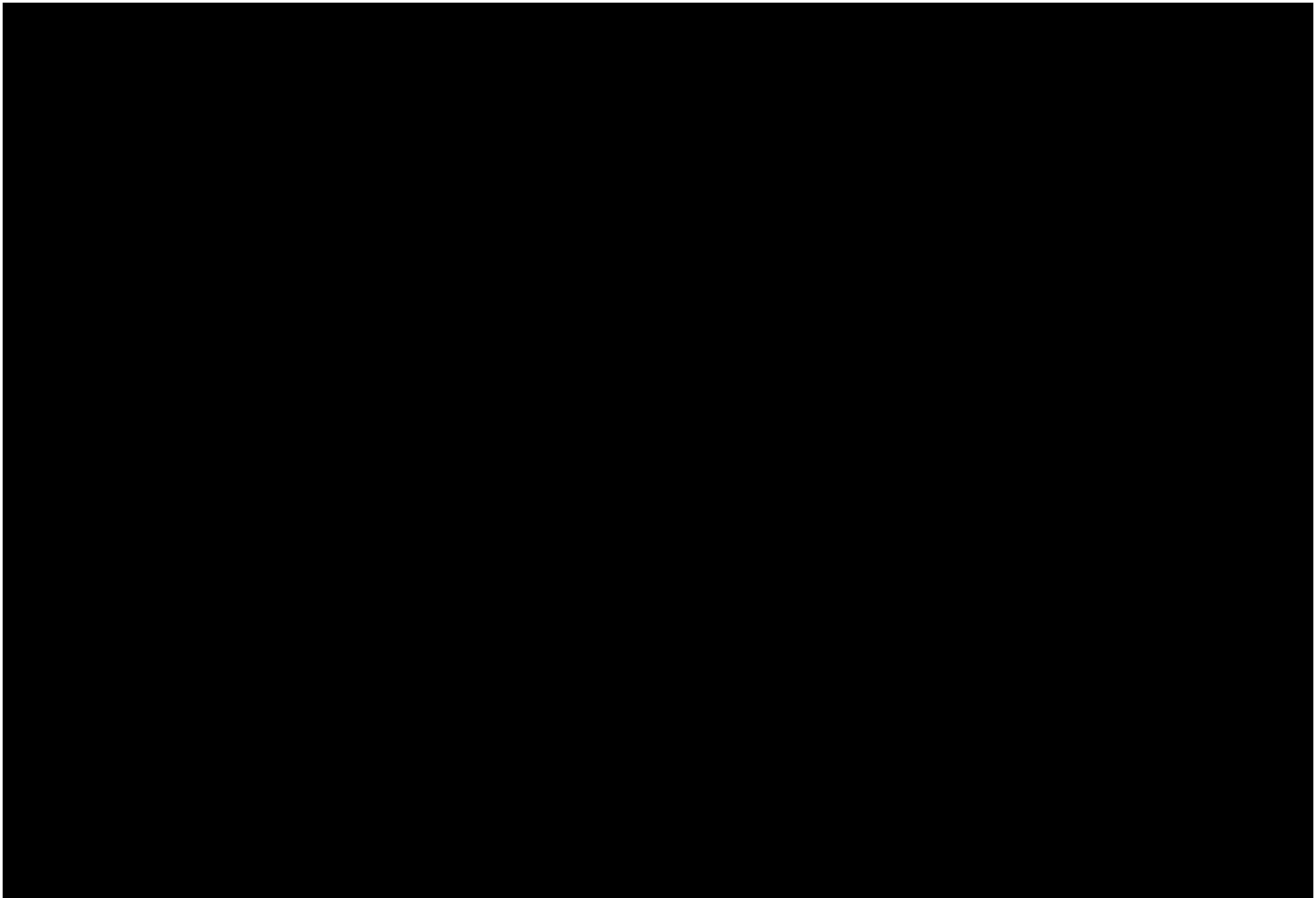
Member Forecasted Off Peak Demand Day for July 2021

Poudre Valley Electric Association, Inc.

Date of Off Peak Day - 07/04/2021



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Member Forecasted Off Peak Demand Day for August 2021

Poudre Valley Electric Association, Inc.

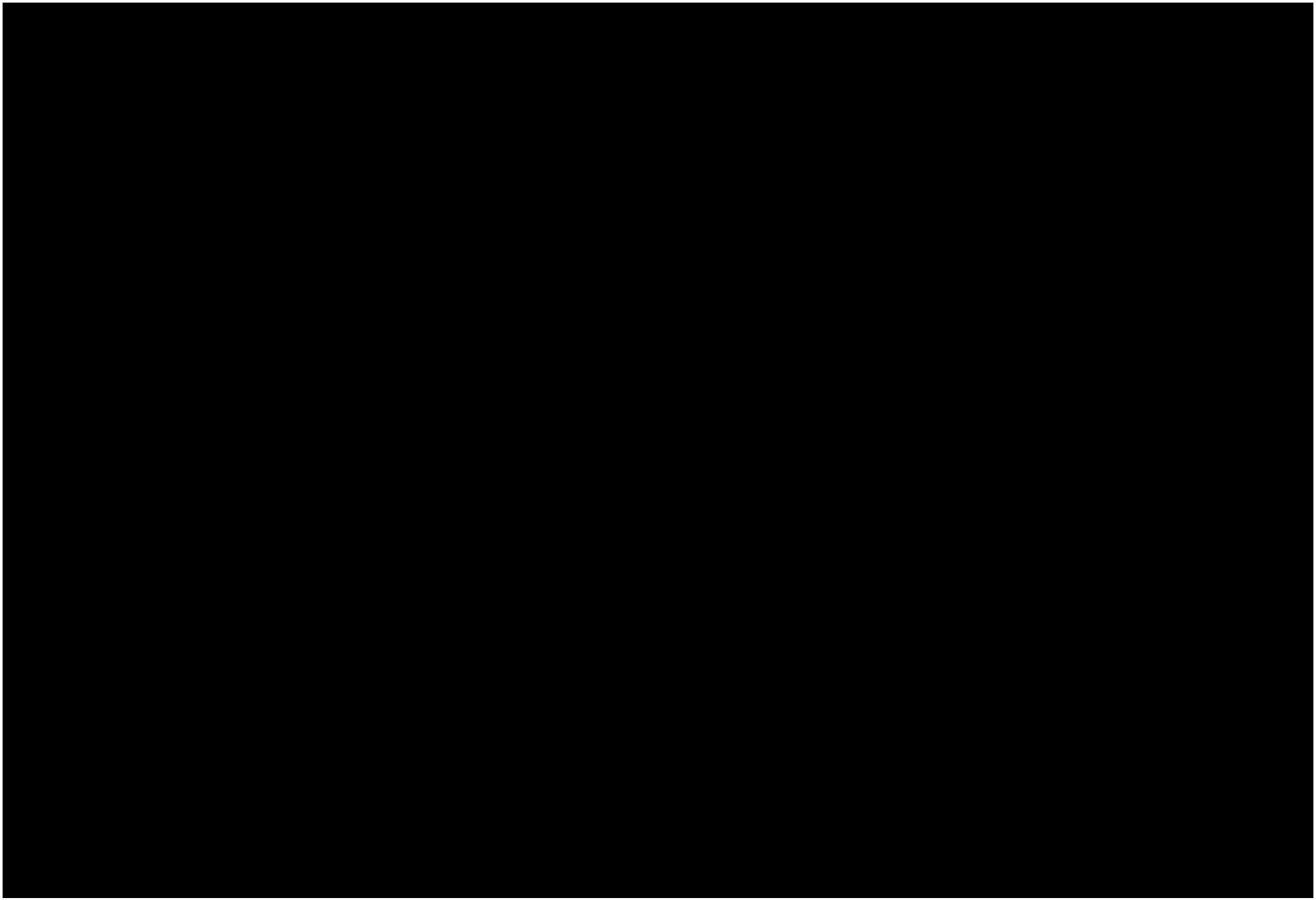
Date of Off Peak Day - 08/30/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Poudre Valley Electric Association, Inc.

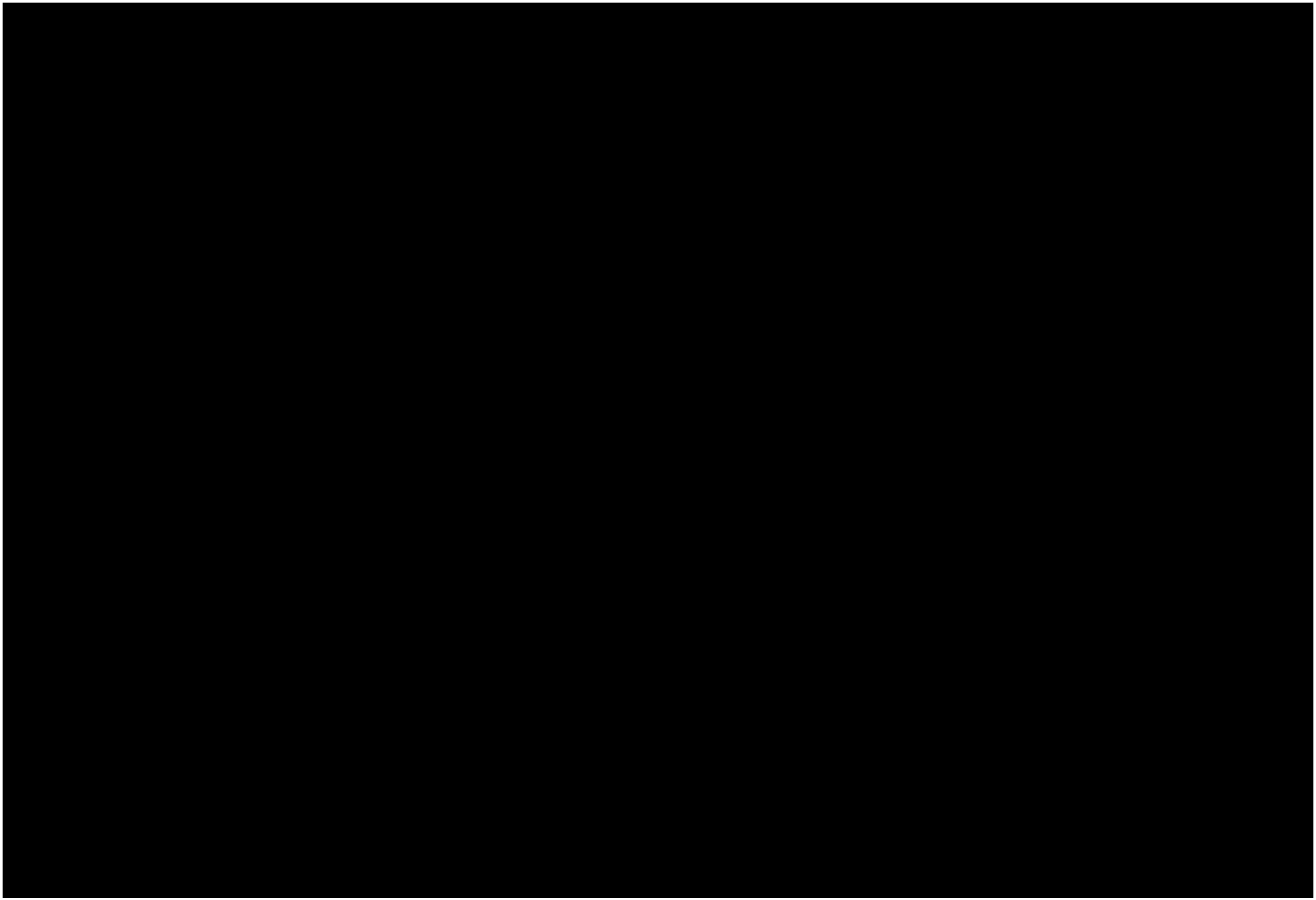
Date of Off Peak Day - 09/13/2021



Member Forecasted Off Peak Demand Day for October 2021

Poudre Valley Electric Association, Inc.

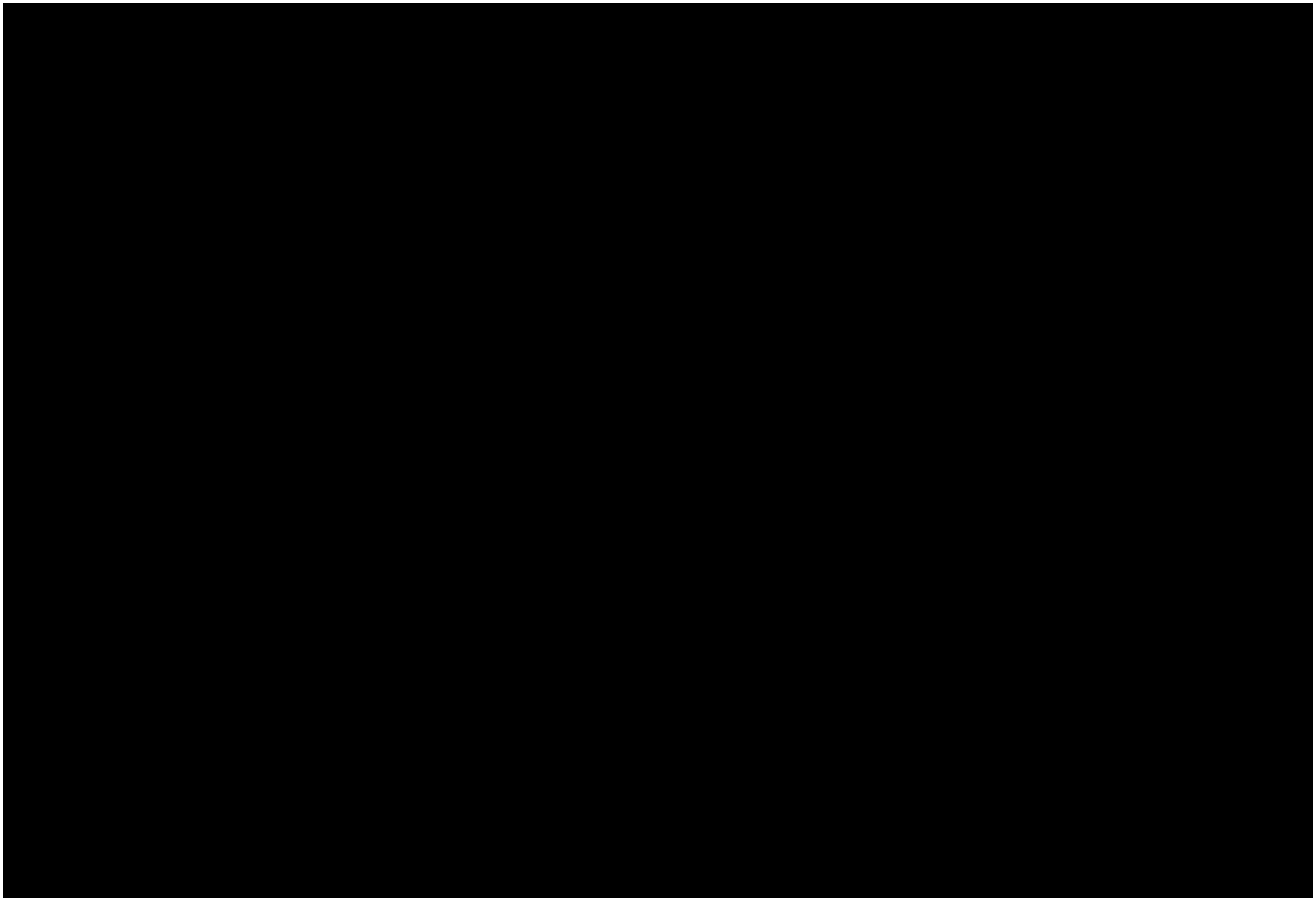
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Poudre Valley Electric Association, Inc.

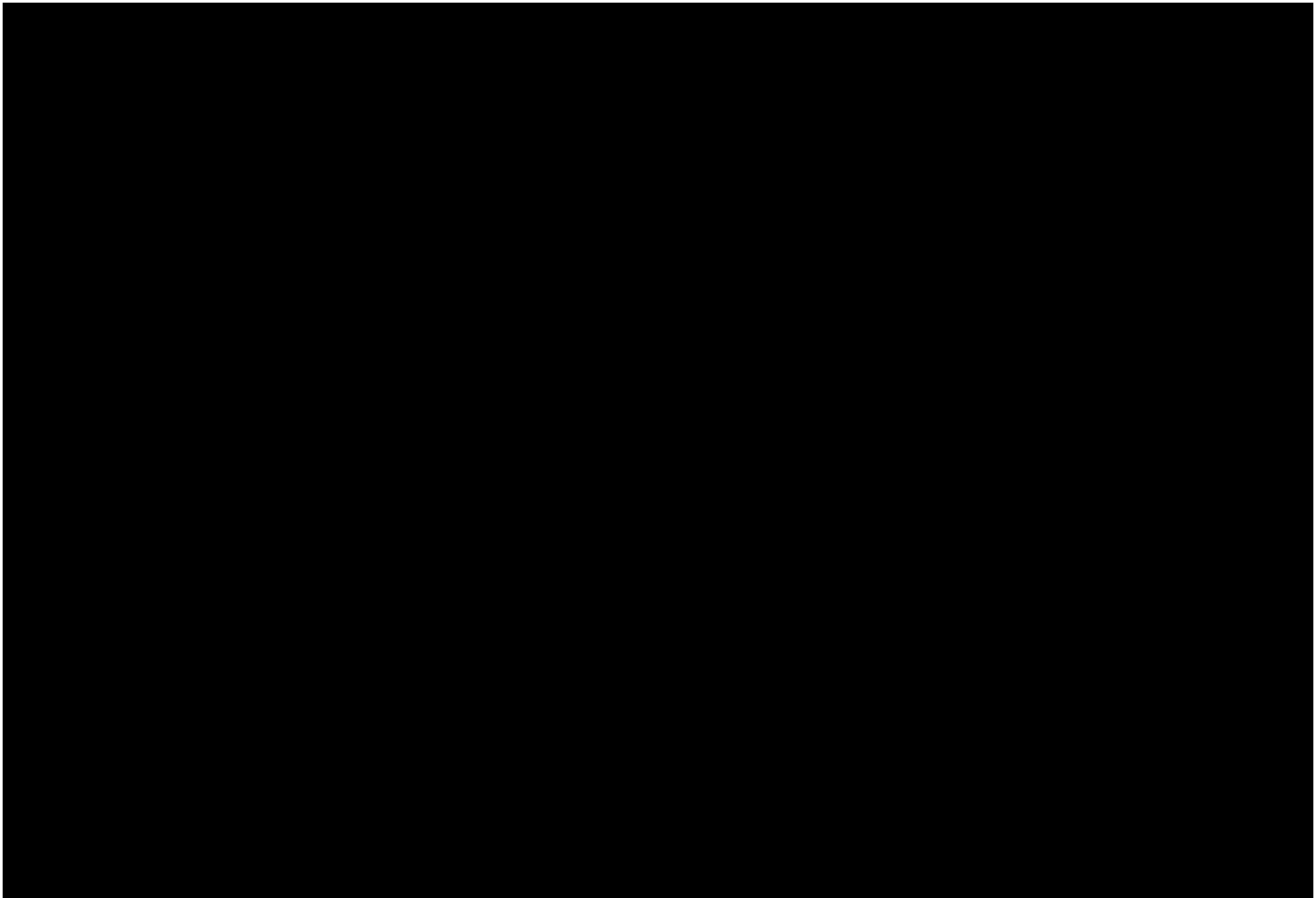
Date of Off Peak Day - 11/19/2021



Member Forecasted Off Peak Demand Day for December 2021

Poudre Valley Electric Association, Inc.

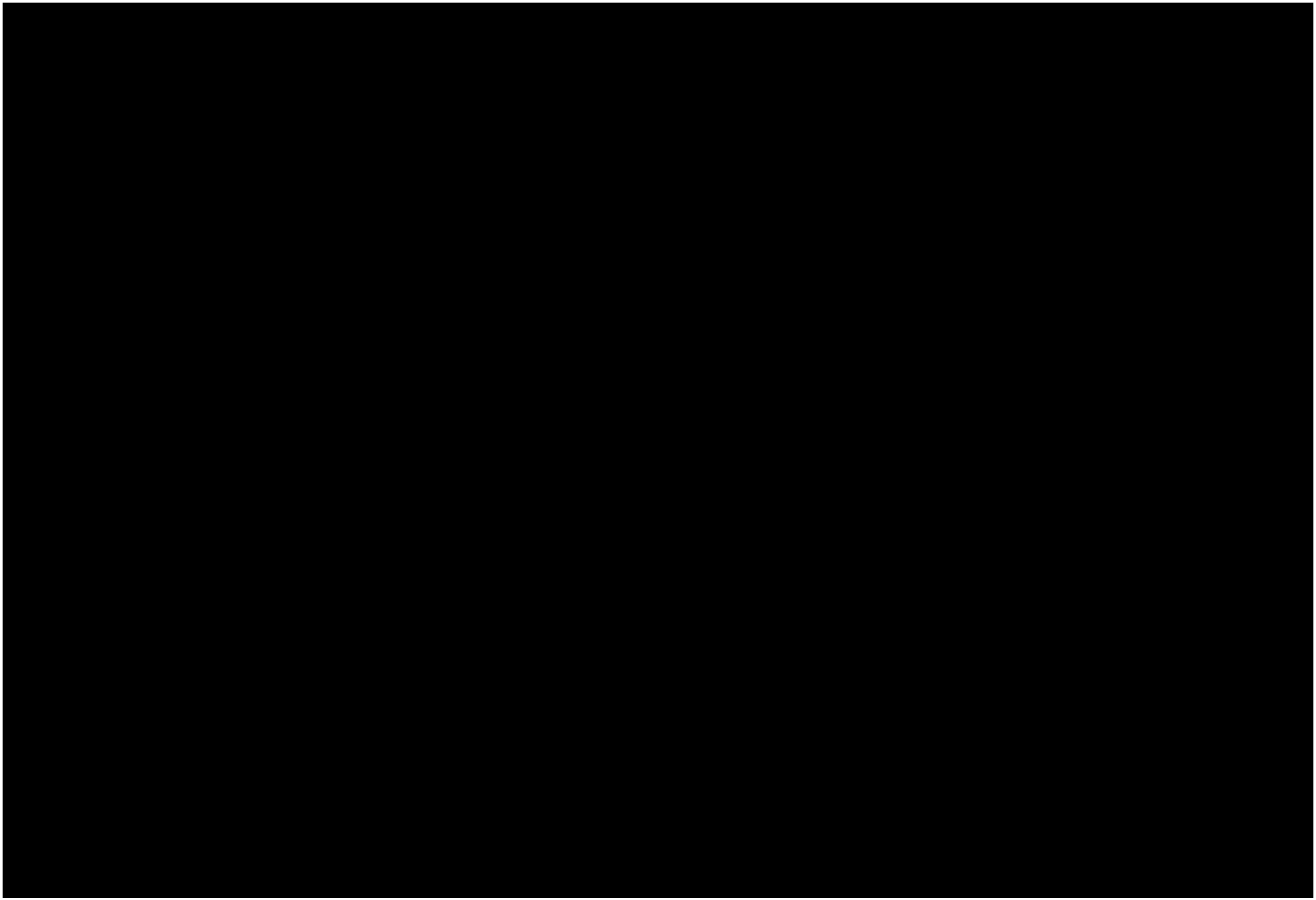
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.

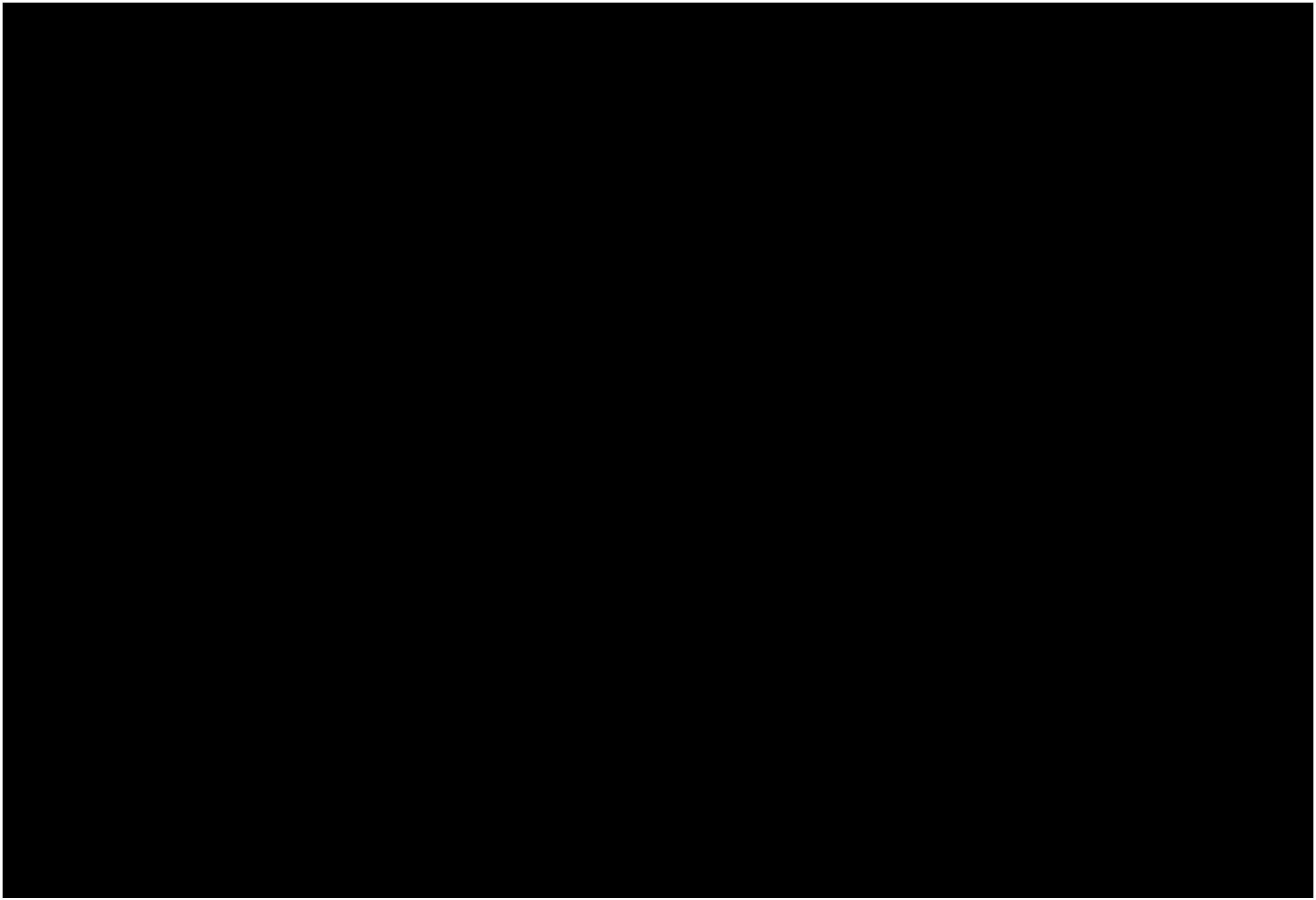
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of Off Peak Day - 02/02/2021



Member Forecasted Off Peak Demand Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

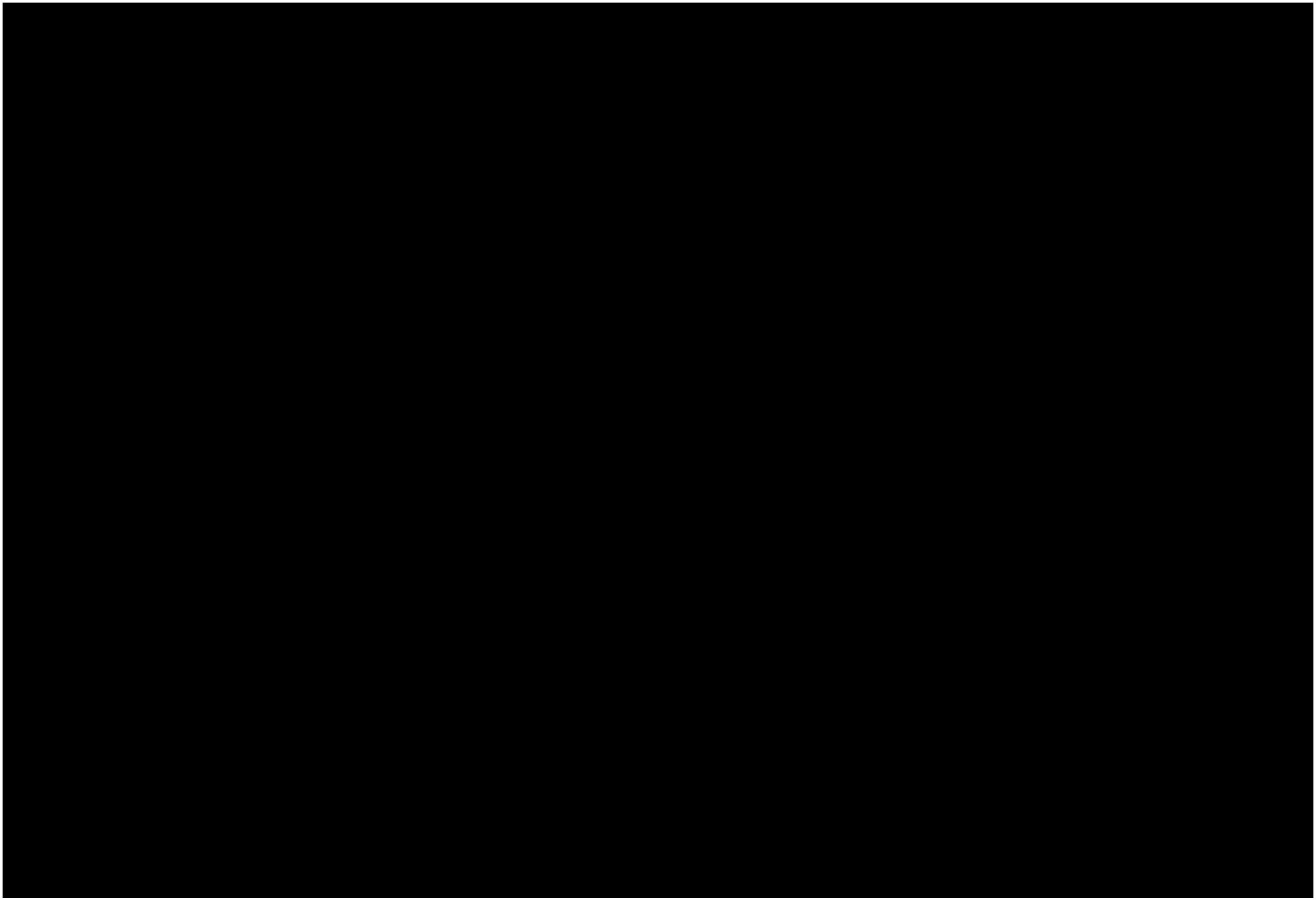
Date of Off Peak Day - 03/28/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.

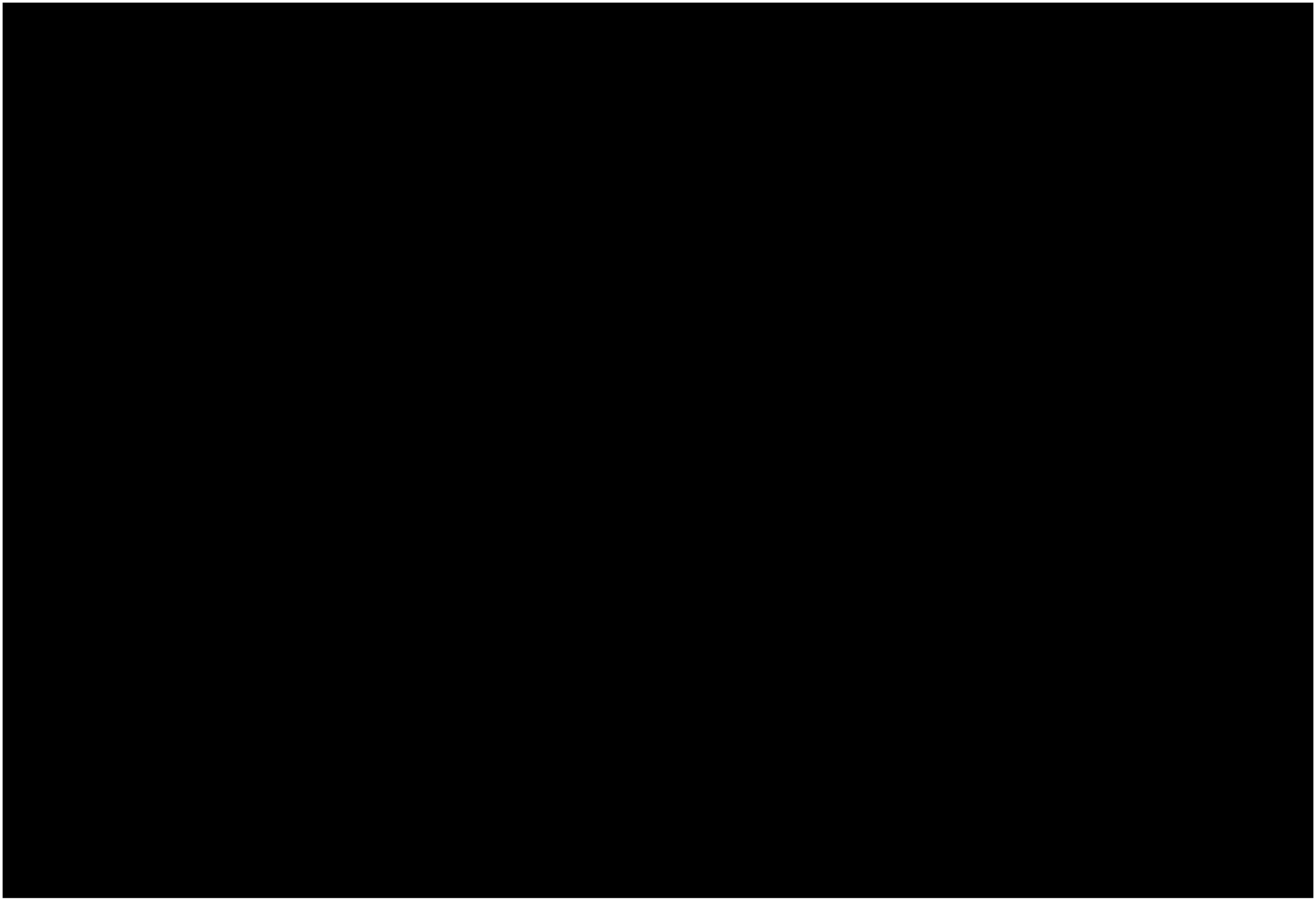
Date of Off Peak Day - 04/18/2021



Member Forecasted Off Peak Demand Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

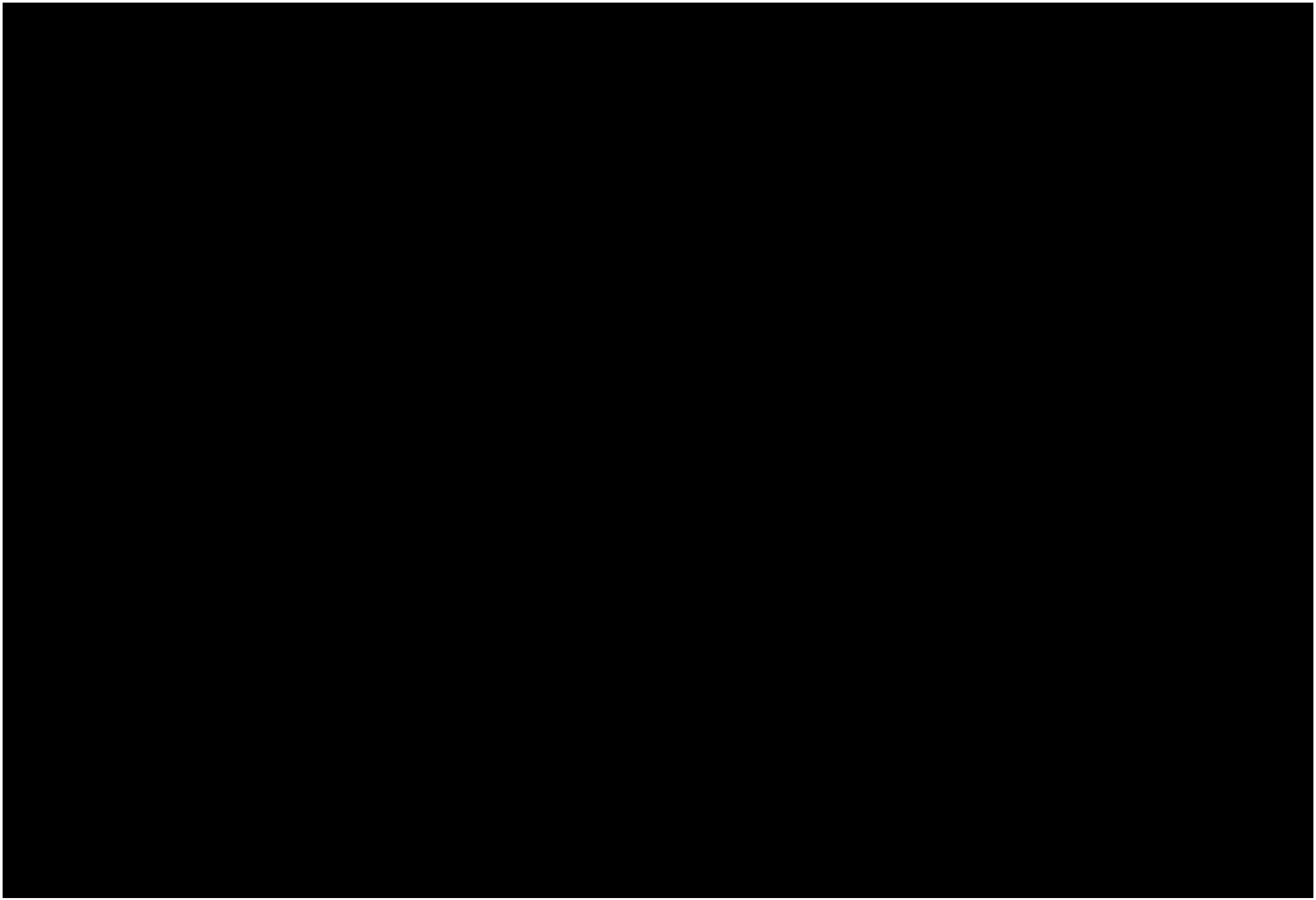
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.

Date of Off Peak Day - 06/19/2021



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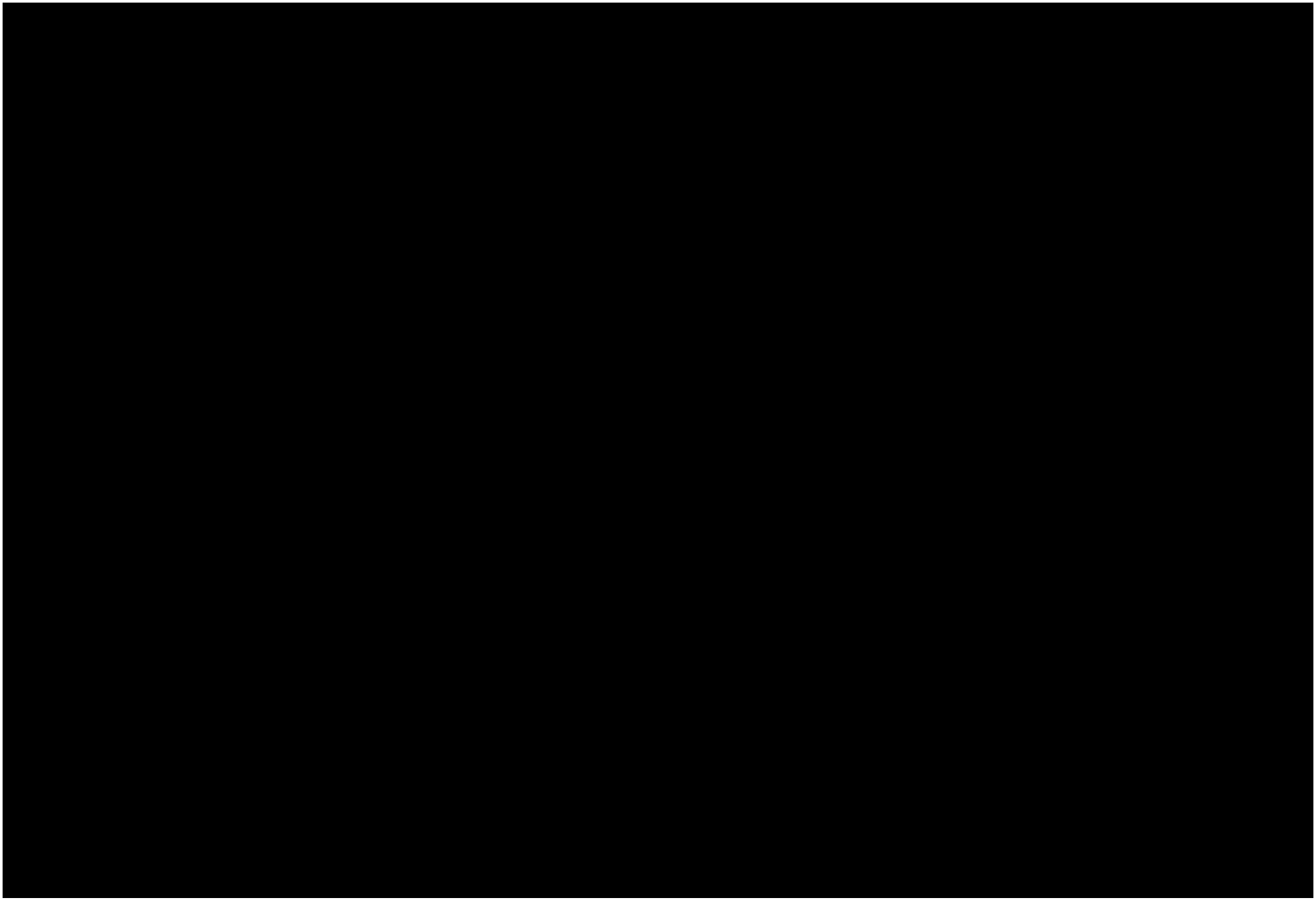
Member Forecasted Off Peak Demand Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

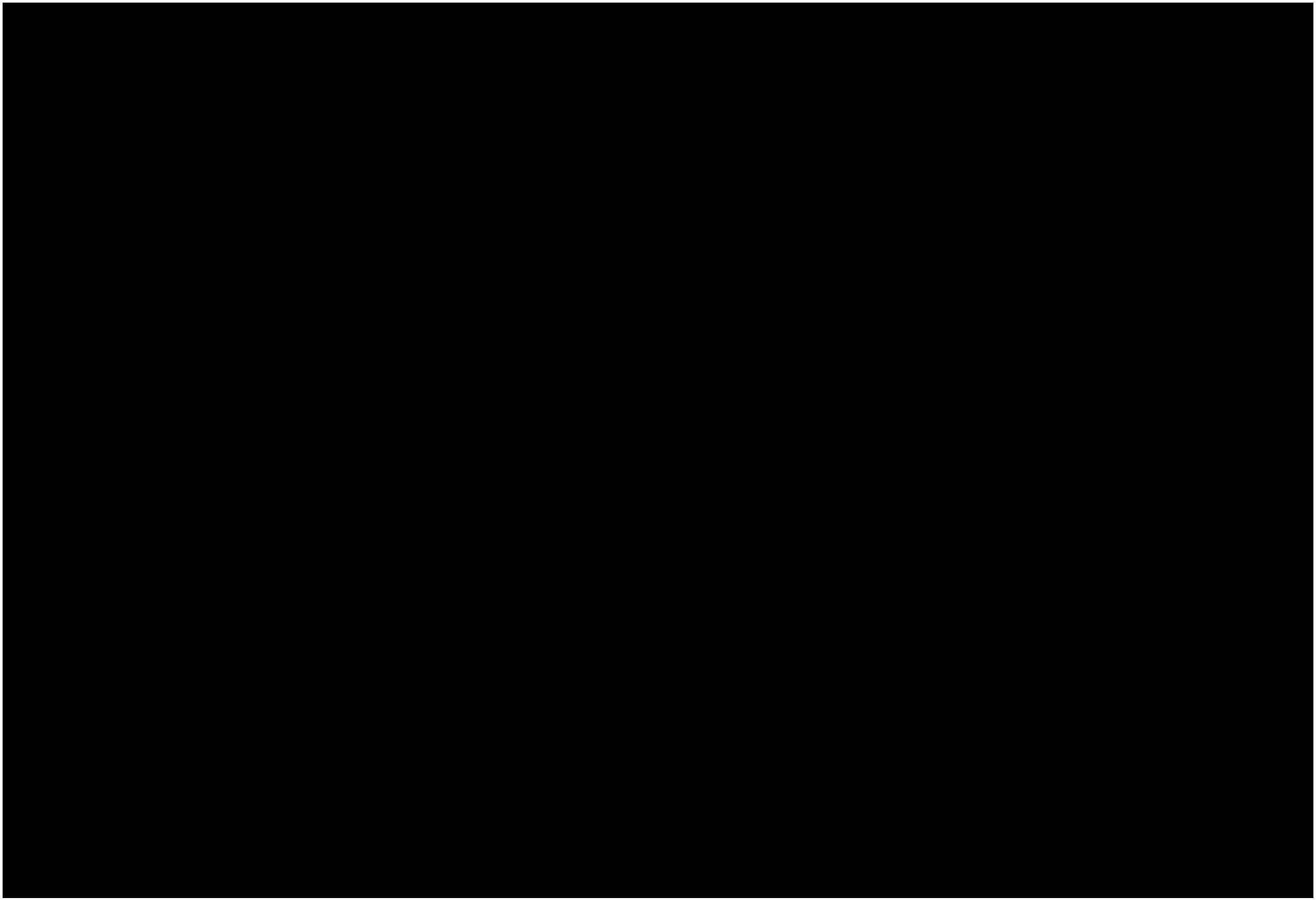
Date of Off Peak Day - 07/06/2021



Member Forecasted Off Peak Demand Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

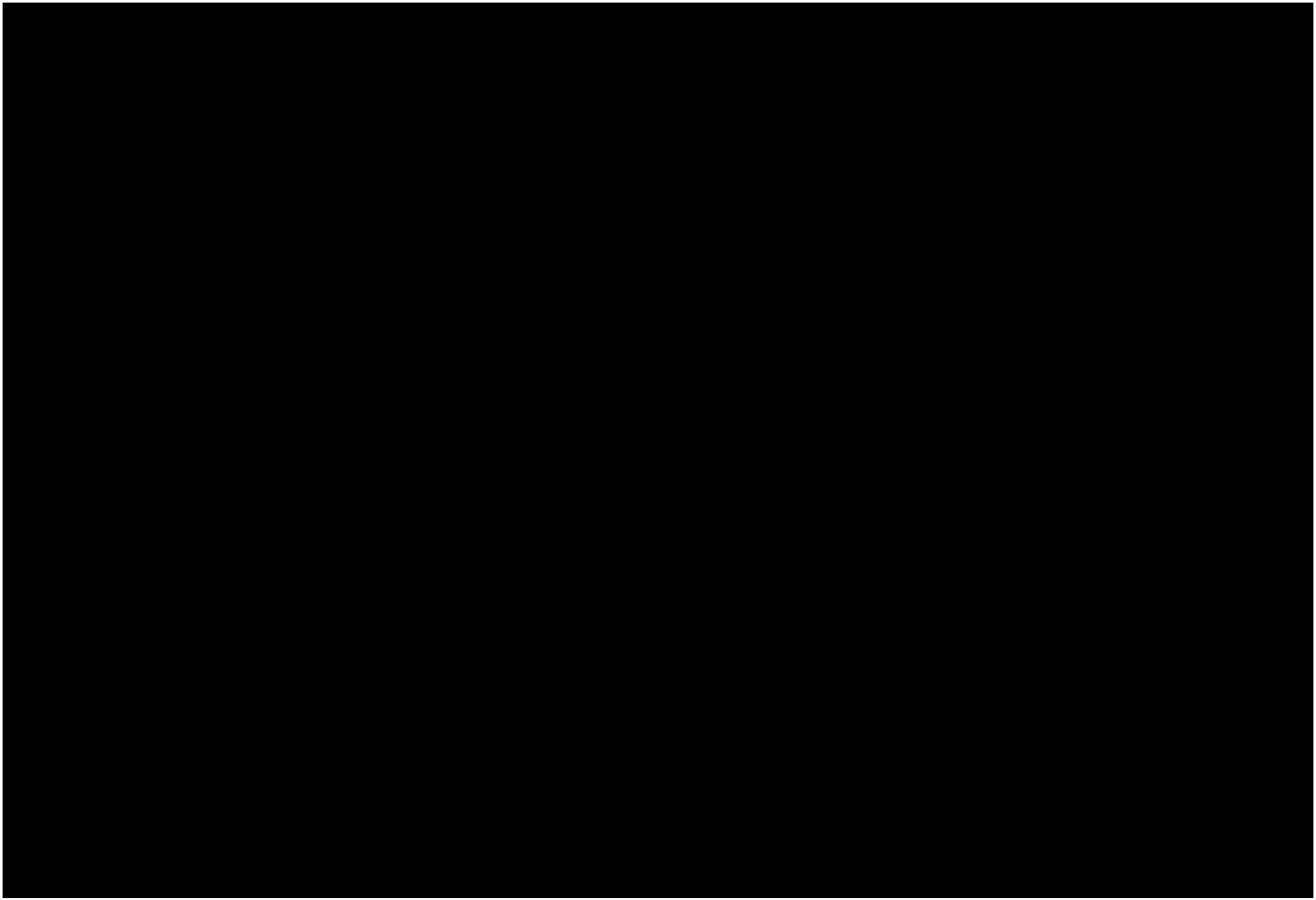
Date of Off Peak Day - 08/24/2021



Member Forecasted Off Peak Demand Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

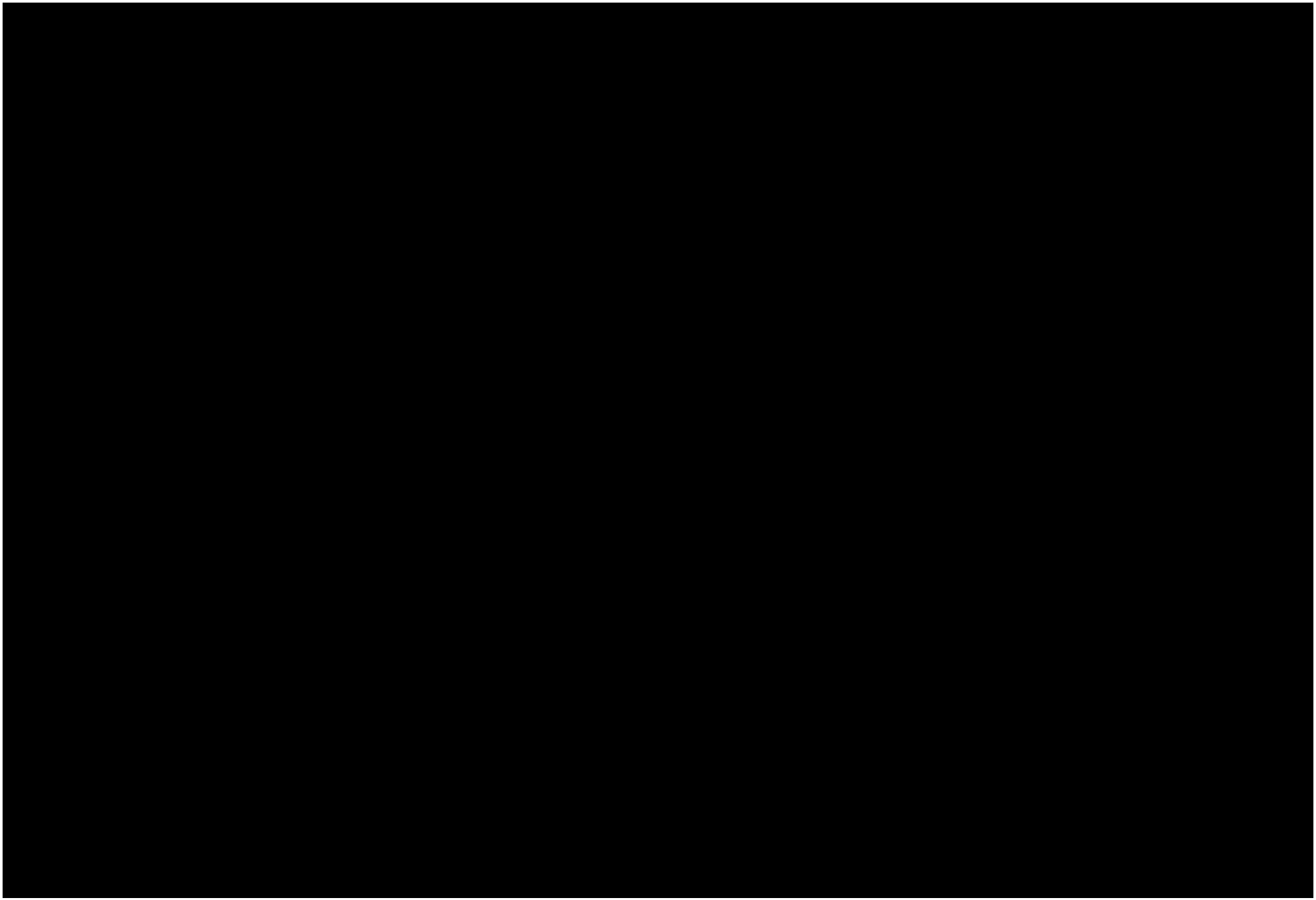
Date of Off Peak Day - 09/14/2021



Member Forecasted Off Peak Demand Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

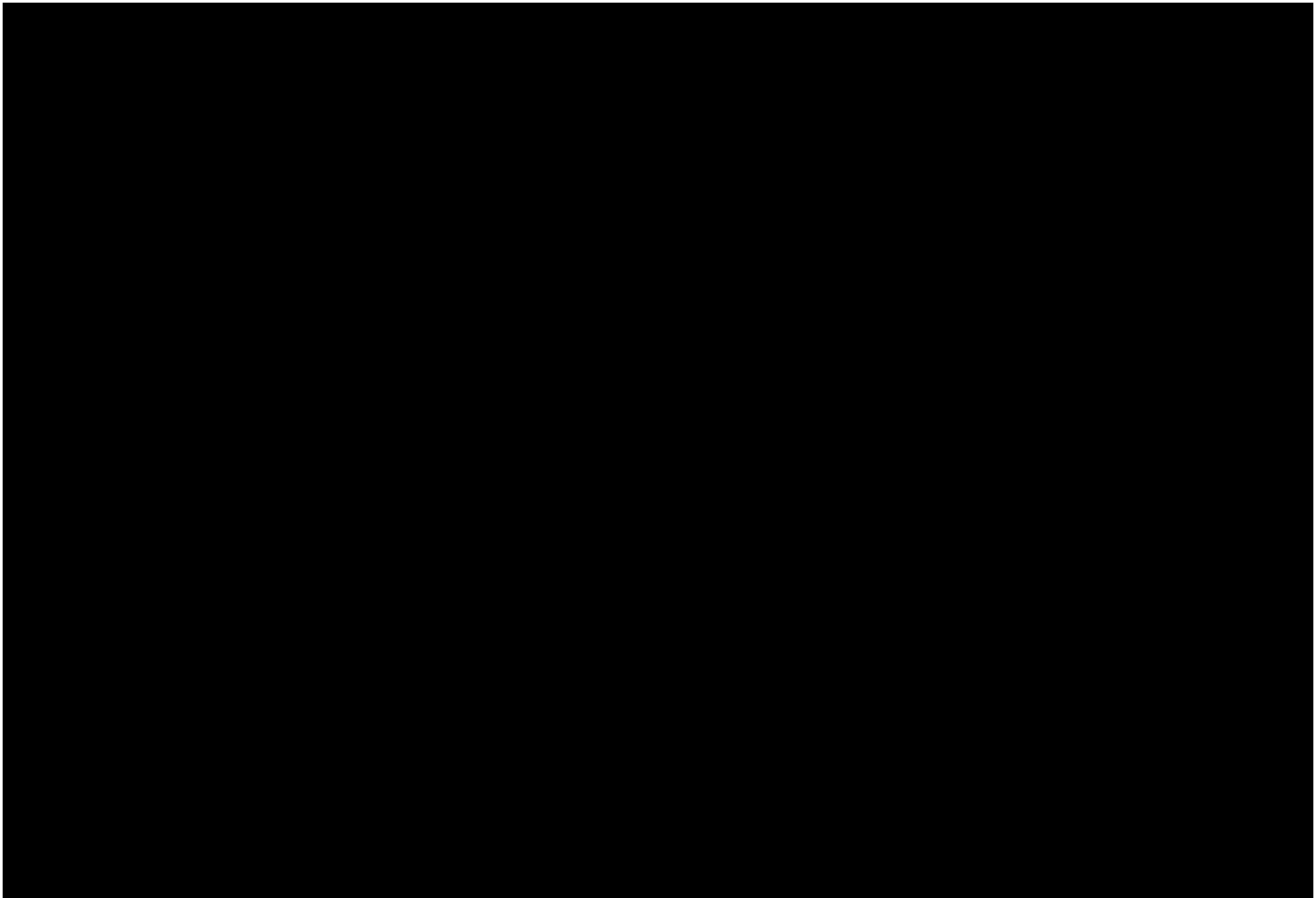
Date of Off Peak Day - 10/14/2021



Member Forecasted Off Peak Demand Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

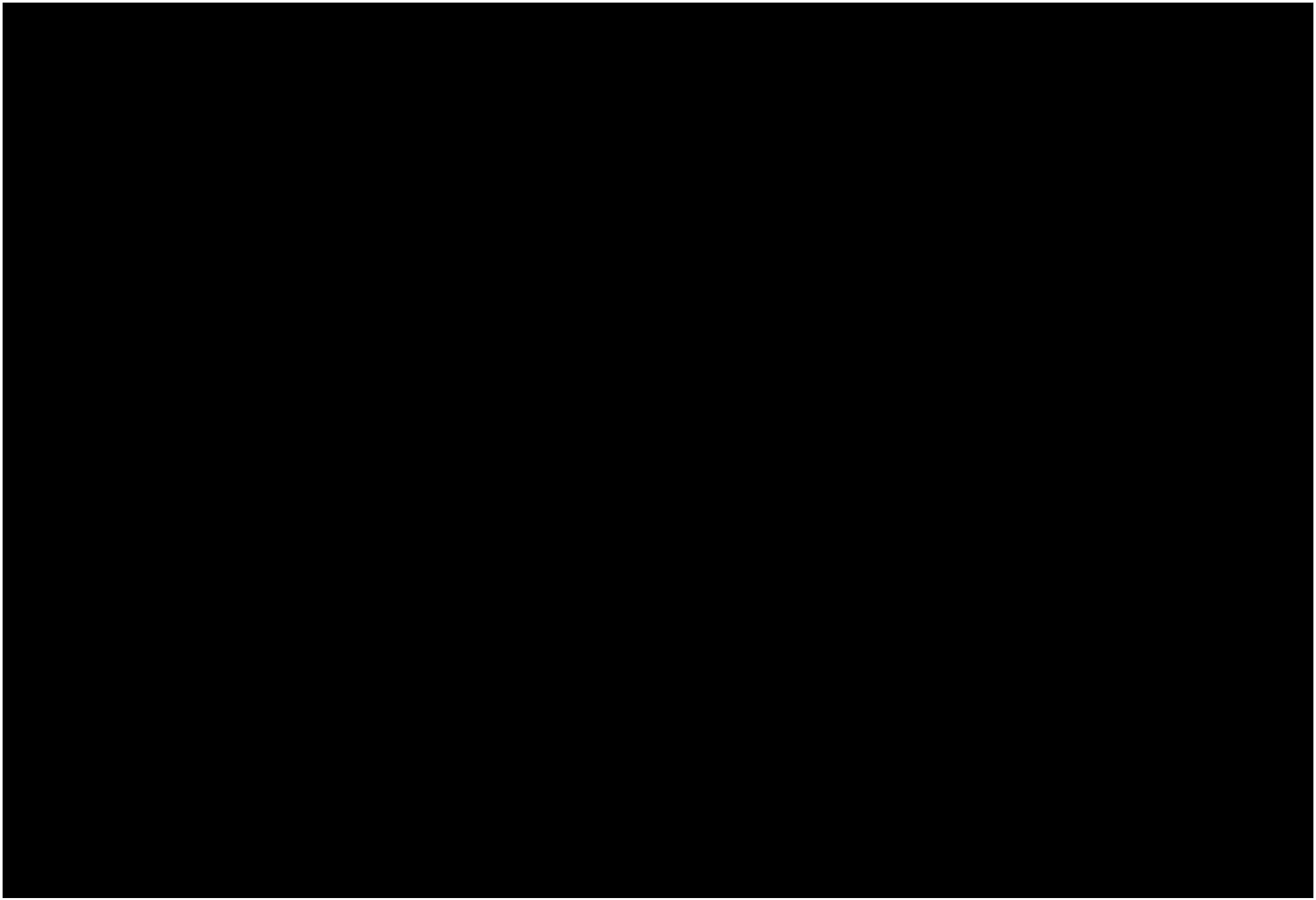
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

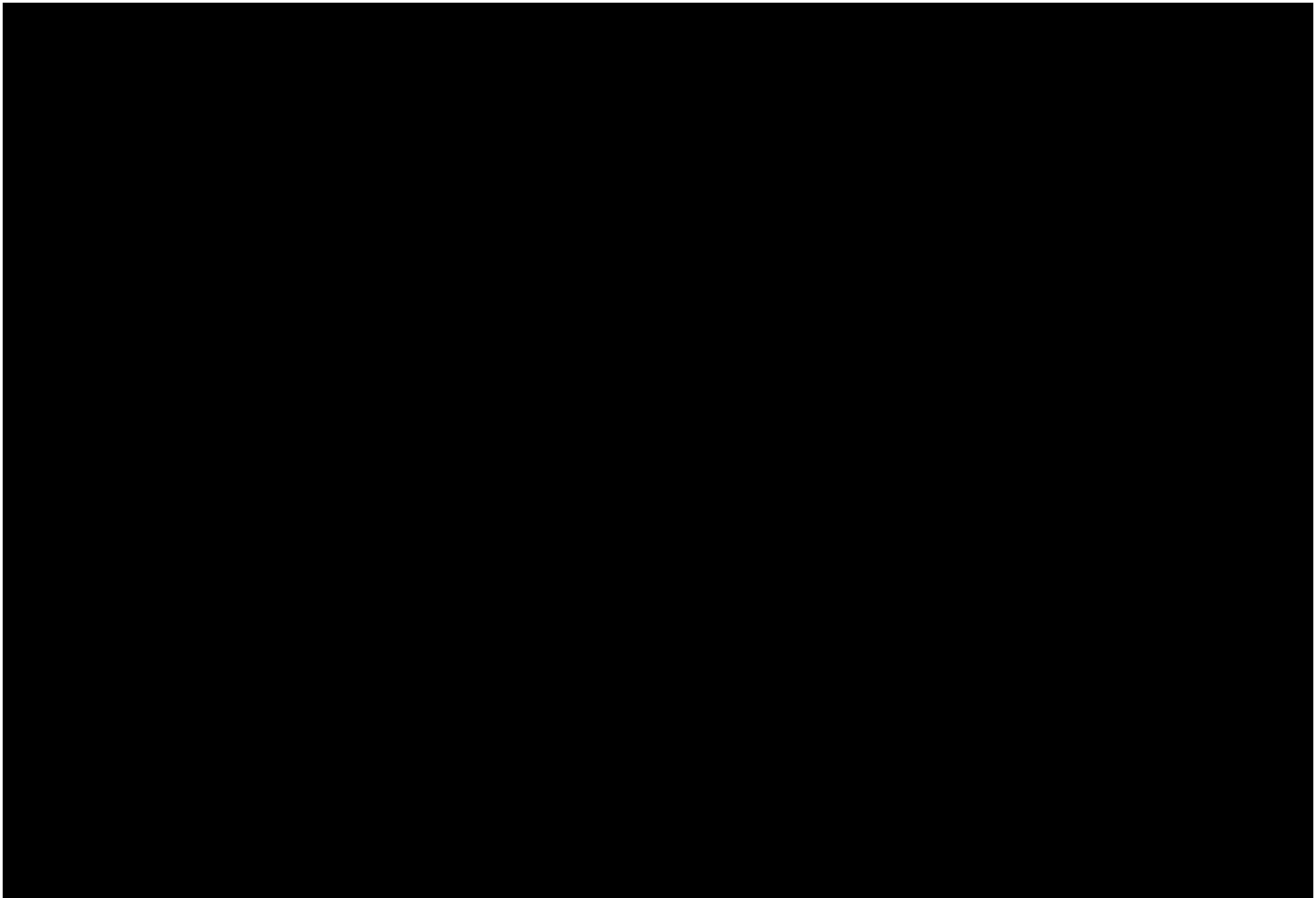
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Roosevelt Public Power District

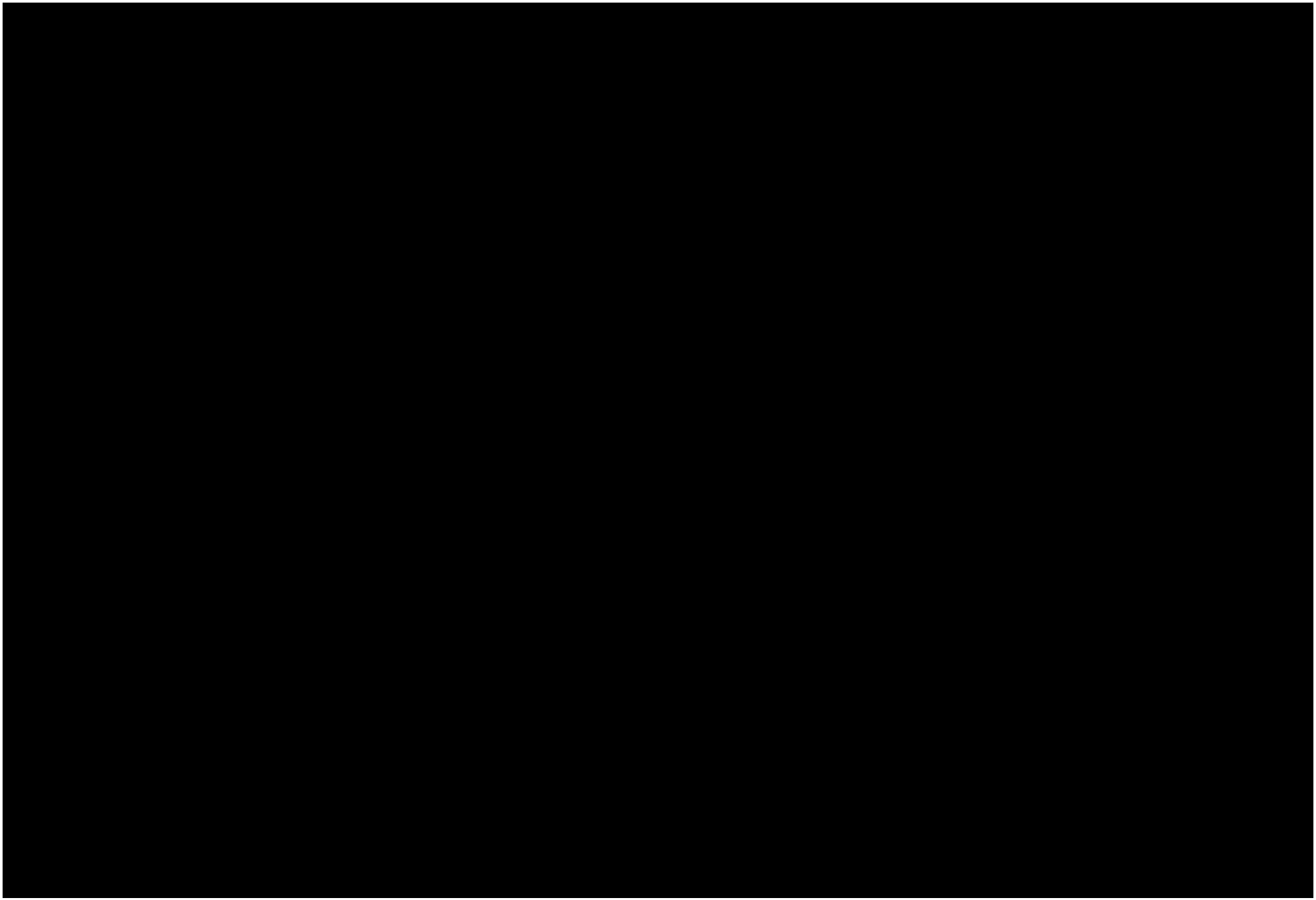
Date of Off Peak Day - 01/18/2021



Member Forecasted Off Peak Demand Day for February 2021

Roosevelt Public Power District

Date of Off Peak Day - 02/16/2021



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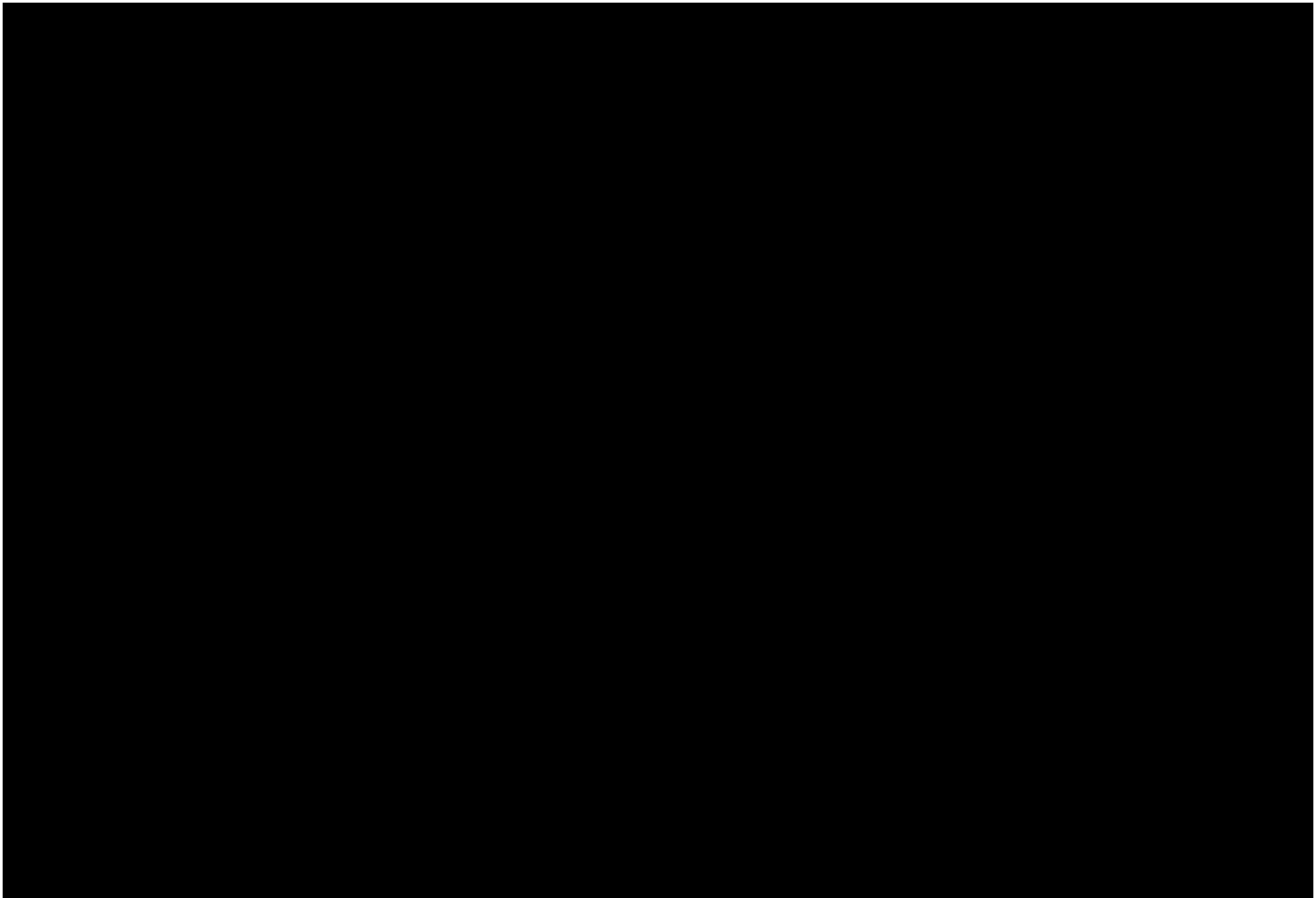
Member Forecasted Off Peak Demand Day for March 2021

Roosevelt Public Power District

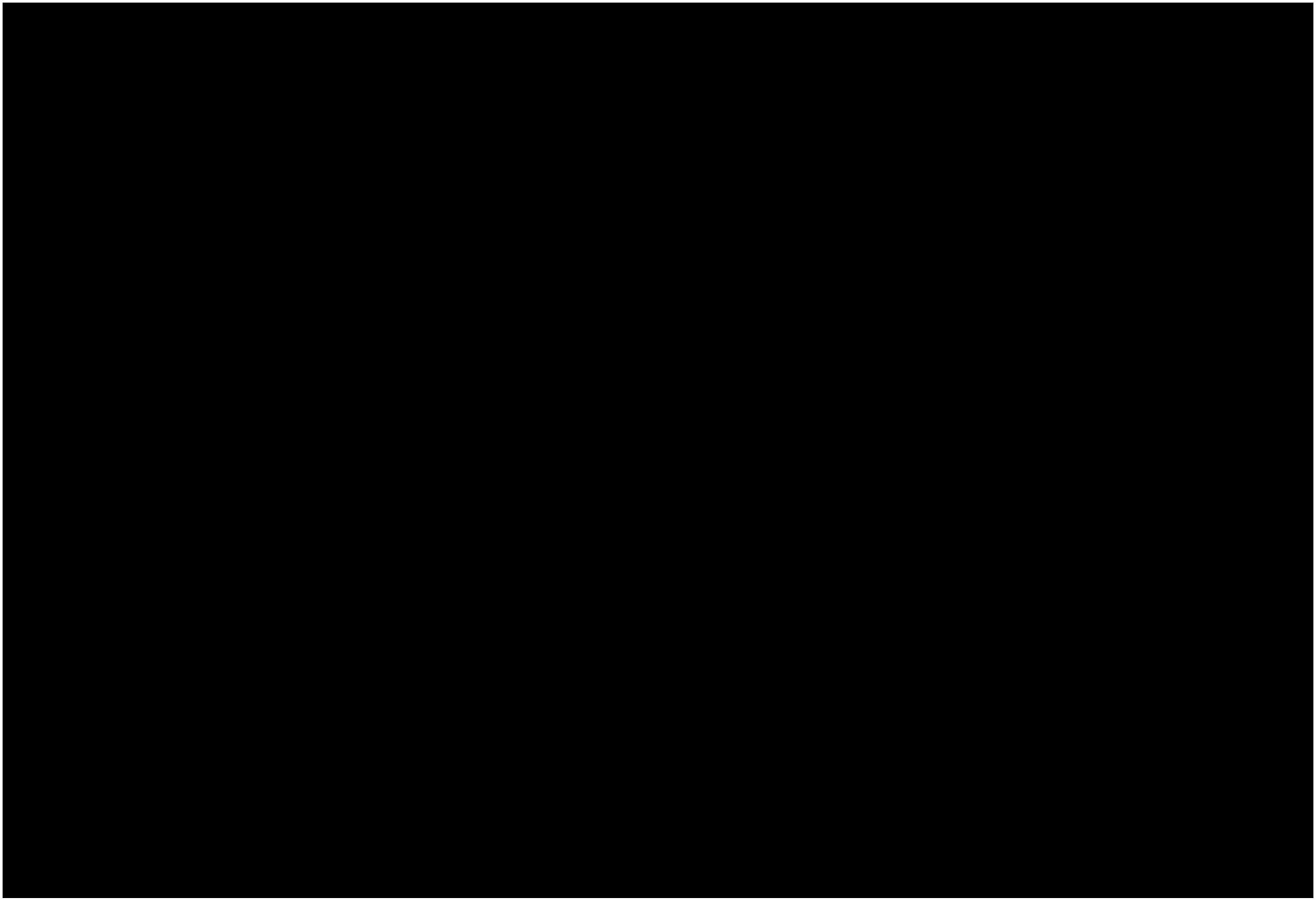
Date of Off Peak Day - 03/28/2021



Member Forecasted Off Peak Demand Day for April 2021

Roosevelt Public Power District

Date of Off Peak Day - 04/30/2021



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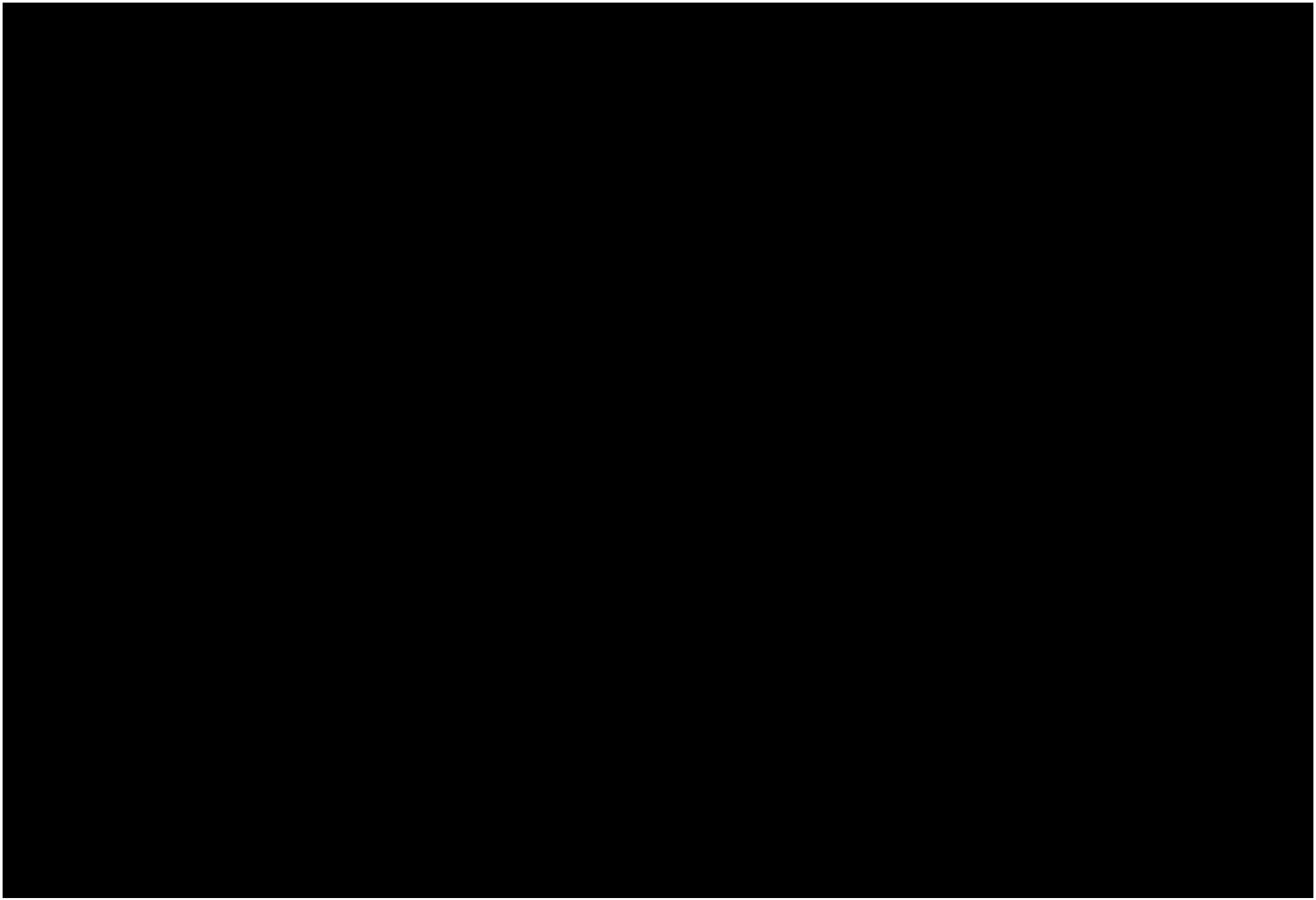
Member Forecasted Off Peak Demand Day for May 2021

Roosevelt Public Power District

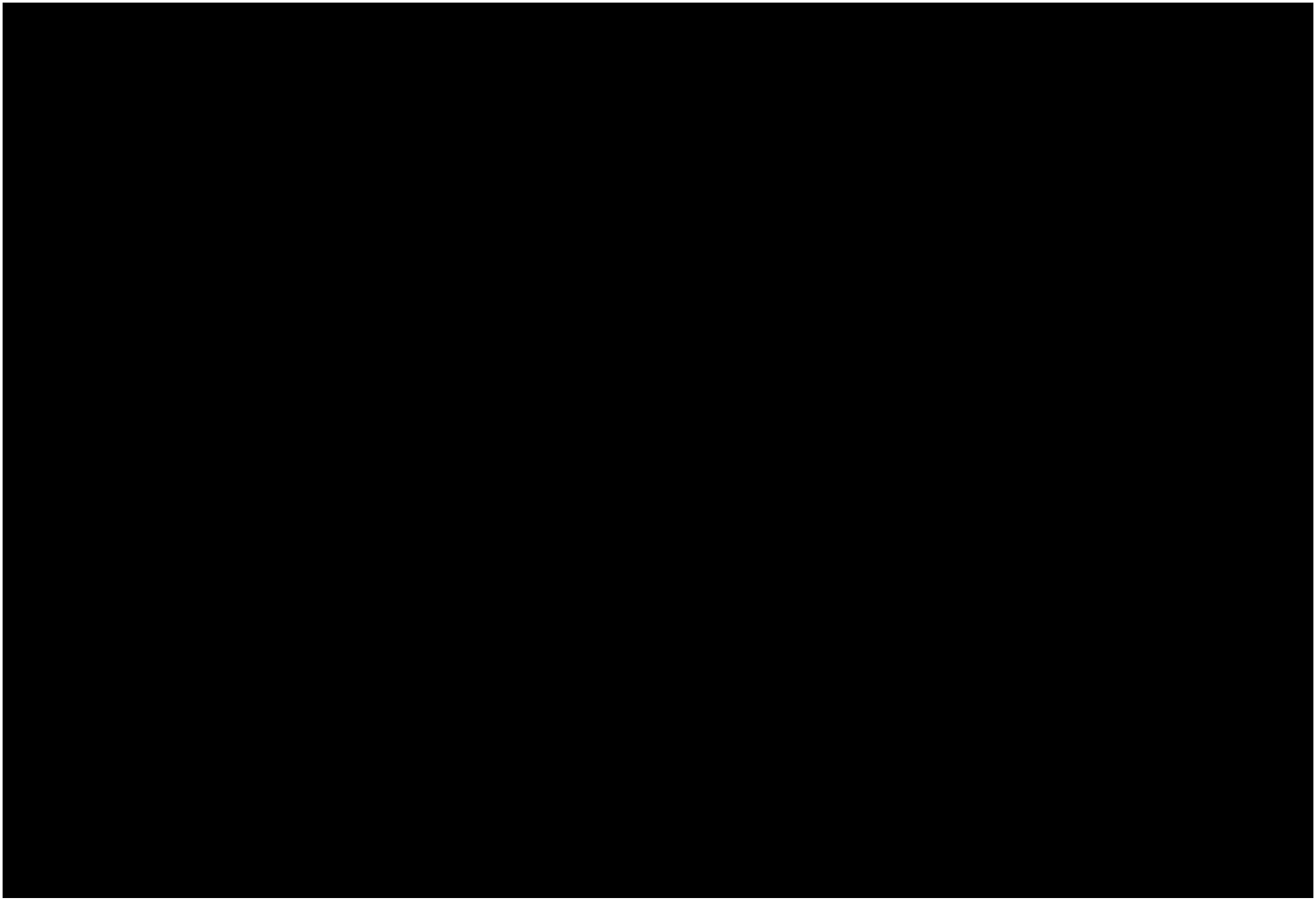
Date of Off Peak Day - 05/06/2021



Member Forecasted Off Peak Demand Day for June 2021

Roosevelt Public Power District

Date of Off Peak Day - 06/01/2021



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Member Forecasted Off Peak Demand Day for July 2021

Roosevelt Public Power District

Date of Off Peak Day - 07/31/2021

[redacted]

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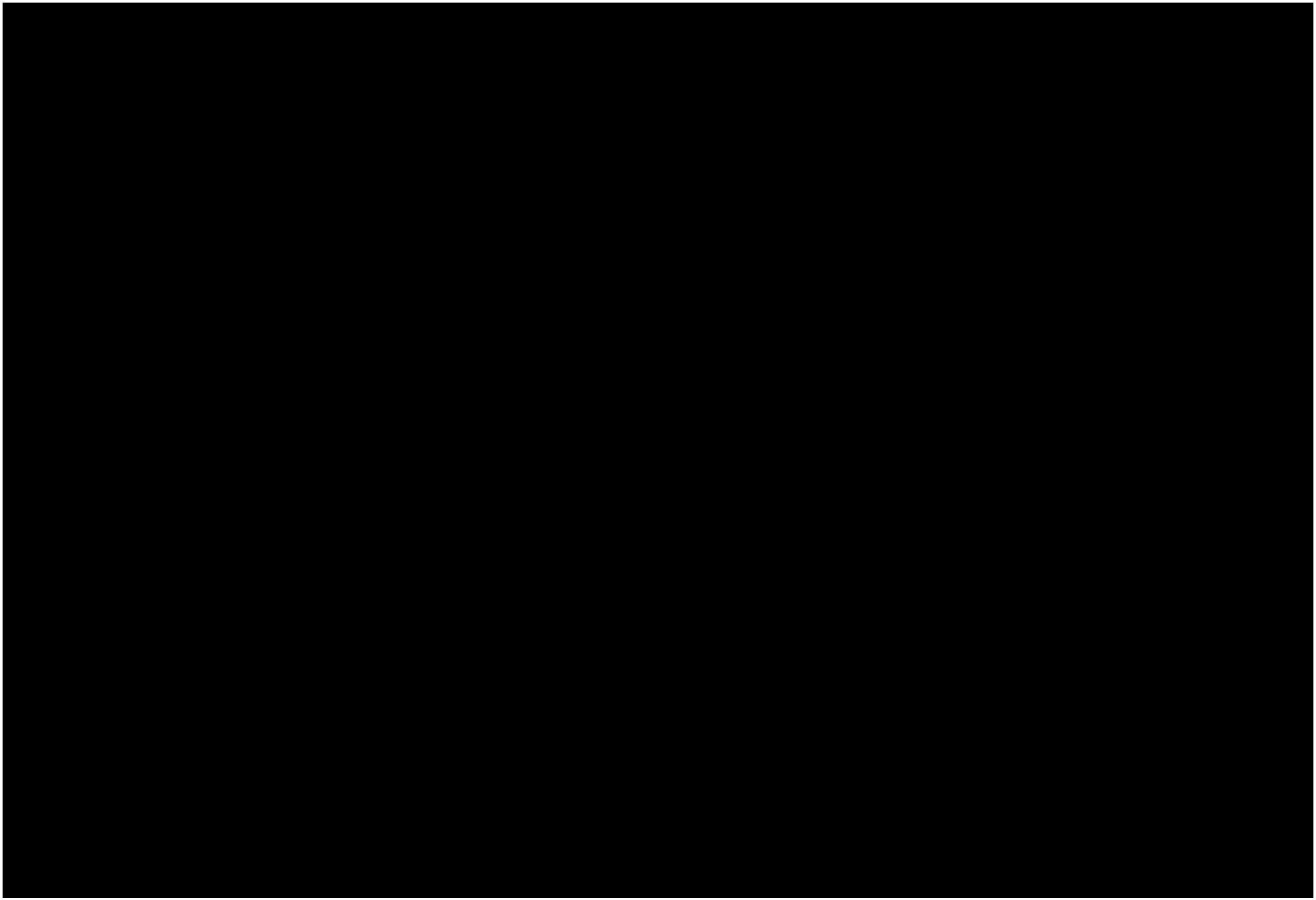
Member Forecasted Off Peak Demand Day for August 2021

Roosevelt Public Power District

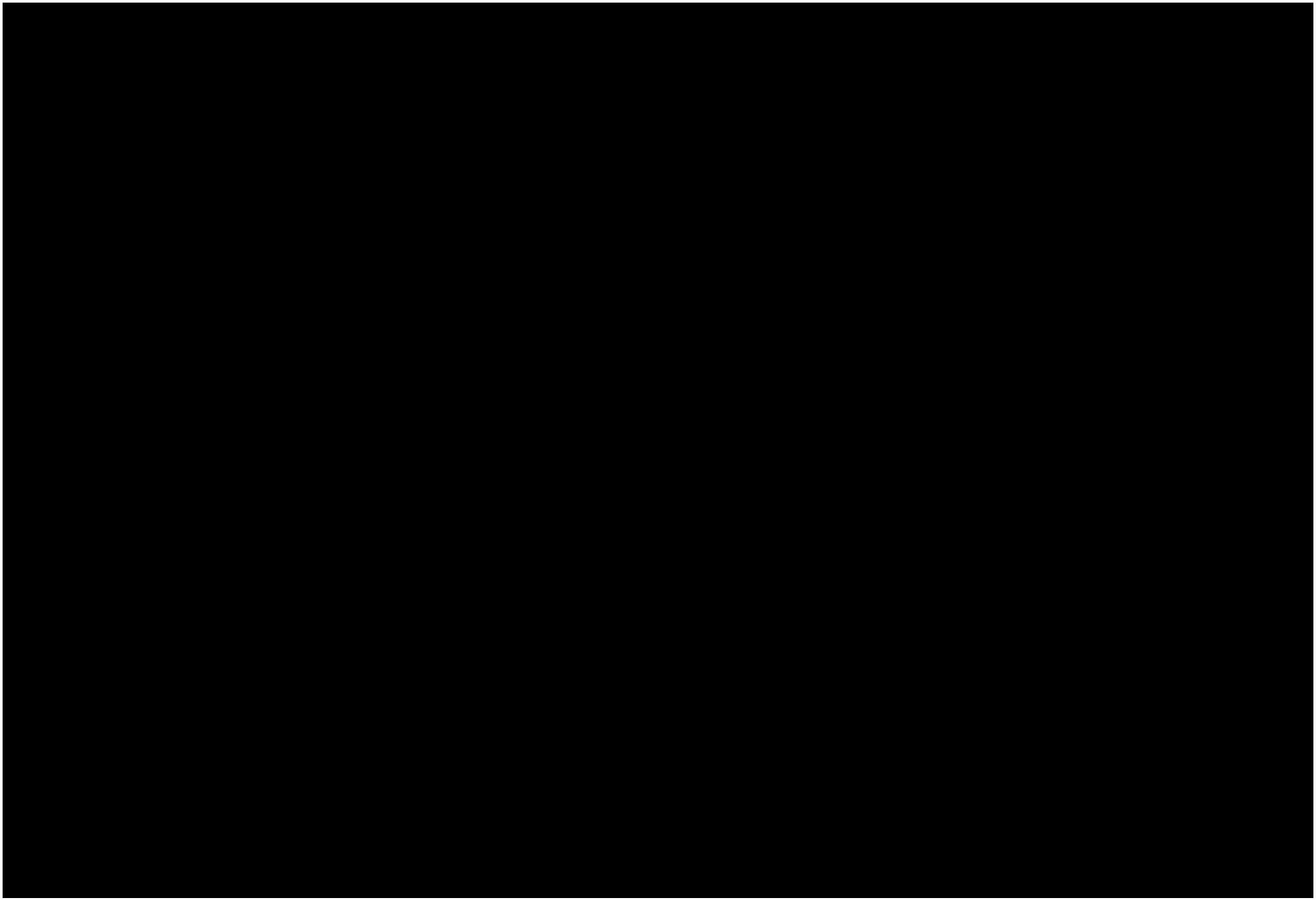
Date of Off Peak Day - 08/11/2021



Member Forecasted Off Peak Demand Day for September 2021

Roosevelt Public Power District

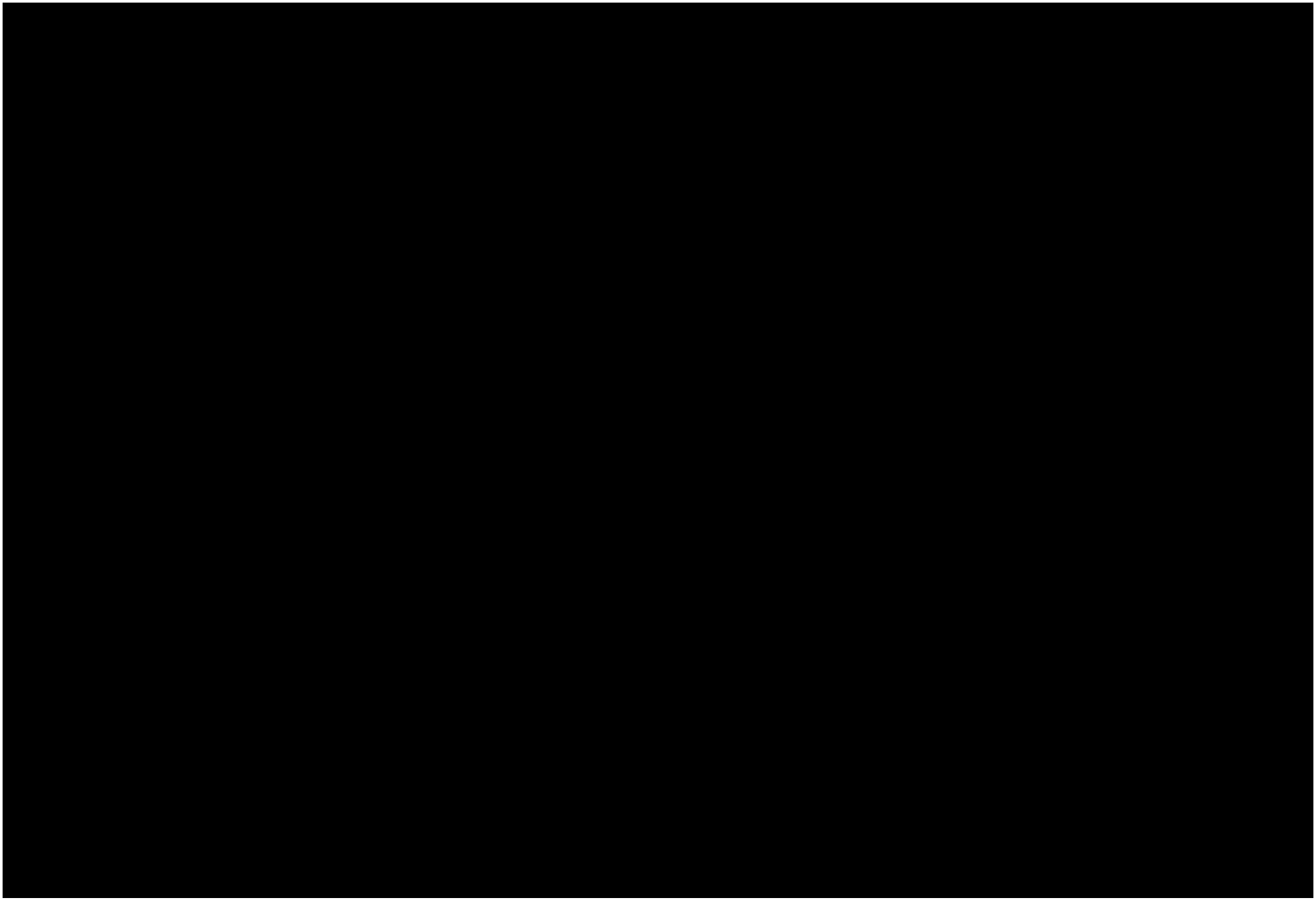
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Roosevelt Public Power District

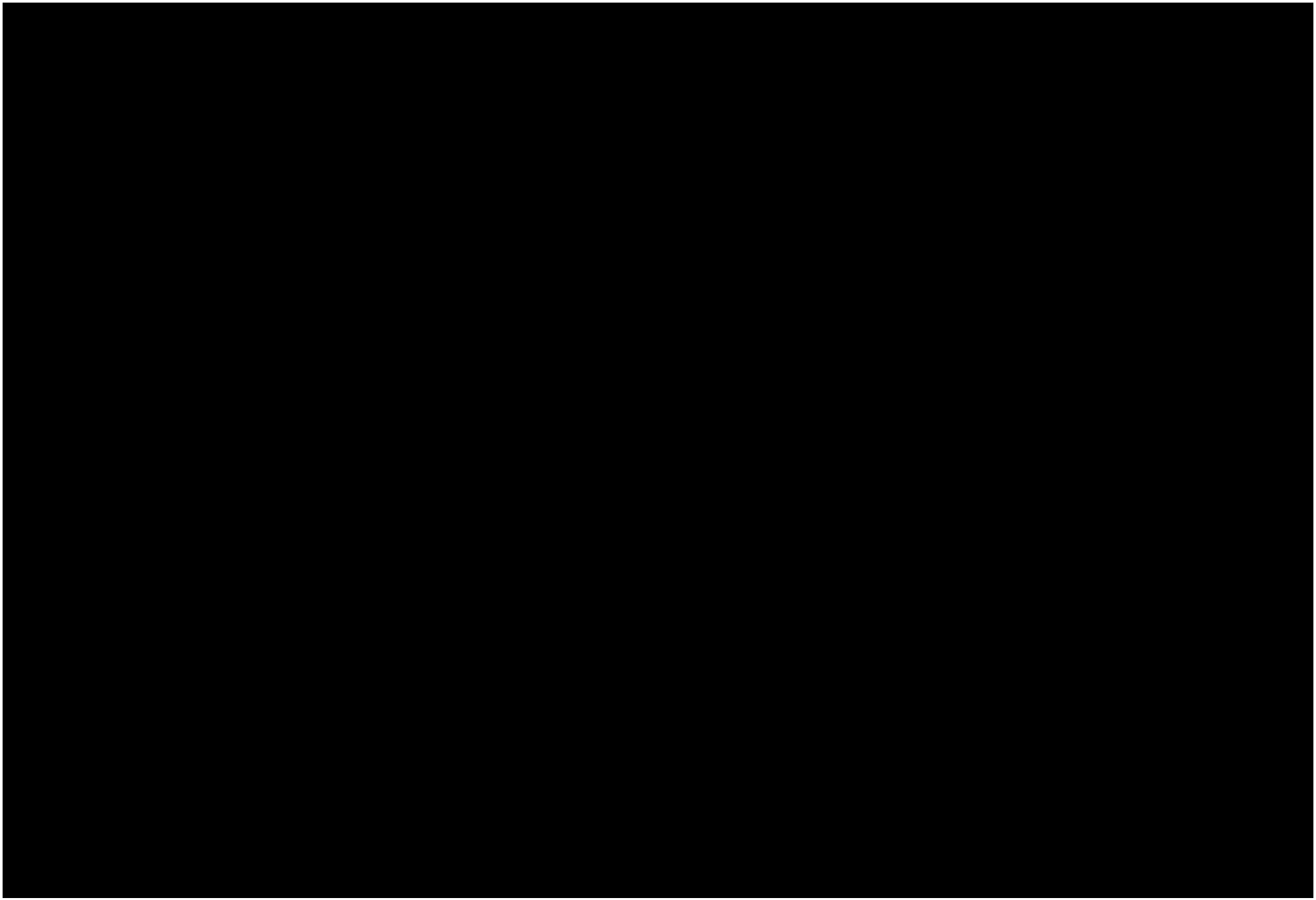
Date of Off Peak Day - 10/10/2021



Member Forecasted Off Peak Demand Day for November 2021

Roosevelt Public Power District

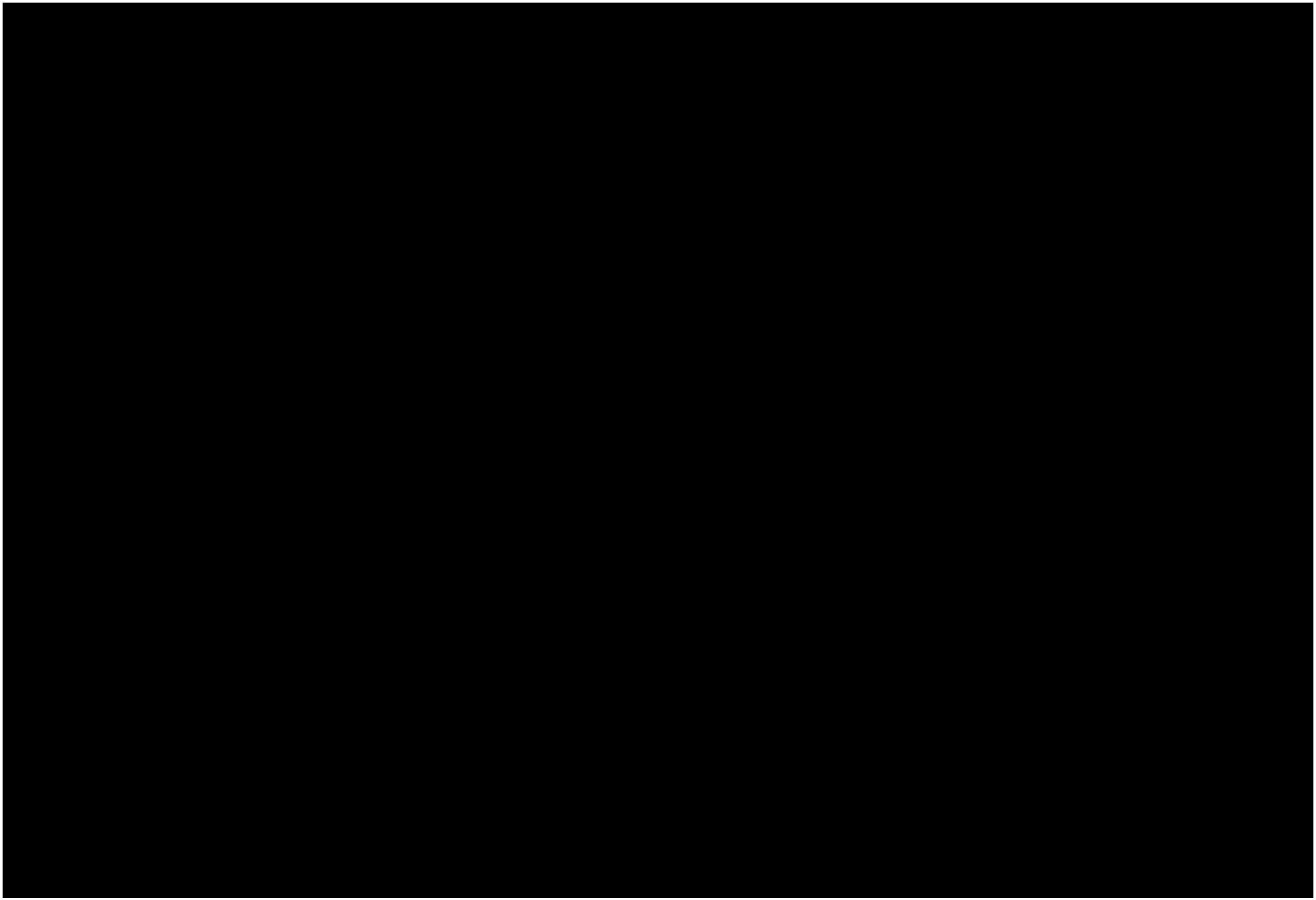
Date of Off Peak Day - 11/03/2021



Member Forecasted Off Peak Demand Day for December 2021

Roosevelt Public Power District

Date of Off Peak Day - 12/08/2021



Member Forecasted Off Peak Demand Day for January 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 01/12/2021

[redacted]

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Member Forecasted Off Peak Demand Day for February 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 02/20/2021

[redacted]

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Member Forecasted Off Peak Demand Day for March 2021

Sierra Electric Cooperative, Inc.

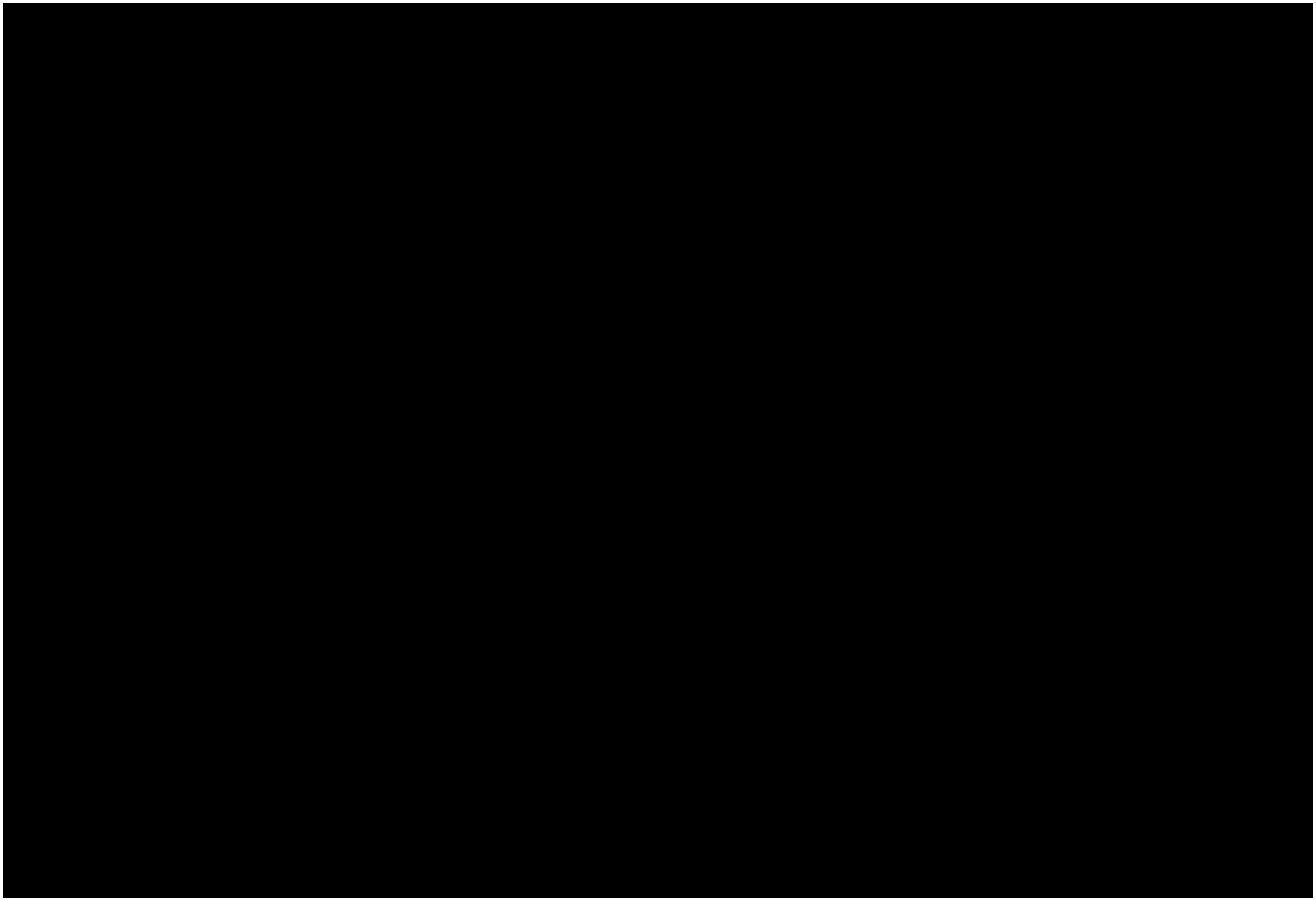
Date of Off Peak Day - 03/14/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 04/10/2021



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Member Forecasted Off Peak Demand Day for May 2021

Sierra Electric Cooperative, Inc.

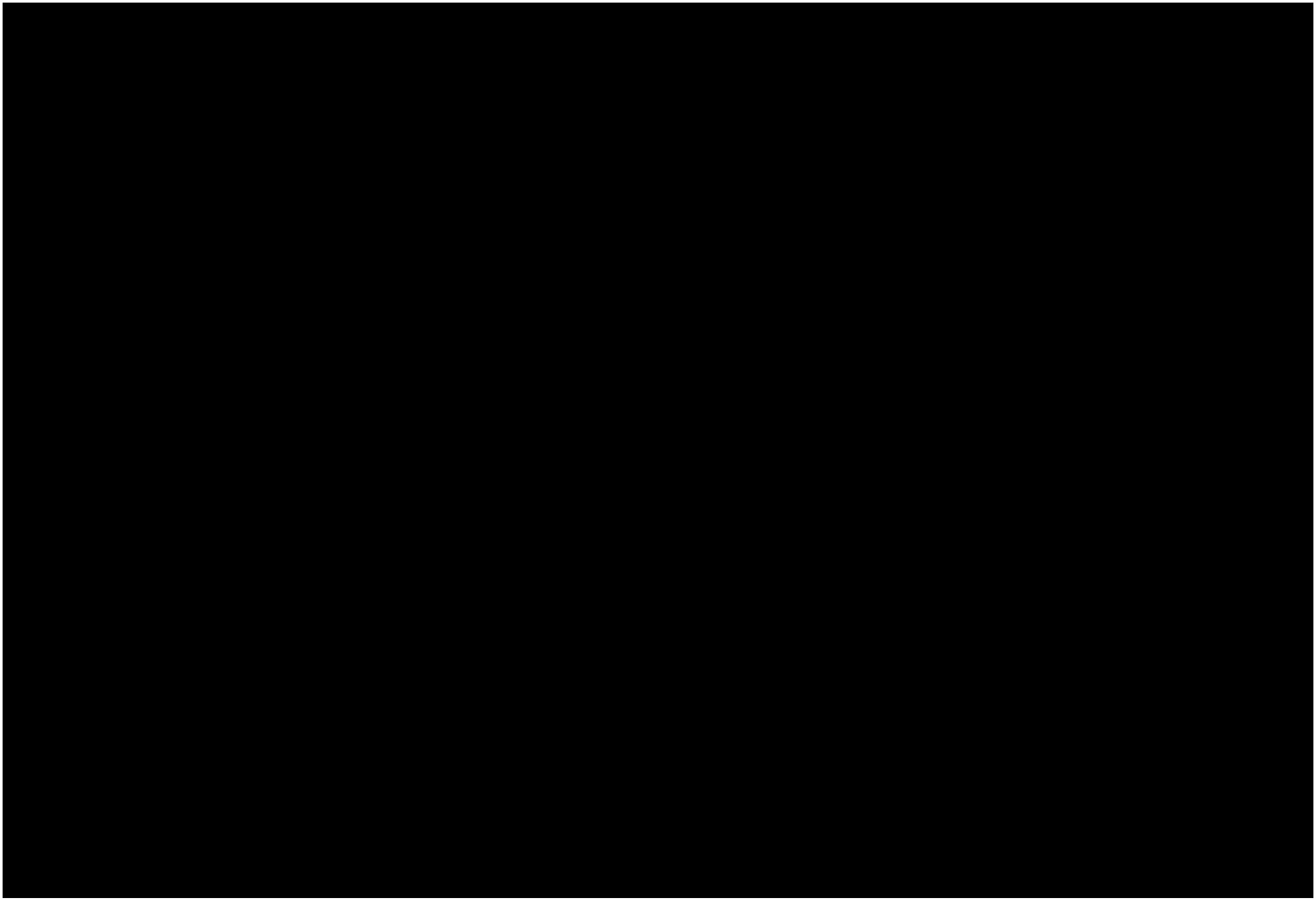
Date of Off Peak Day - 05/02/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 06/01/2021



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Member Forecasted Off Peak Demand Day for July 2021

Sierra Electric Cooperative, Inc.

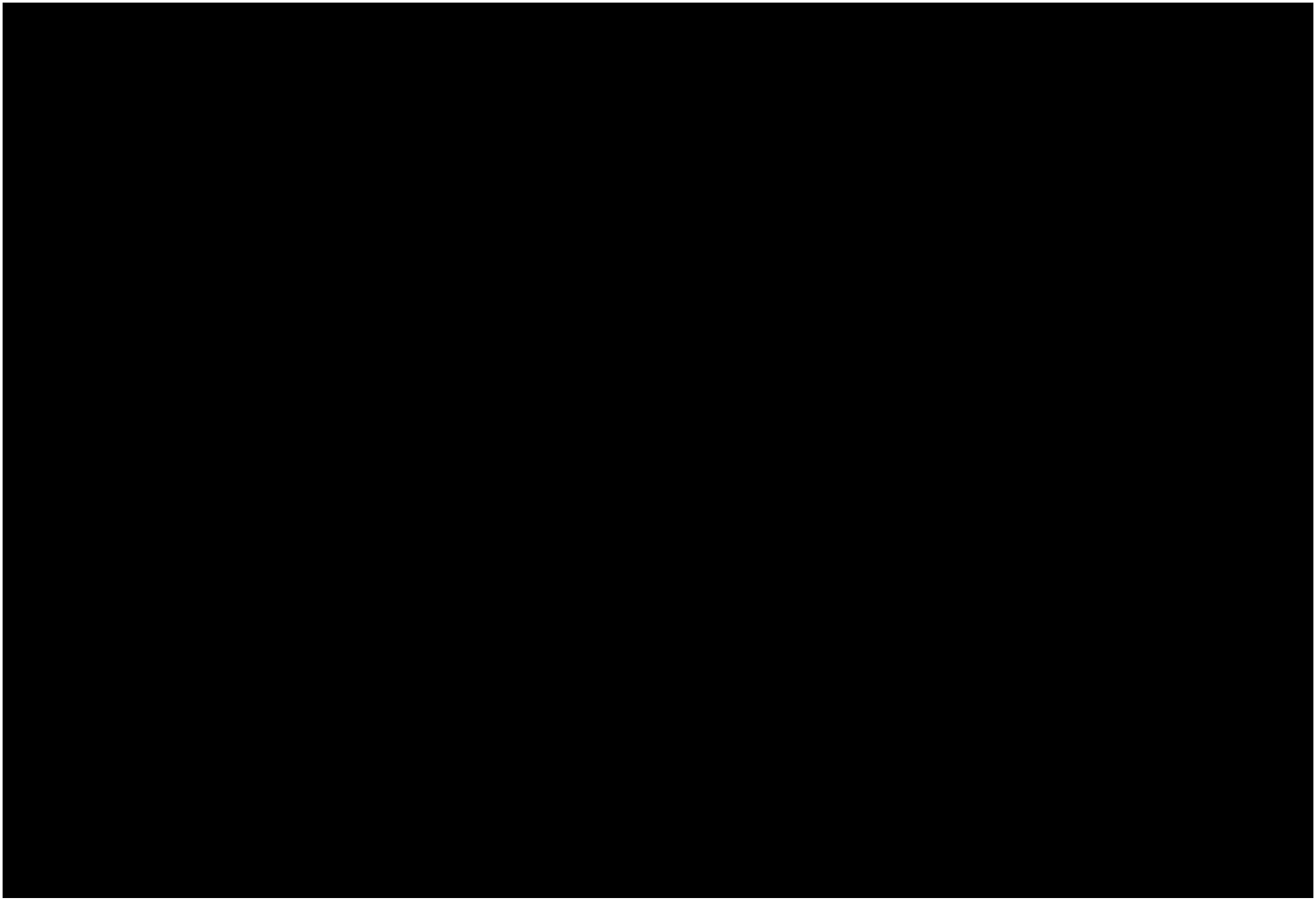
Date of Off Peak Day - 07/02/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Sierra Electric Cooperative, Inc.

Date of Off Peak Day - 08/30/2021



Member Forecasted Off Peak Demand Day for September 2021

Sierra Electric Cooperative, Inc.

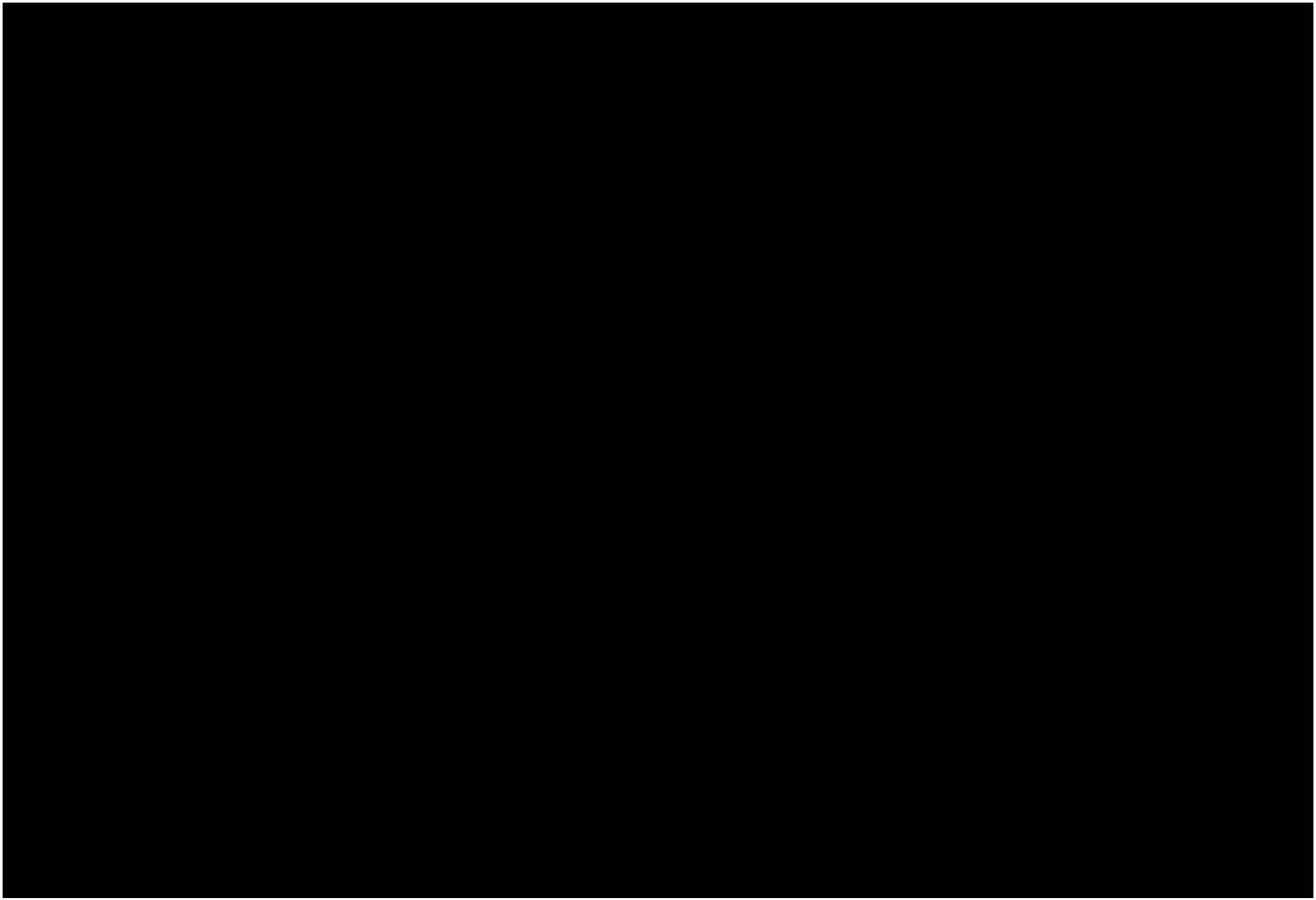
Date of Off Peak Day - 09/11/2021

[redacted]

Member Forecasted Off Peak Demand Day for October 2021

Sierra Electric Cooperative, Inc.

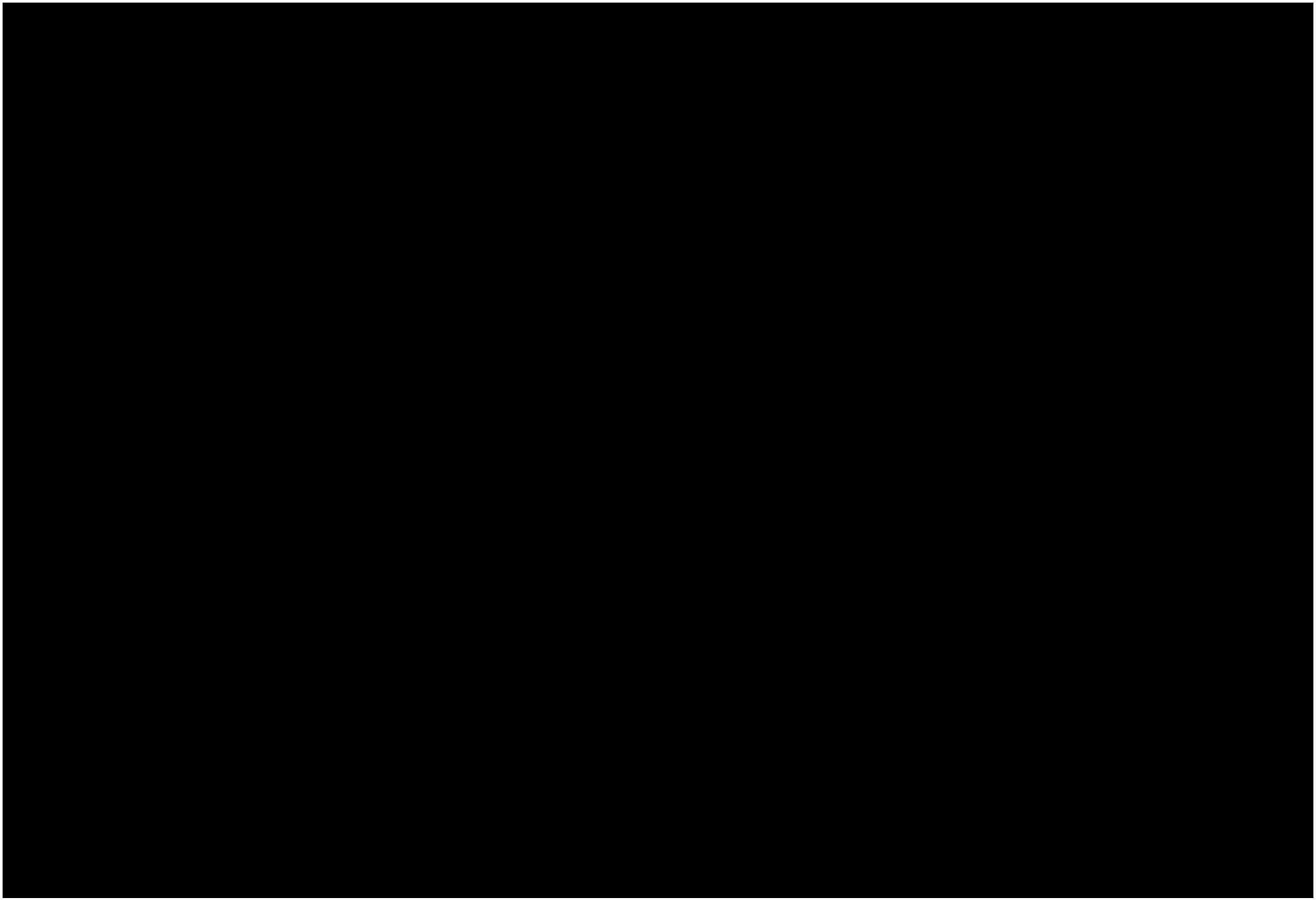
Date of Off Peak Day - 10/24/2021



Member Forecasted Off Peak Demand Day for November 2021

Sierra Electric Cooperative, Inc.

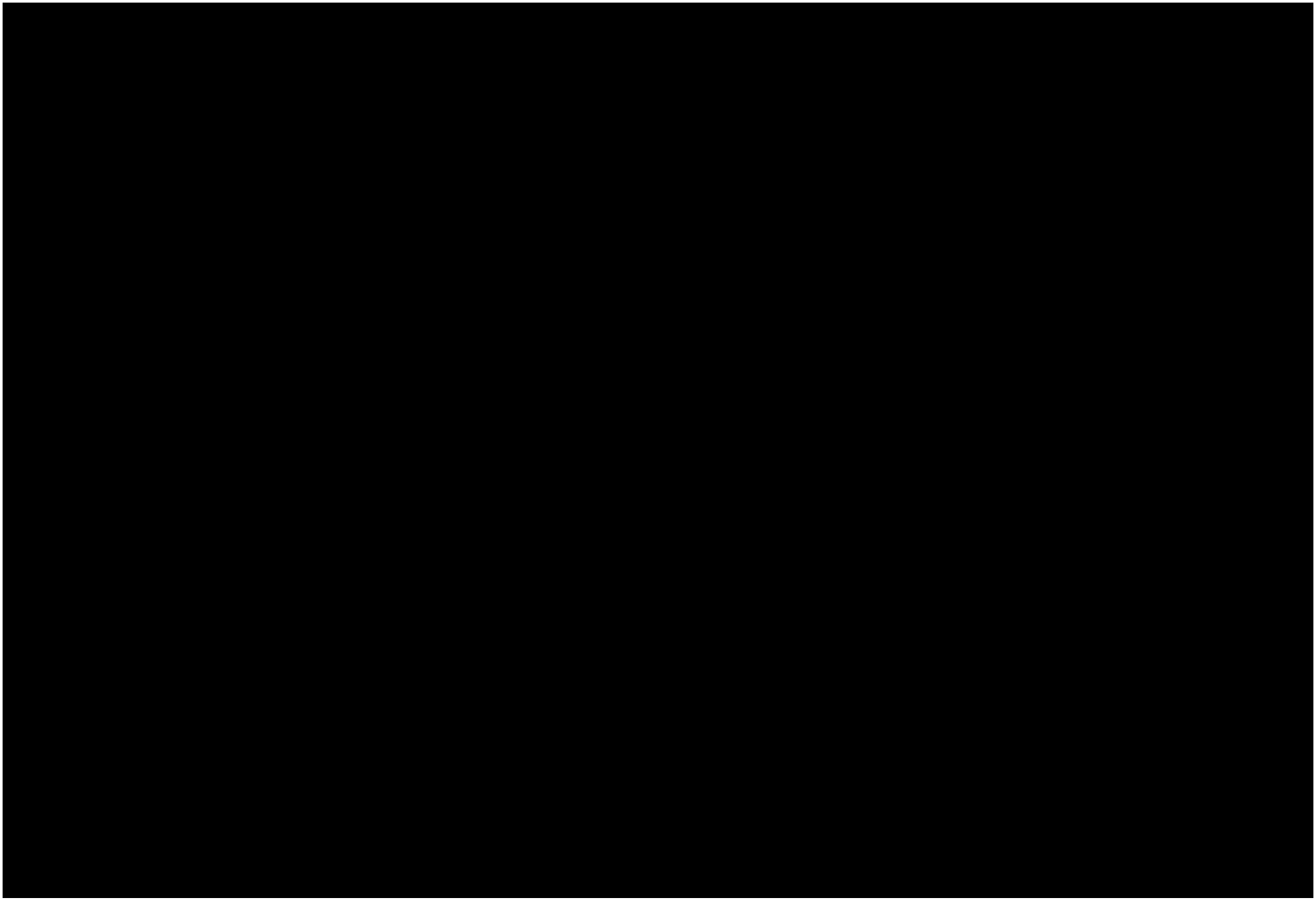
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Sierra Electric Cooperative, Inc.

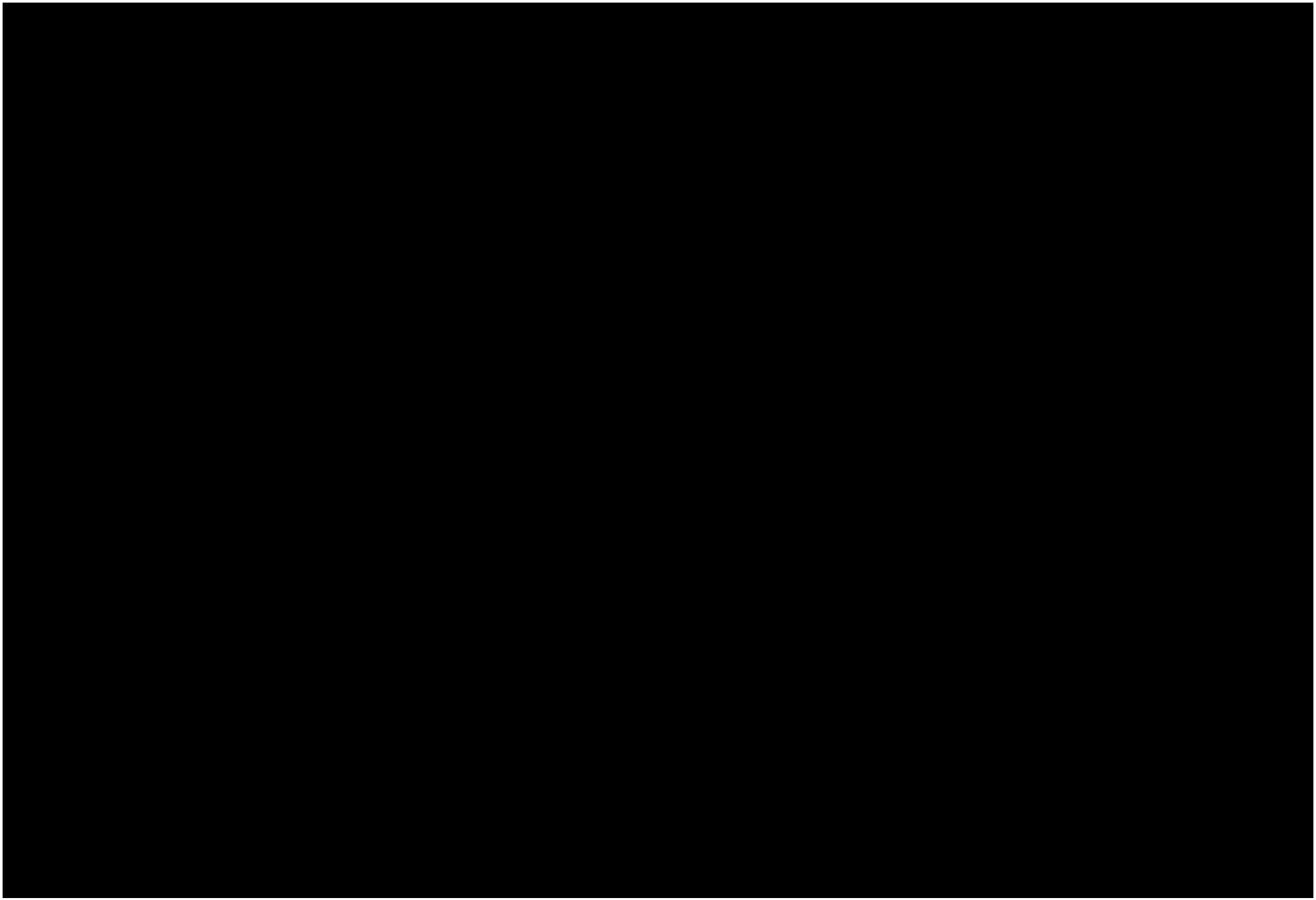
Date of Off Peak Day - 12/05/2021



Member Forecasted Off Peak Demand Day for January 2021

Sangre de Cristo Electric Association, Inc.

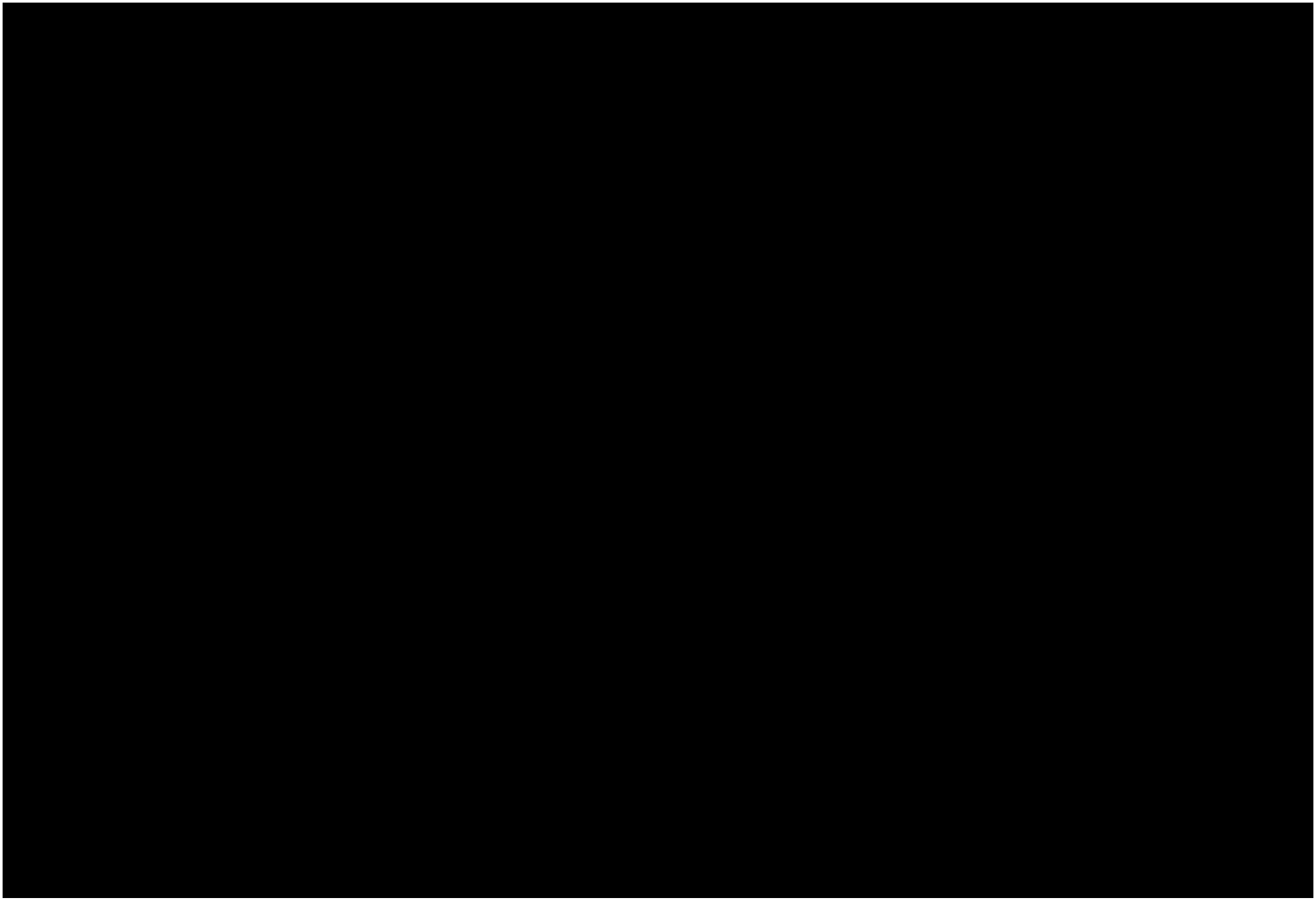
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Sangre de Cristo Electric Association, Inc.

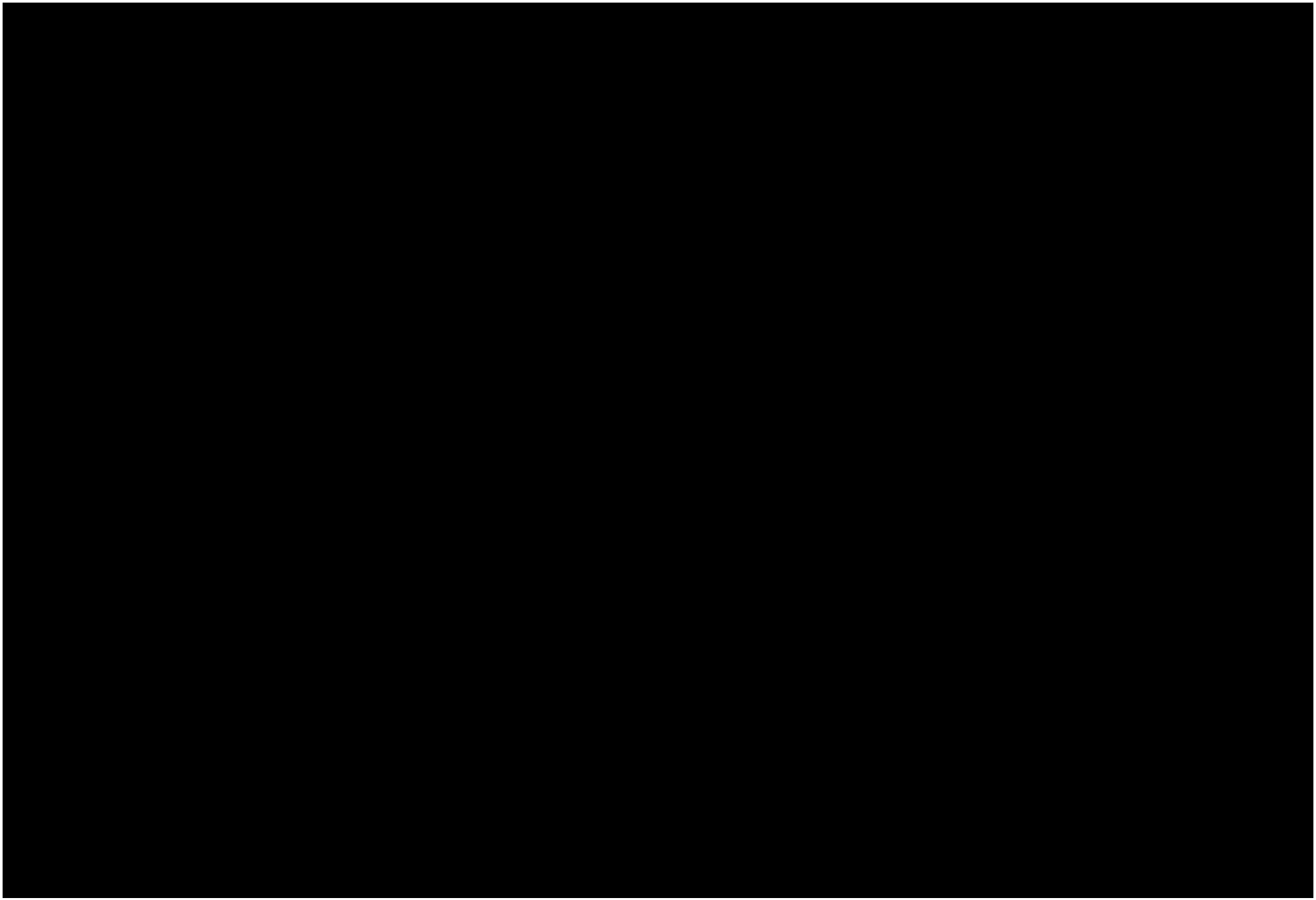
Date of Off Peak Day - 02/10/2021



Member Forecasted Off Peak Demand Day for March 2021

Sangre de Cristo Electric Association, Inc.

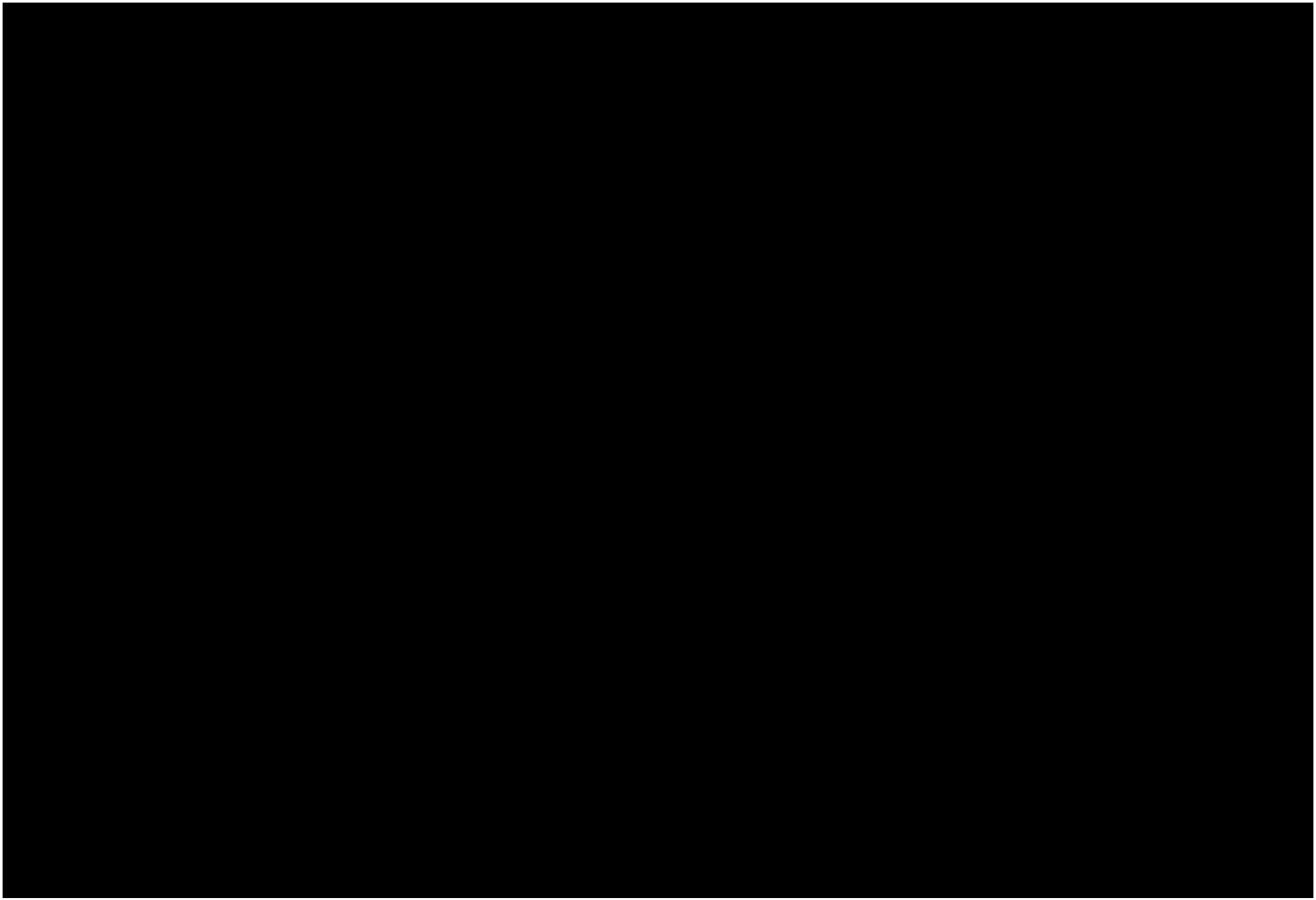
Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

Sangre de Cristo Electric Association, Inc.

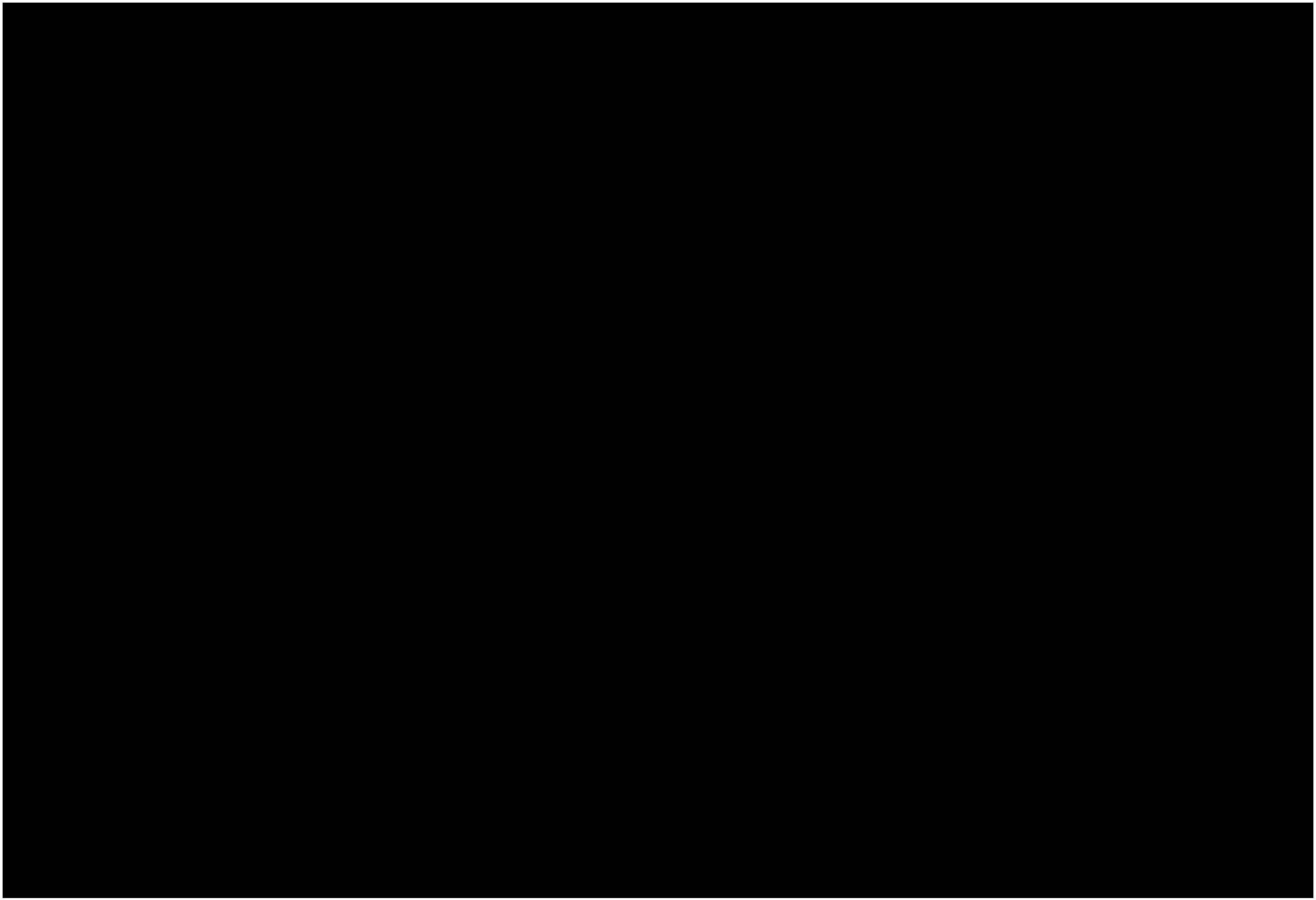
Date of Off Peak Day - 04/30/2021



Member Forecasted Off Peak Demand Day for May 2021

Sangre de Cristo Electric Association, Inc.

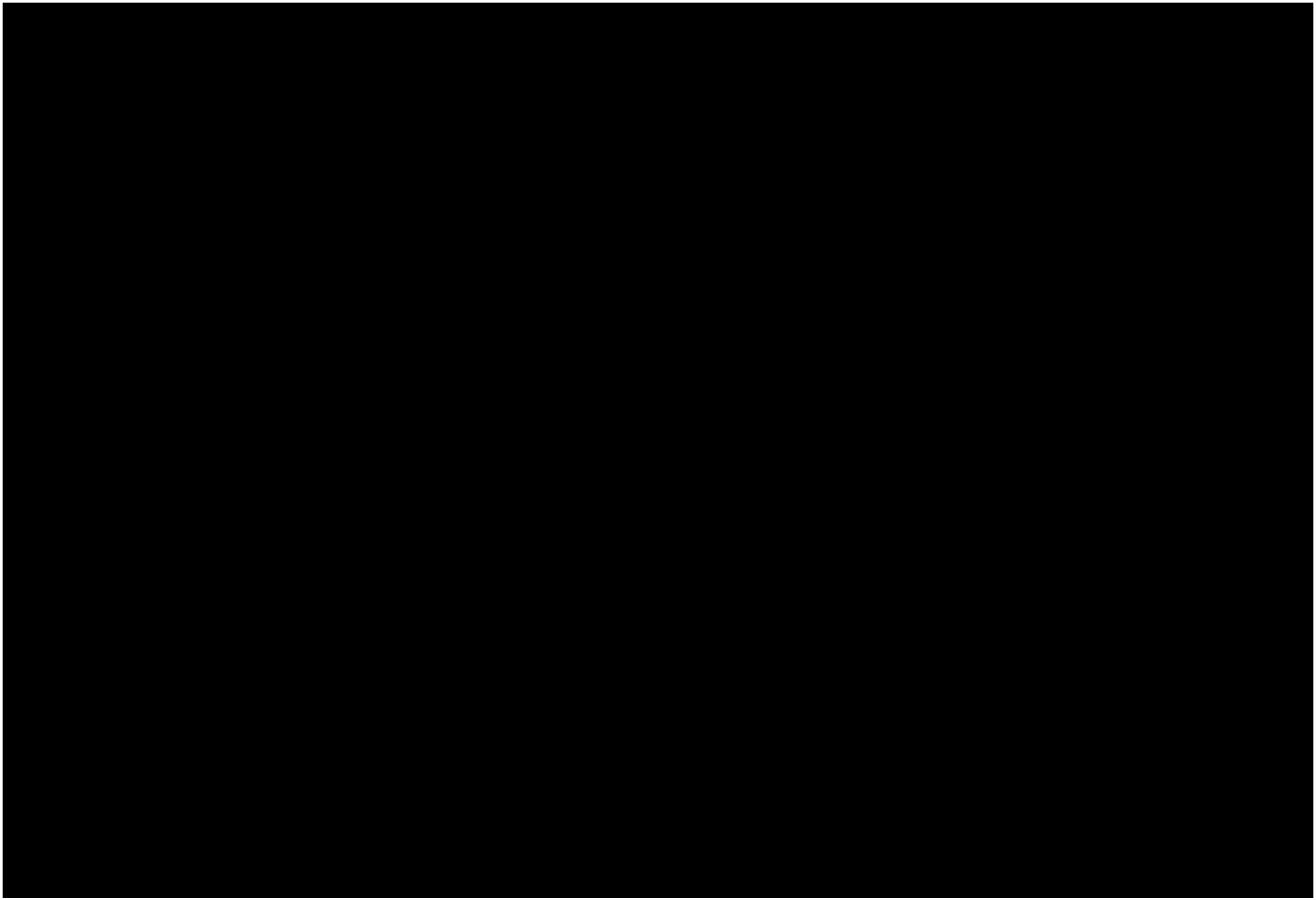
Date of Off Peak Day - 05/13/2021



Member Forecasted Off Peak Demand Day for June 2021

Sangre de Cristo Electric Association, Inc.

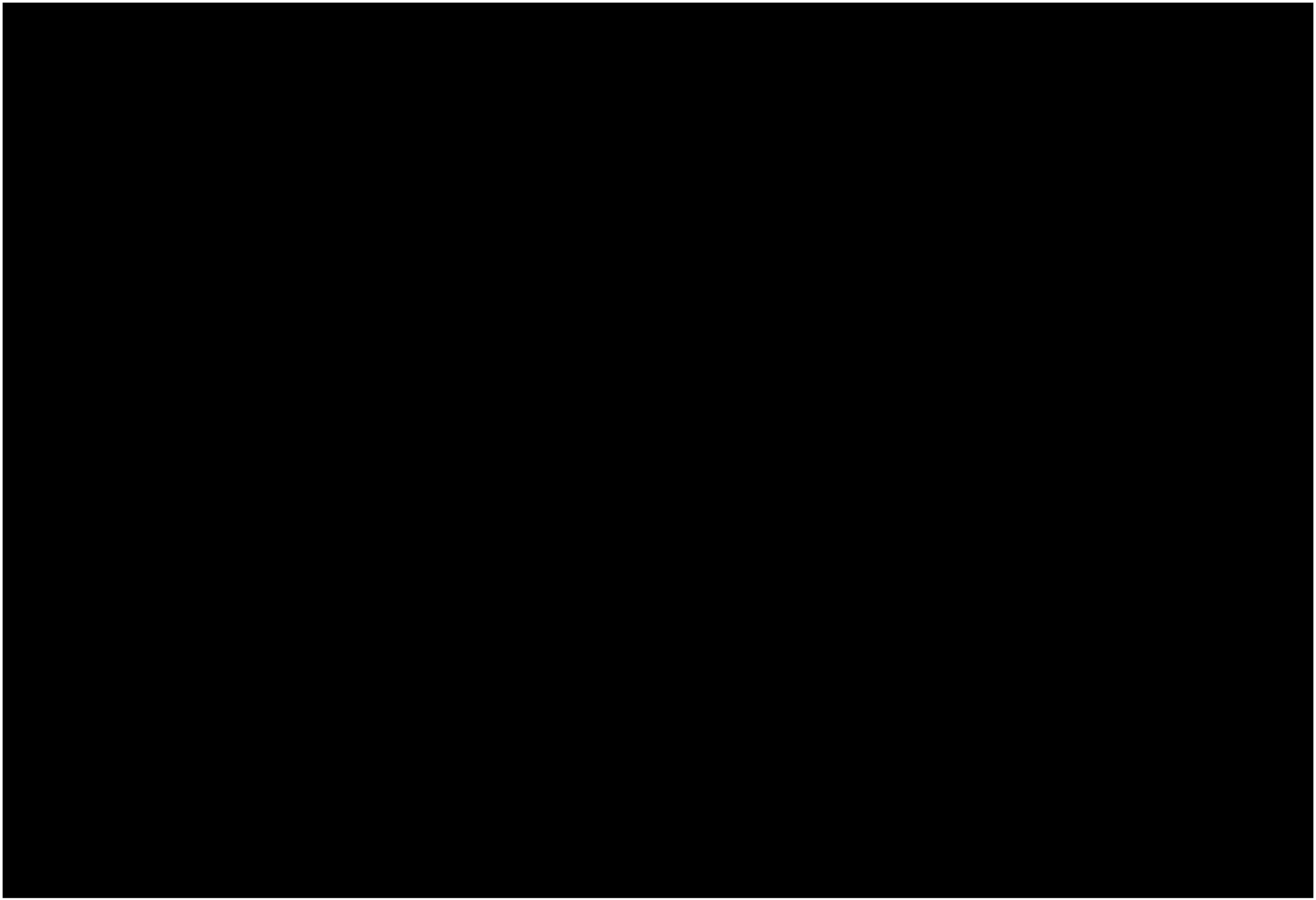
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Sangre de Cristo Electric Association, Inc.

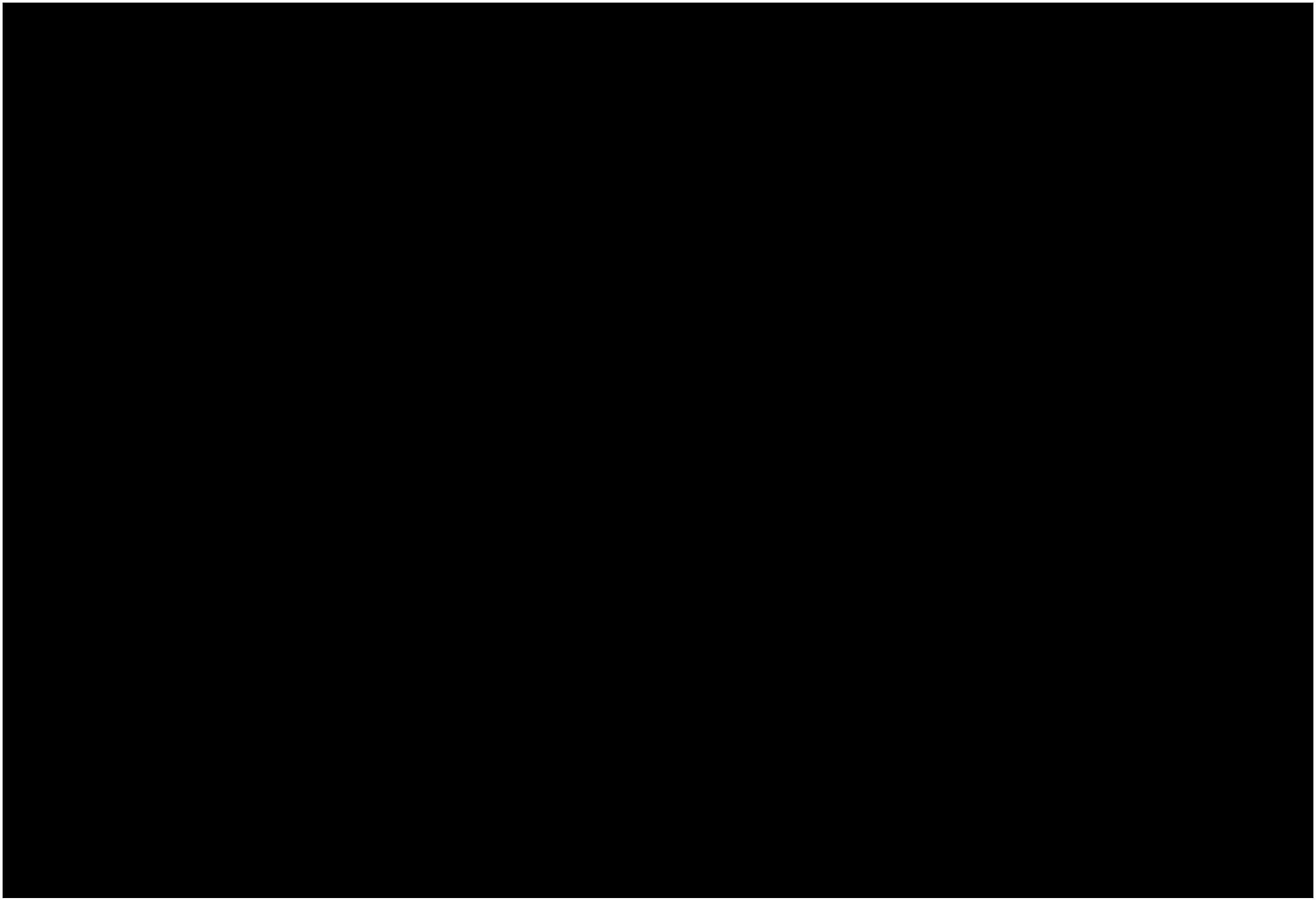
Date of Off Peak Day - 07/31/2021



Member Forecasted Off Peak Demand Day for August 2021

Sangre de Cristo Electric Association, Inc.

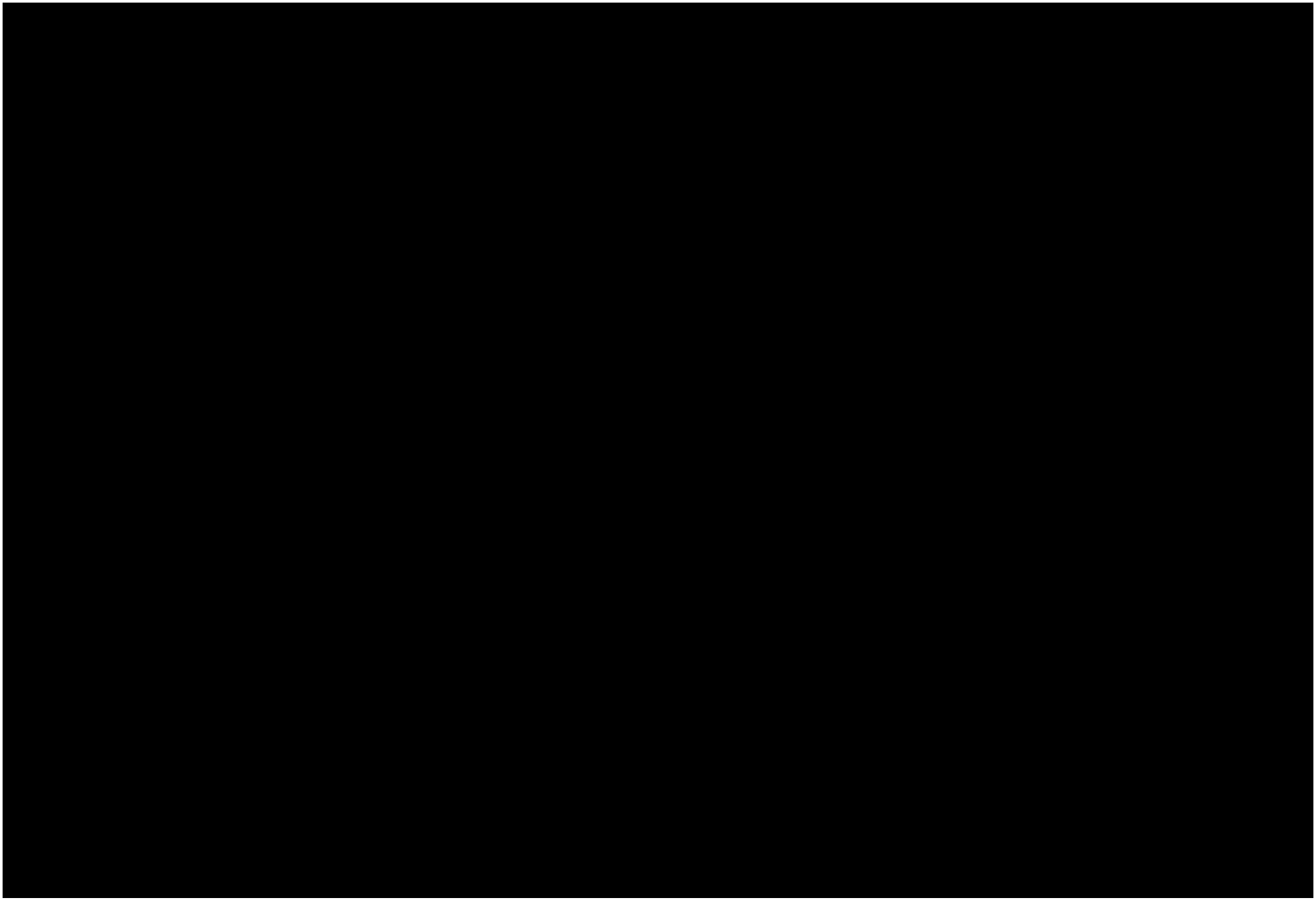
Date of Off Peak Day - 08/26/2021



Member Forecasted Off Peak Demand Day for September 2021

Sangre de Cristo Electric Association, Inc.

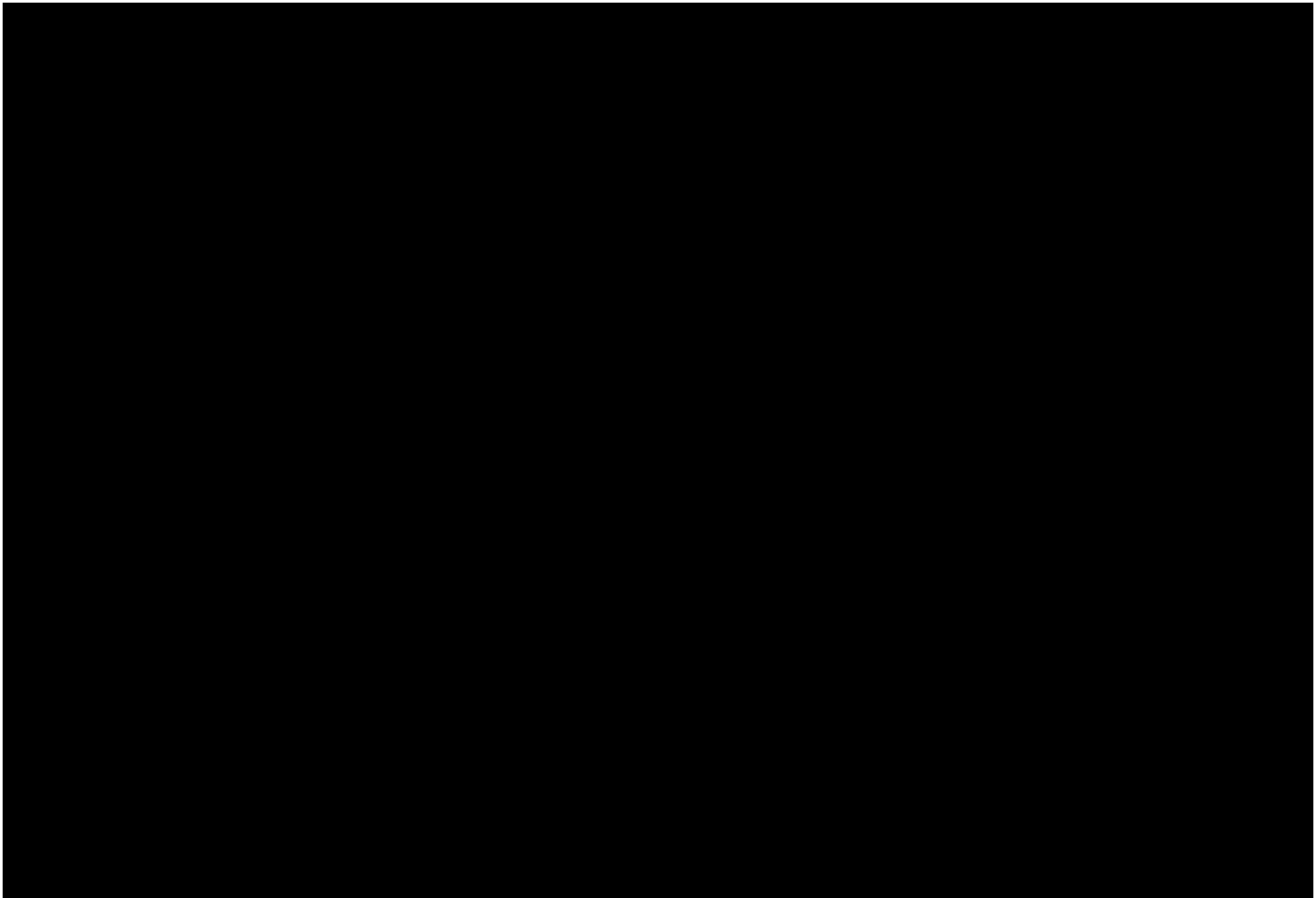
Date of Off Peak Day - 09/28/2021



Member Forecasted Off Peak Demand Day for October 2021

Sangre de Cristo Electric Association, Inc.

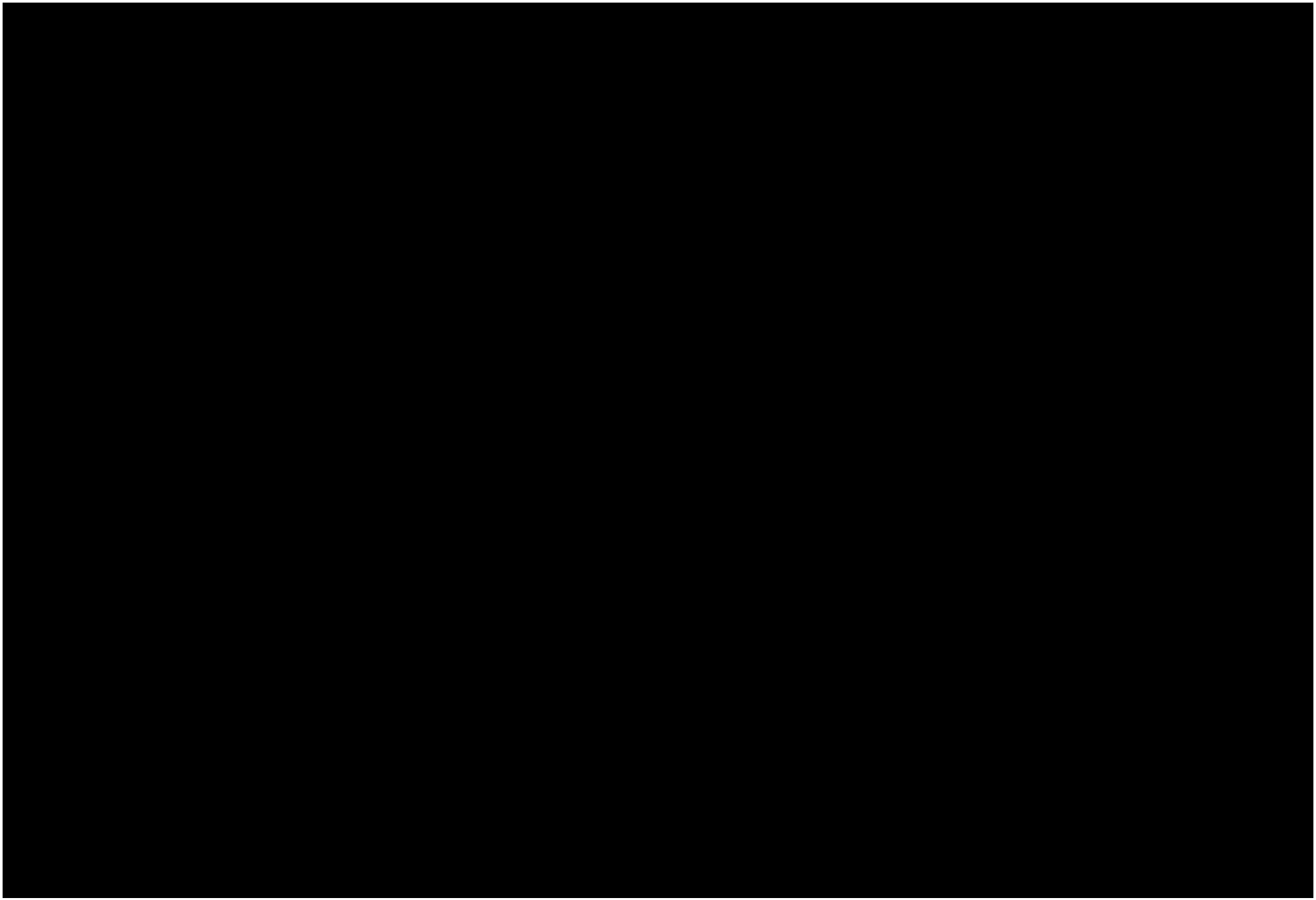
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Sangre de Cristo Electric Association, Inc.

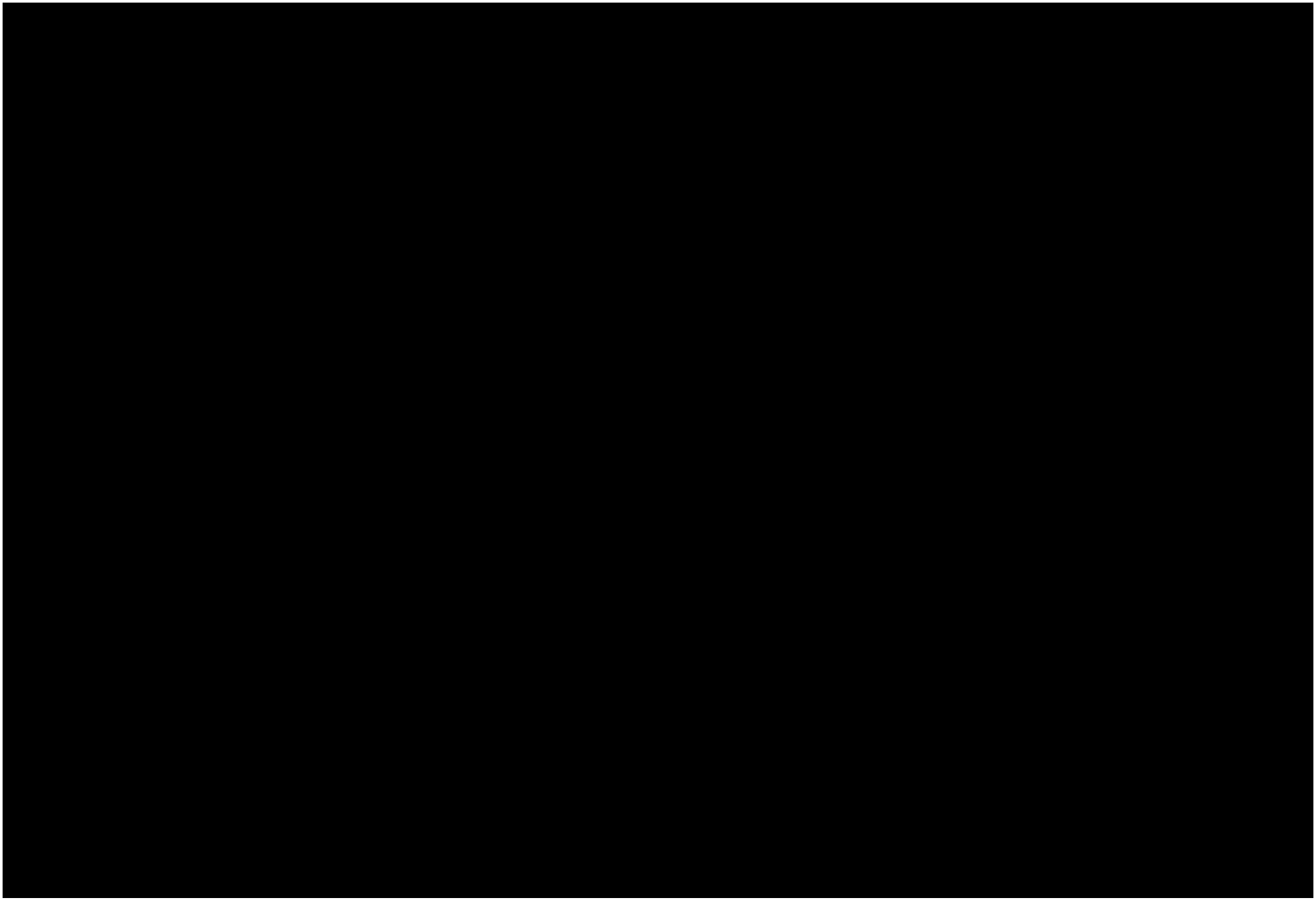
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Sangre de Cristo Electric Association, Inc.

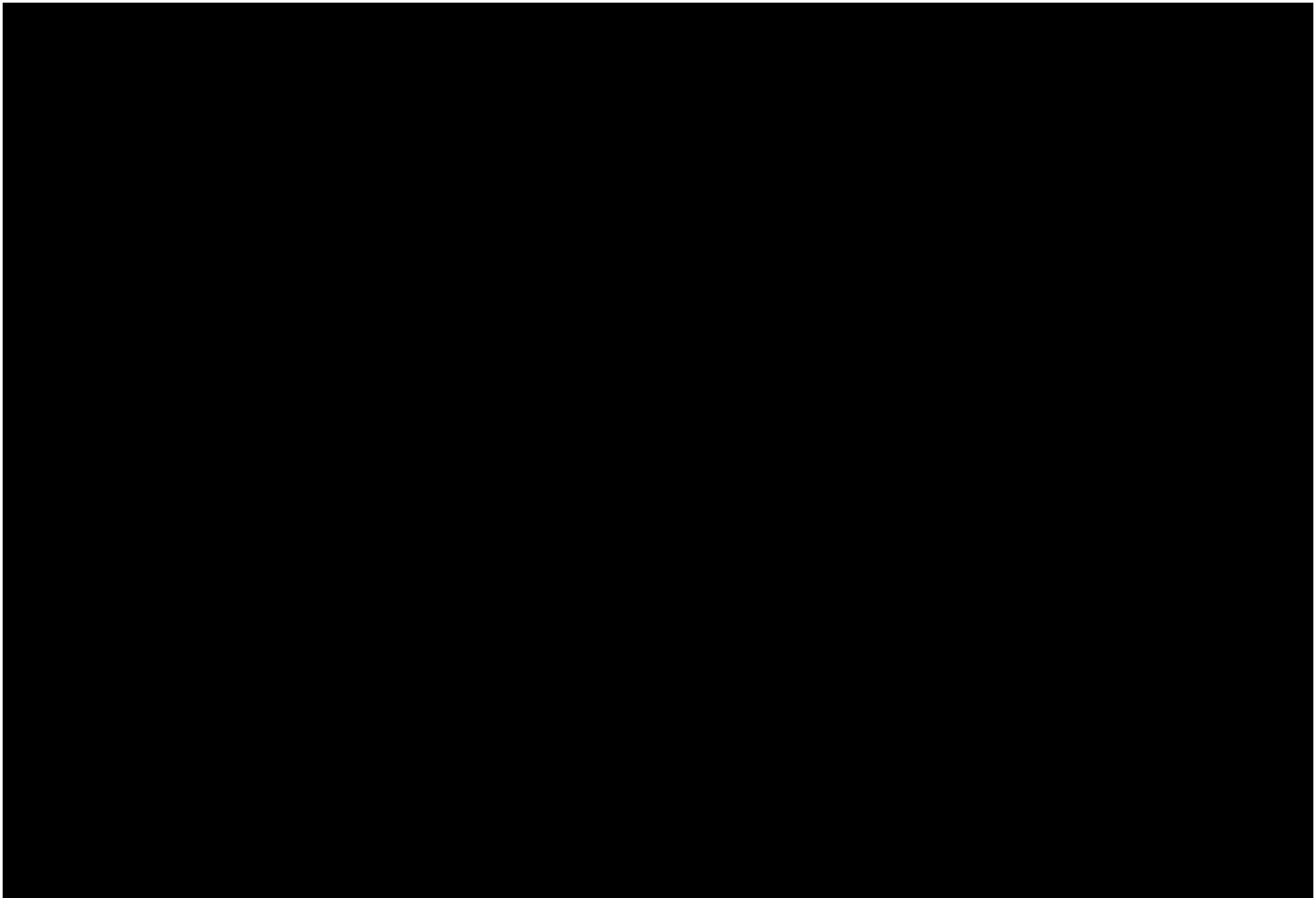
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Southeast Colorado Power Association

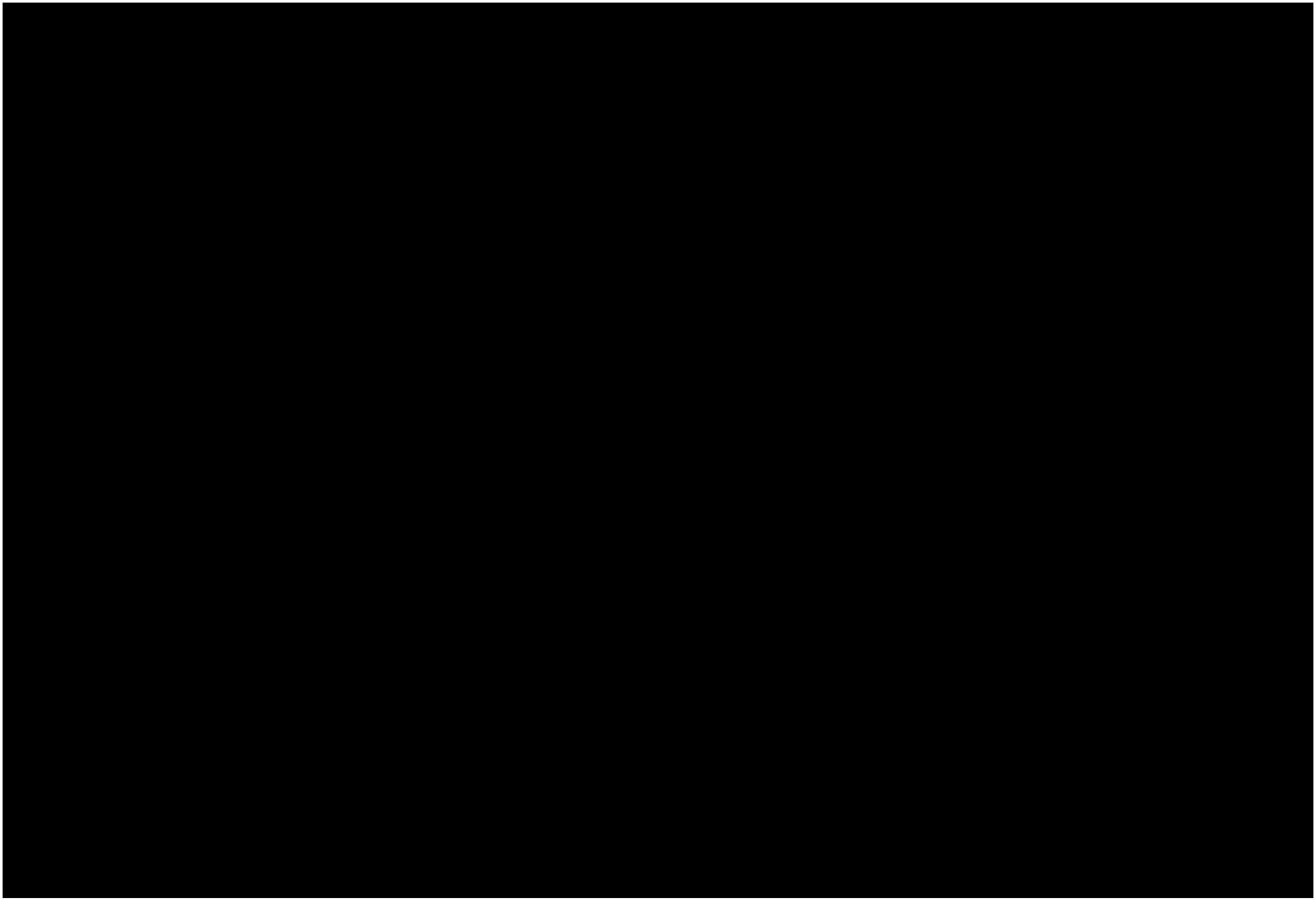
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Southeast Colorado Power Association

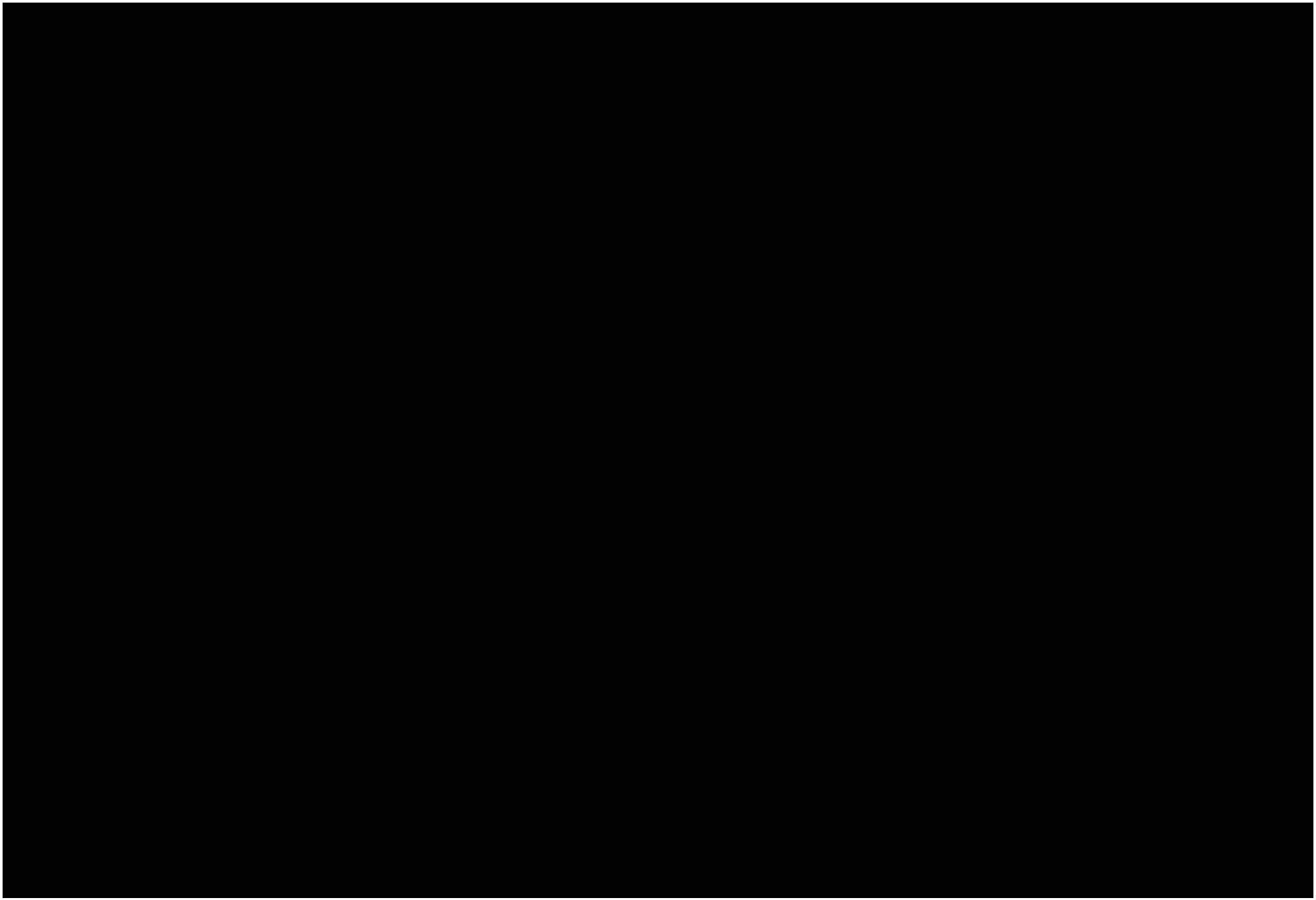
Date of Off Peak Day - 02/27/2021



Member Forecasted Off Peak Demand Day for March 2021

Southeast Colorado Power Association

Date of Off Peak Day - 03/05/2021



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Member Forecasted Off Peak Demand Day for April 2021

Southeast Colorado Power Association

Date of Off Peak Day - 04/03/2021

[redacted]

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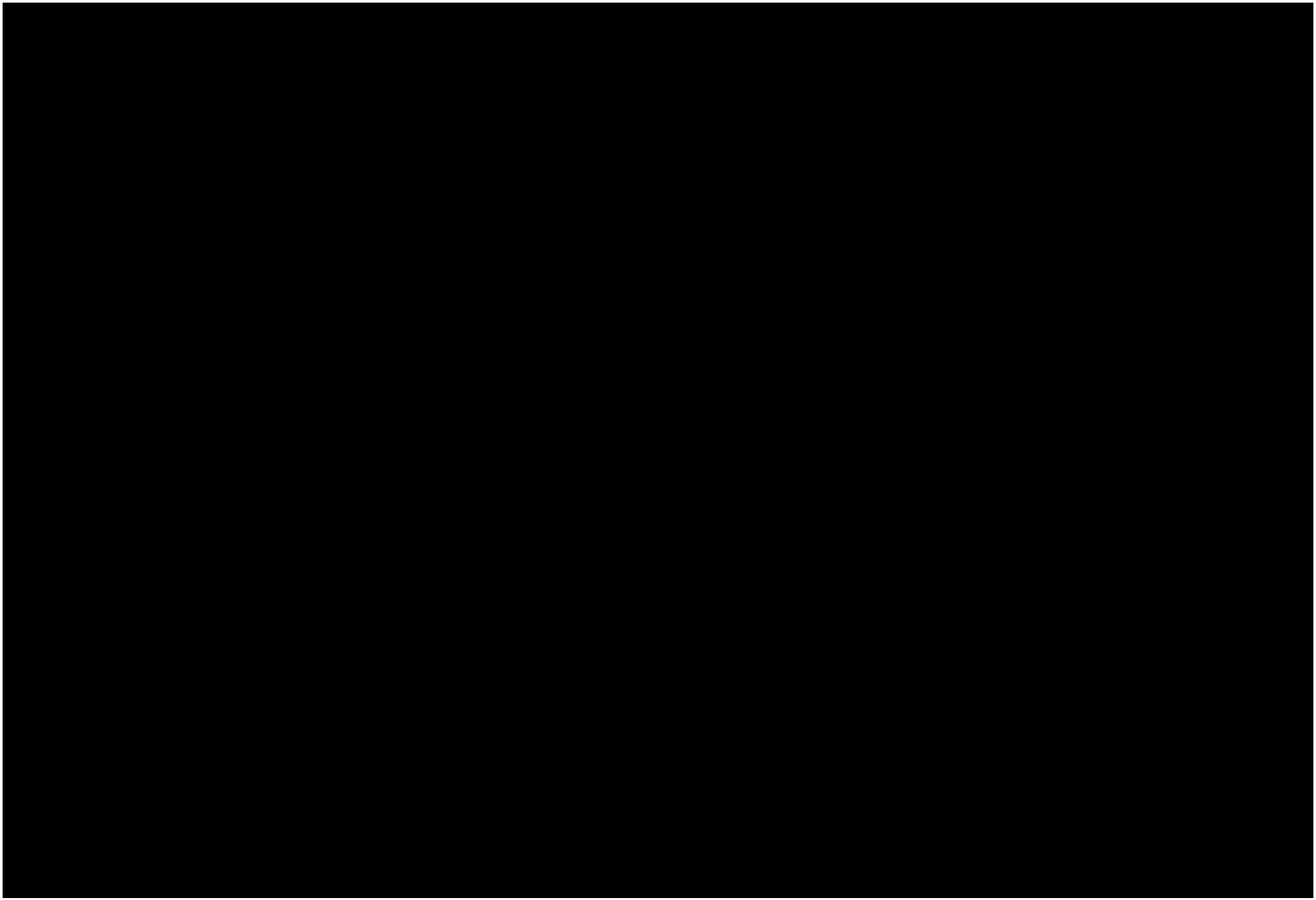
Member Forecasted Off Peak Demand Day for May 2021

Southeast Colorado Power Association

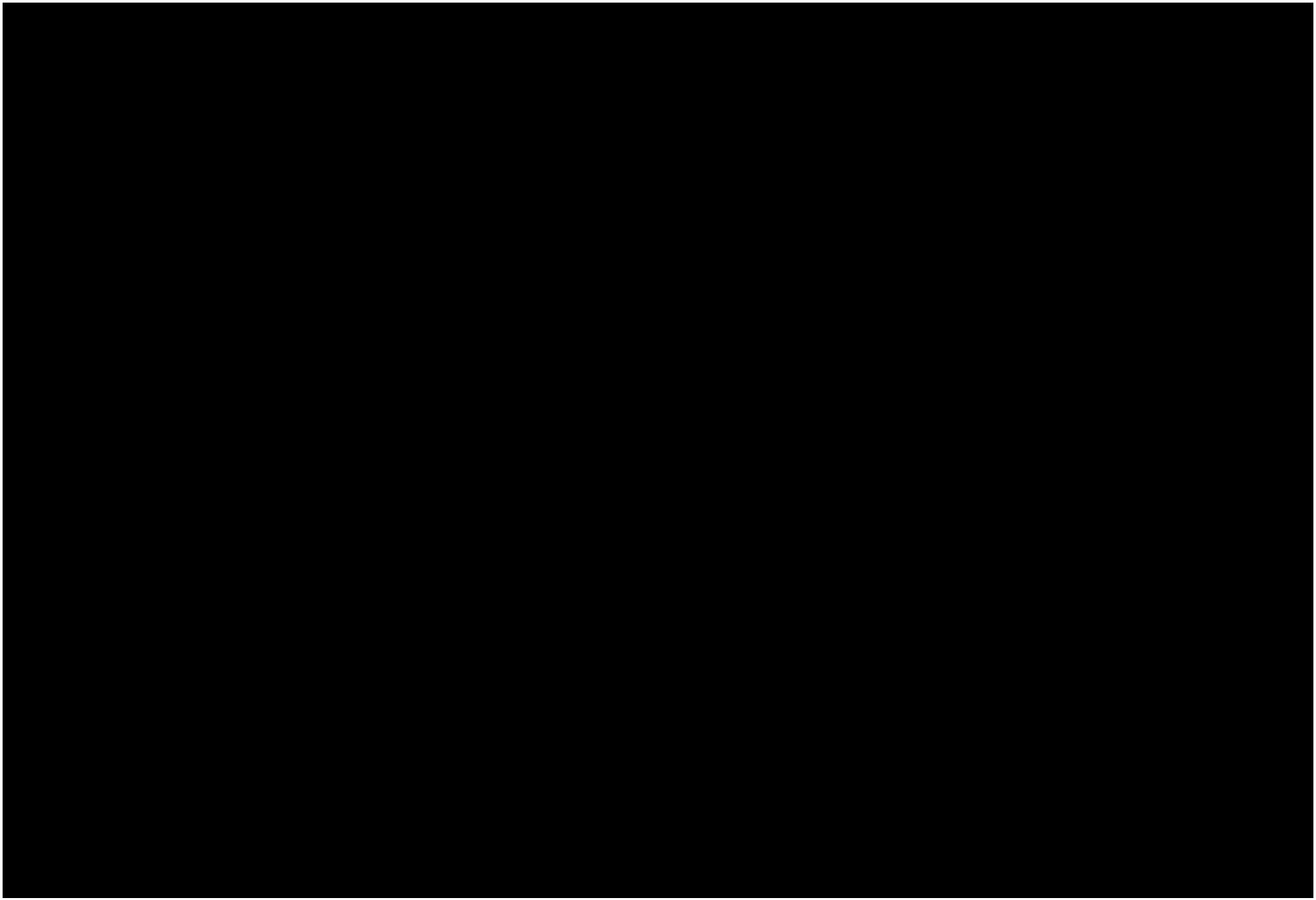
Date of Off Peak Day - 05/02/2021



Member Forecasted Off Peak Demand Day for June 2021

Southeast Colorado Power Association

Date of Off Peak Day - 06/25/2021



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Member Forecasted Off Peak Demand Day for July 2021

Southeast Colorado Power Association

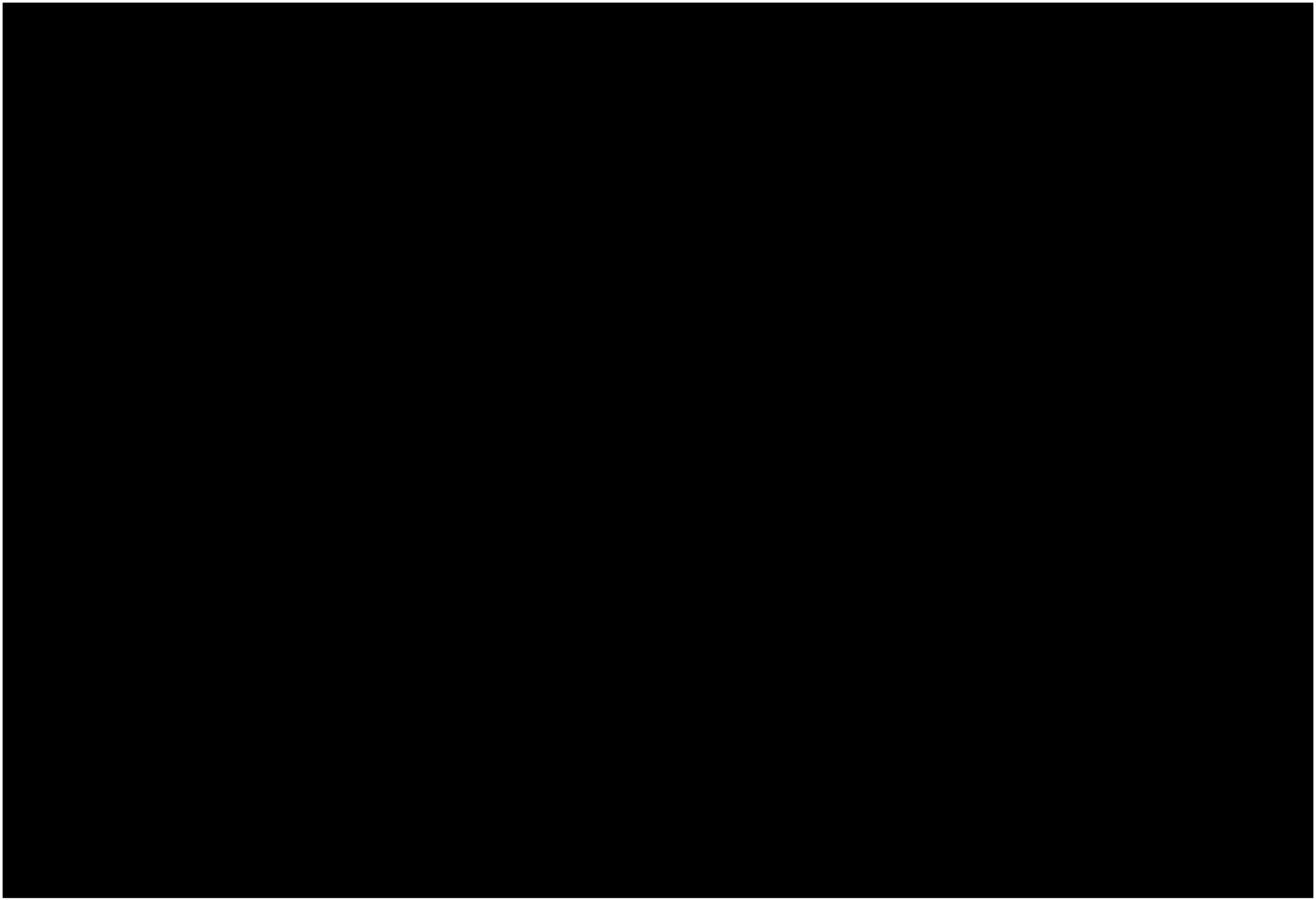
Date of Off Peak Day - 07/04/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Southeast Colorado Power Association

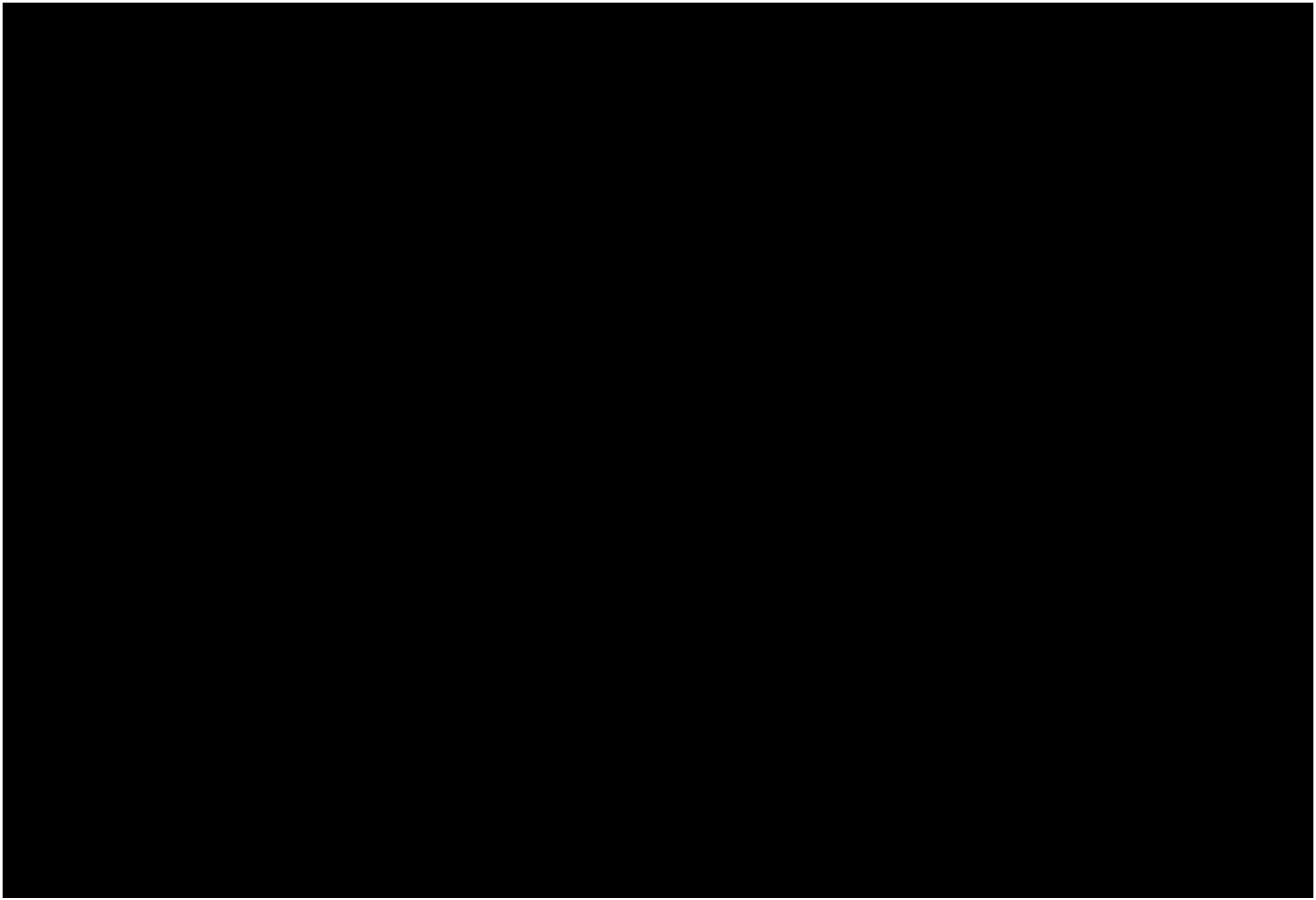
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Southeast Colorado Power Association

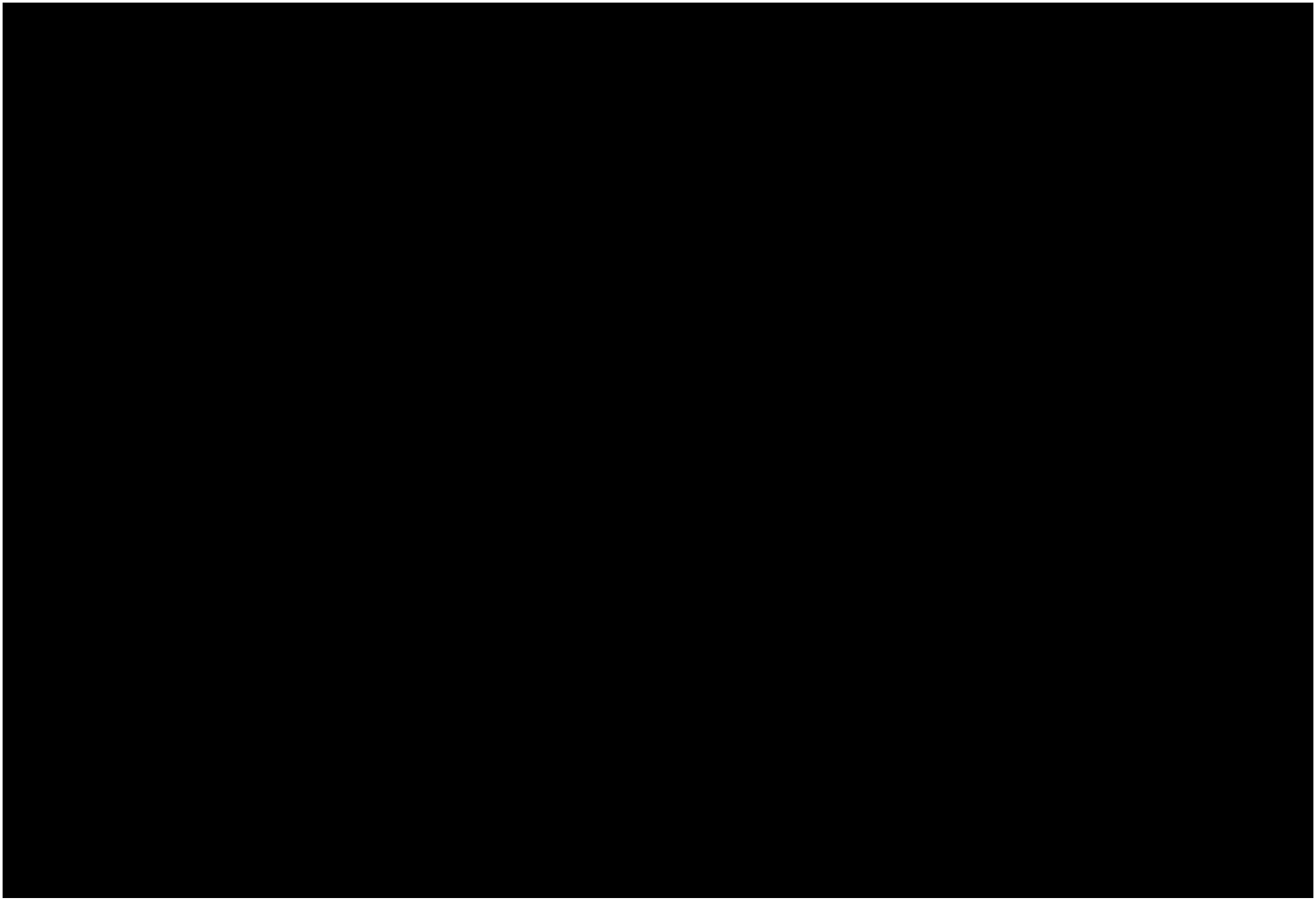
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Southeast Colorado Power Association

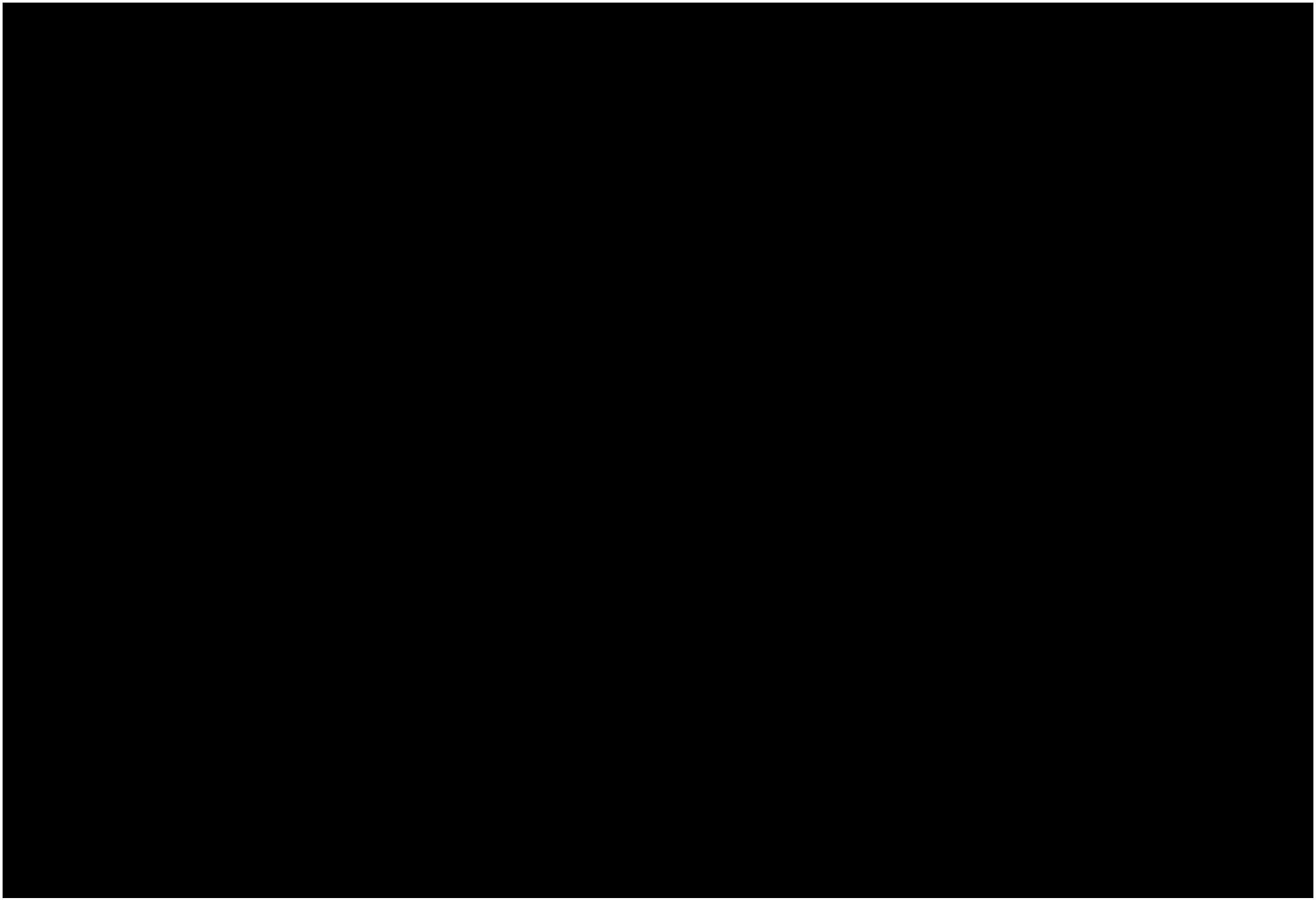
Date of Off Peak Day - 10/31/2021



Member Forecasted Off Peak Demand Day for November 2021

Southeast Colorado Power Association

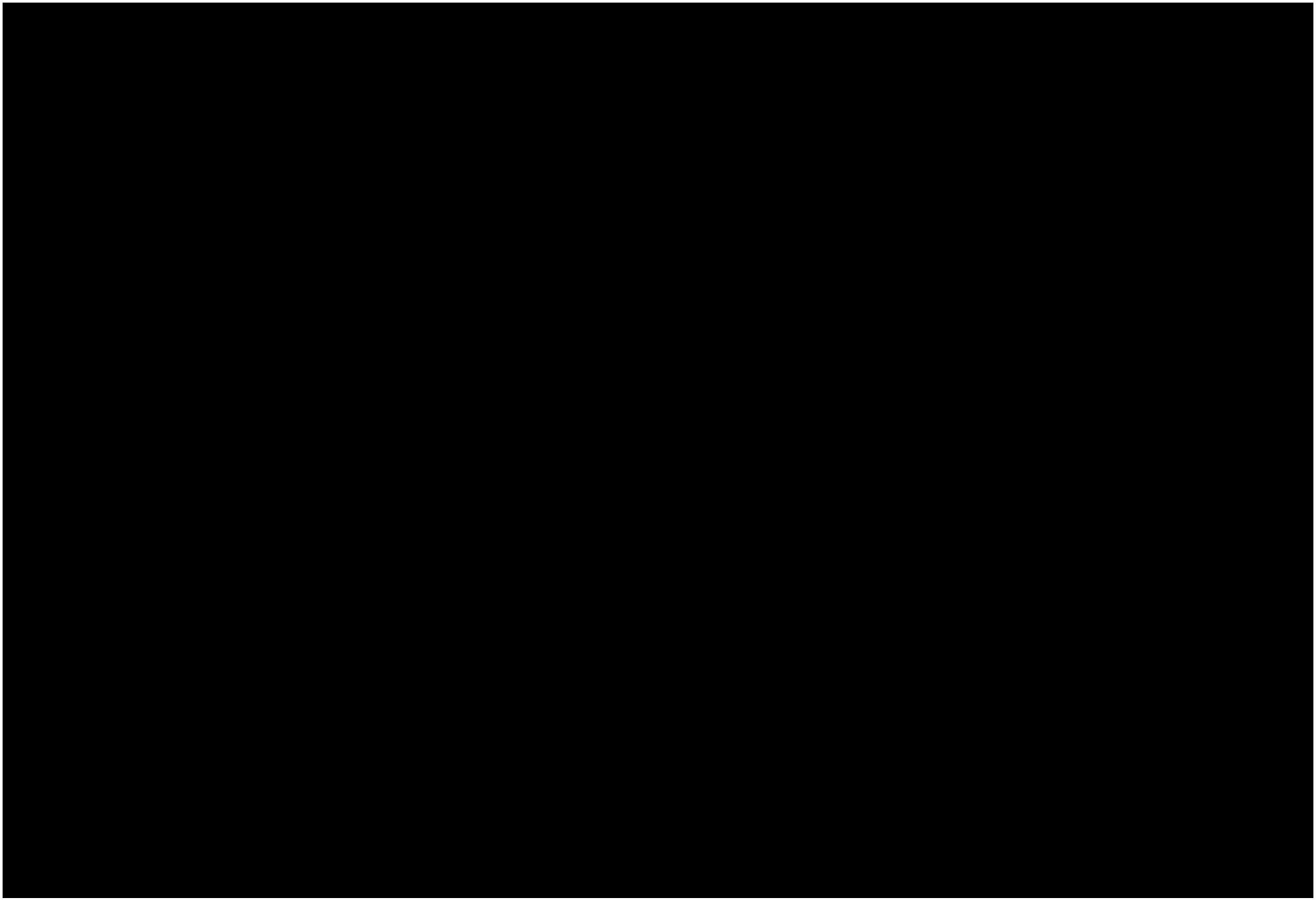
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

Southeast Colorado Power Association

Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

San Isabel Electric Association, Inc.

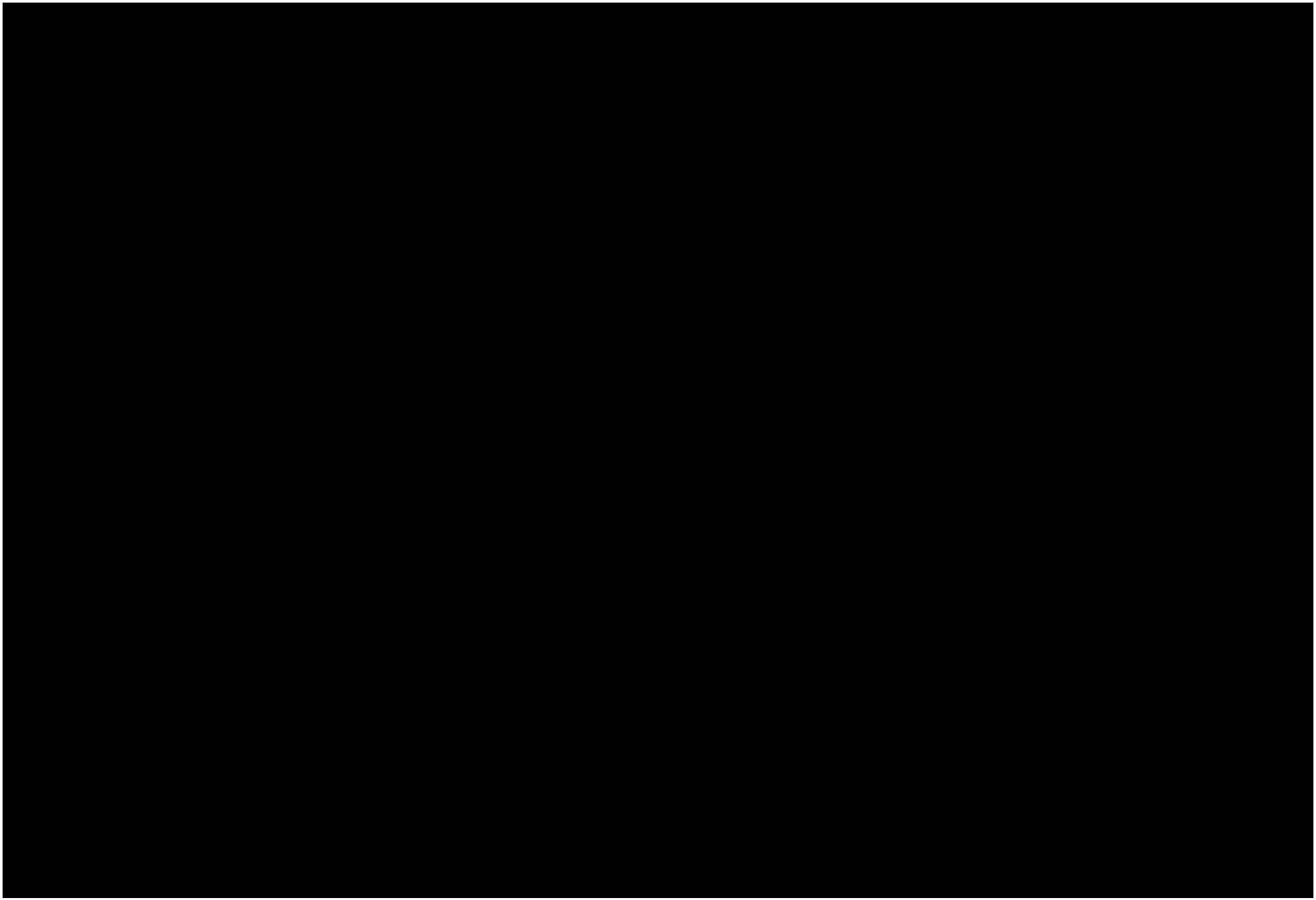
Date of Off Peak Day - 01/12/2021

[redacted]

Member Forecasted Off Peak Demand Day for February 2021

San Isabel Electric Association, Inc.

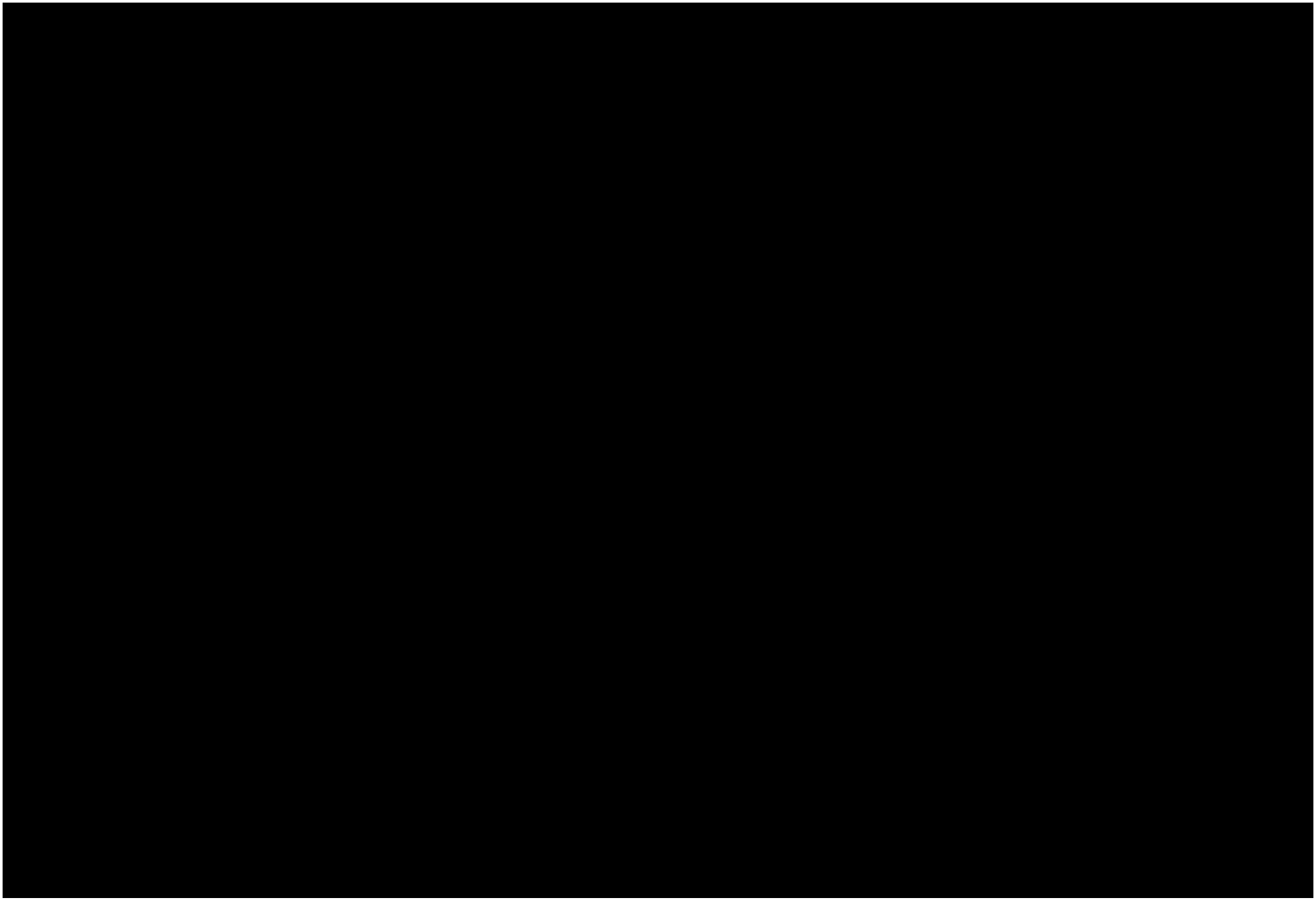
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 03/24/2021



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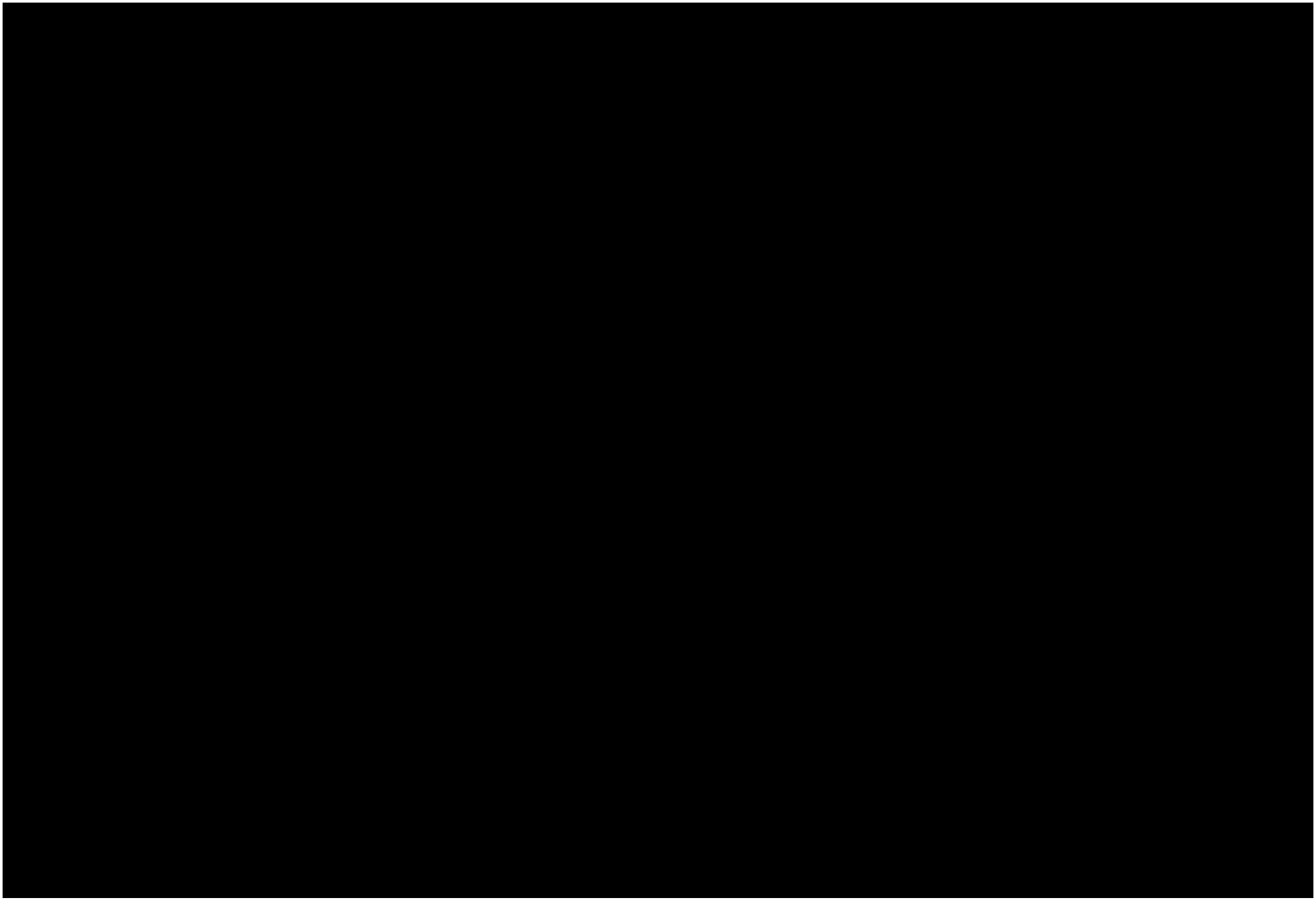
Member Forecasted Off Peak Demand Day for April 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 04/01/2021



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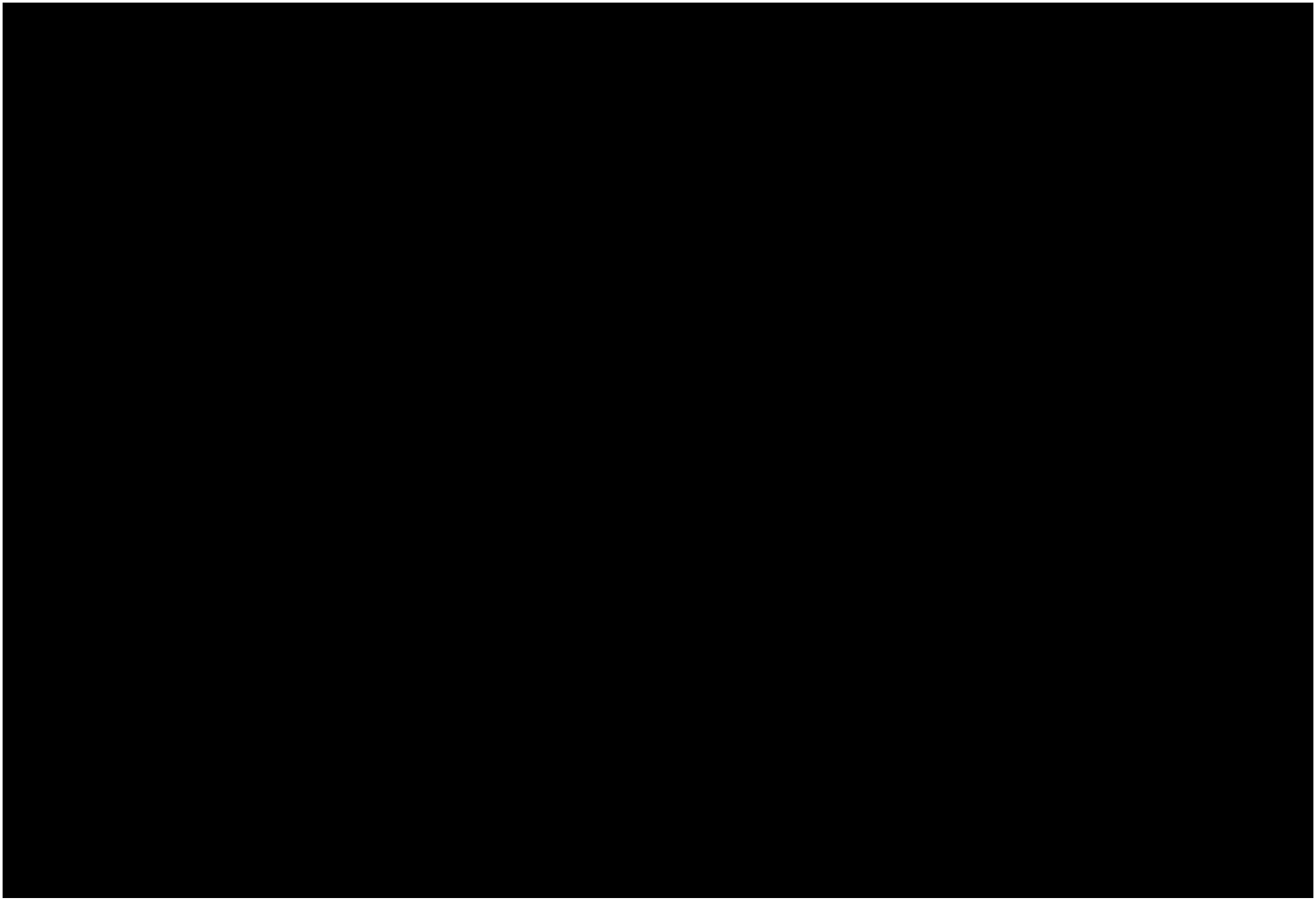
Member Forecasted Off Peak Demand Day for May 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 05/30/2021



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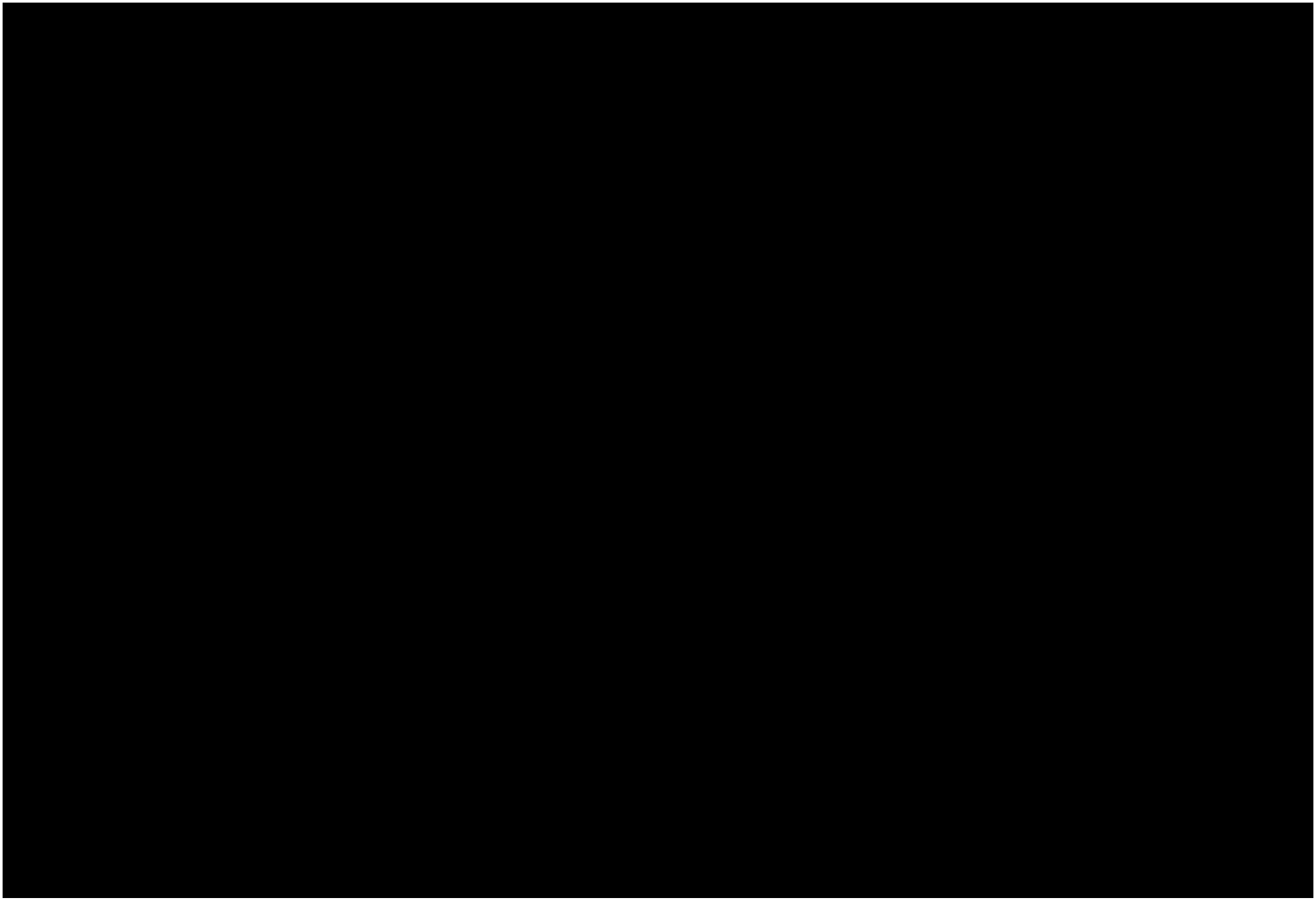
Member Forecasted Off Peak Demand Day for June 2021

San Isabel Electric Association, Inc.

Date of Off Peak Day - 06/30/2021



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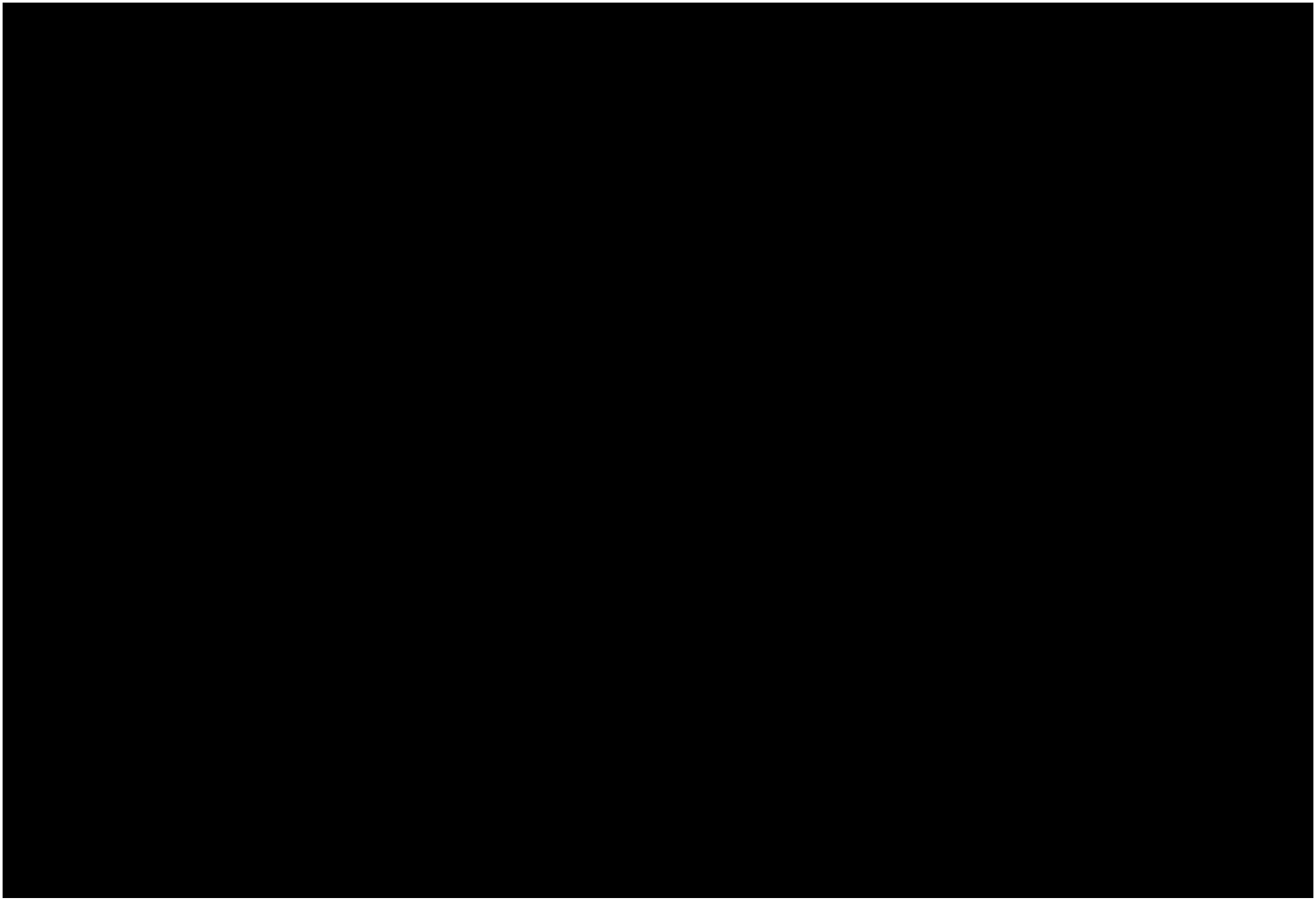
Member Forecasted Off Peak Demand Day for July 2021

San Isabel Electric Association, Inc.

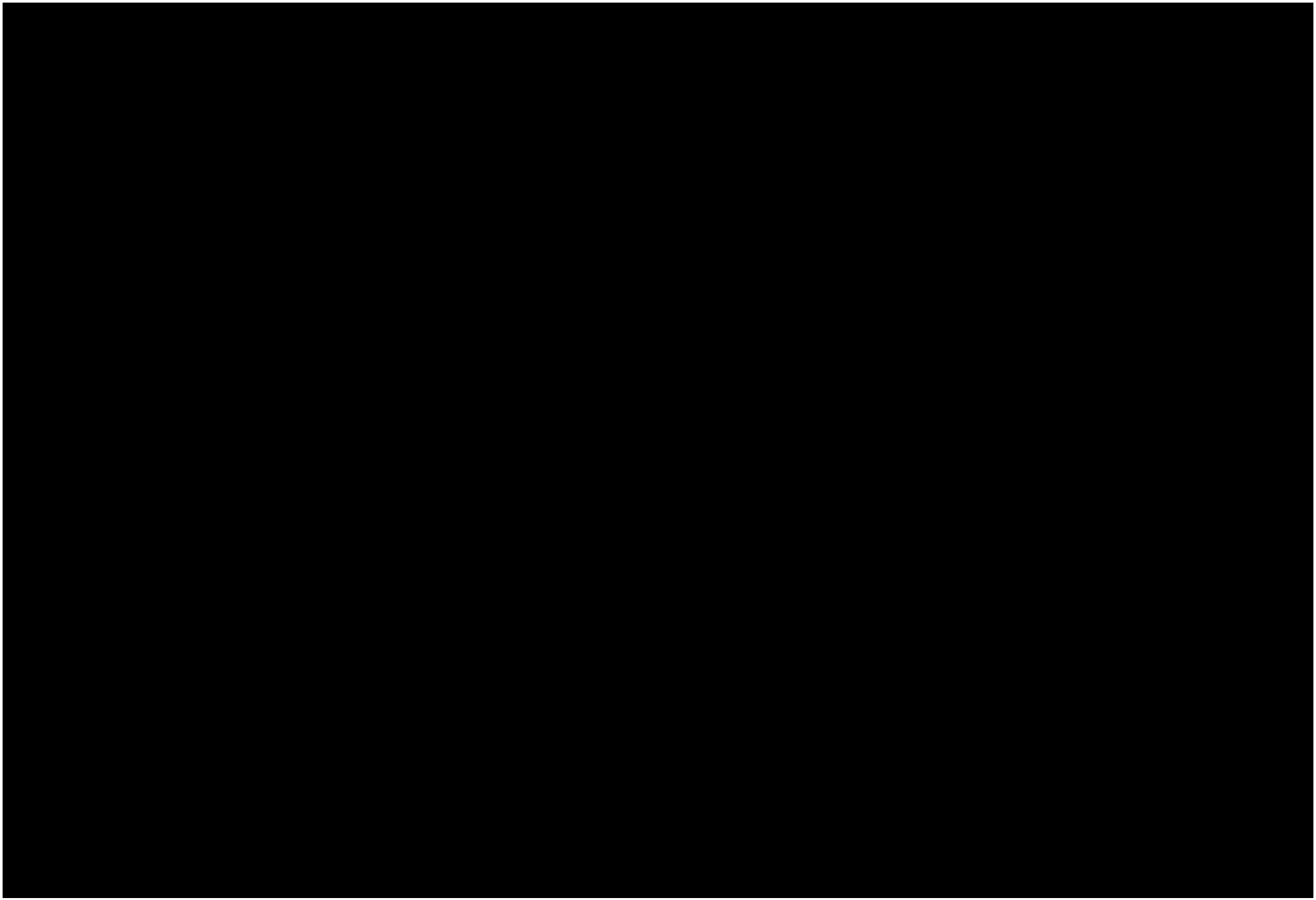
Date of Off Peak Day - 07/04/2021



Member Forecasted Off Peak Demand Day for August 2021

San Isabel Electric Association, Inc.

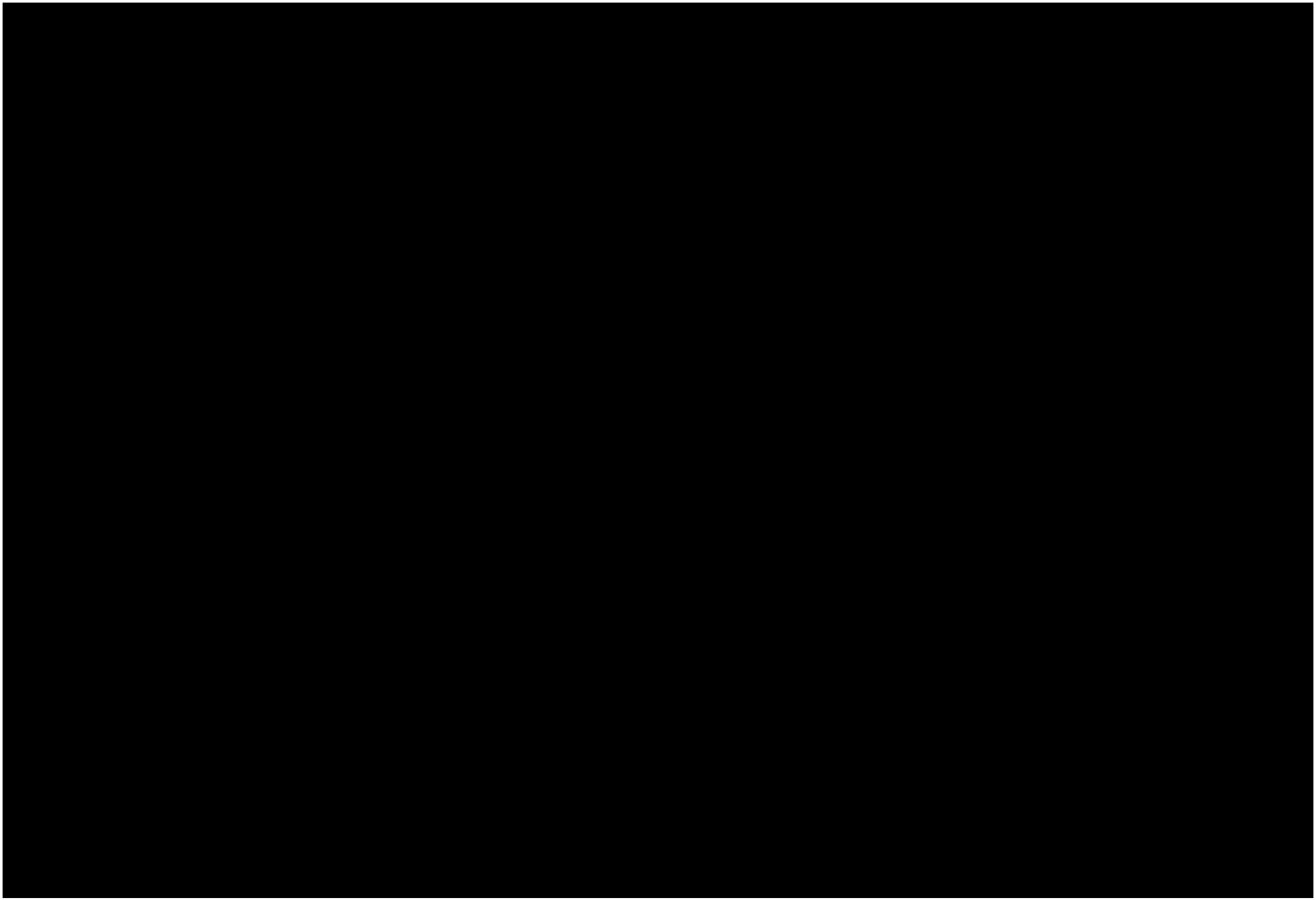
Date of Off Peak Day - 08/17/2021



Member Forecasted Off Peak Demand Day for September 2021

San Isabel Electric Association, Inc.

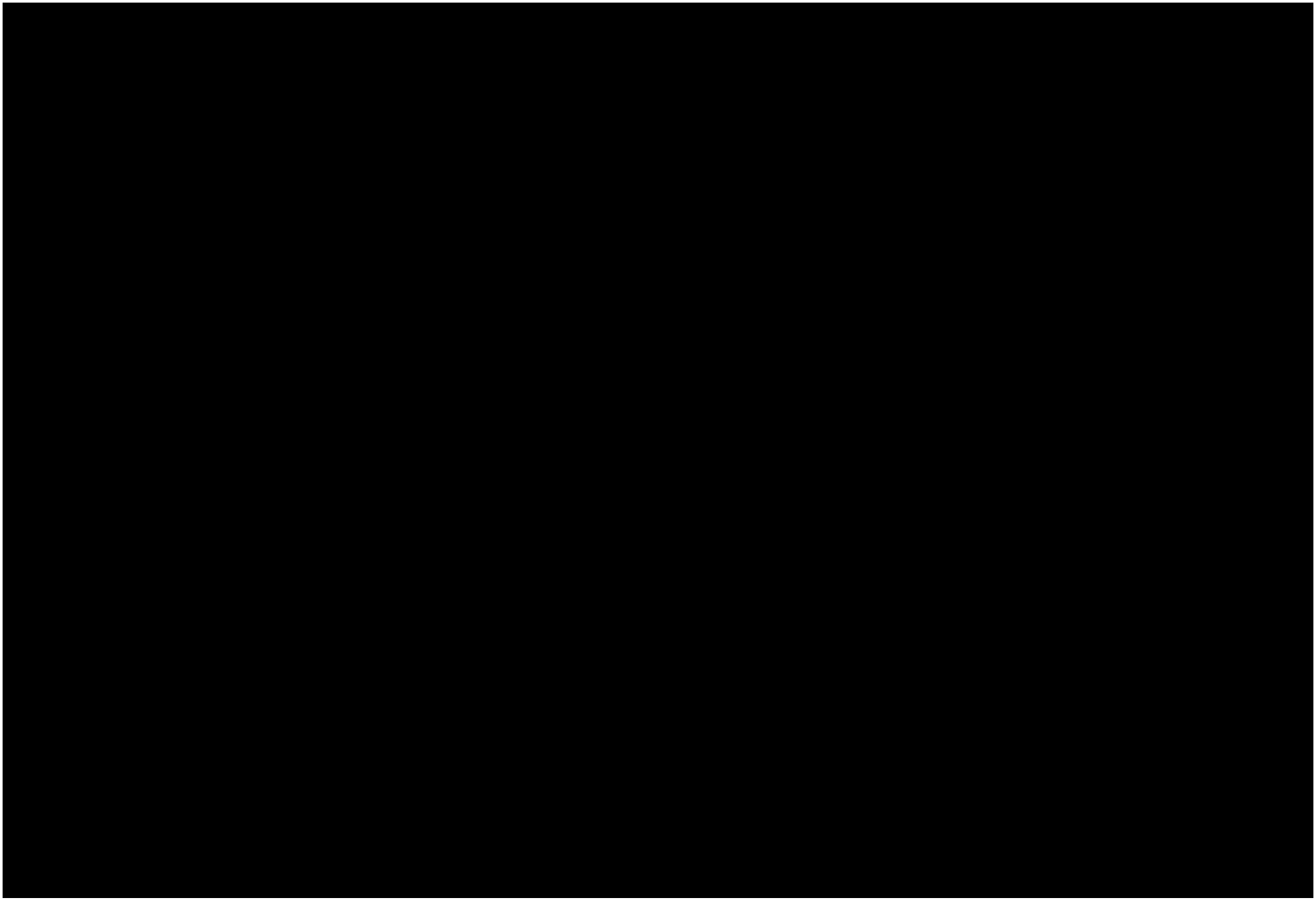
Date of Off Peak Day - 09/02/2021



Member Forecasted Off Peak Demand Day for October 2021

San Isabel Electric Association, Inc.

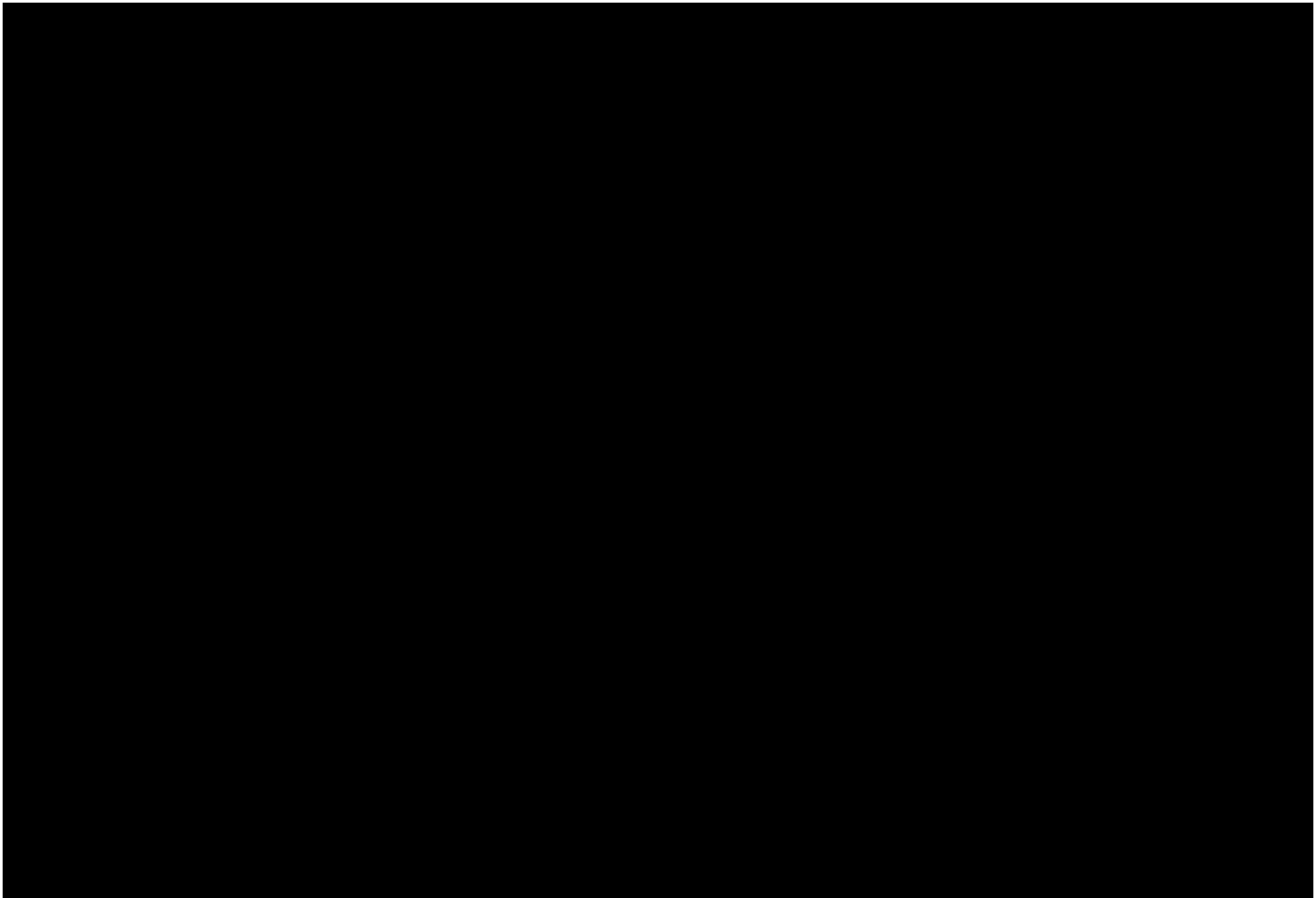
Date of Off Peak Day - 10/26/2021



Member Forecasted Off Peak Demand Day for November 2021

San Isabel Electric Association, Inc.

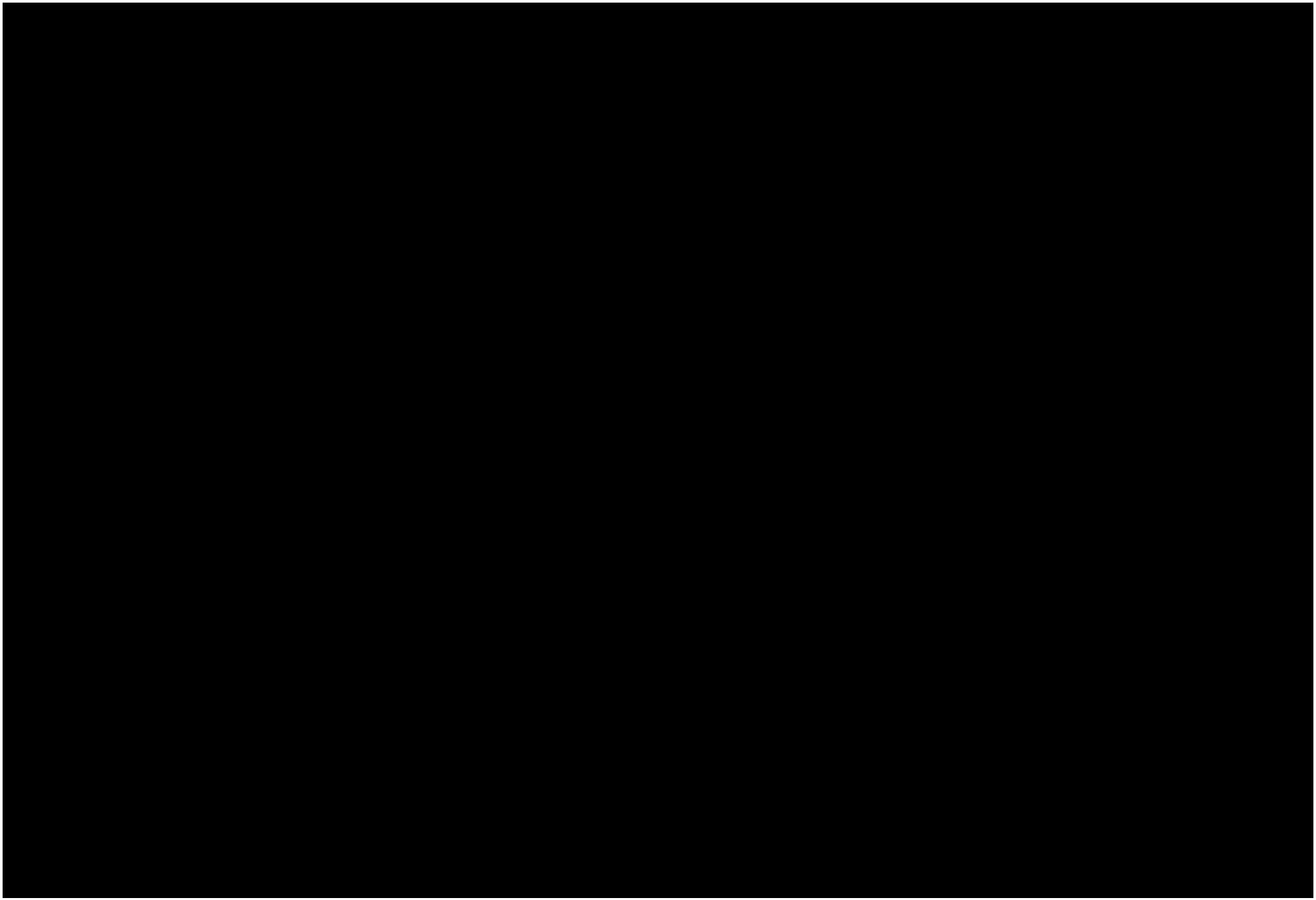
Date of Off Peak Day - 11/10/2021



Member Forecasted Off Peak Demand Day for December 2021

San Isabel Electric Association, Inc.

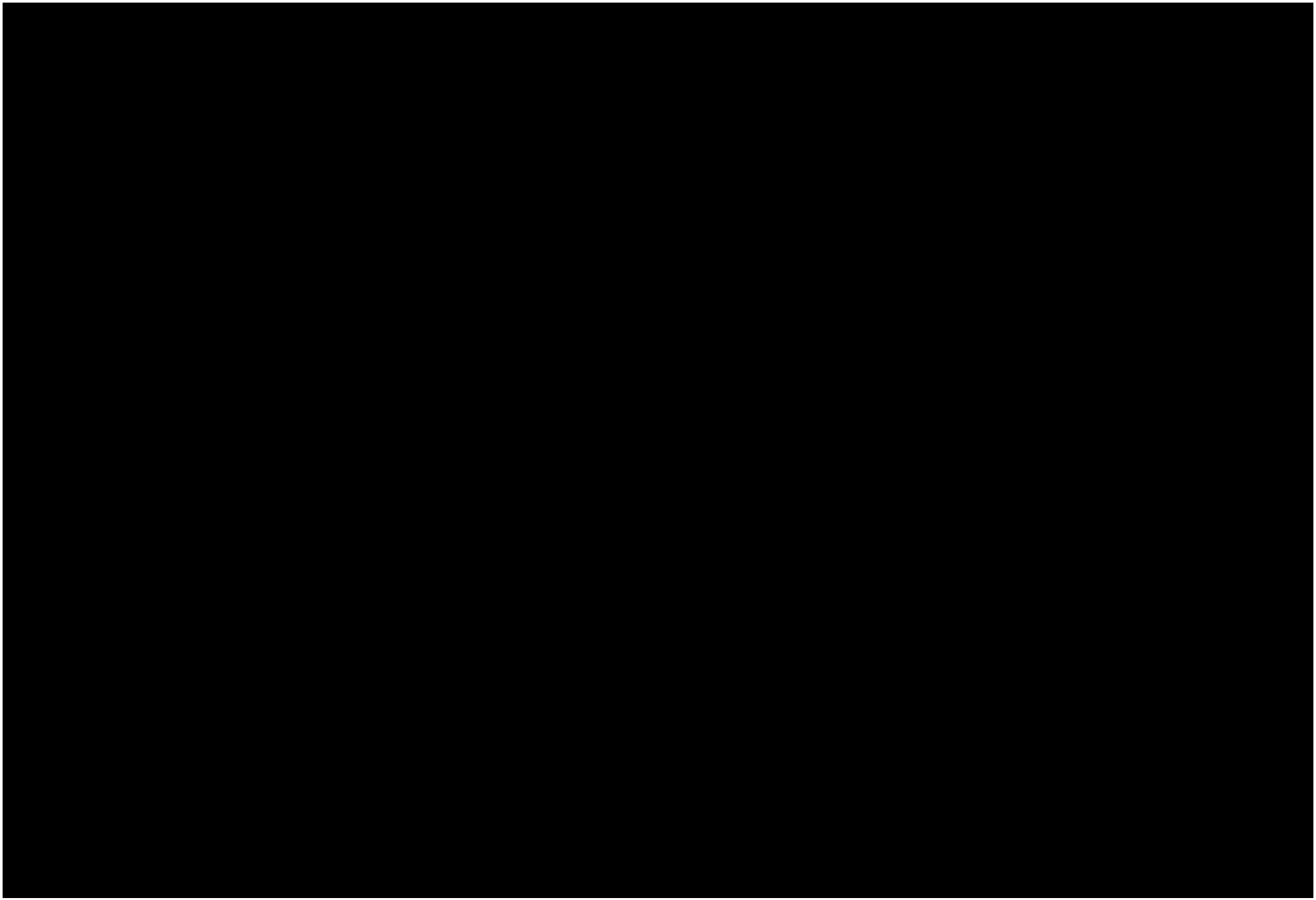
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

San Luis Valley Rural Electric Cooperative, Inc.

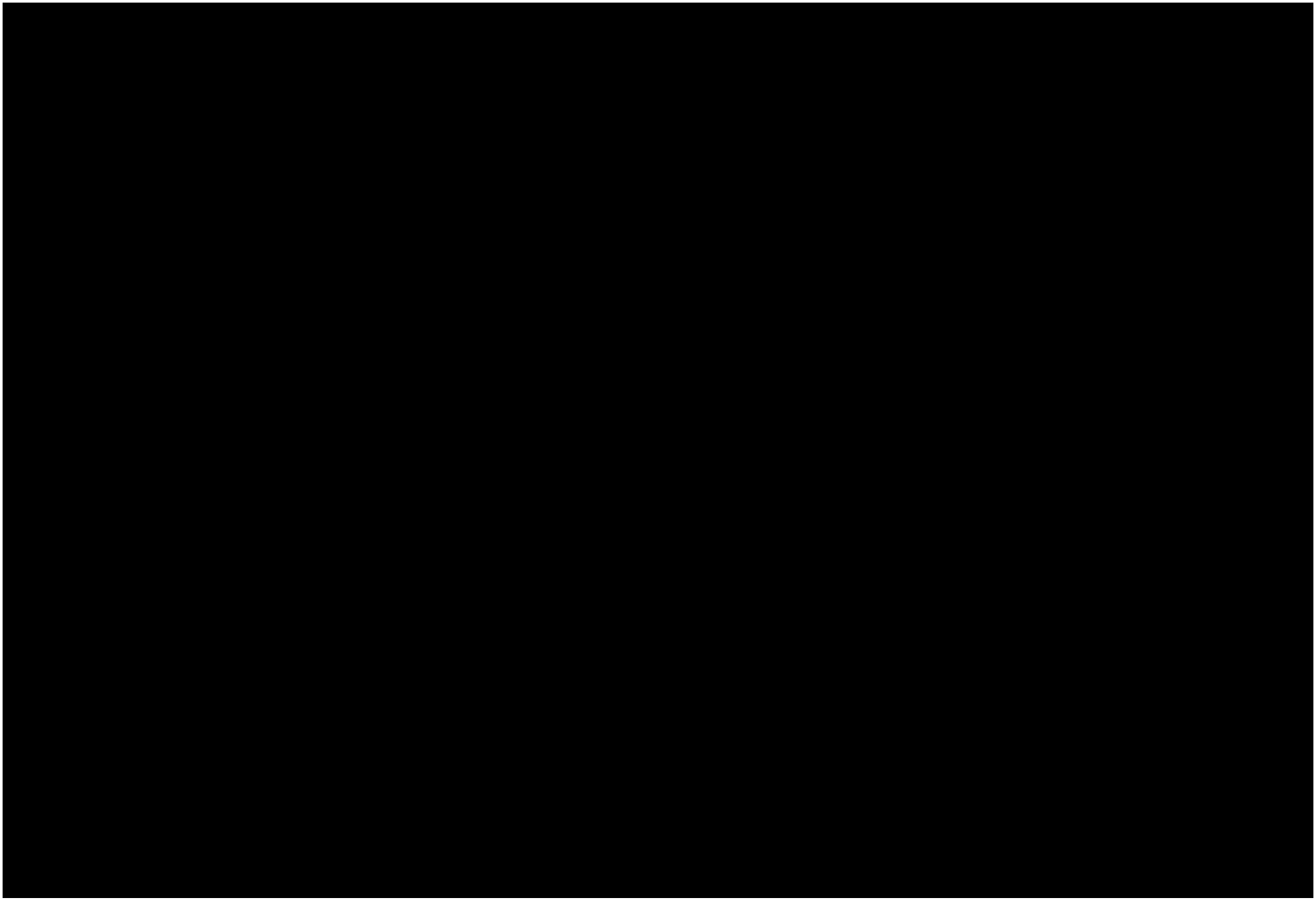
Date of Off Peak Day - 01/14/2021



Member Forecasted Off Peak Demand Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.

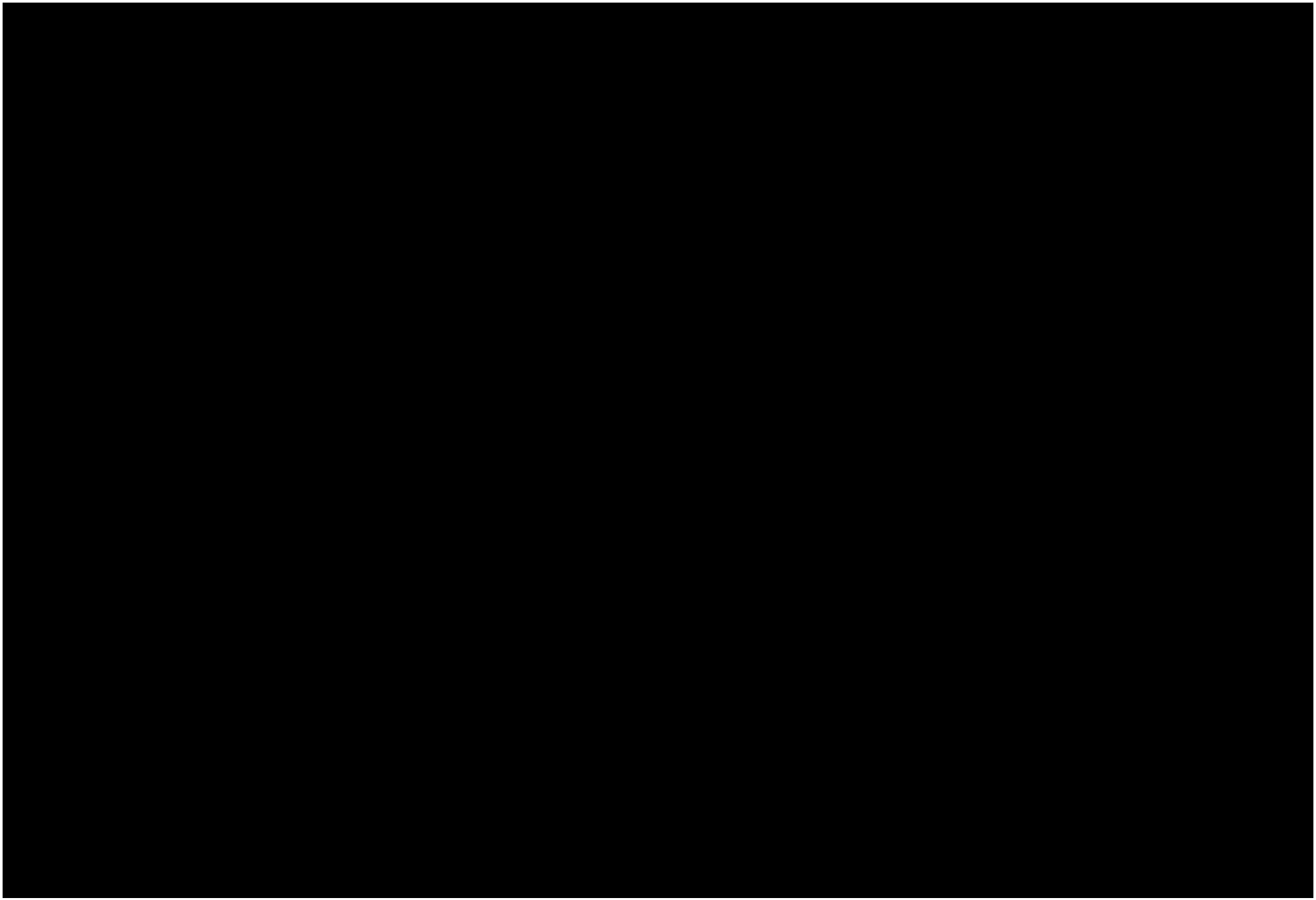
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.

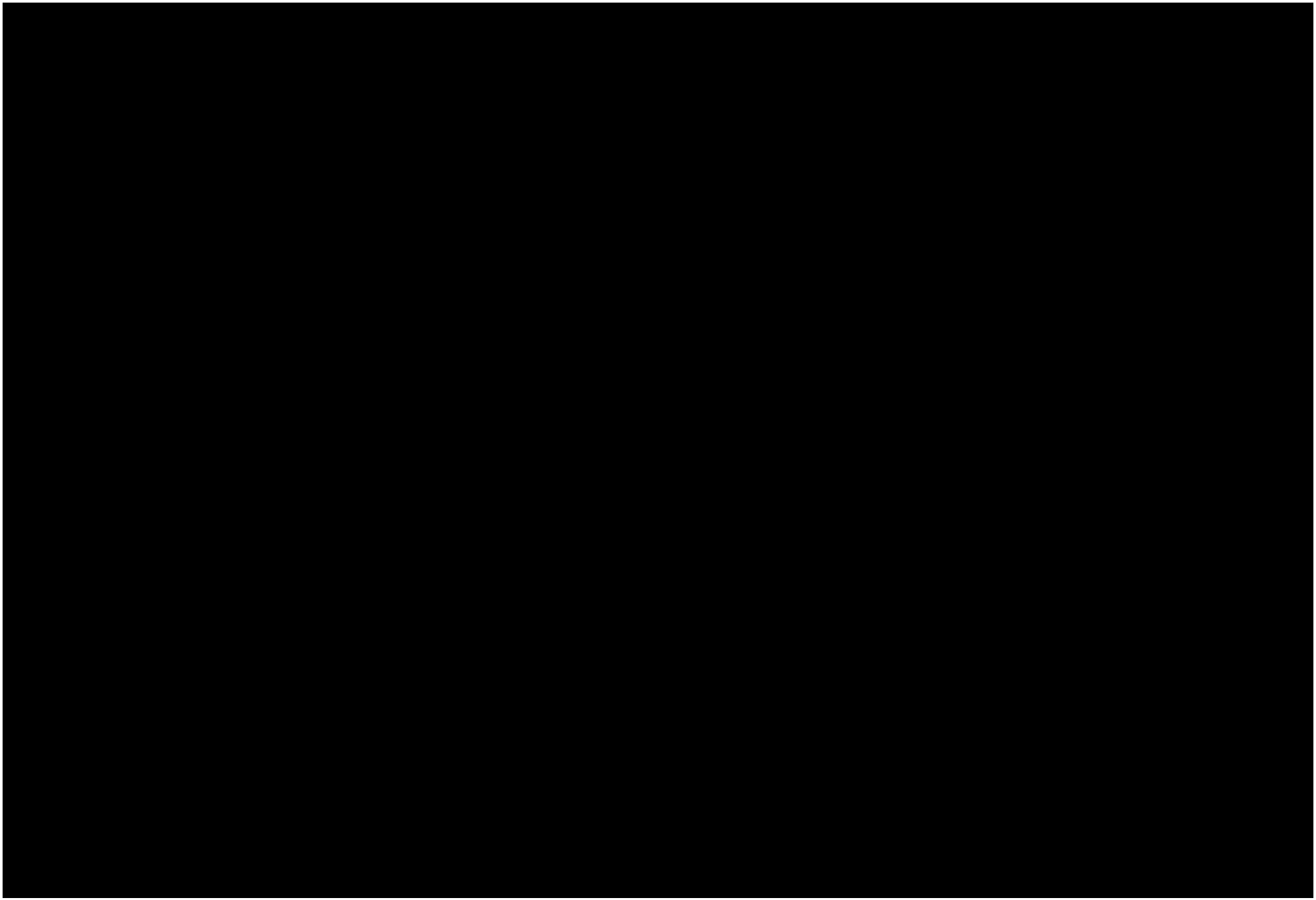
Date of Off Peak Day - 03/20/2021



Member Forecasted Off Peak Demand Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.

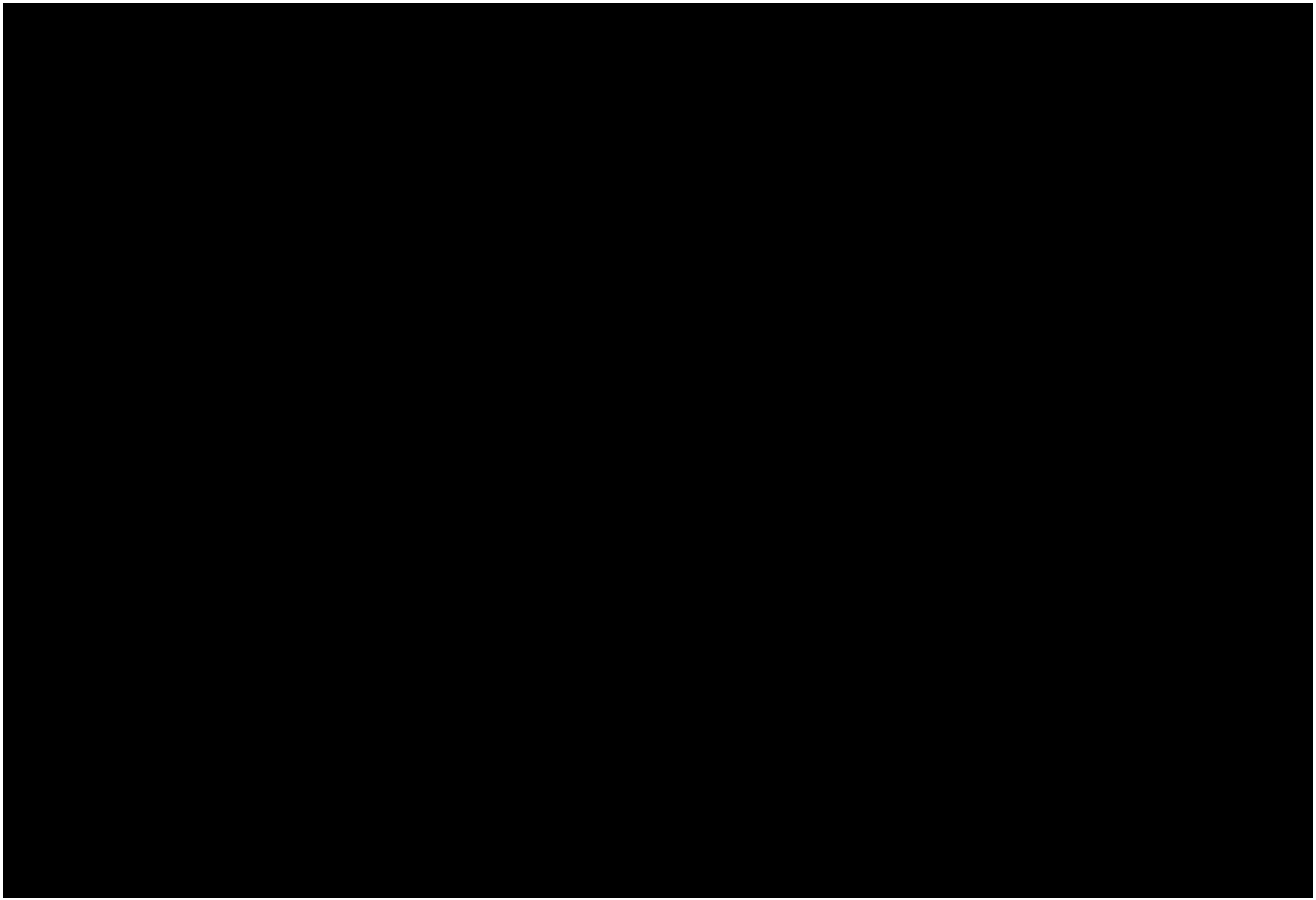
Date of Off Peak Day - 04/02/2021



Member Forecasted Off Peak Demand Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.

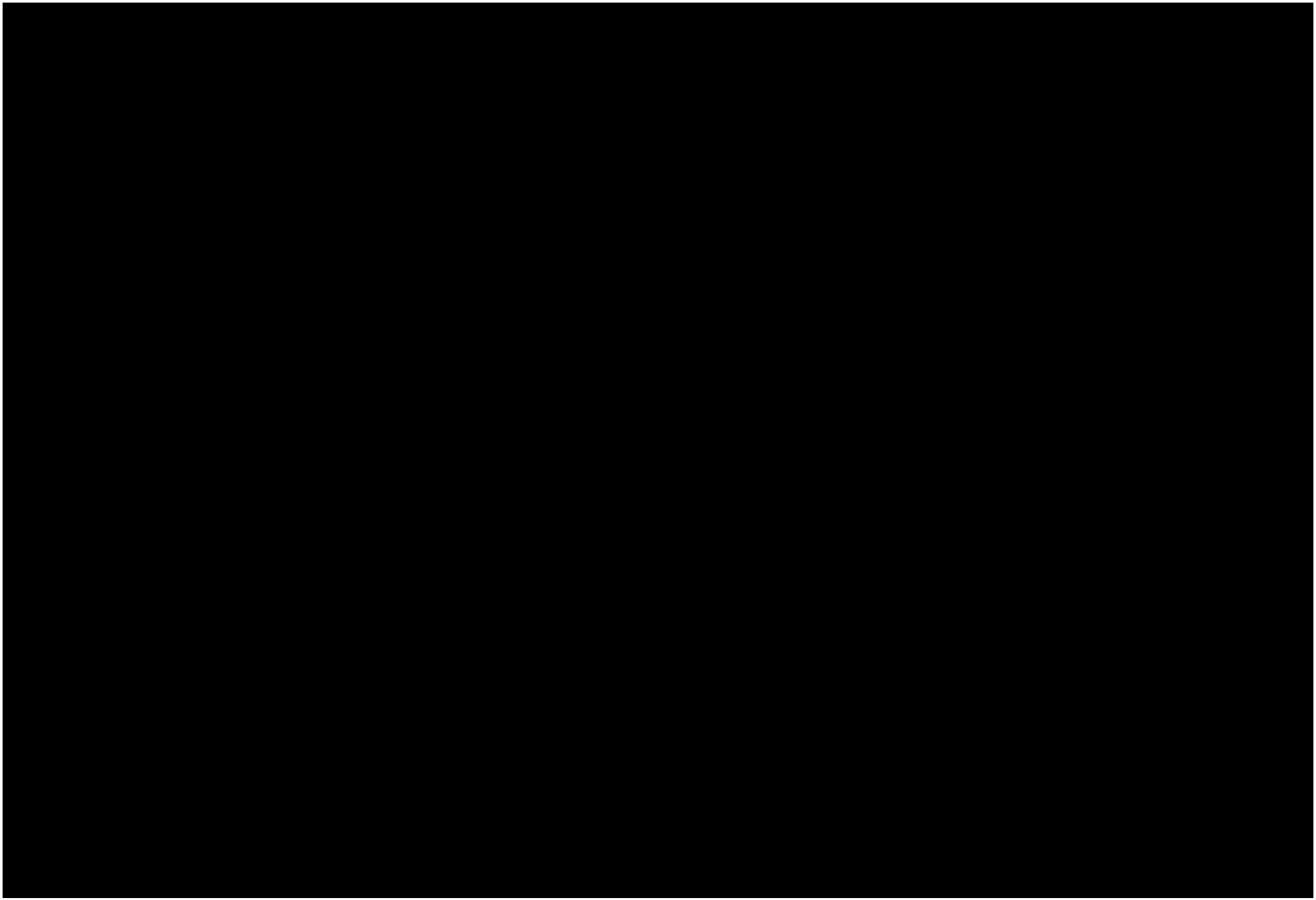
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.

Date of Off Peak Day - 06/05/2021



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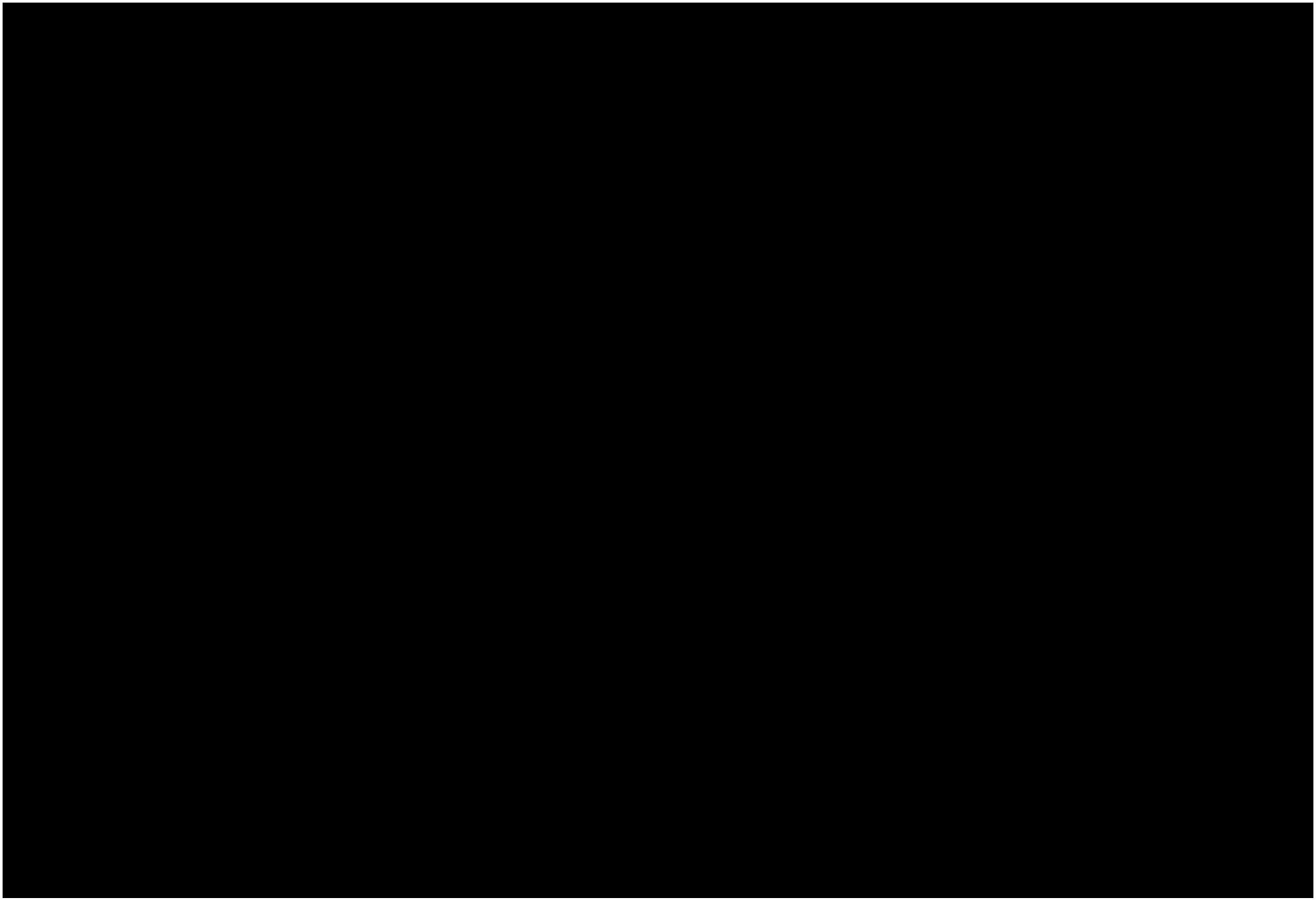
Member Forecasted Off Peak Demand Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.

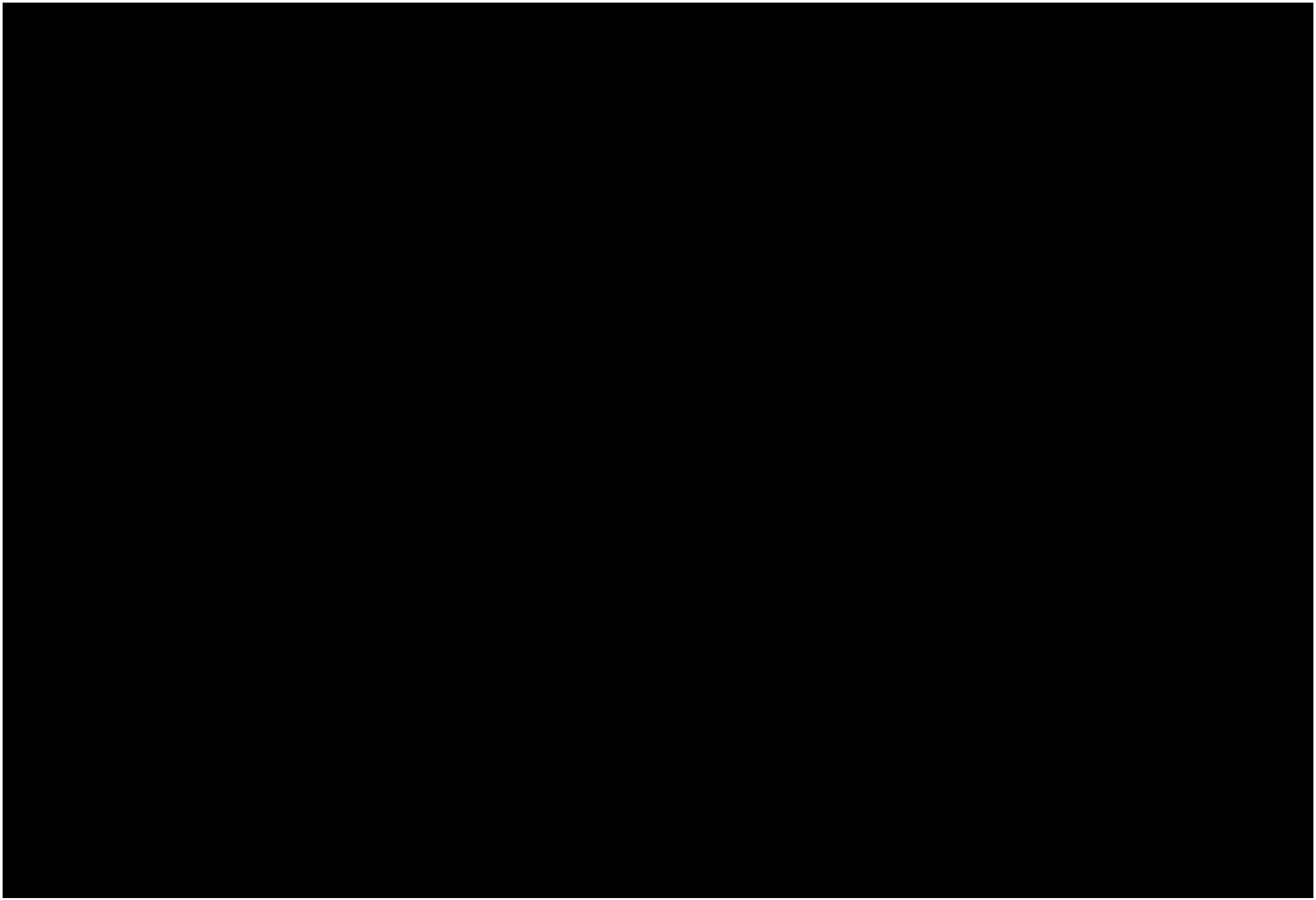
Date of Off Peak Day - 07/03/2021



Member Forecasted Off Peak Demand Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.

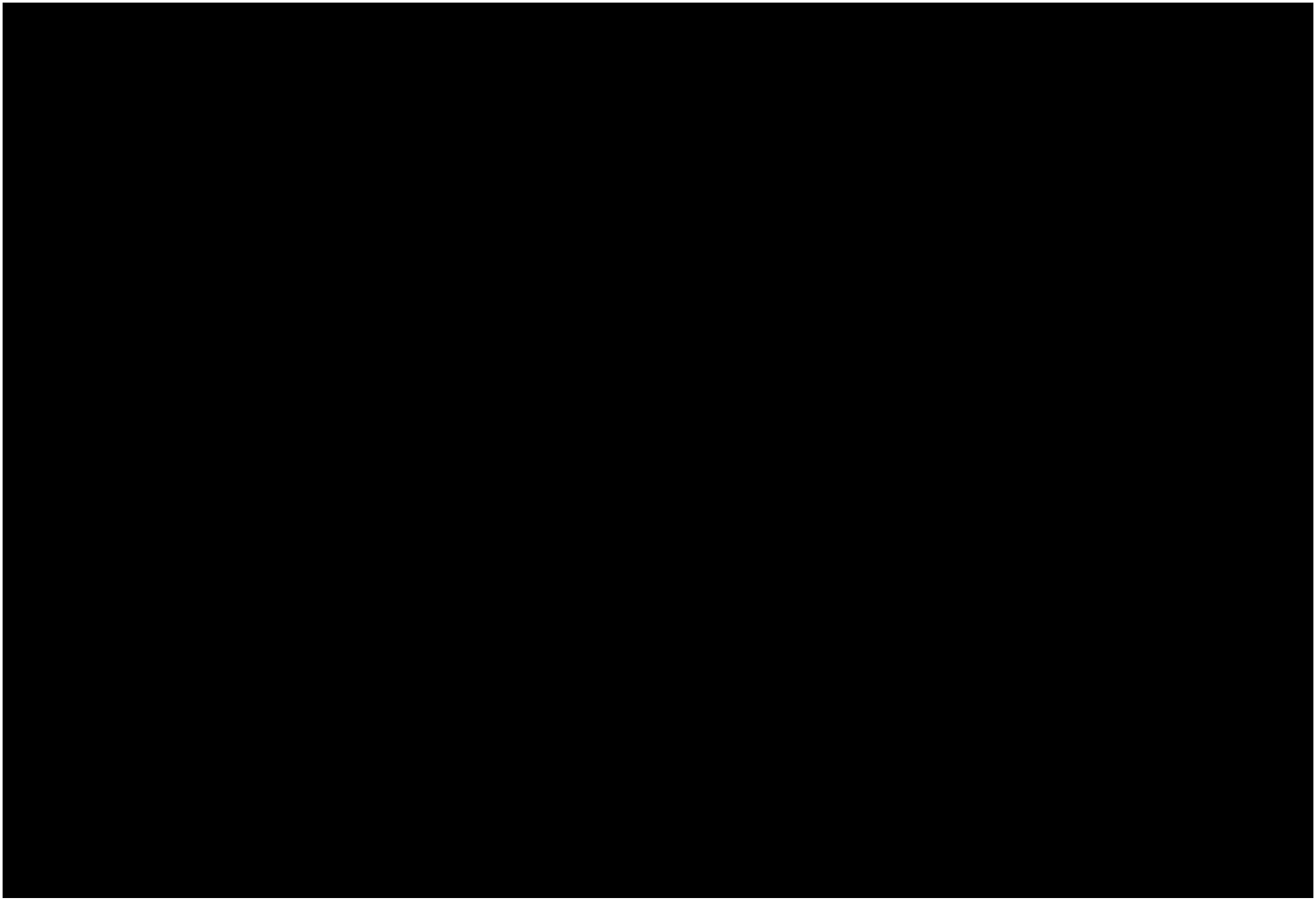
Date of Off Peak Day - 08/01/2021



Member Forecasted Off Peak Demand Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

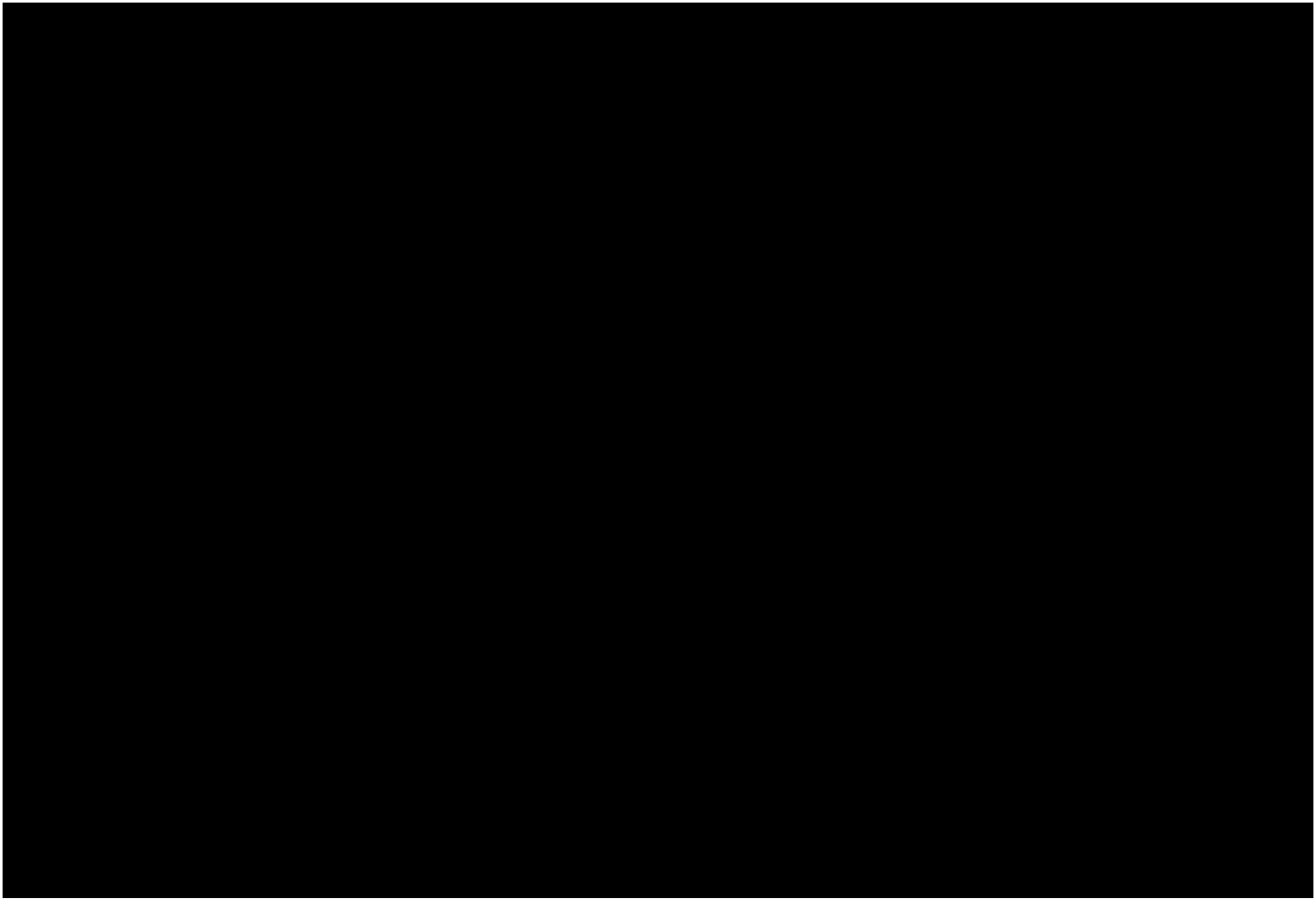
Date of Off Peak Day - 09/25/2021



Member Forecasted Off Peak Demand Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.

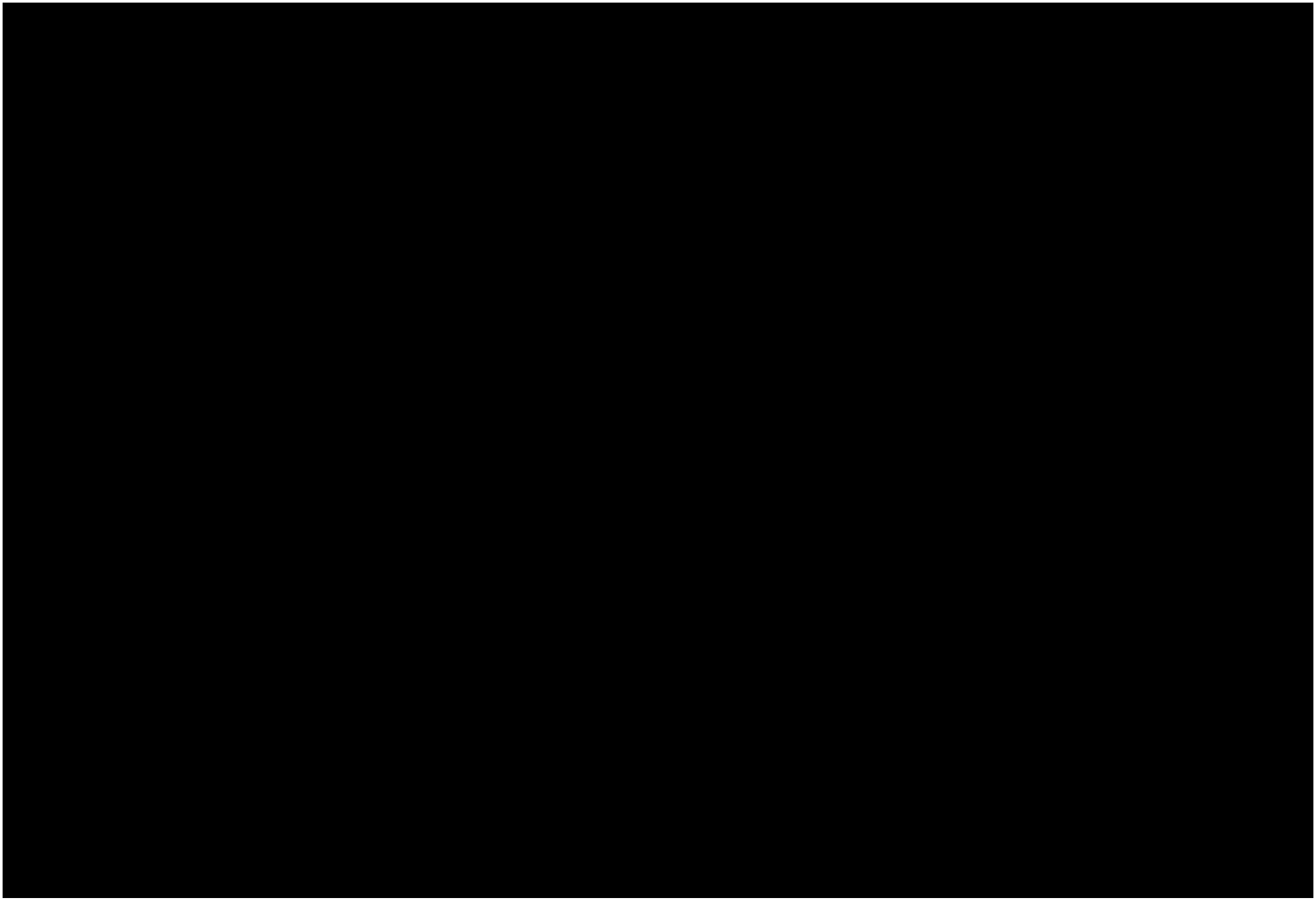
Date of Off Peak Day - 10/24/2021



Member Forecasted Off Peak Demand Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.

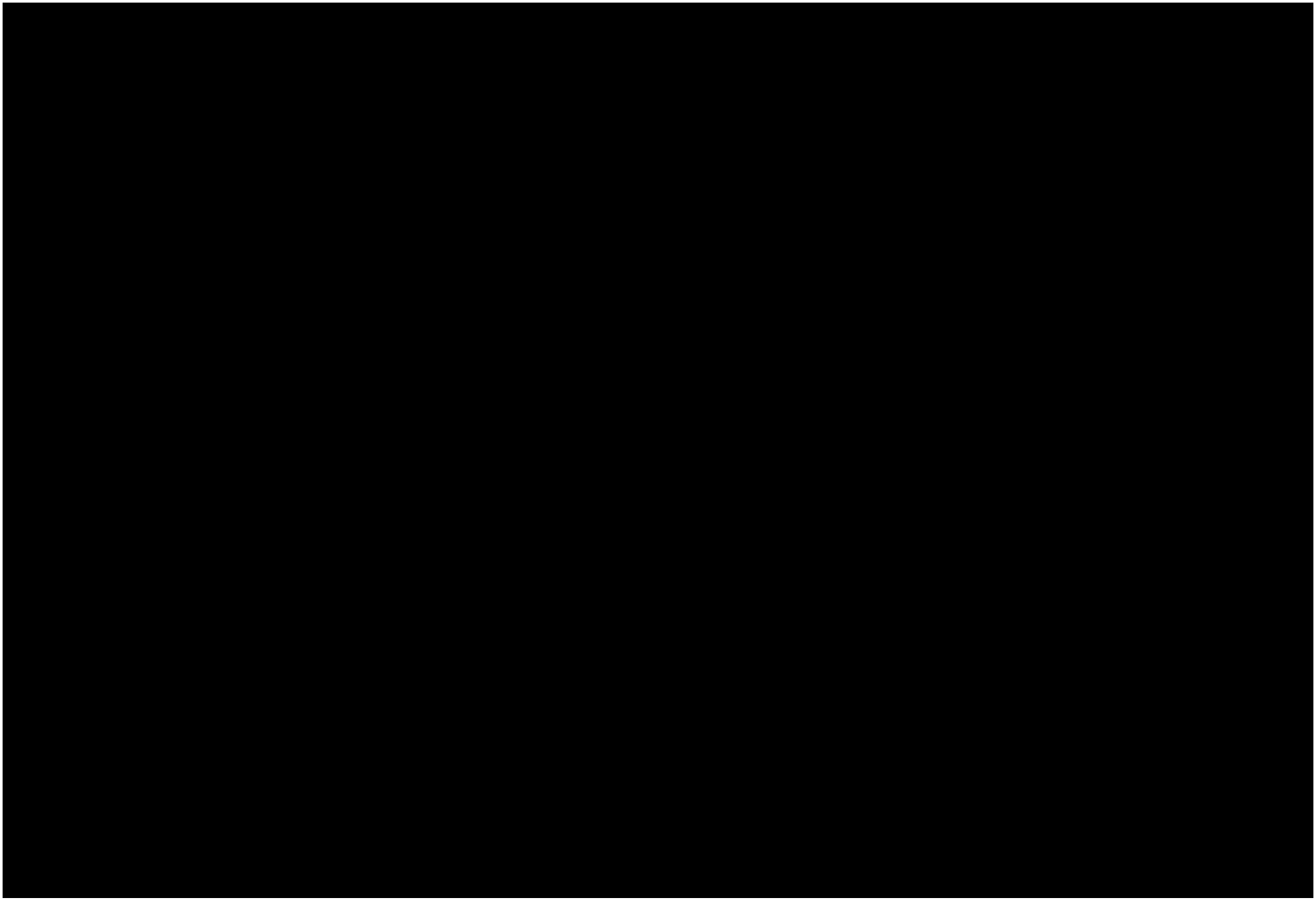
Date of Off Peak Day - 11/06/2021



Member Forecasted Off Peak Demand Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.

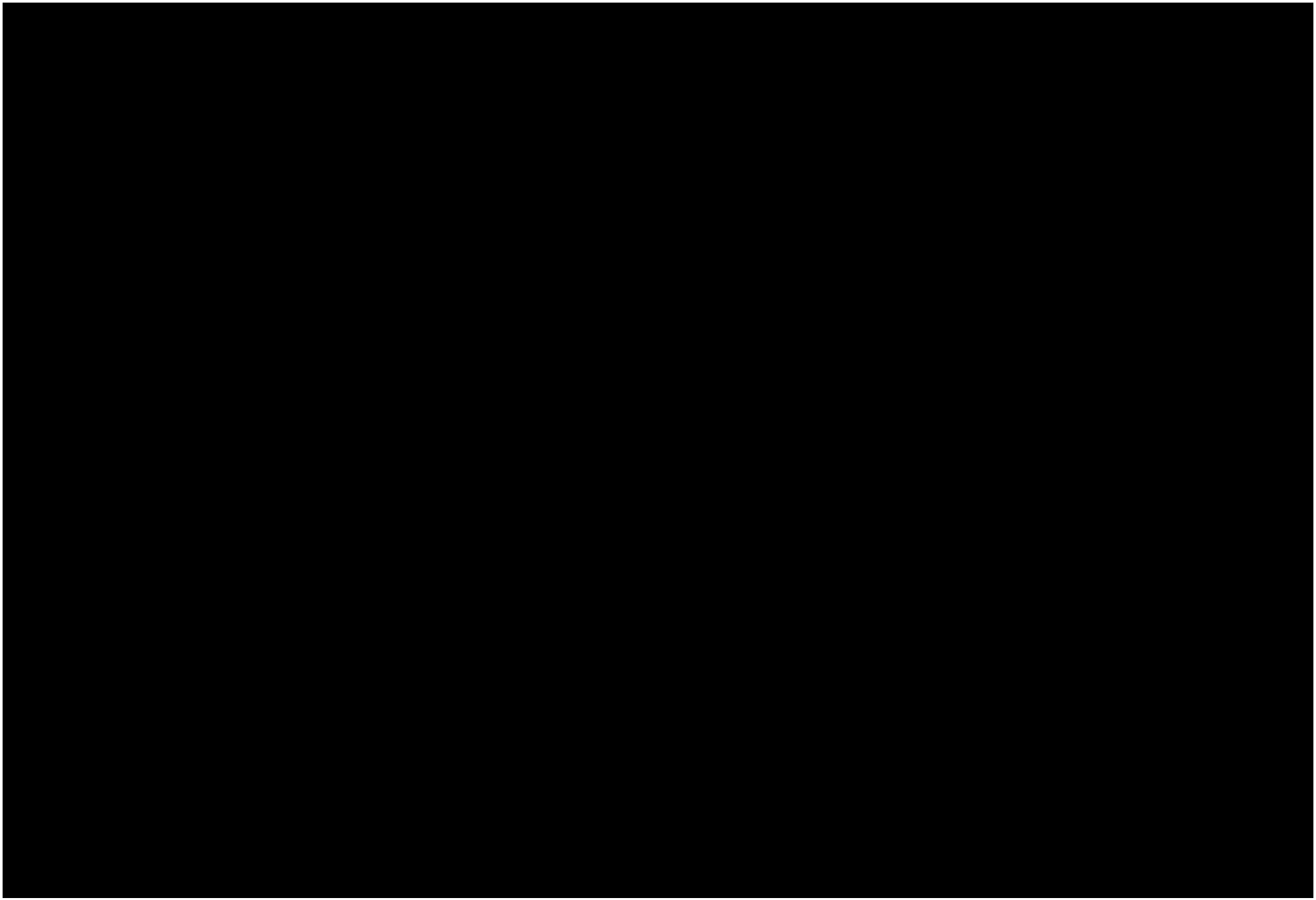
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

San Miguel Power Association, Inc.

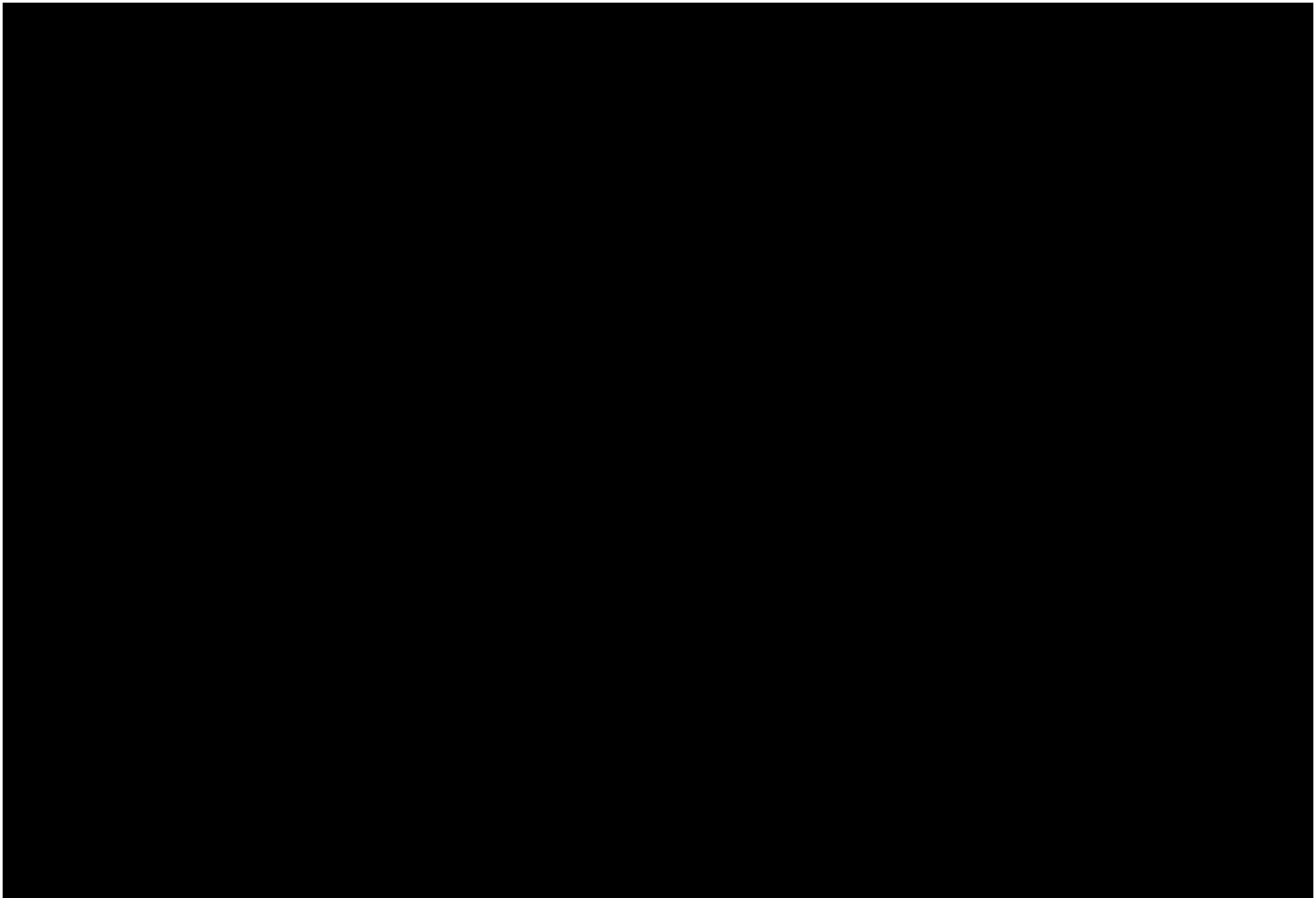
Date of Off Peak Day - 01/11/2021



Member Forecasted Off Peak Demand Day for February 2021

San Miguel Power Association, Inc.

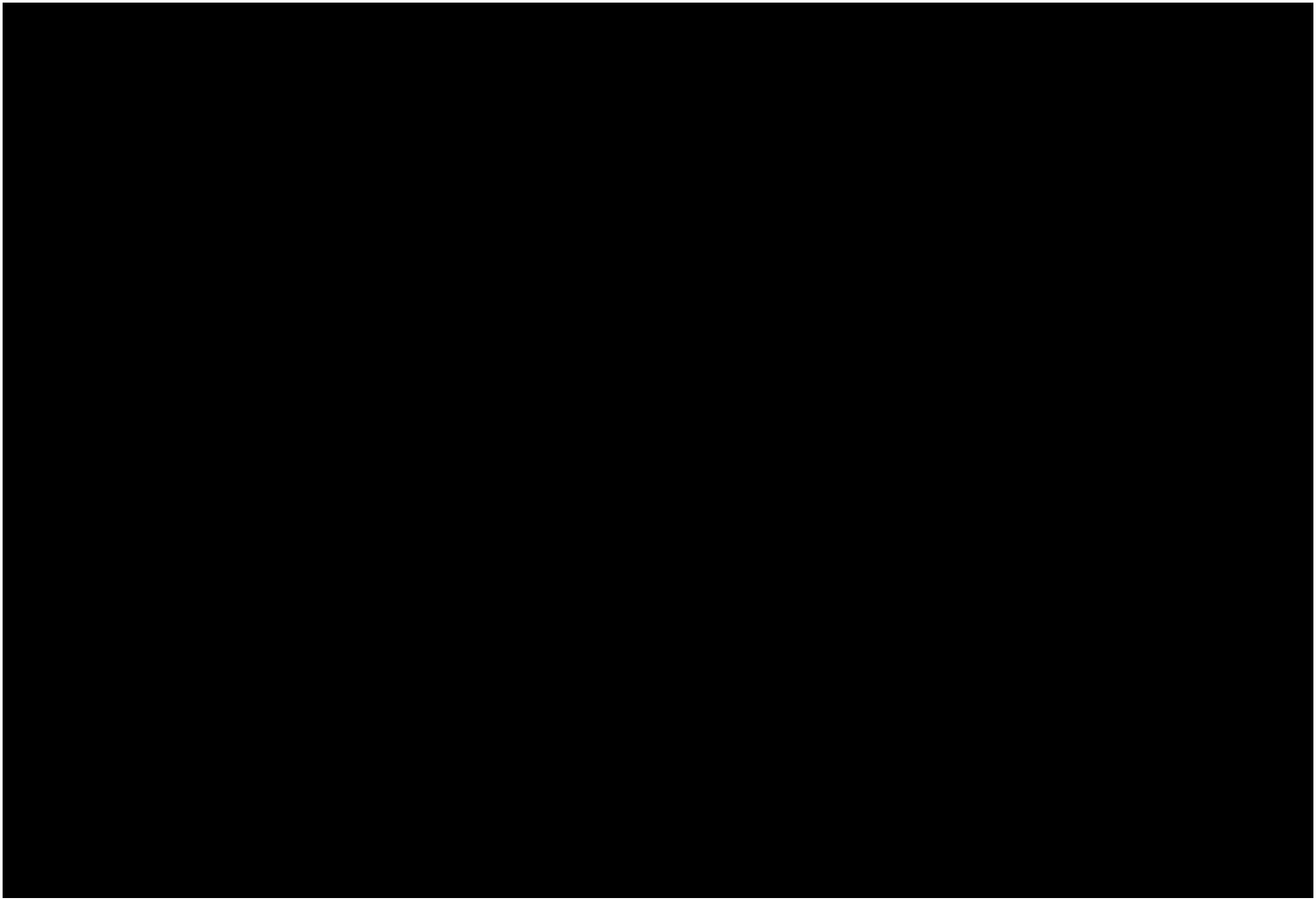
Date of Off Peak Day - 02/10/2021



Member Forecasted Off Peak Demand Day for March 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 03/21/2021



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Member Forecasted Off Peak Demand Day for April 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 04/30/2021

[redacted]

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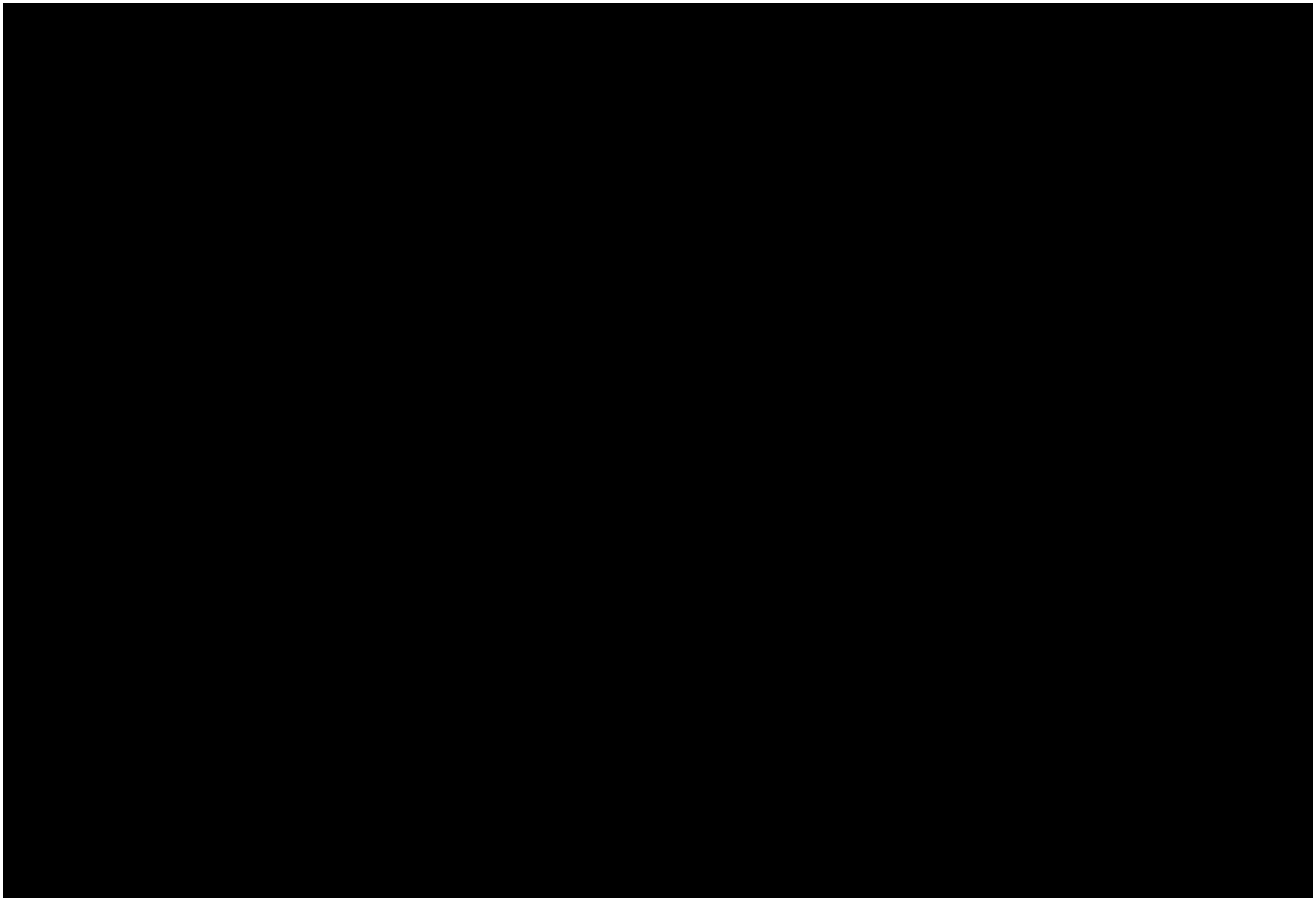
Member Forecasted Off Peak Demand Day for May 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 05/25/2021



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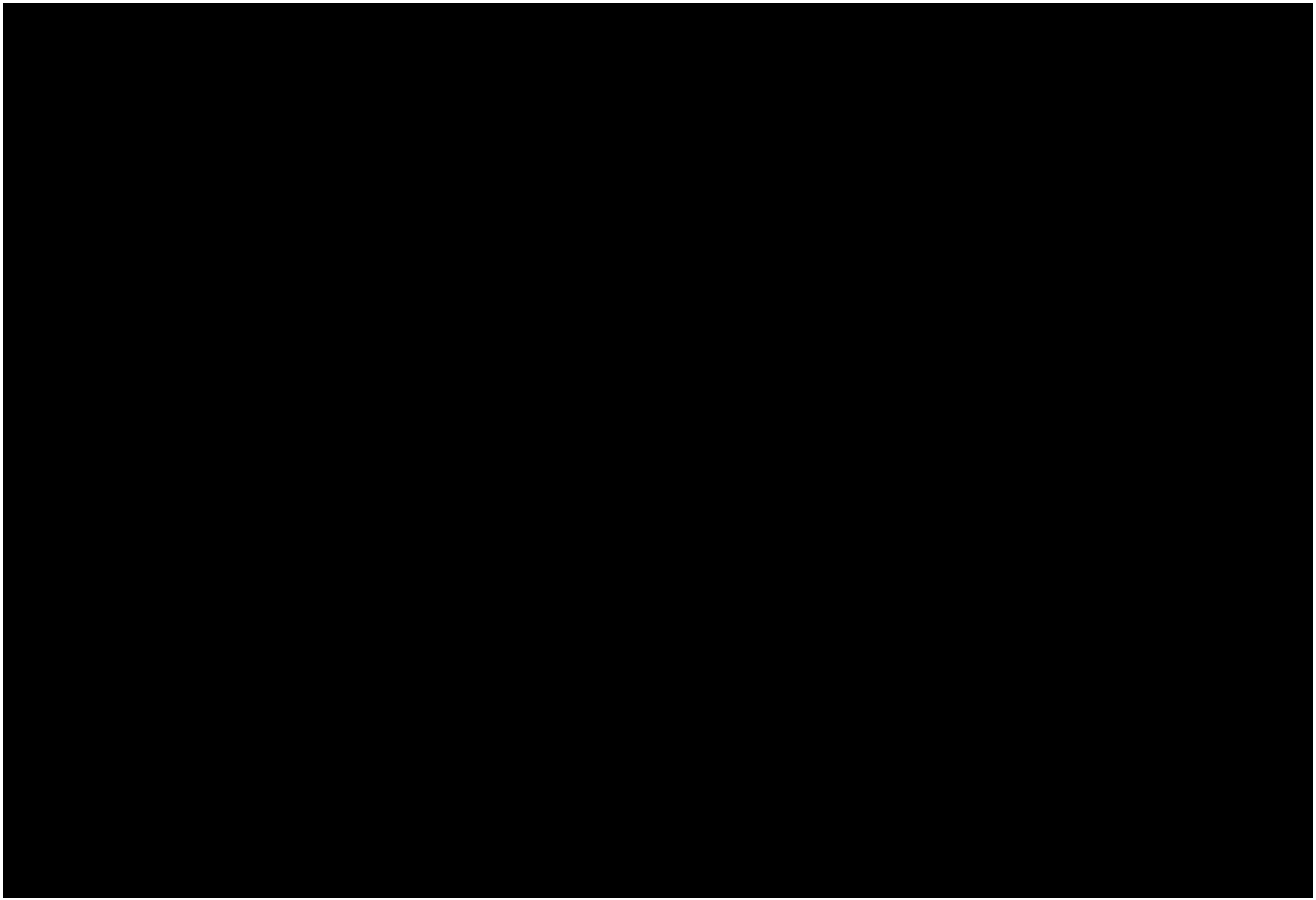
Member Forecasted Off Peak Demand Day for June 2021

San Miguel Power Association, Inc.

Date of Off Peak Day - 06/03/2021



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Member Forecasted Off Peak Demand Day for July 2021

San Miguel Power Association, Inc.

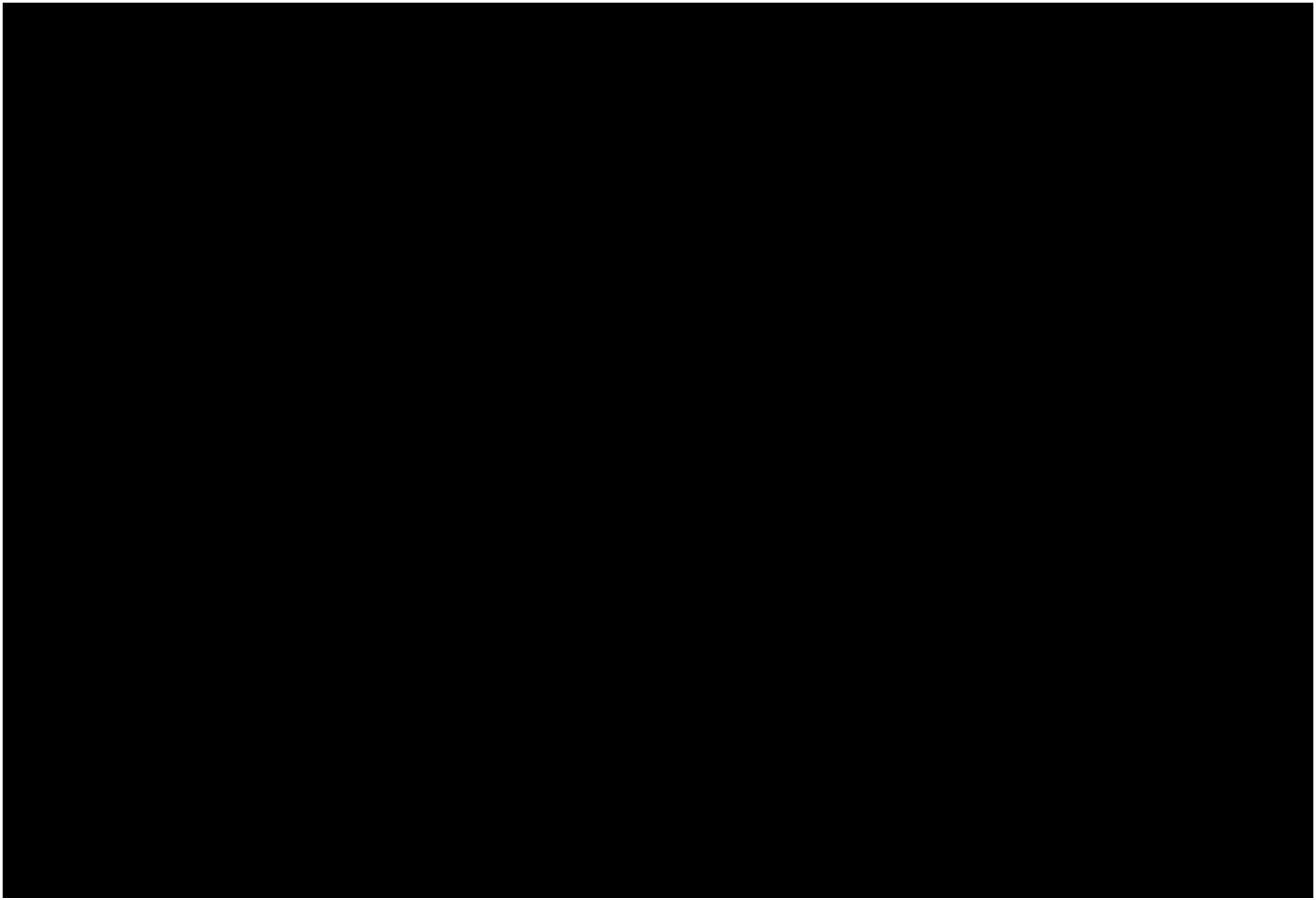
Date of Off Peak Day - 07/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

San Miguel Power Association, Inc.

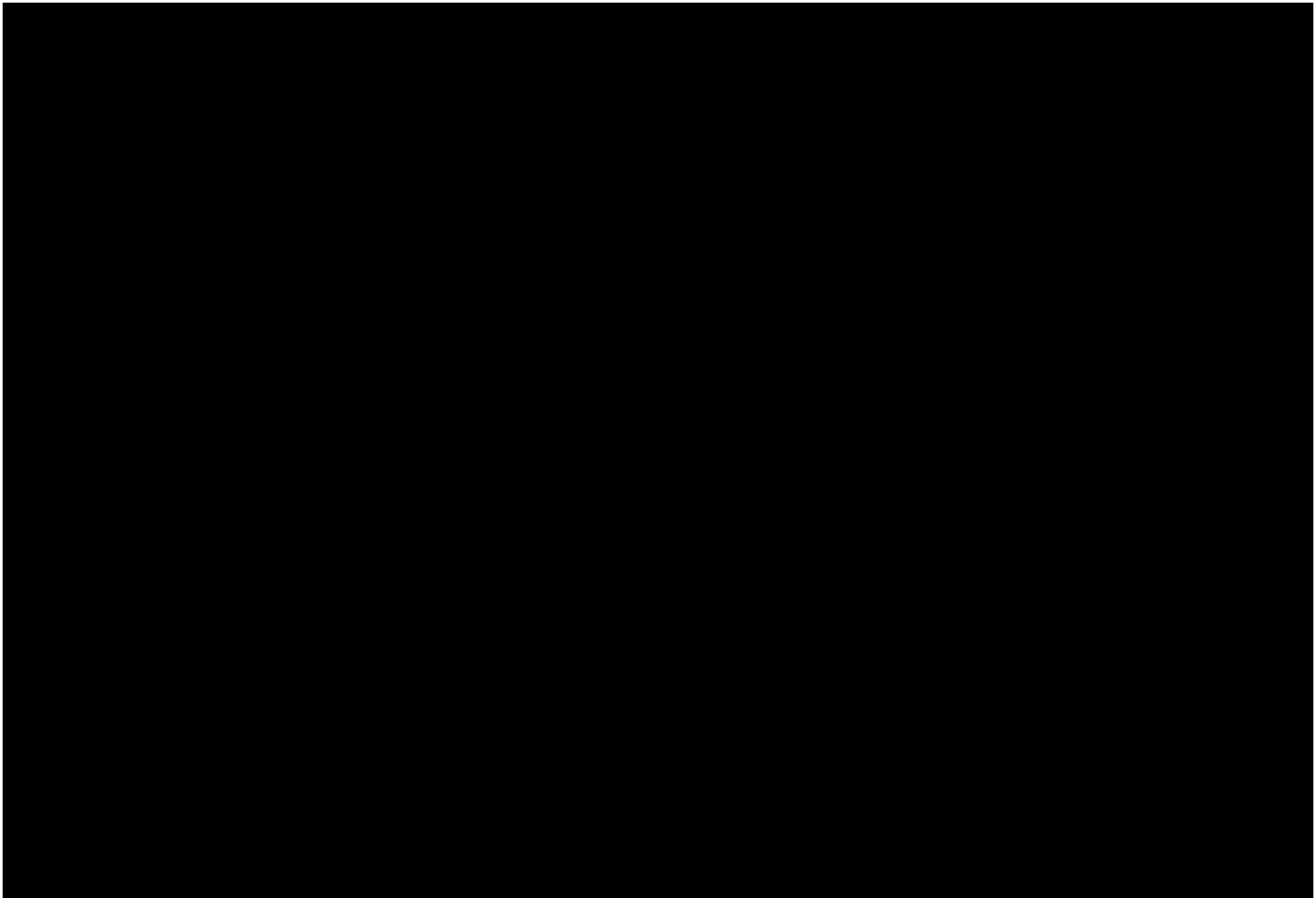
Date of Off Peak Day - 08/10/2021



Member Forecasted Off Peak Demand Day for September 2021

San Miguel Power Association, Inc.

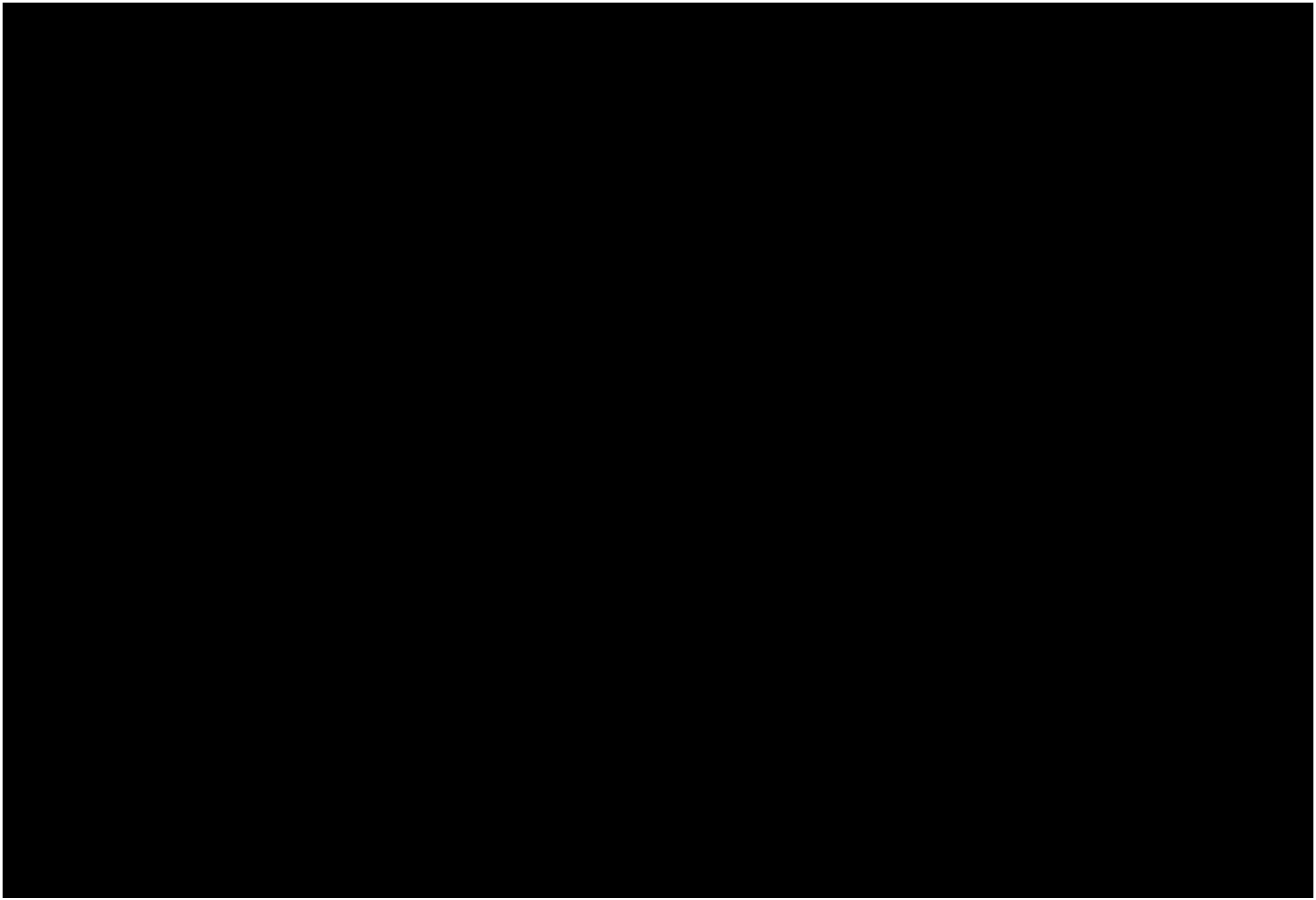
Date of Off Peak Day - 09/29/2021



Member Forecasted Off Peak Demand Day for October 2021

San Miguel Power Association, Inc.

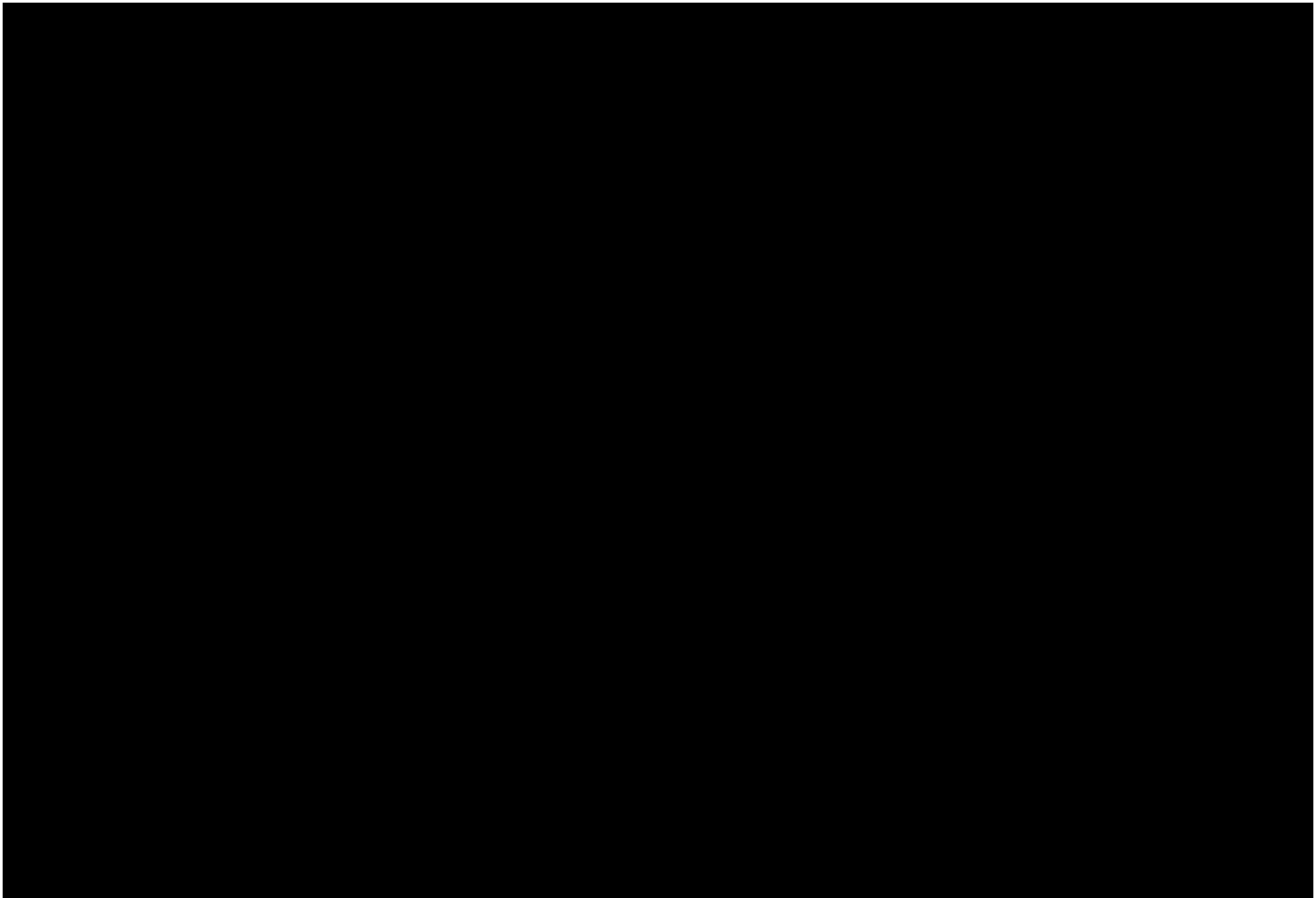
Date of Off Peak Day - 10/03/2021



Member Forecasted Off Peak Demand Day for November 2021

San Miguel Power Association, Inc.

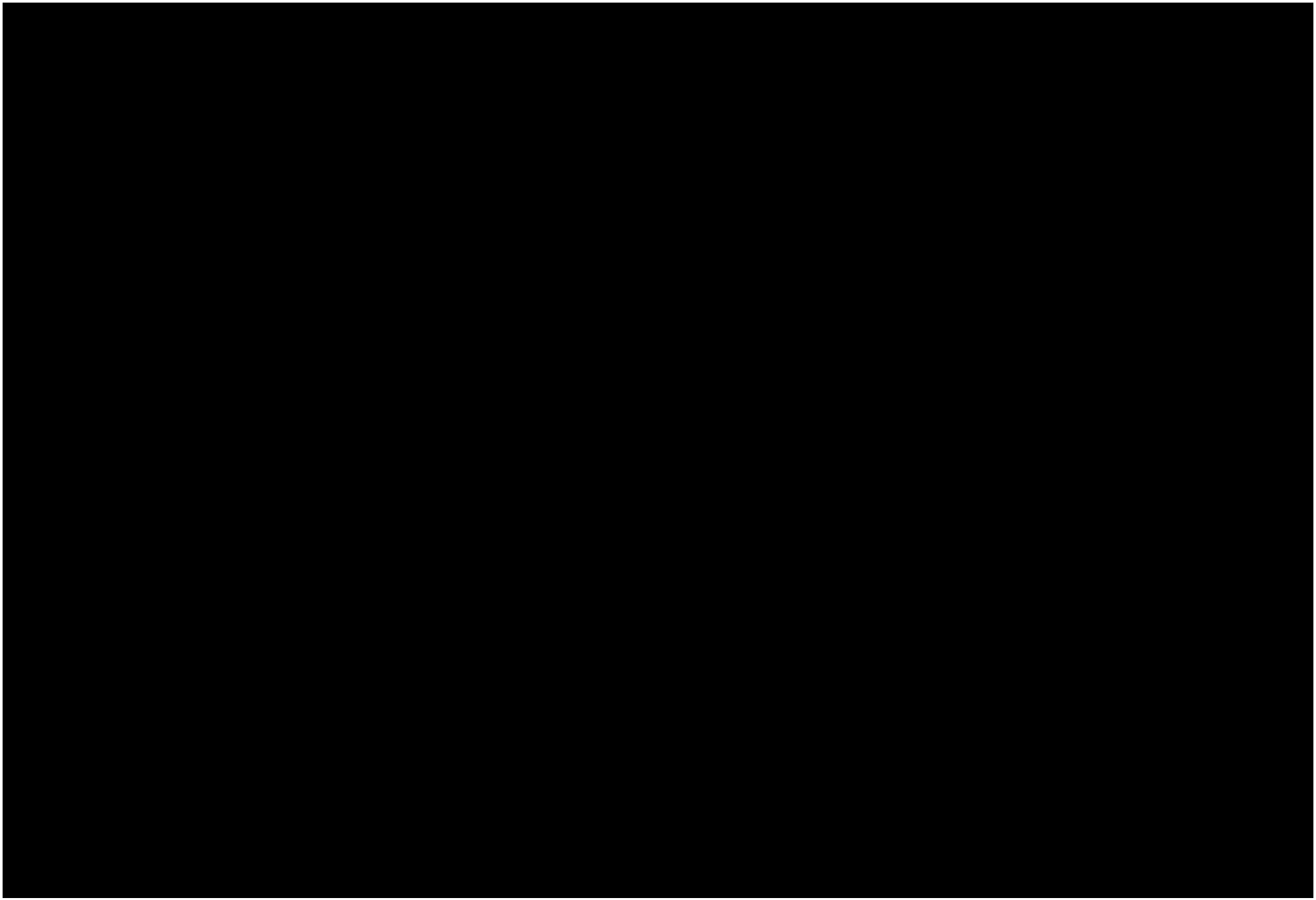
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

San Miguel Power Association, Inc.

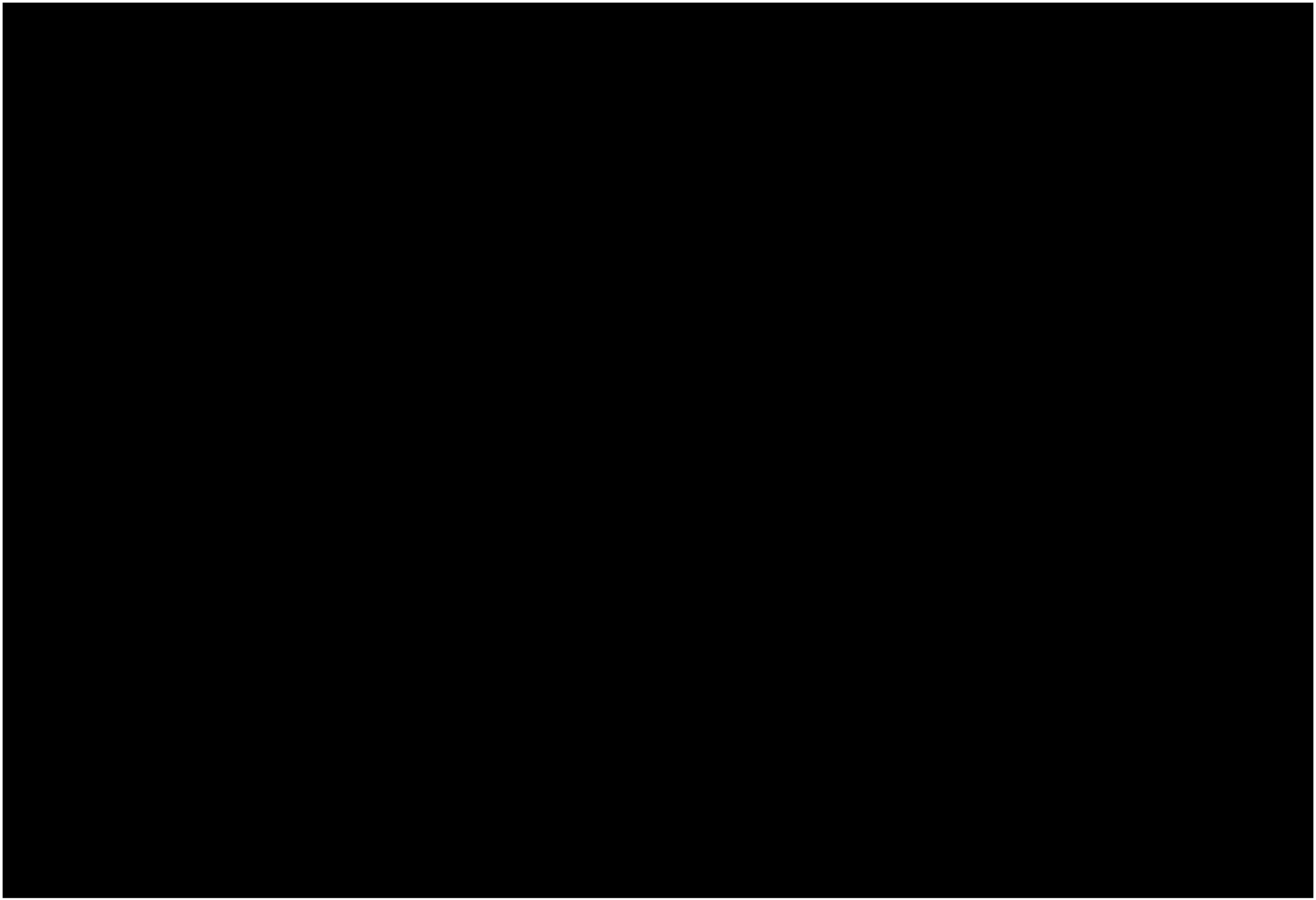
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Socorro Electric Cooperative, Inc.

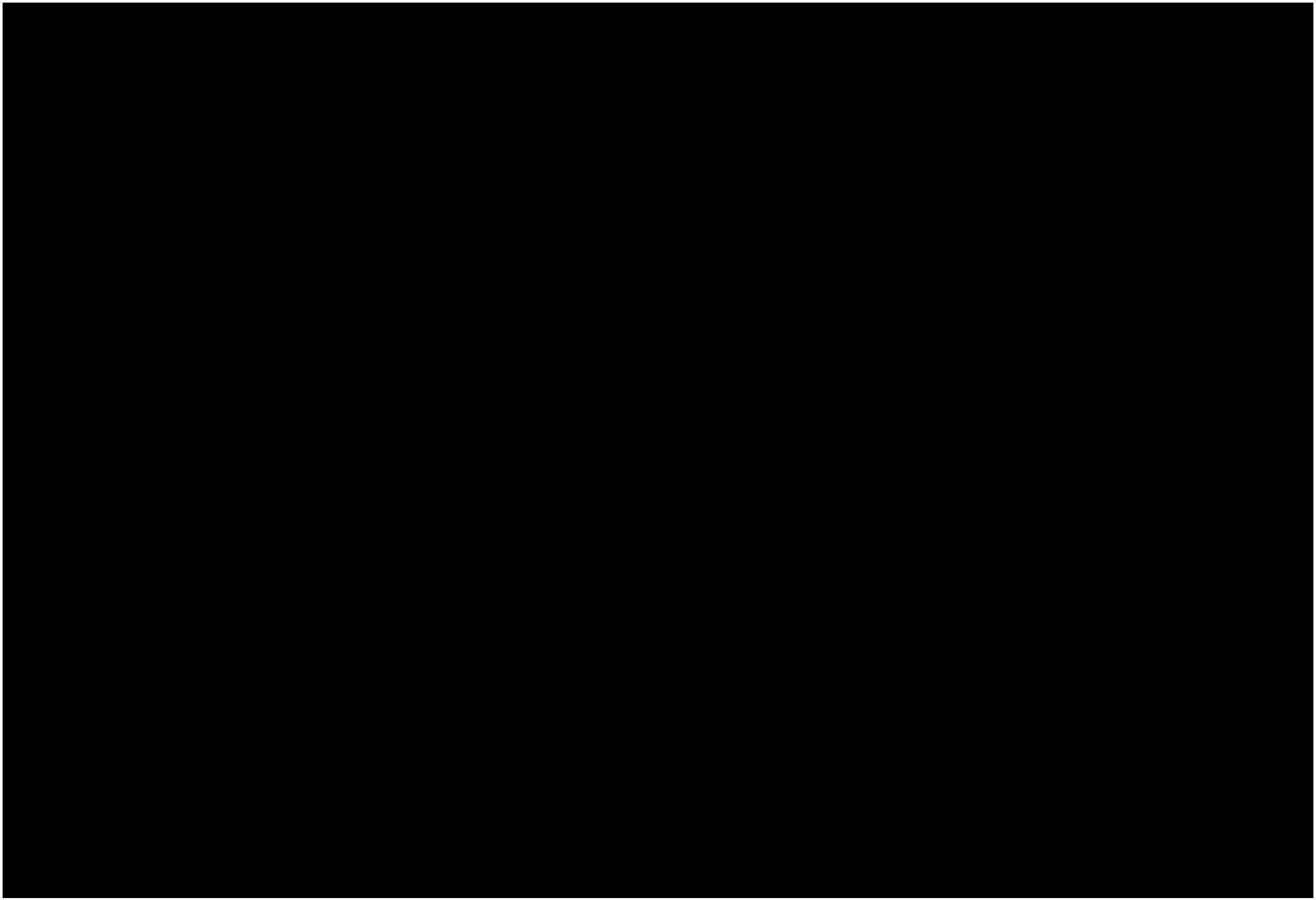
Date of Off Peak Day - 01/04/2021



Member Forecasted Off Peak Demand Day for February 2021

Socorro Electric Cooperative, Inc.

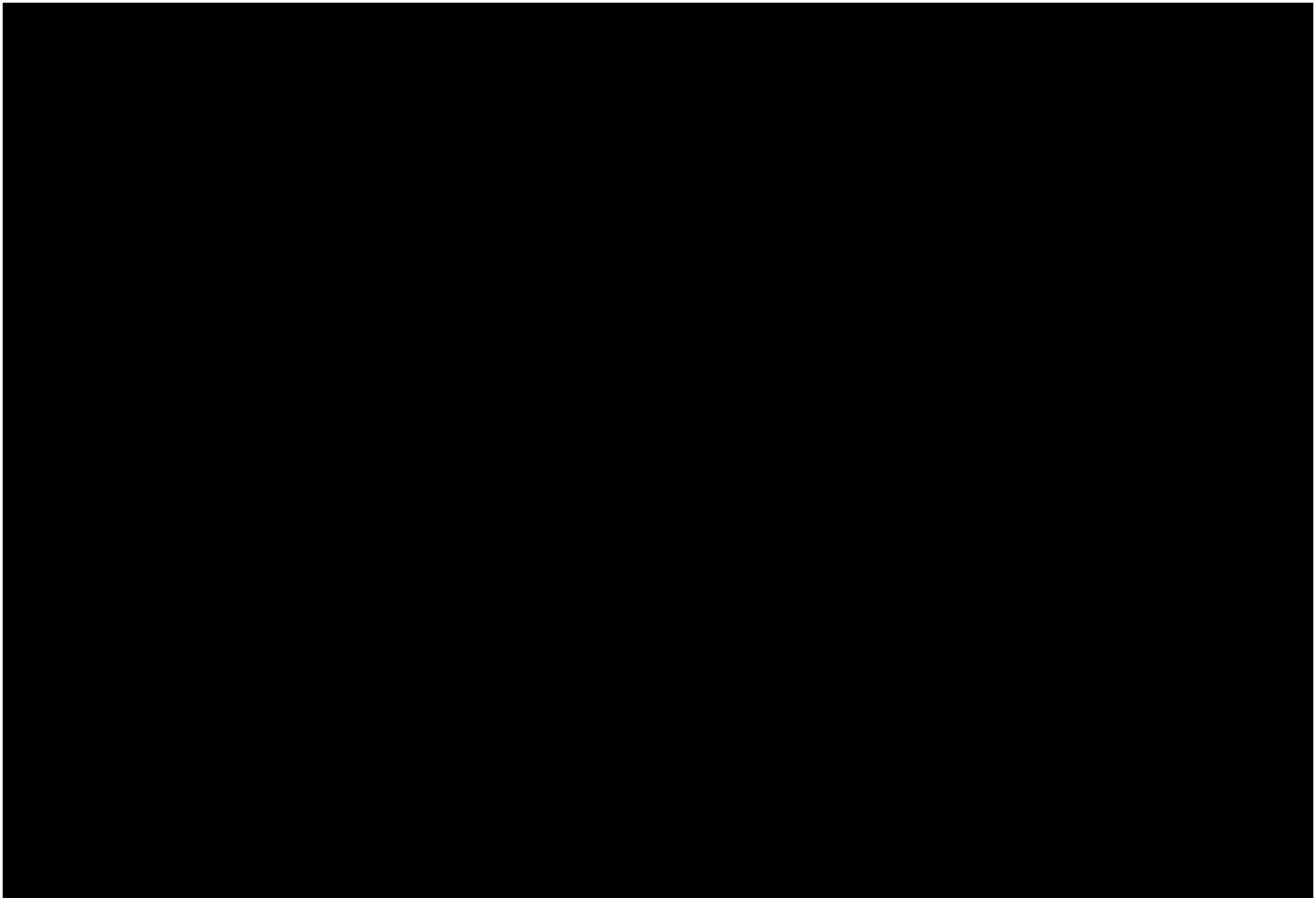
Date of Off Peak Day - 02/20/2021



Member Forecasted Off Peak Demand Day for March 2021

Socorro Electric Cooperative, Inc.

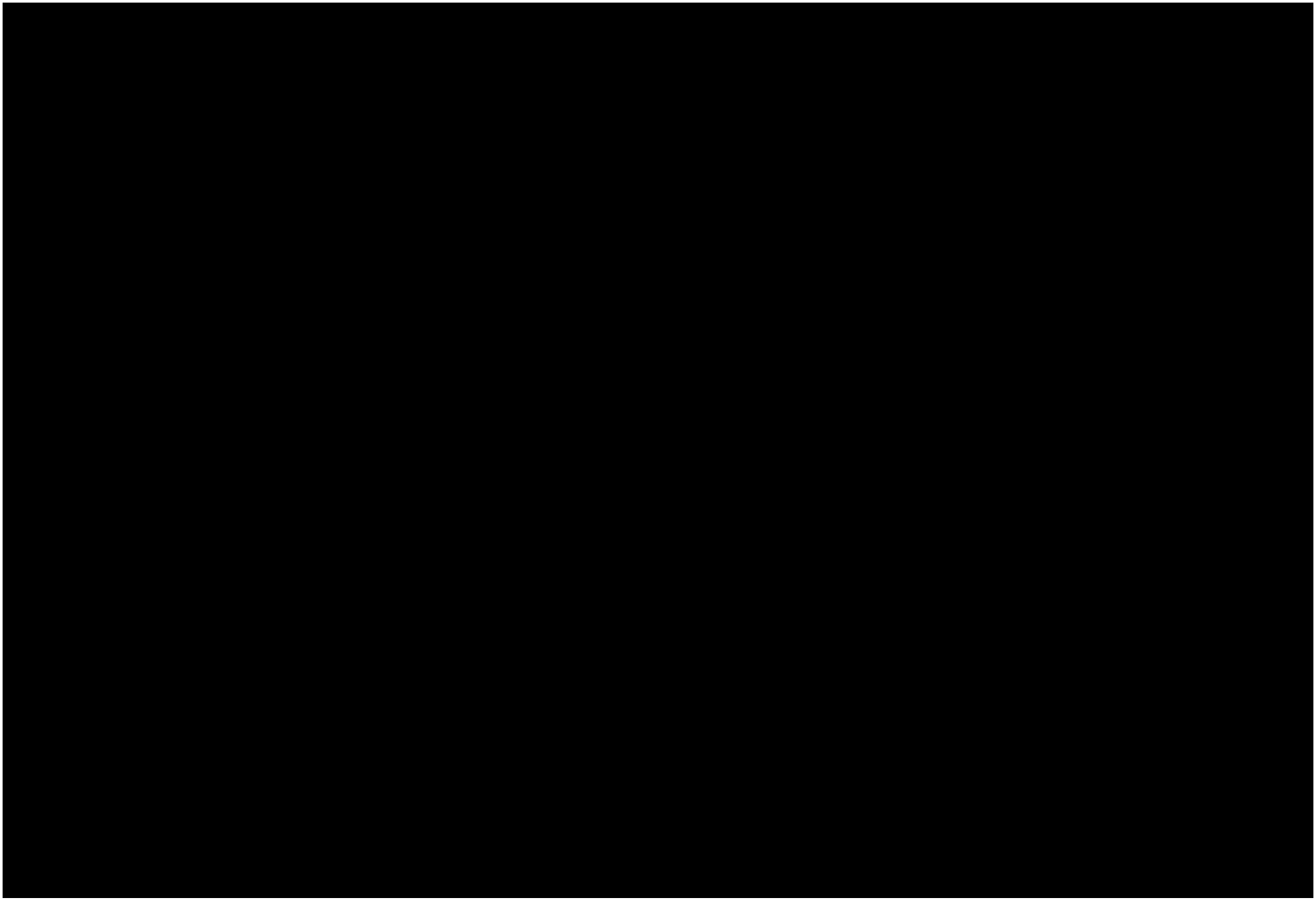
Date of Off Peak Day - 03/18/2021



Member Forecasted Off Peak Demand Day for April 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 04/09/2021



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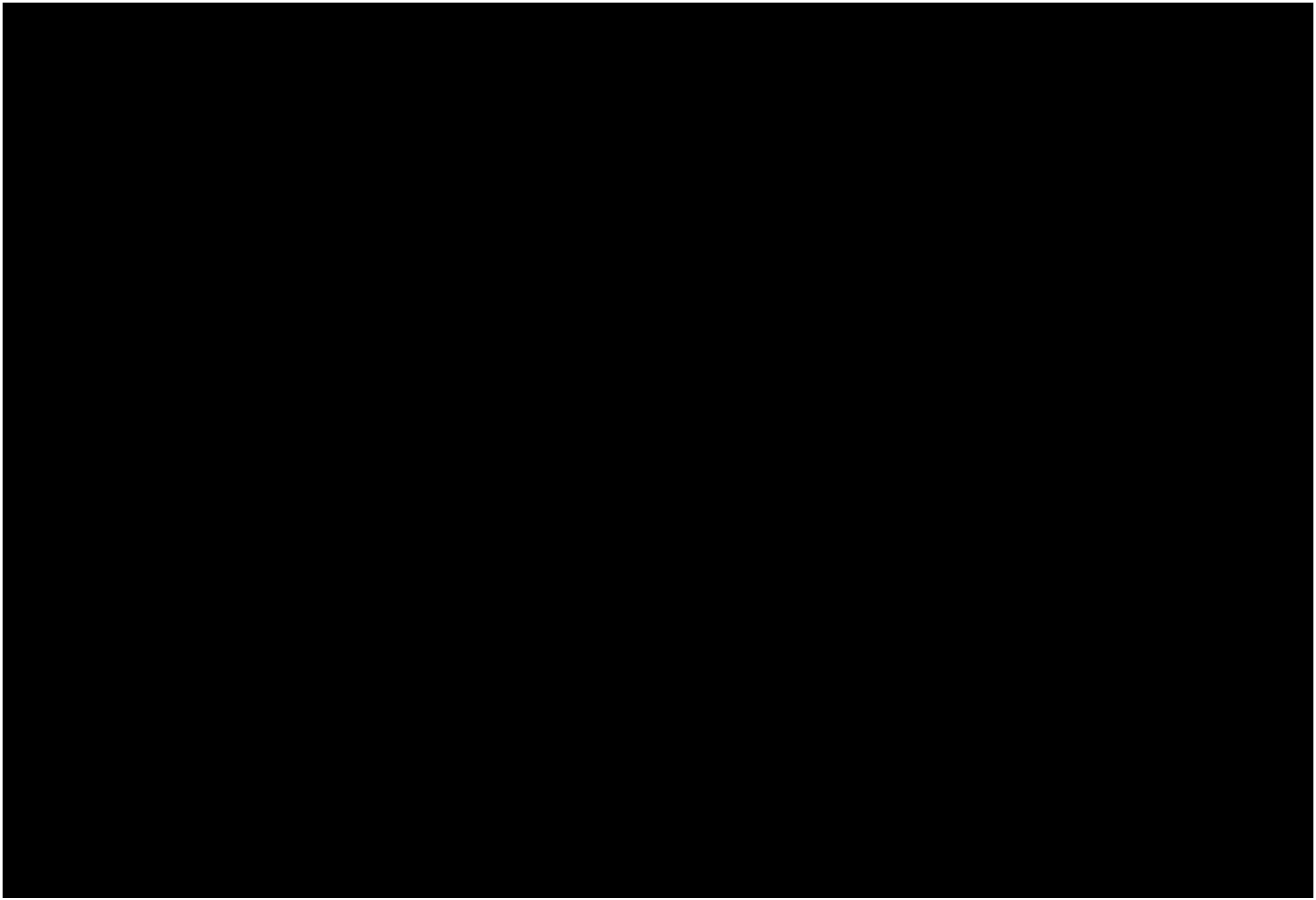
Member Forecasted Off Peak Demand Day for May 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 05/30/2021



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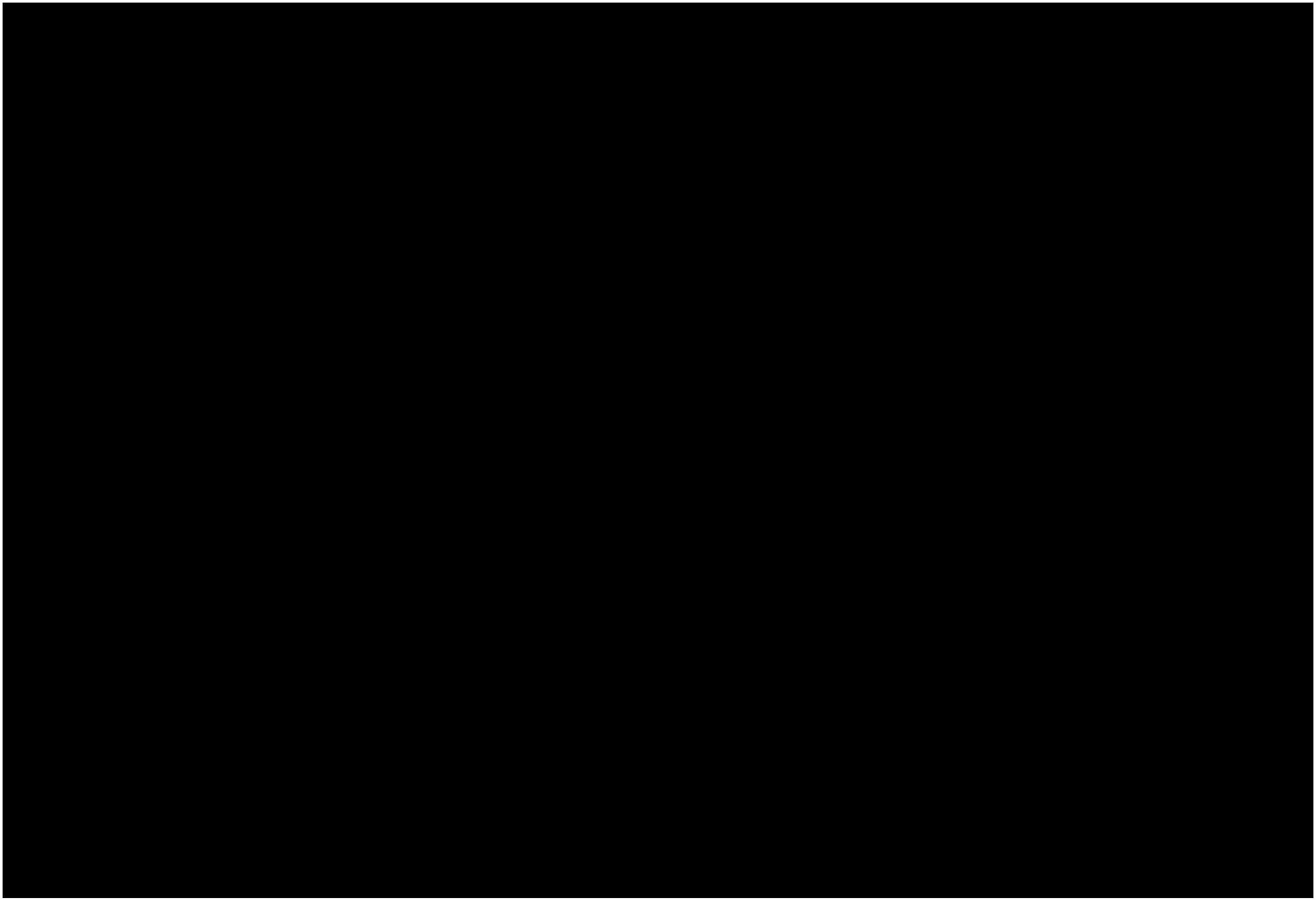
Member Forecasted Off Peak Demand Day for June 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 06/02/2021



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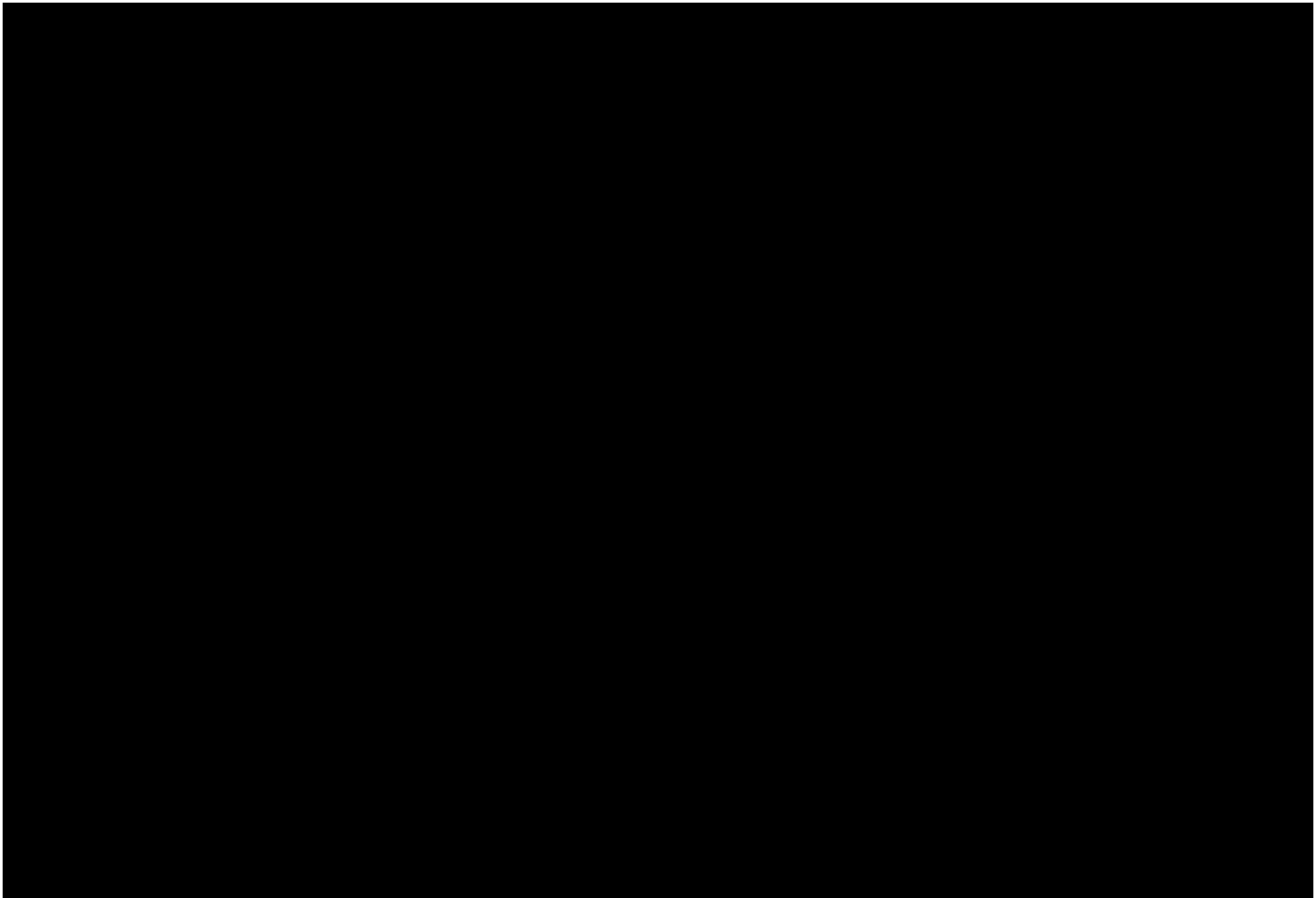
Member Forecasted Off Peak Demand Day for July 2021

Socorro Electric Cooperative, Inc.

Date of Off Peak Day - 07/04/2021



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Member Forecasted Off Peak Demand Day for August 2021

Socorro Electric Cooperative, Inc.

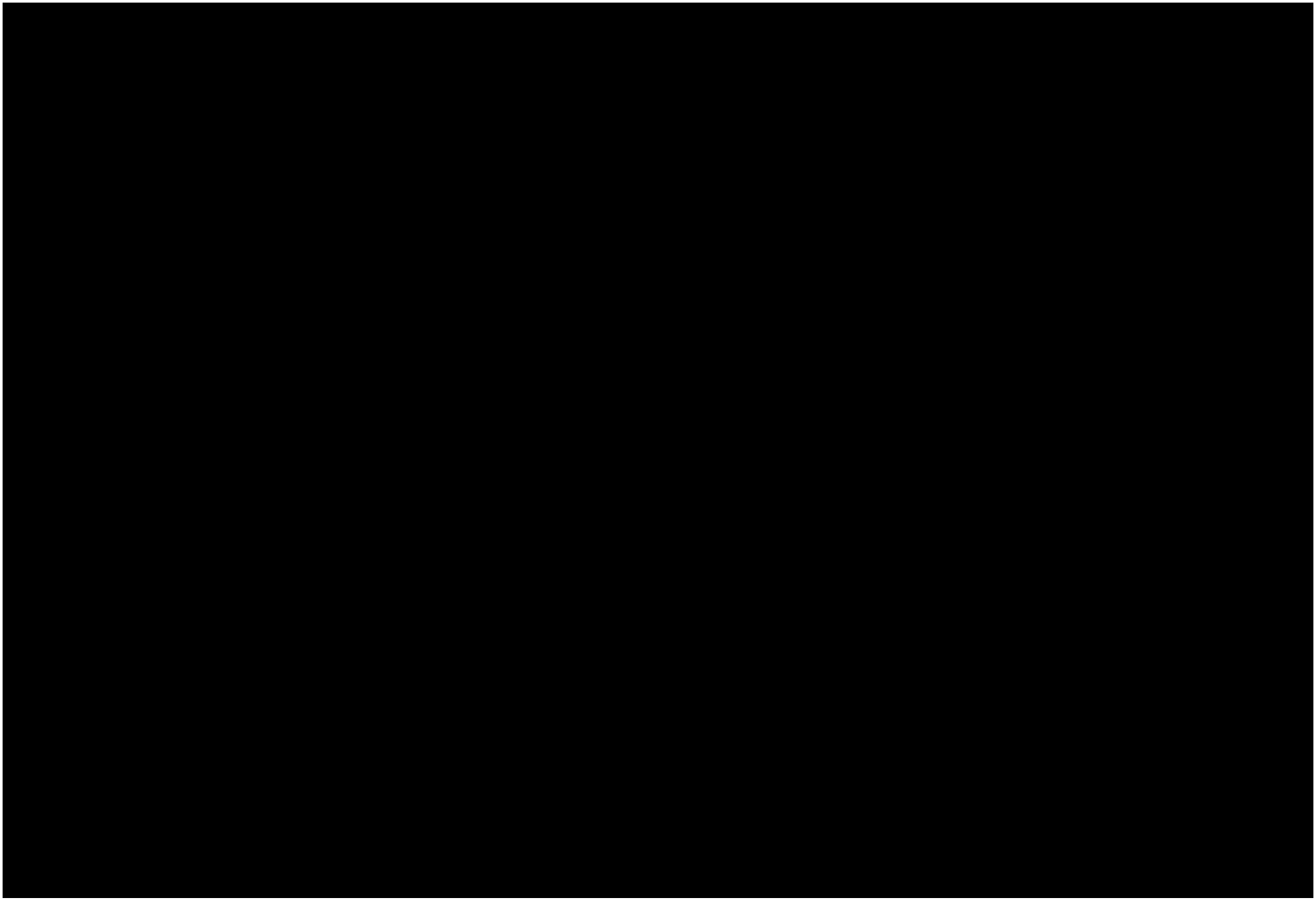
Date of Off Peak Day - 08/30/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Socorro Electric Cooperative, Inc.

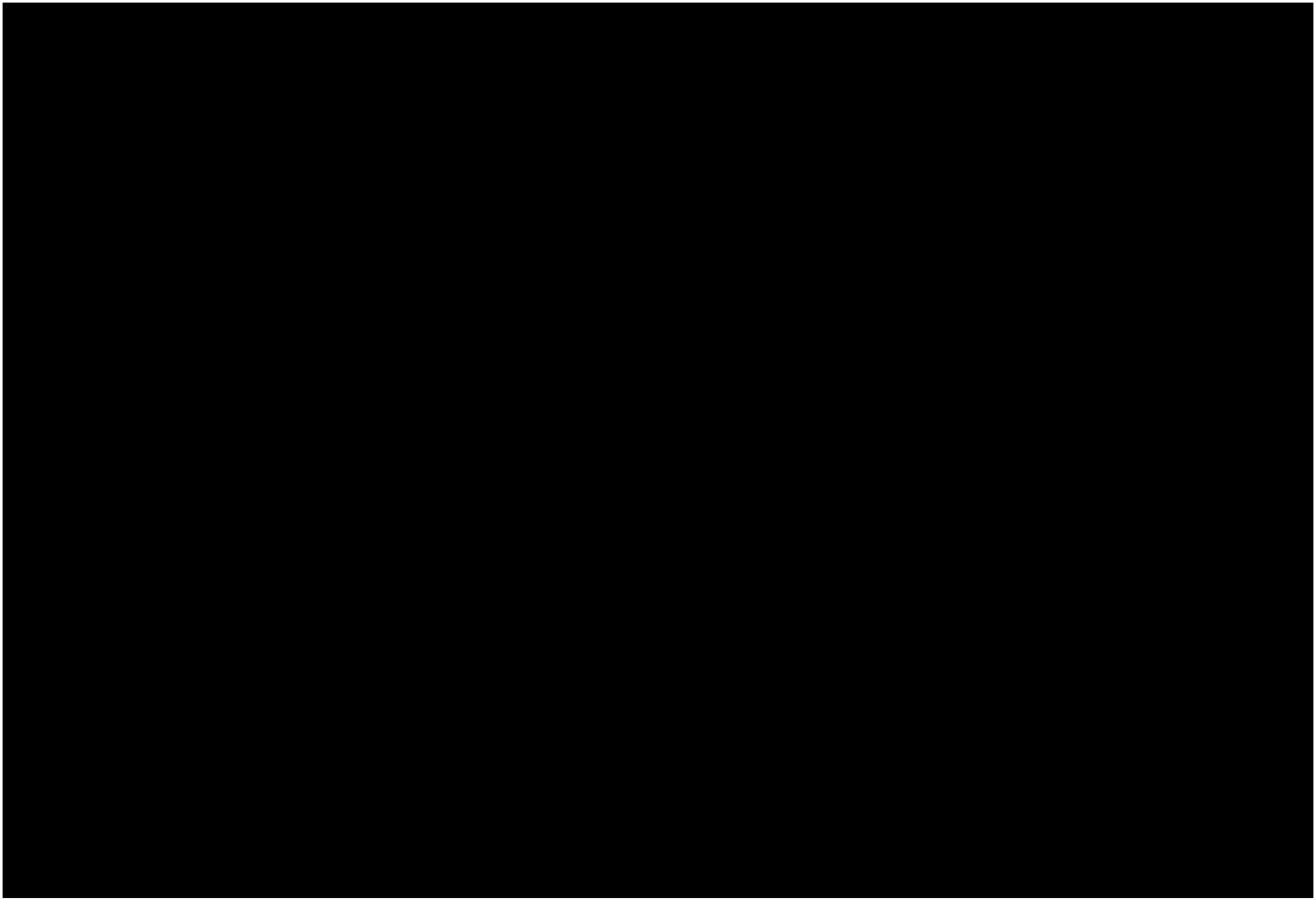
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Socorro Electric Cooperative, Inc.

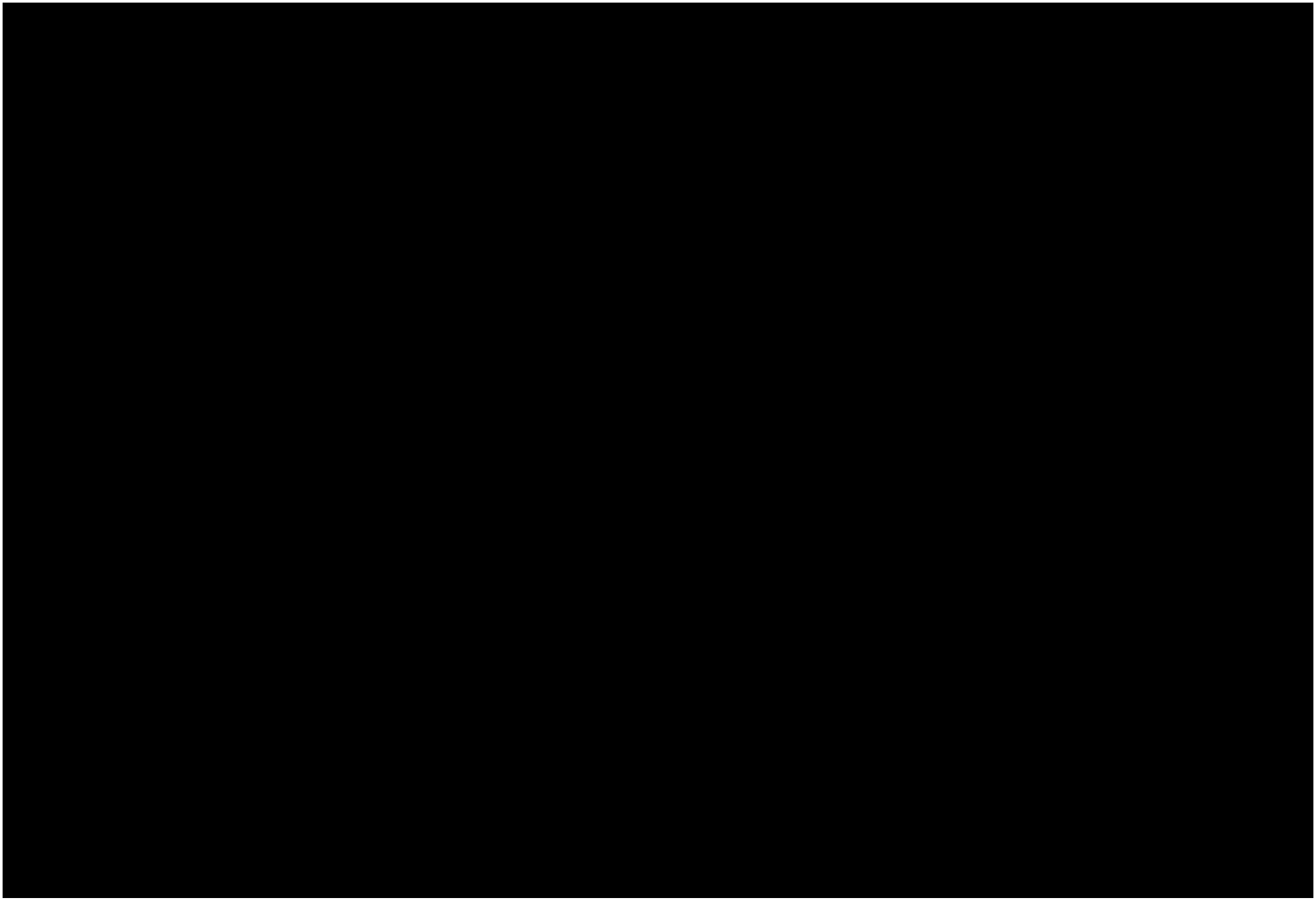
Date of Off Peak Day - 10/30/2021



Member Forecasted Off Peak Demand Day for November 2021

Socorro Electric Cooperative, Inc.

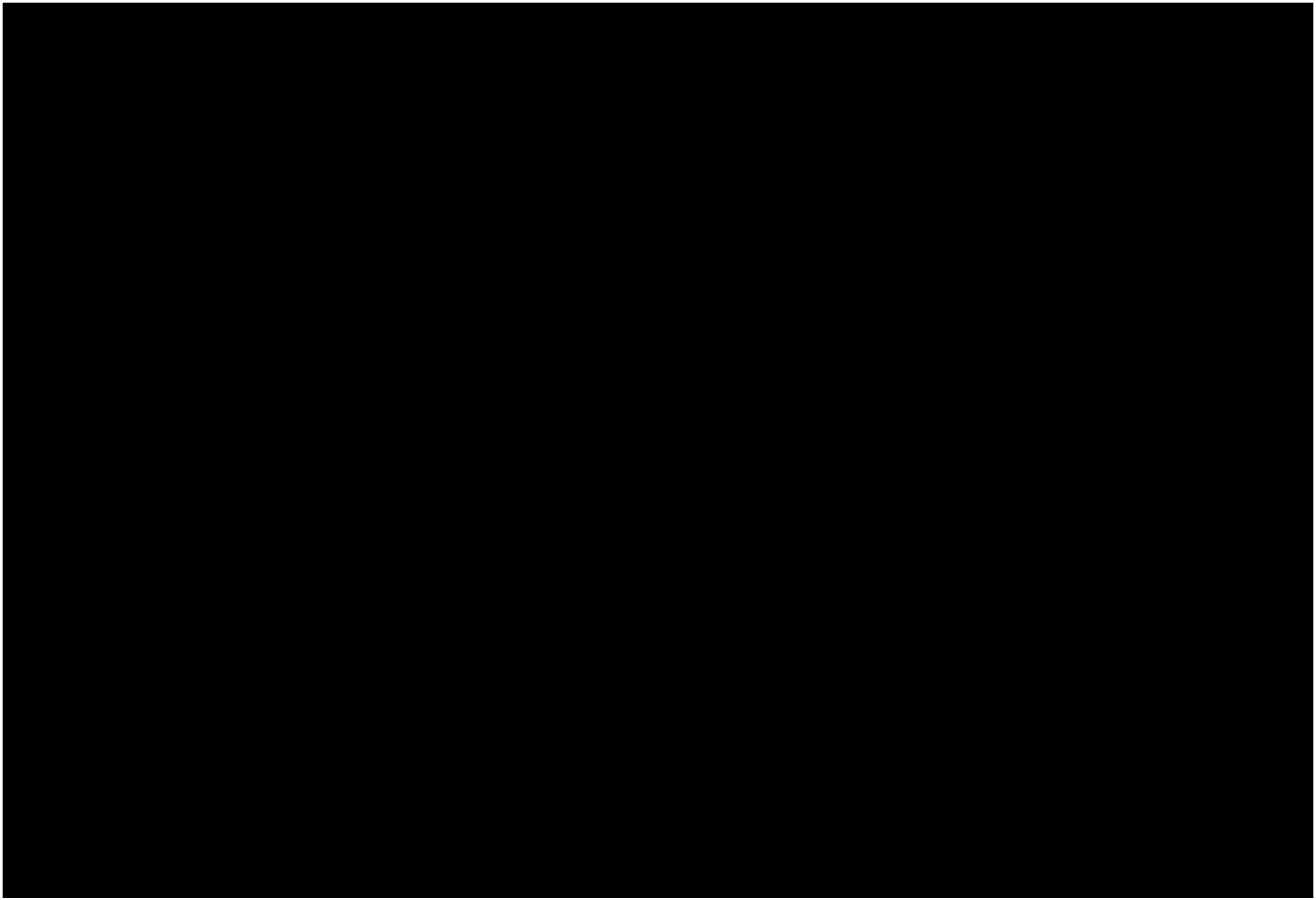
Date of Off Peak Day - 11/07/2021



Member Forecasted Off Peak Demand Day for December 2021

Socorro Electric Cooperative, Inc.

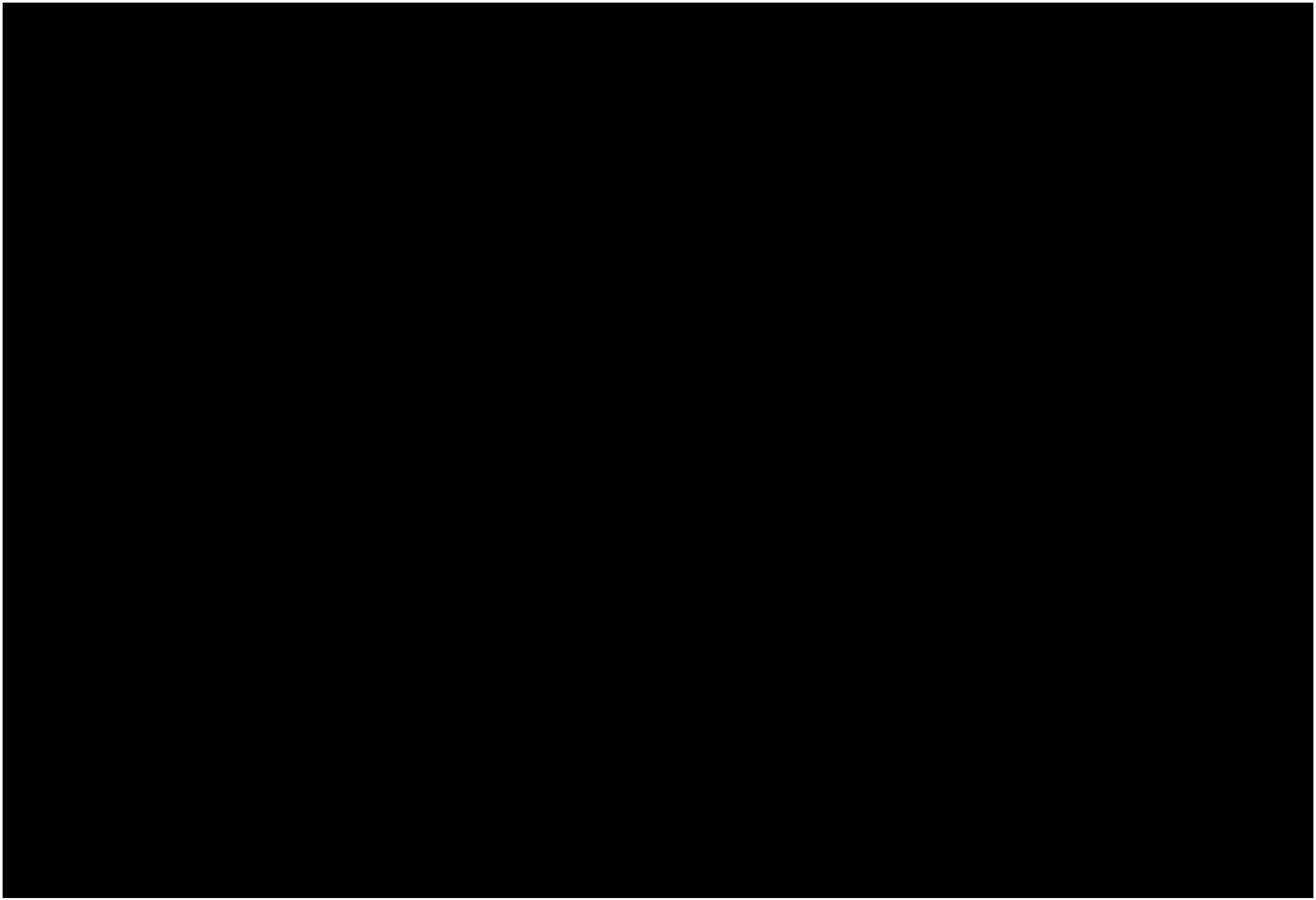
Date of Off Peak Day - 12/10/2021



Member Forecasted Off Peak Demand Day for January 2021

Springer Electric Cooperative, Inc.

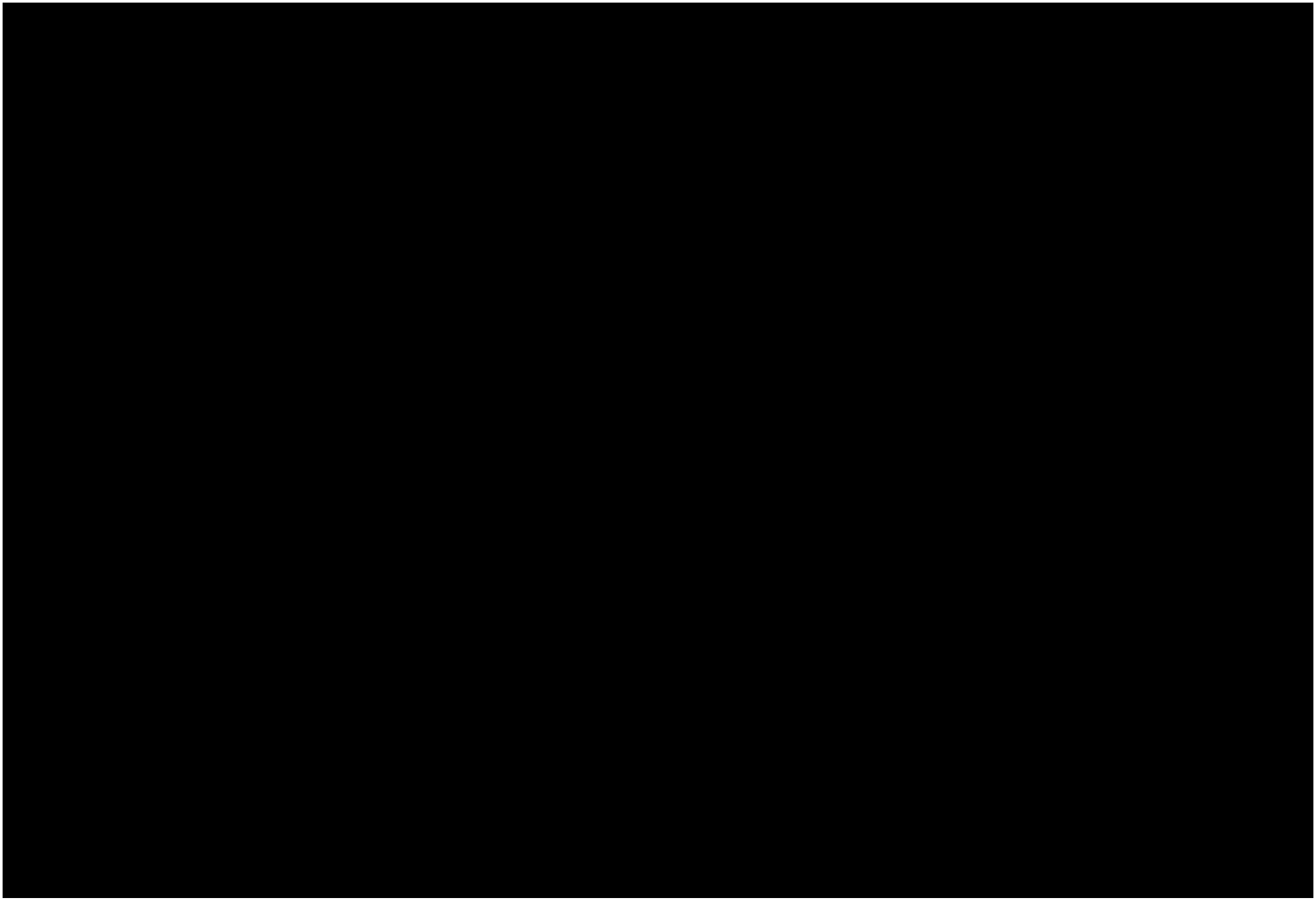
Date of Off Peak Day - 01/09/2021



Member Forecasted Off Peak Demand Day for February 2021

Springer Electric Cooperative, Inc.

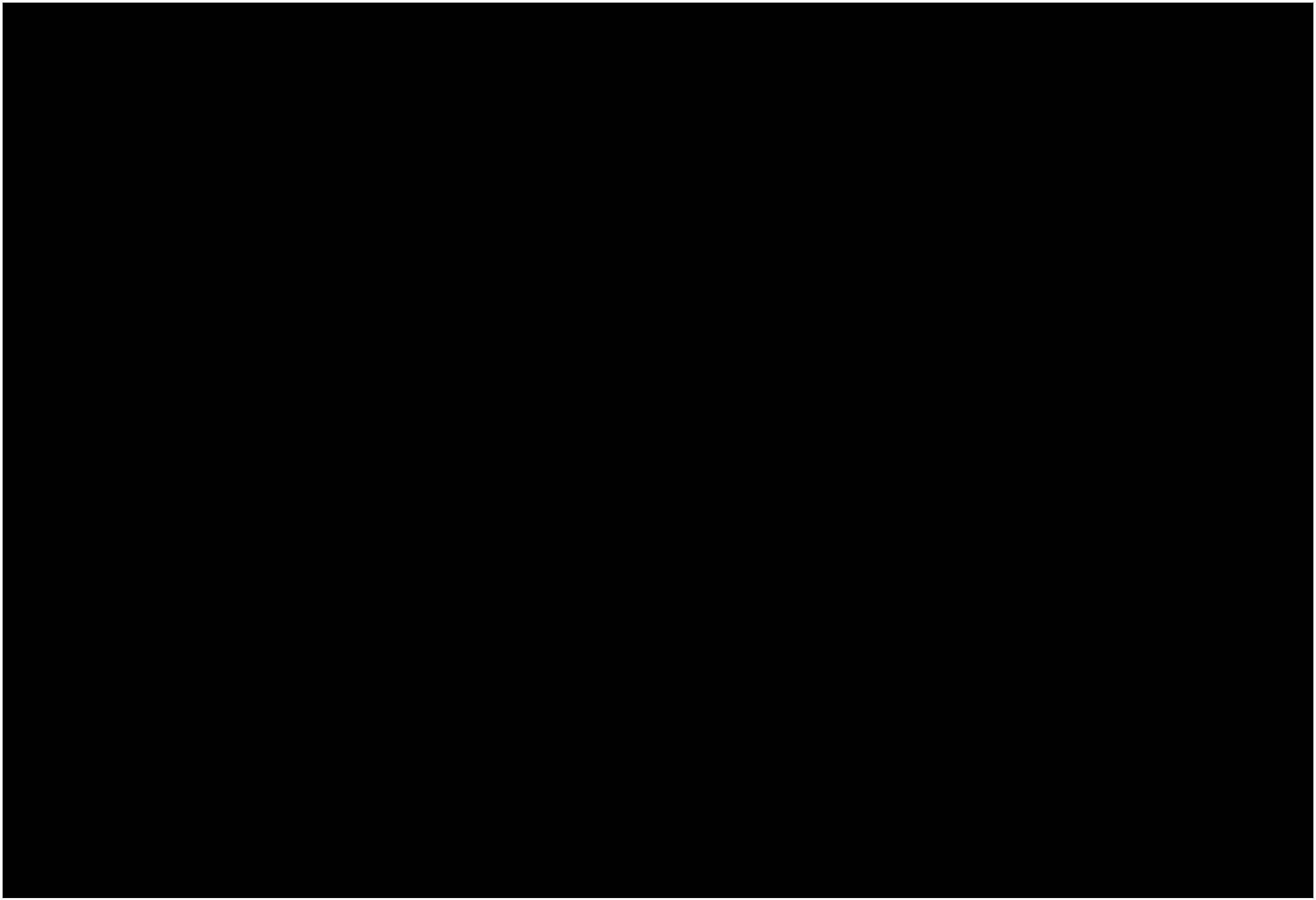
Date of Off Peak Day - 02/07/2021



Member Forecasted Off Peak Demand Day for March 2021

Springer Electric Cooperative, Inc.

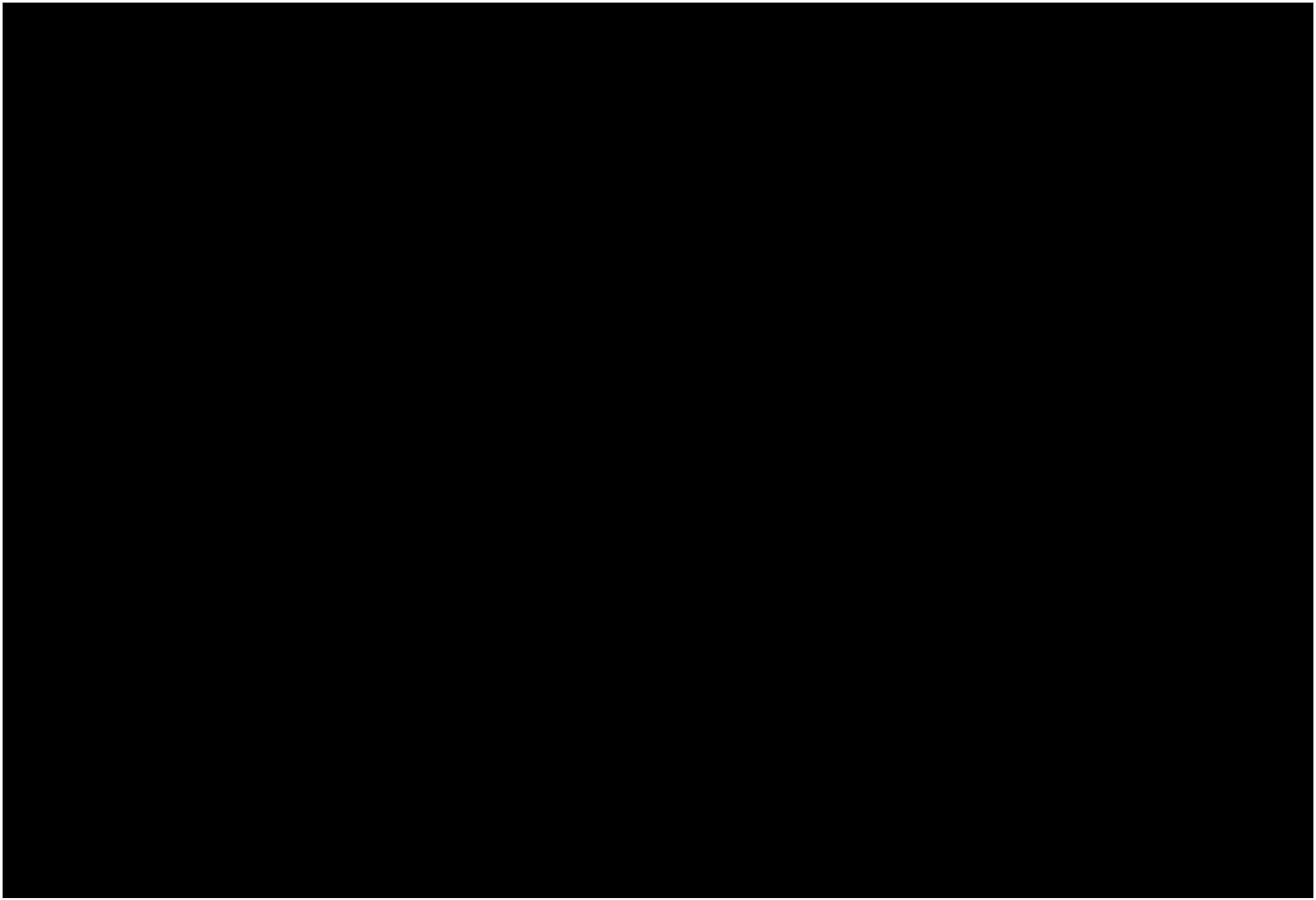
Date of Off Peak Day - 03/24/2021



Member Forecasted Off Peak Demand Day for April 2021

Springer Electric Cooperative, Inc.

Date of Off Peak Day - 04/26/2021



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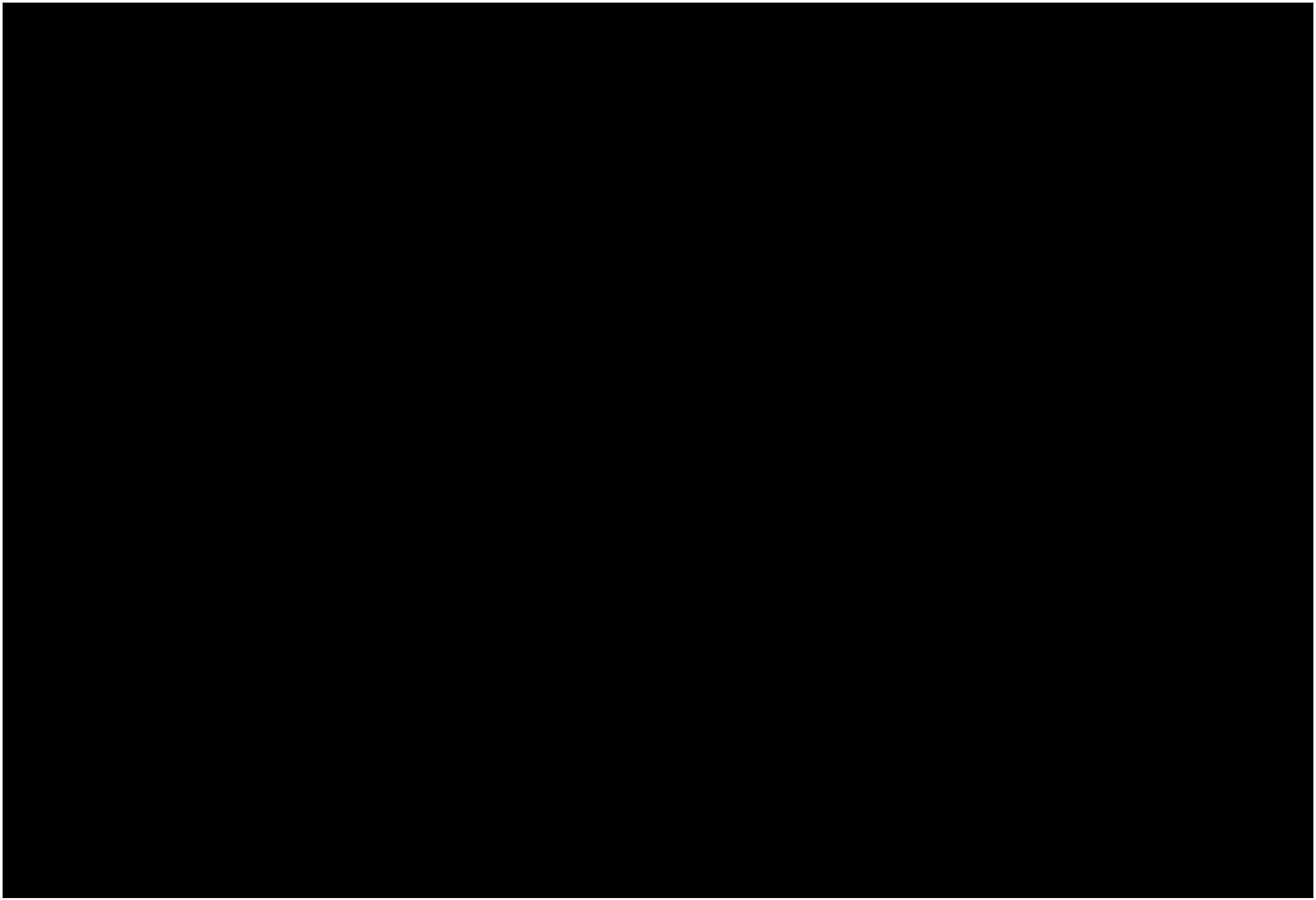
Member Forecasted Off Peak Demand Day for May 2021

Springer Electric Cooperative, Inc.

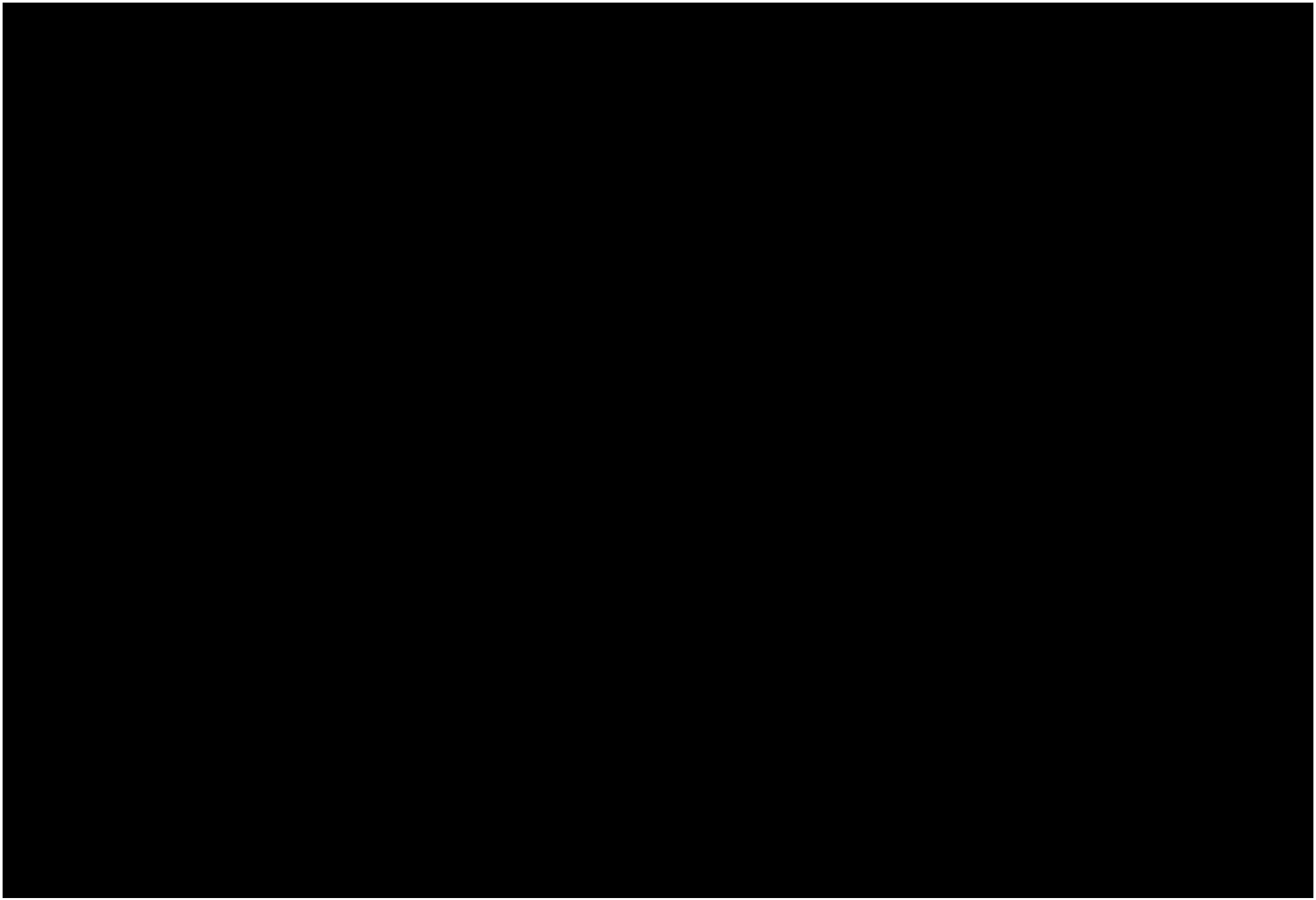
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Springer Electric Cooperative, Inc.

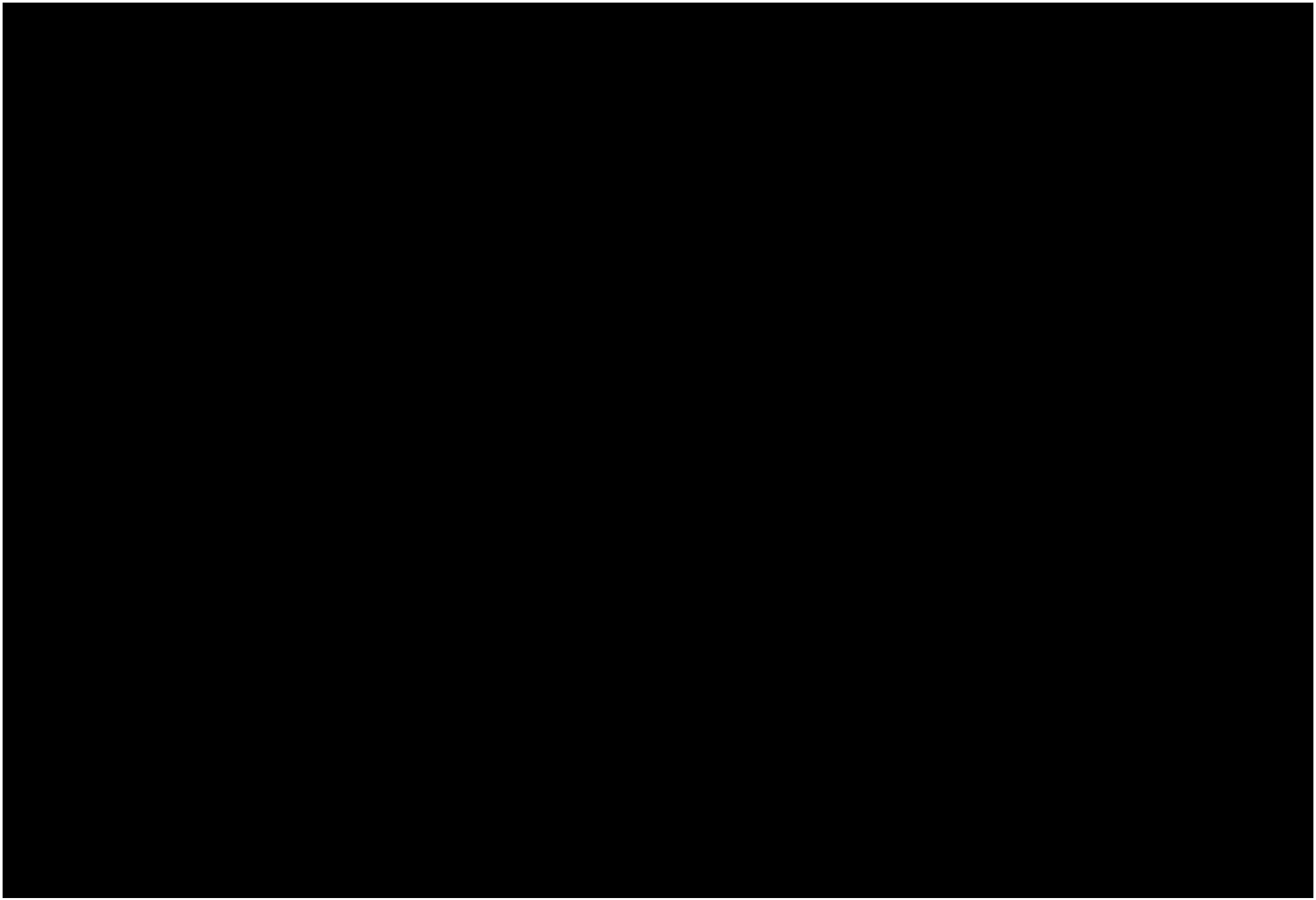
Date of Off Peak Day - 06/03/2021



Member Forecasted Off Peak Demand Day for July 2021

Springer Electric Cooperative, Inc.

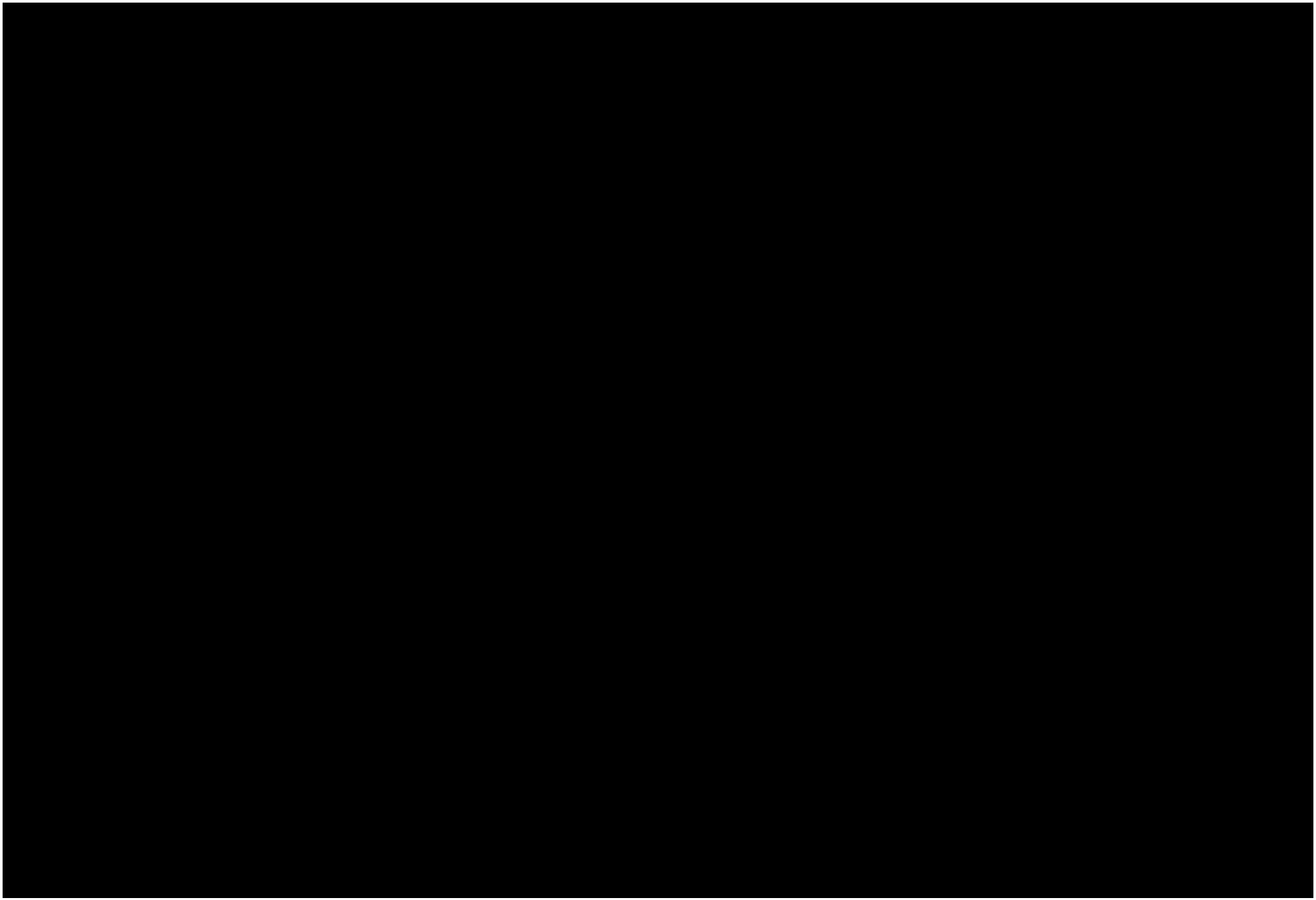
Date of Off Peak Day - 07/25/2021



Member Forecasted Off Peak Demand Day for August 2021

Springer Electric Cooperative, Inc.

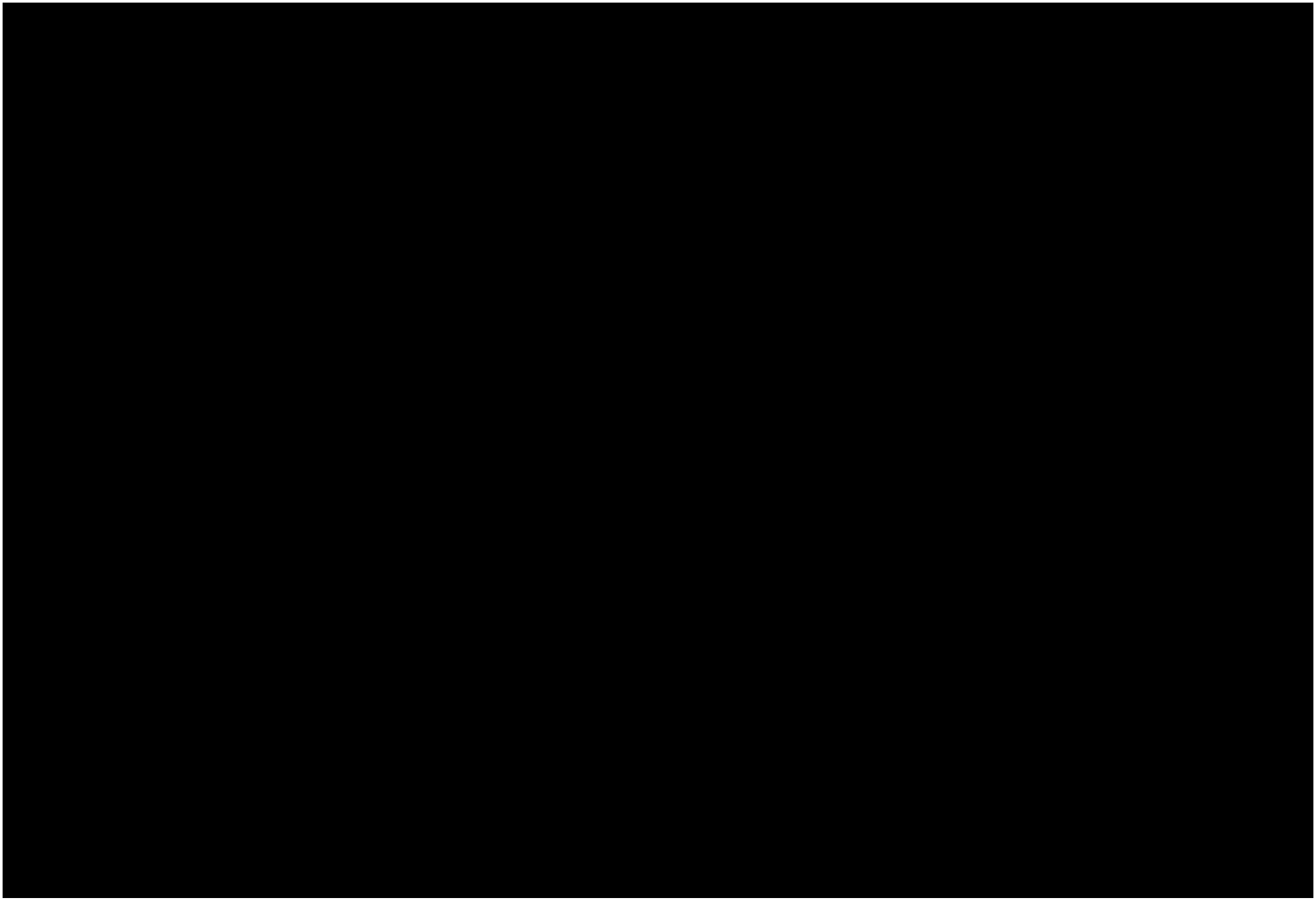
Date of Off Peak Day - 08/31/2021



Member Forecasted Off Peak Demand Day for September 2021

Springer Electric Cooperative, Inc.

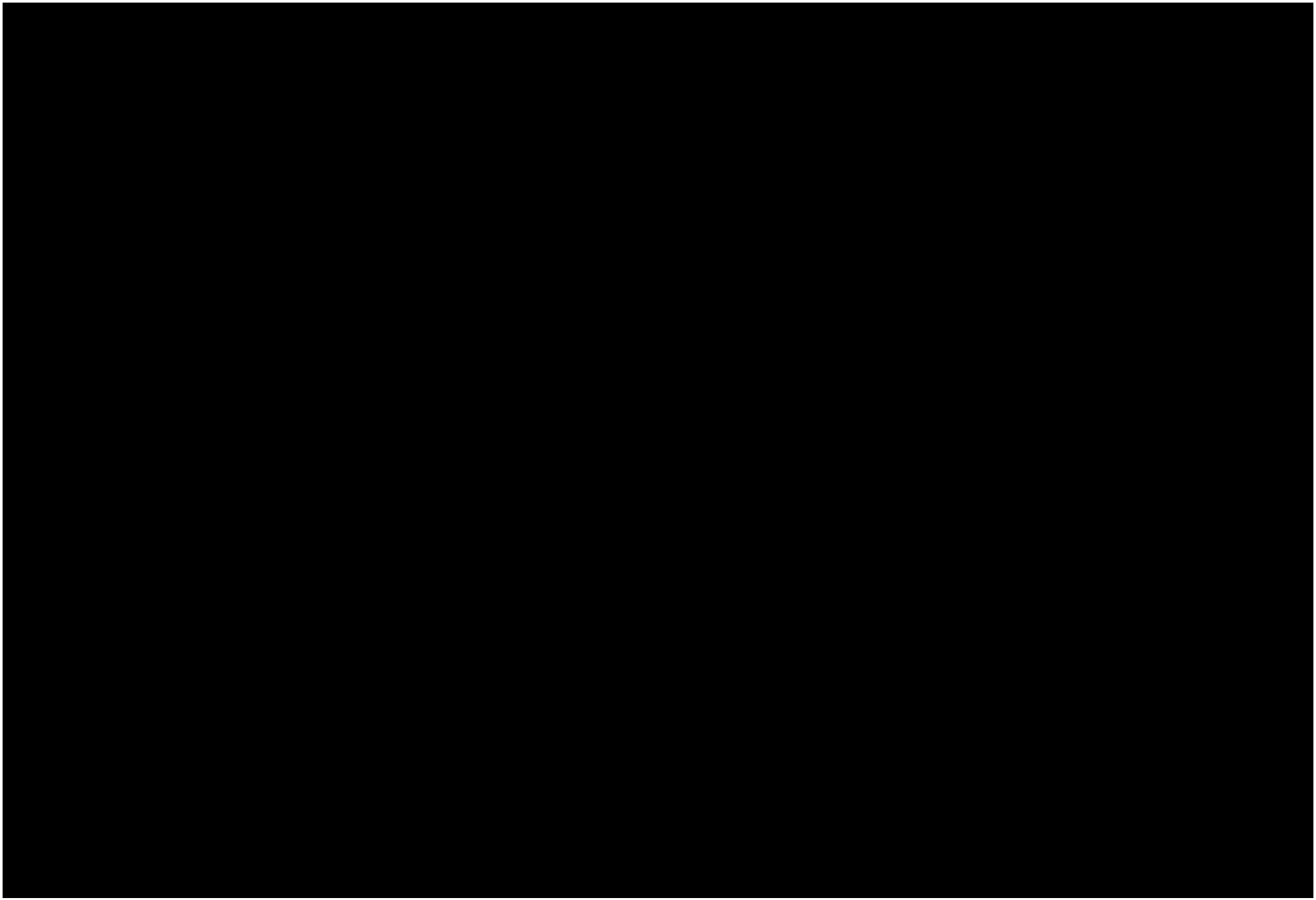
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Springer Electric Cooperative, Inc.

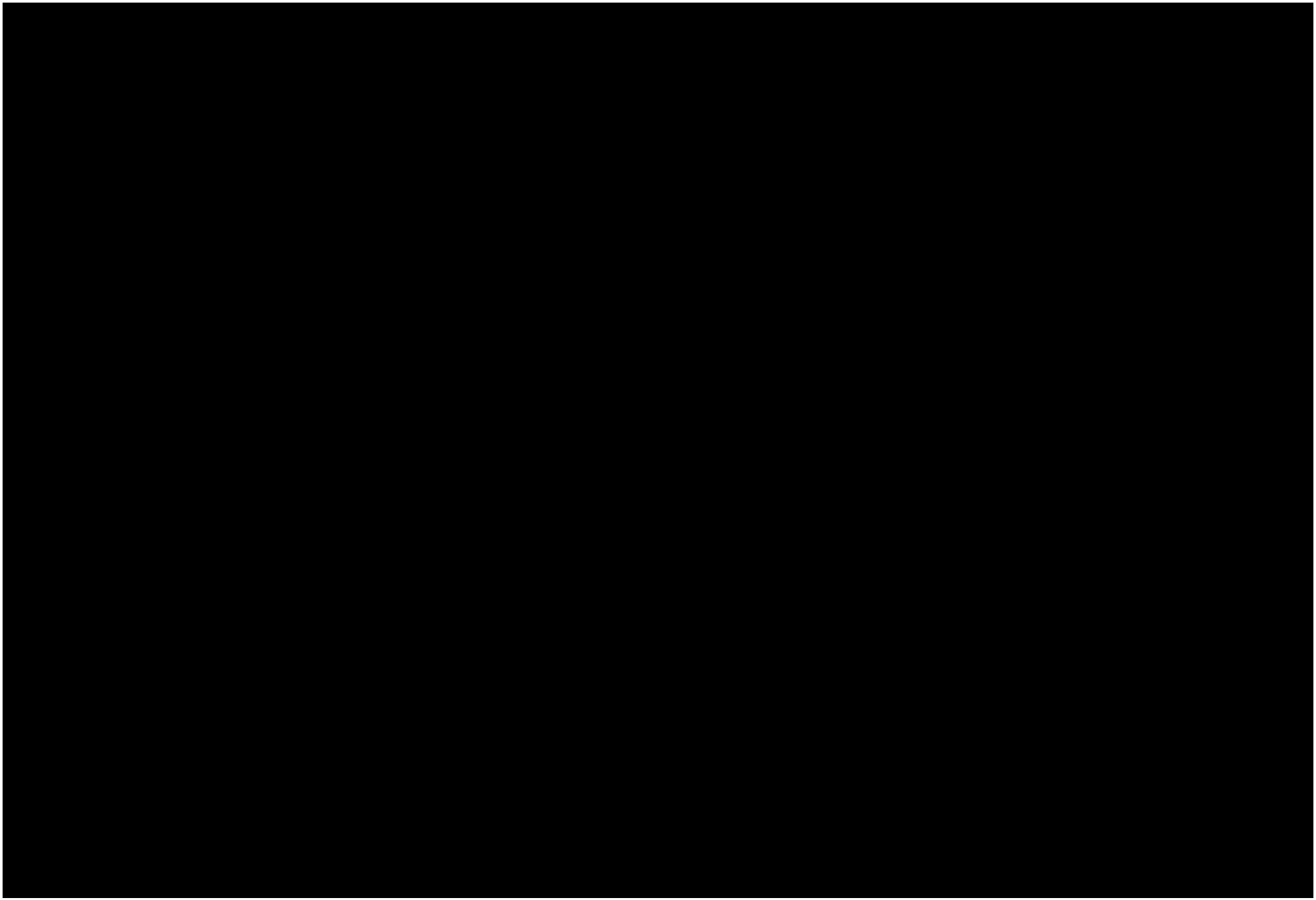
Date of Off Peak Day - 10/20/2021



Member Forecasted Off Peak Demand Day for November 2021

Springer Electric Cooperative, Inc.

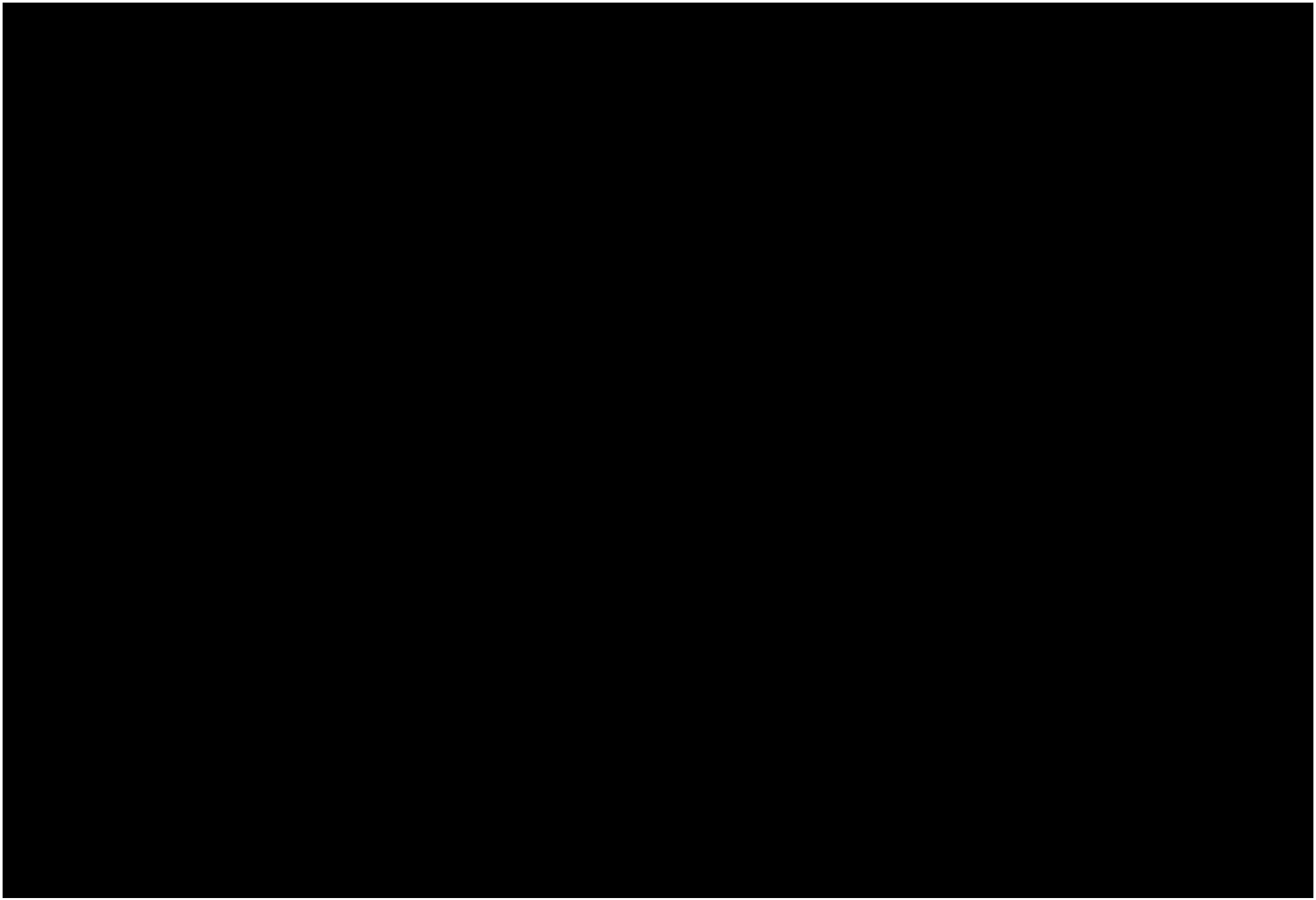
Date of Off Peak Day - 11/18/2021



Member Forecasted Off Peak Demand Day for December 2021

Springer Electric Cooperative, Inc.

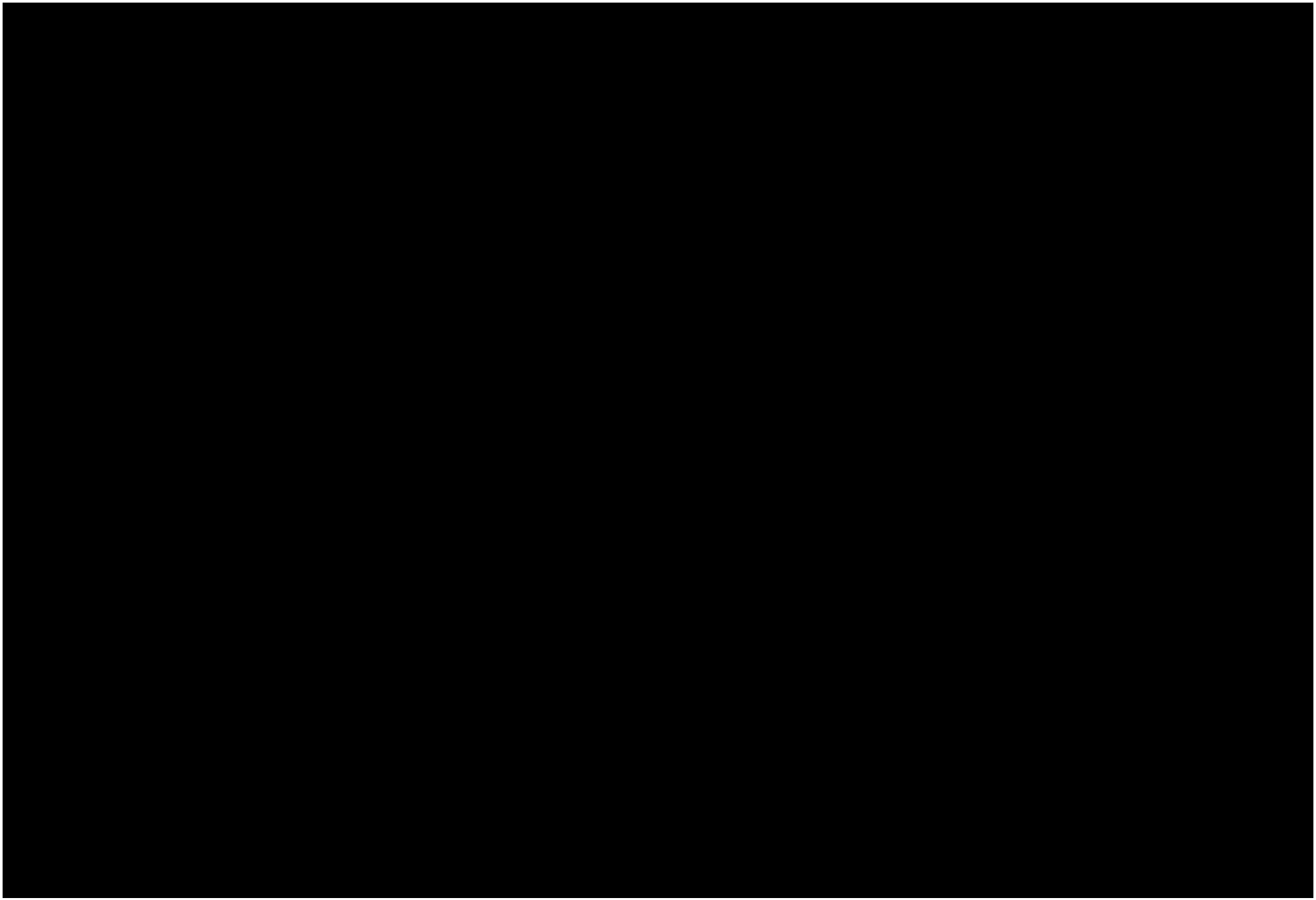
Date of Off Peak Day - 12/30/2021



Member Forecasted Off Peak Demand Day for January 2021

Southwestern Electric Cooperative, Inc.

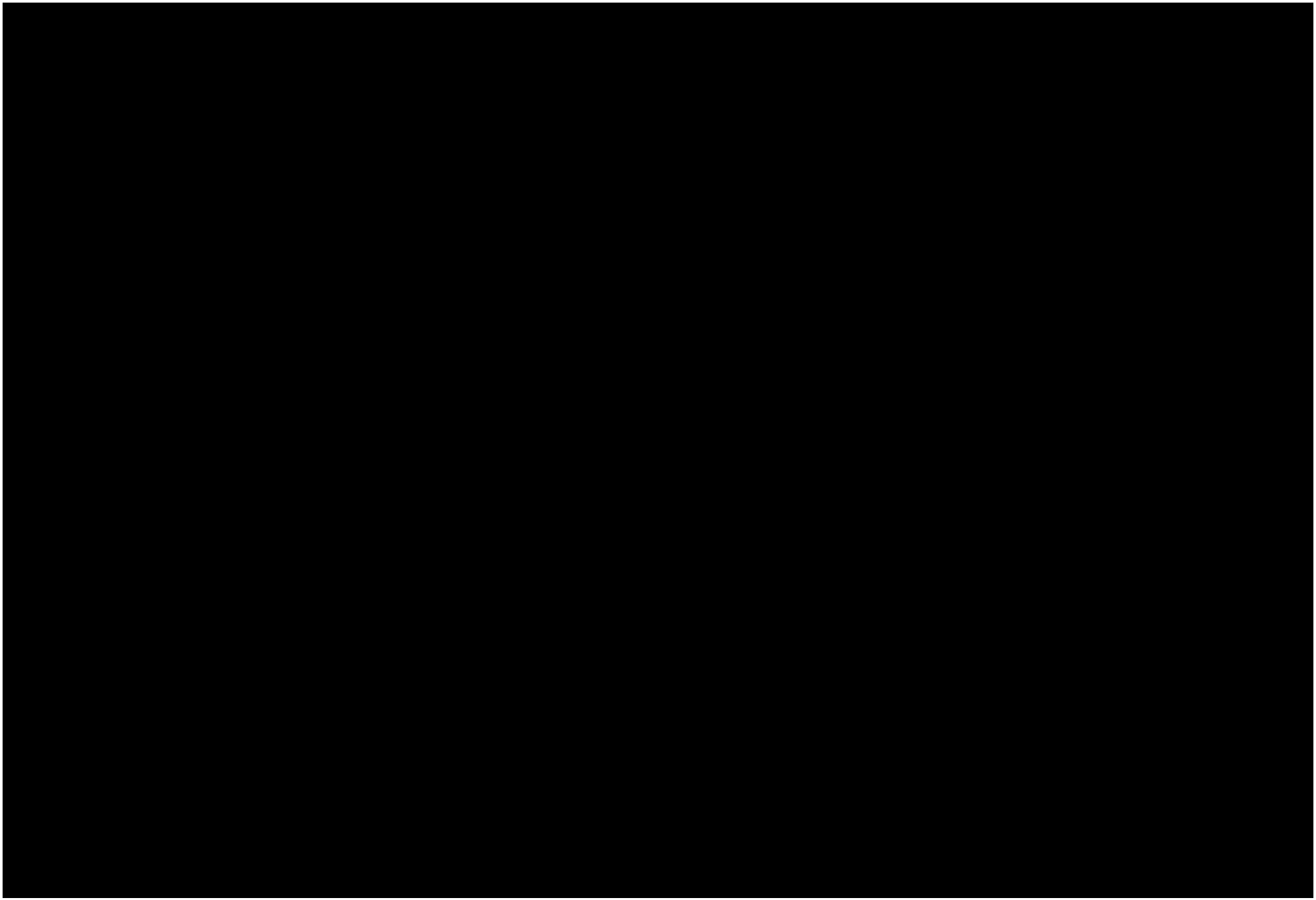
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Southwestern Electric Cooperative, Inc.

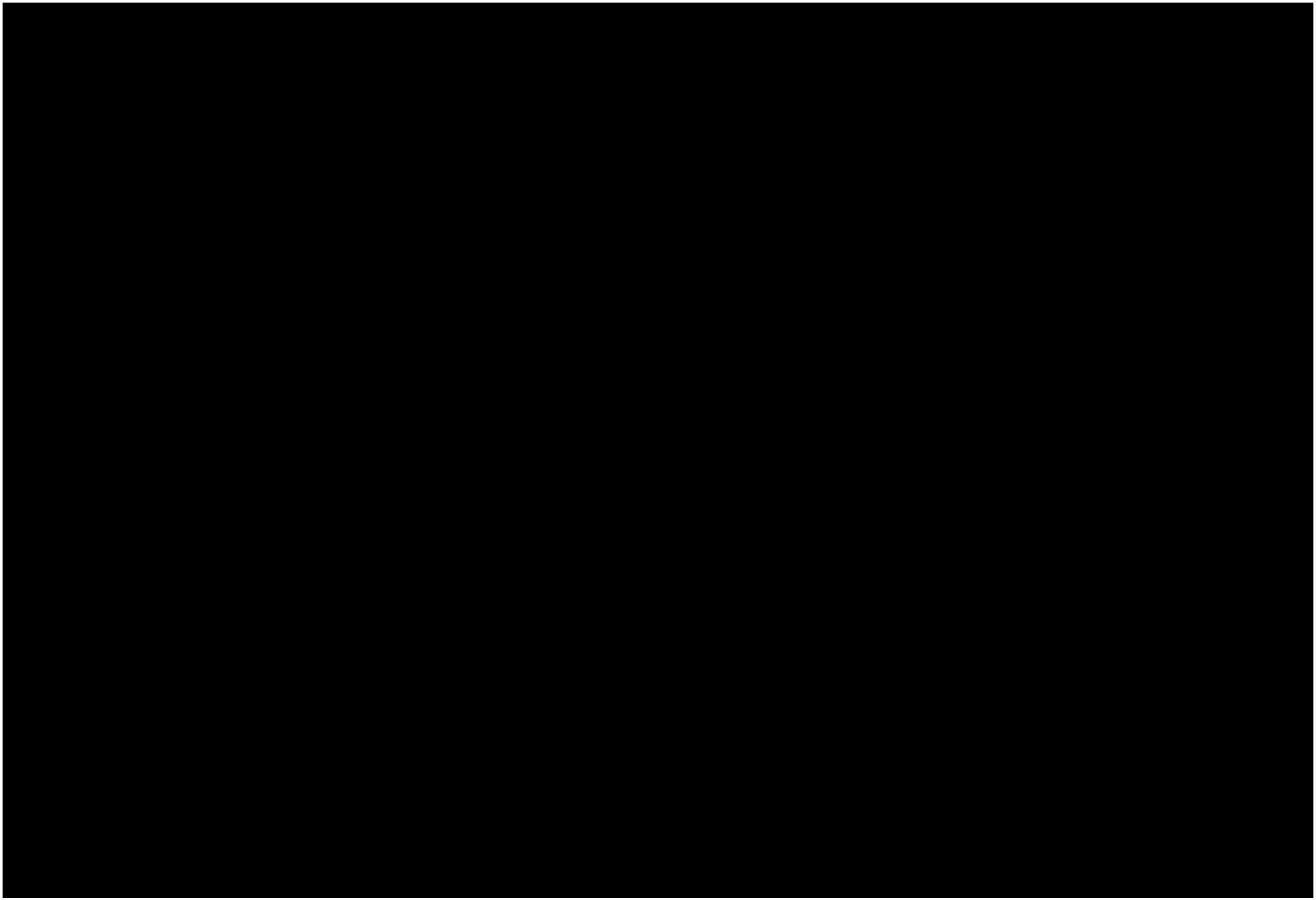
Date of Off Peak Day - 02/02/2021



Member Forecasted Off Peak Demand Day for March 2021

Southwestern Electric Cooperative, Inc.

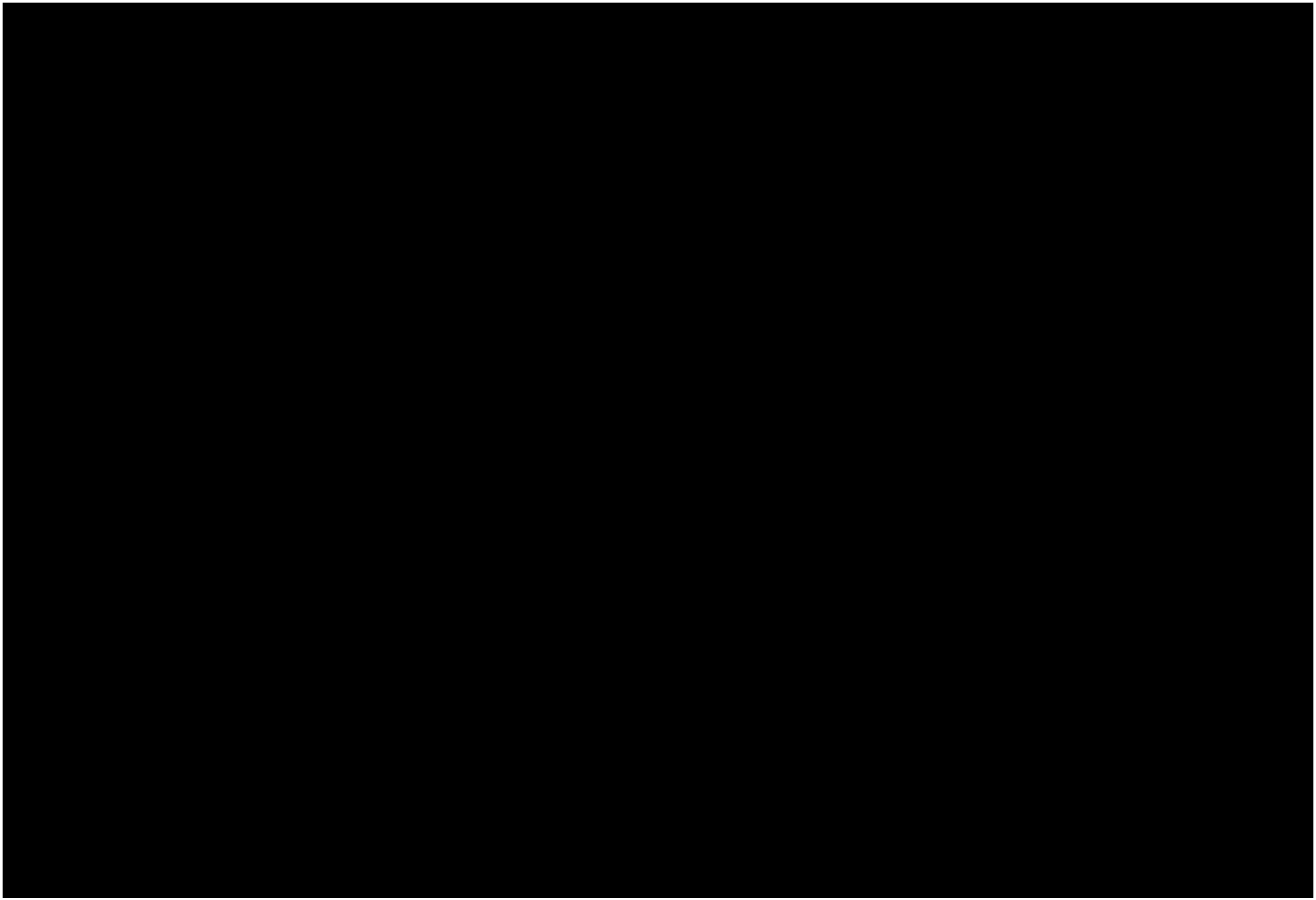
Date of Off Peak Day - 03/10/2021



Member Forecasted Off Peak Demand Day for April 2021

Southwestern Electric Cooperative, Inc.

Date of Off Peak Day - 04/13/2021



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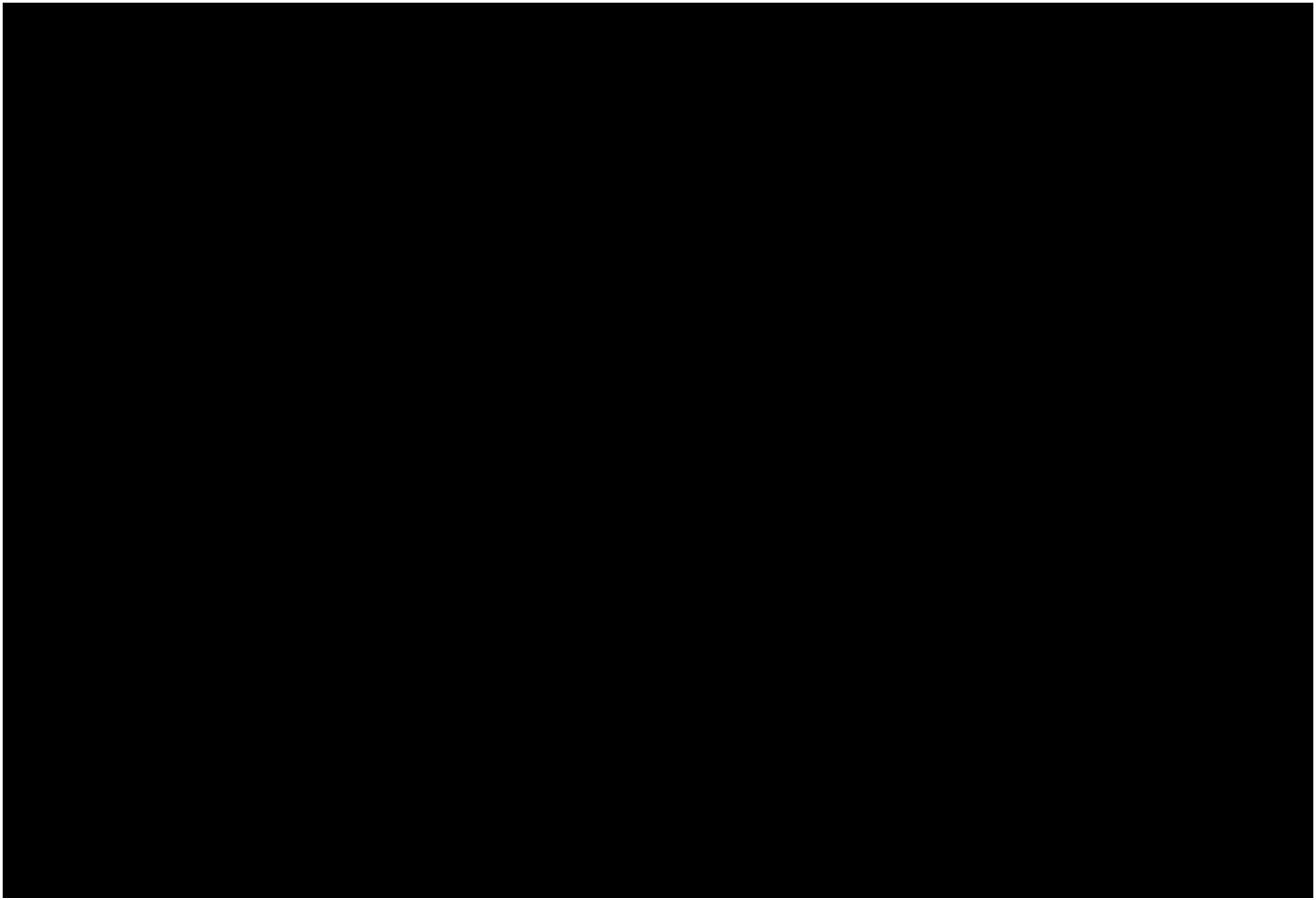
Member Forecasted Off Peak Demand Day for May 2021

Southwestern Electric Cooperative, Inc.

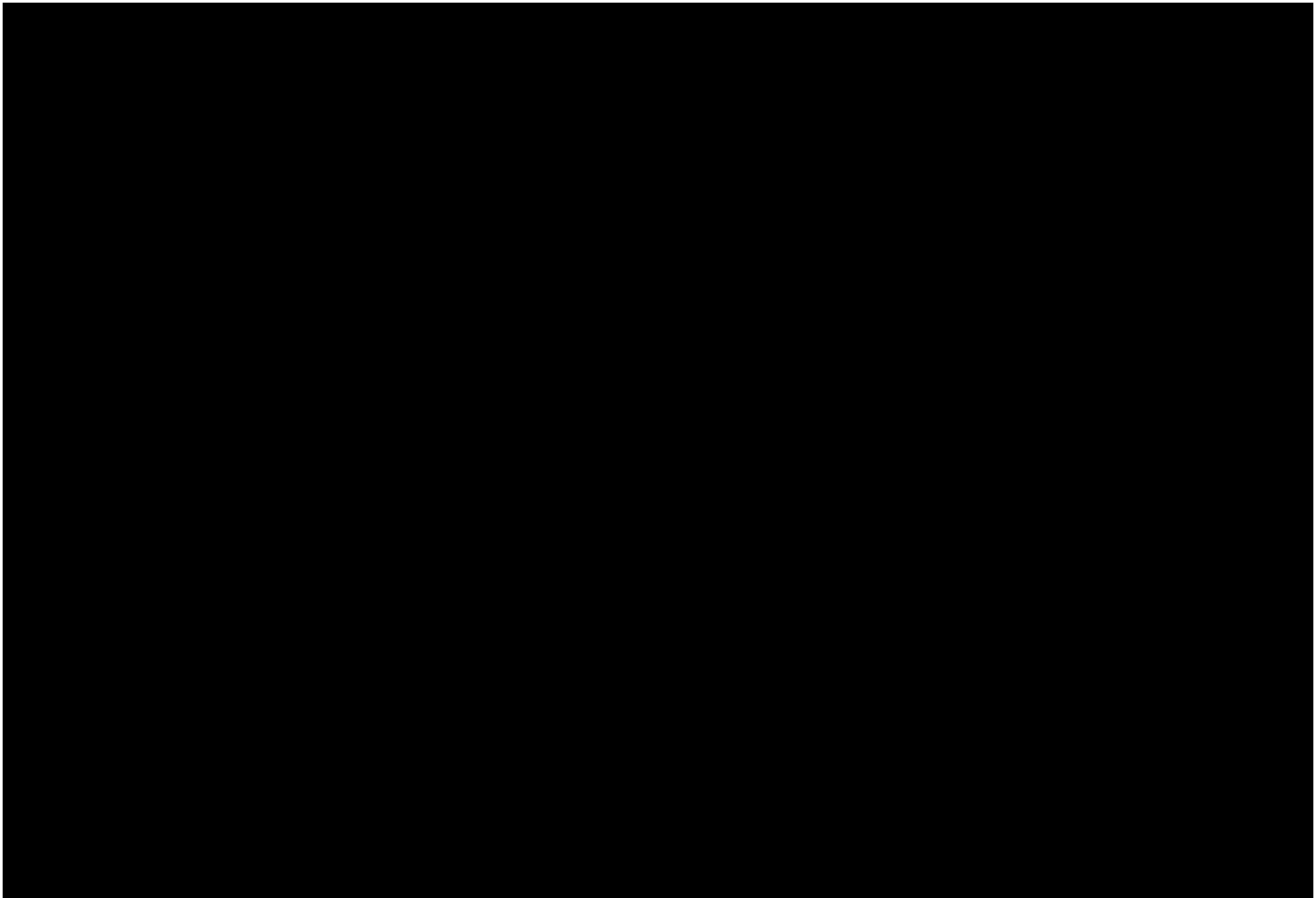
Date of Off Peak Day - 05/05/2021



Member Forecasted Off Peak Demand Day for June 2021

Southwestern Electric Cooperative, Inc.

Date of Off Peak Day - 06/03/2021



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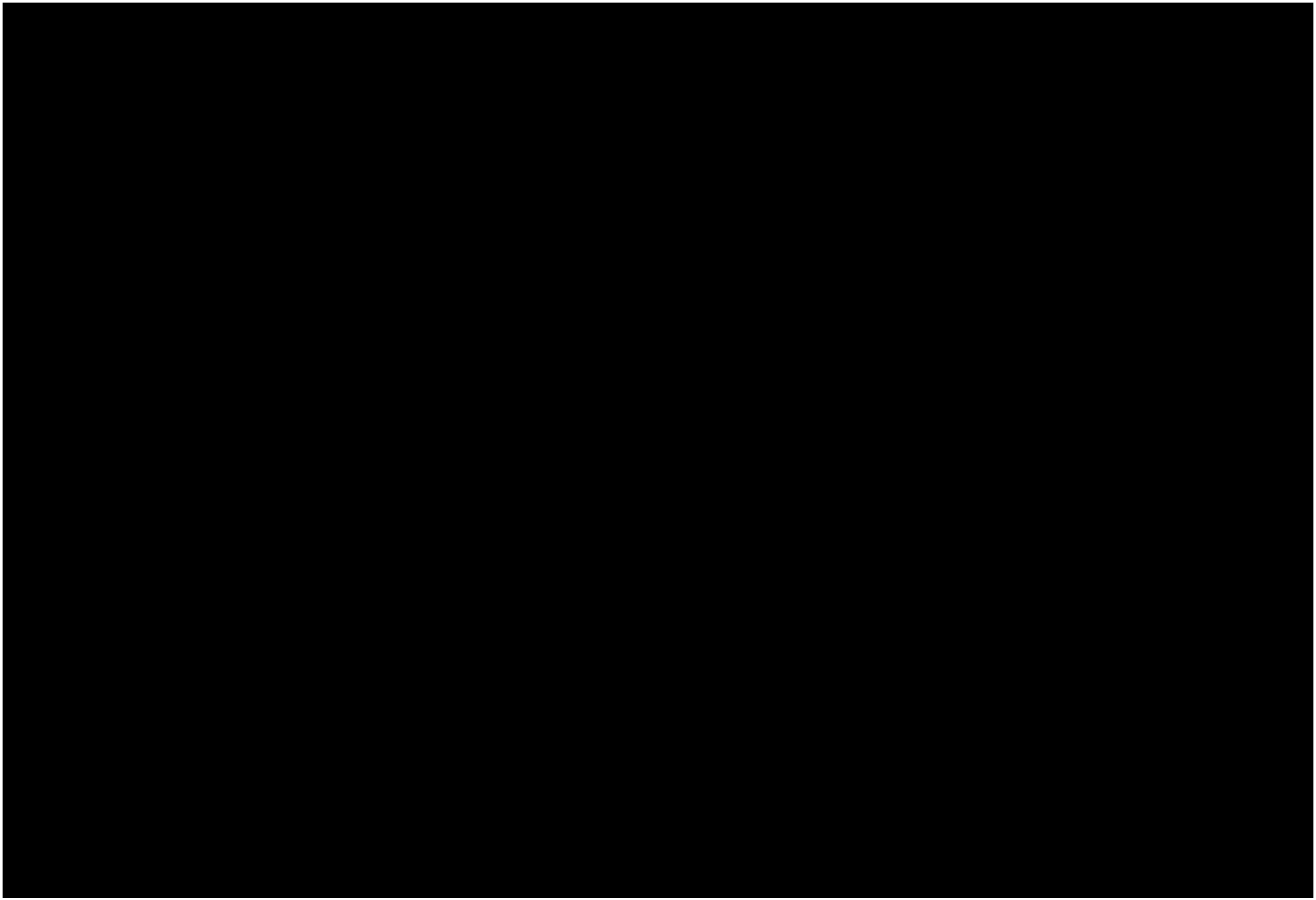
Member Forecasted Off Peak Demand Day for July 2021

Southwestern Electric Cooperative, Inc.

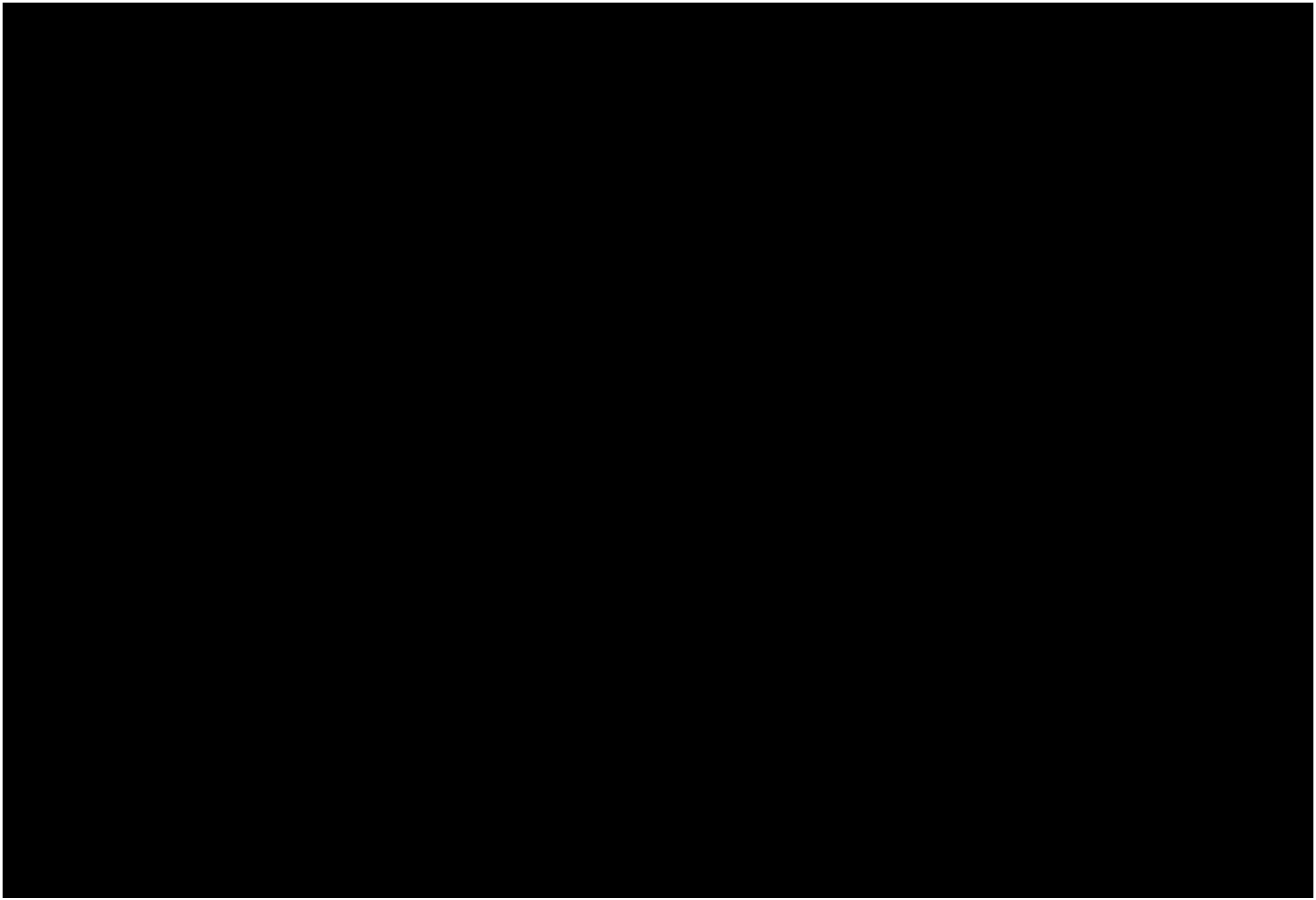
Date of Off Peak Day - 07/29/2021



Member Forecasted Off Peak Demand Day for August 2021

Southwestern Electric Cooperative, Inc.

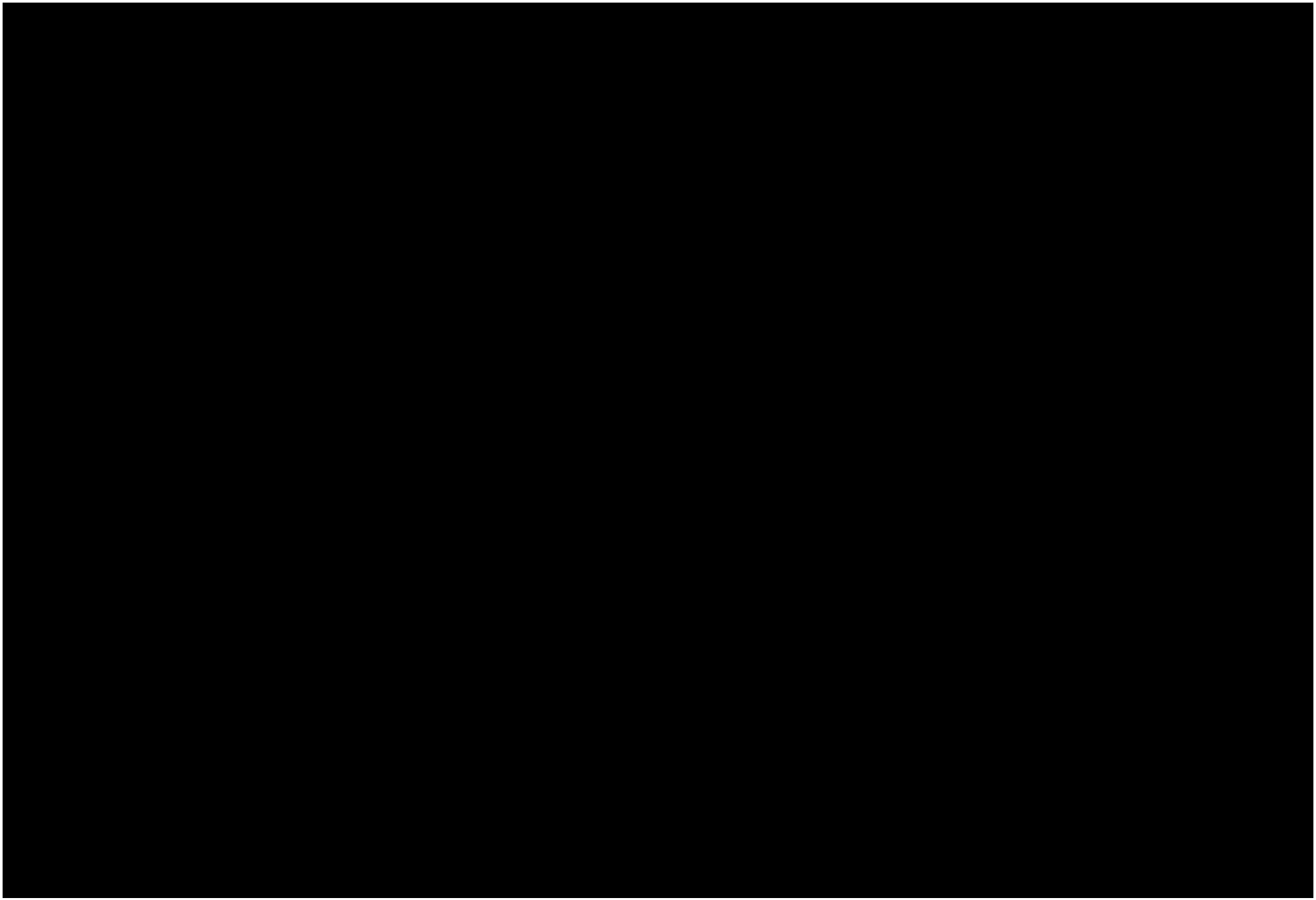
Date of Off Peak Day - 08/29/2021



Member Forecasted Off Peak Demand Day for September 2021

Southwestern Electric Cooperative, Inc.

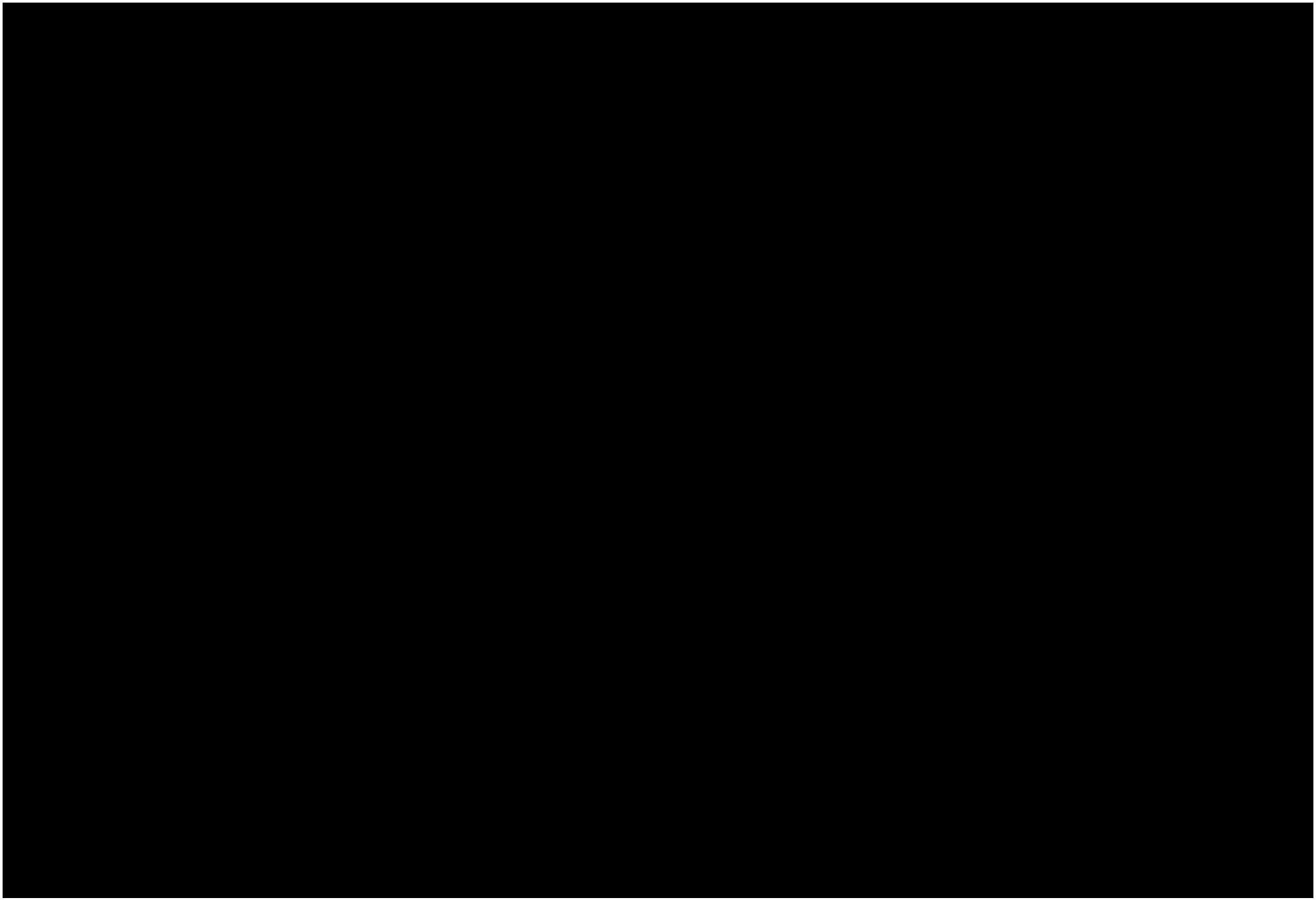
Date of Off Peak Day - 09/22/2021



Member Forecasted Off Peak Demand Day for October 2021

Southwestern Electric Cooperative, Inc.

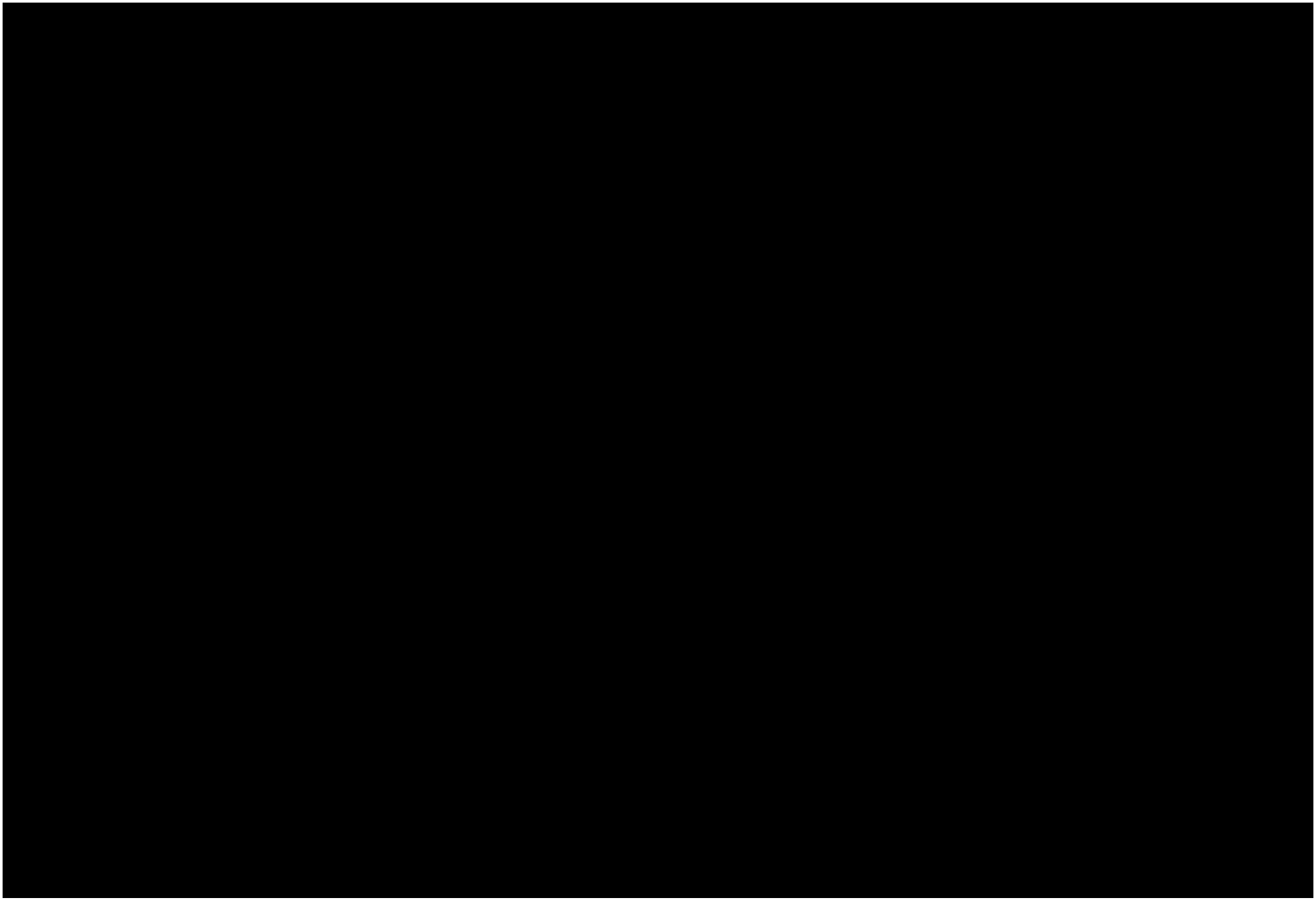
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Southwestern Electric Cooperative, Inc.

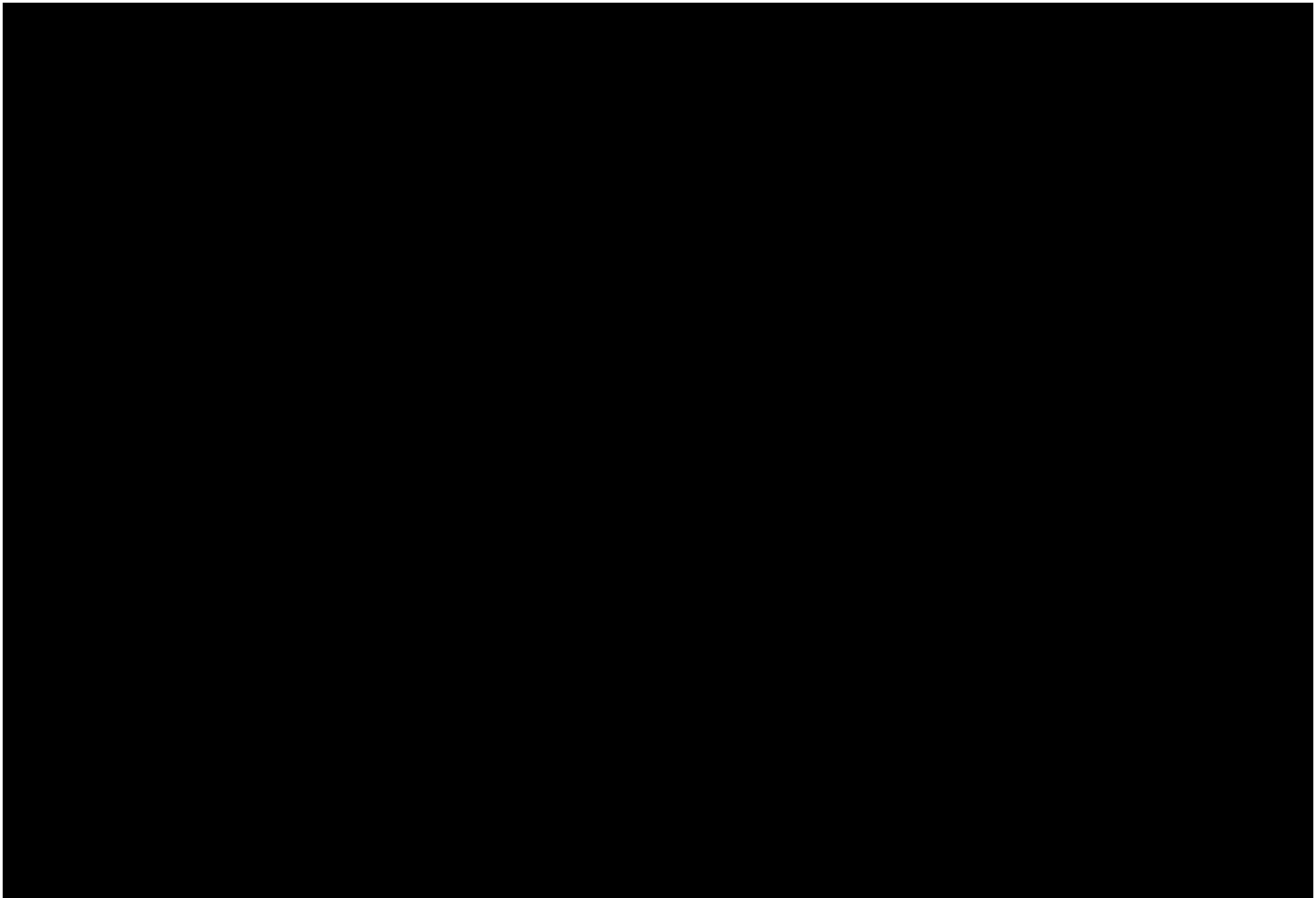
Date of Off Peak Day - 11/12/2021



Member Forecasted Off Peak Demand Day for December 2021

Southwestern Electric Cooperative, Inc.

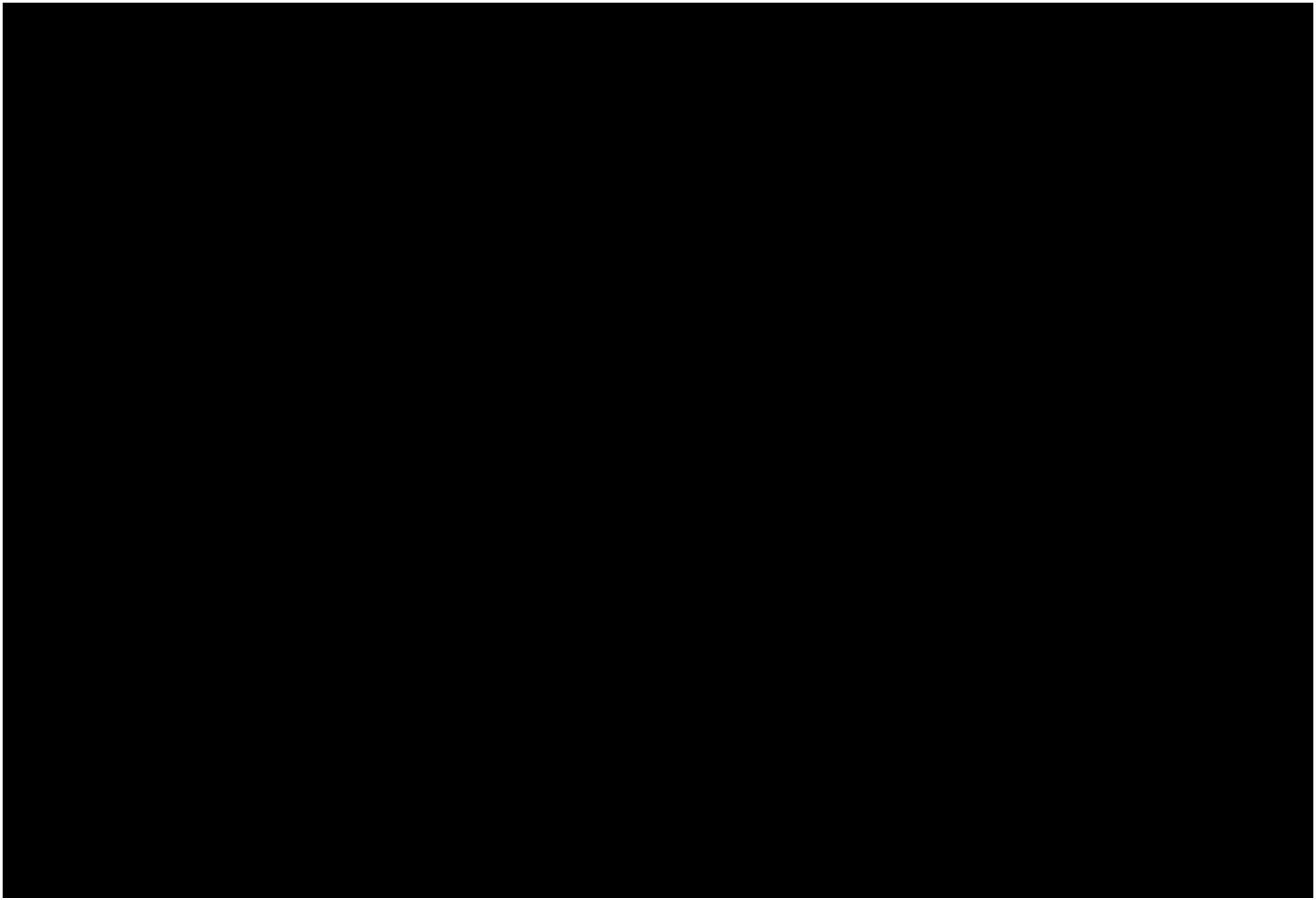
Date of Off Peak Day - 12/13/2021



Member Forecasted Off Peak Demand Day for January 2021

United Power, Inc.

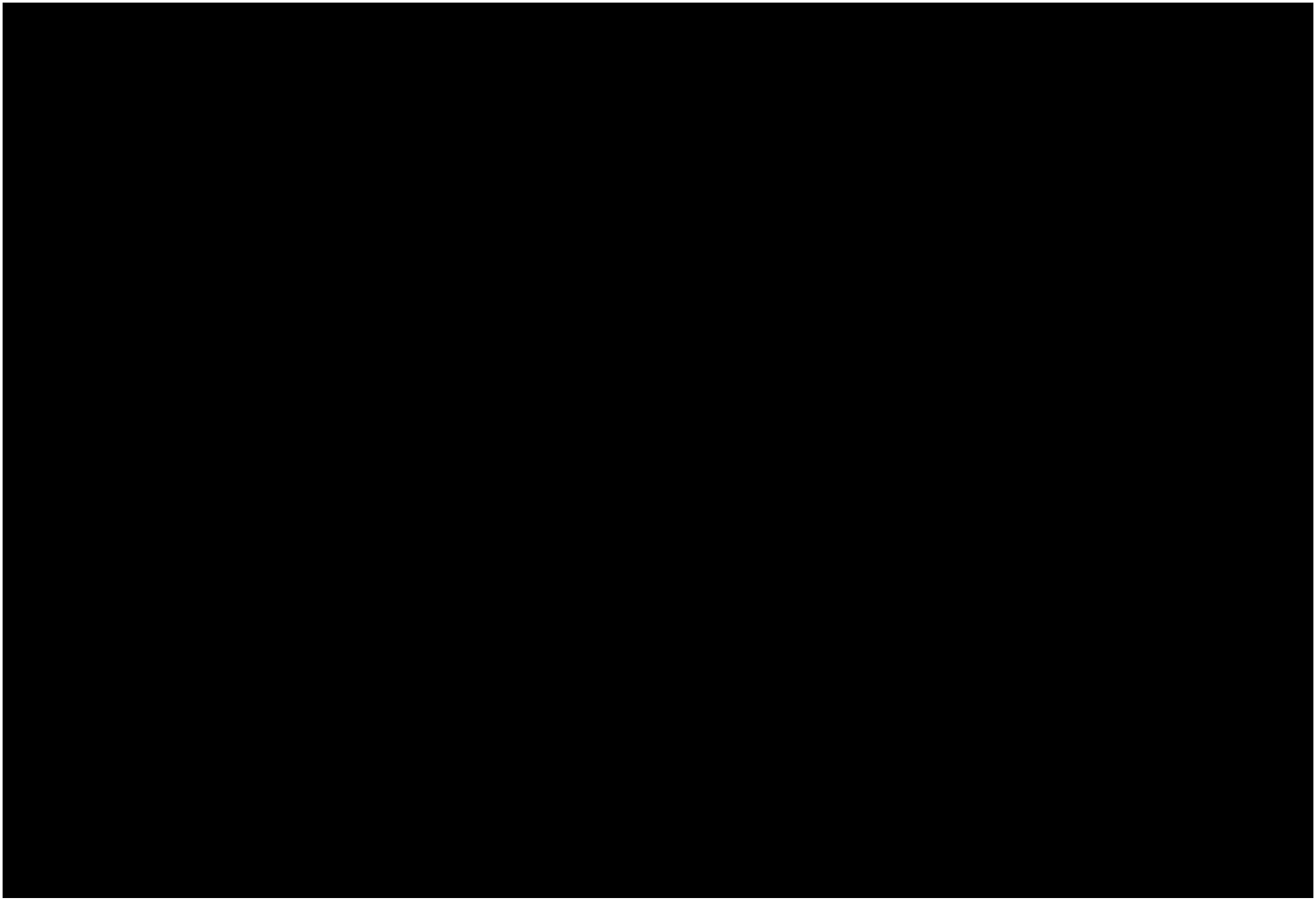
Date of Off Peak Day - 01/20/2021



Member Forecasted Off Peak Demand Day for February 2021

United Power, Inc.

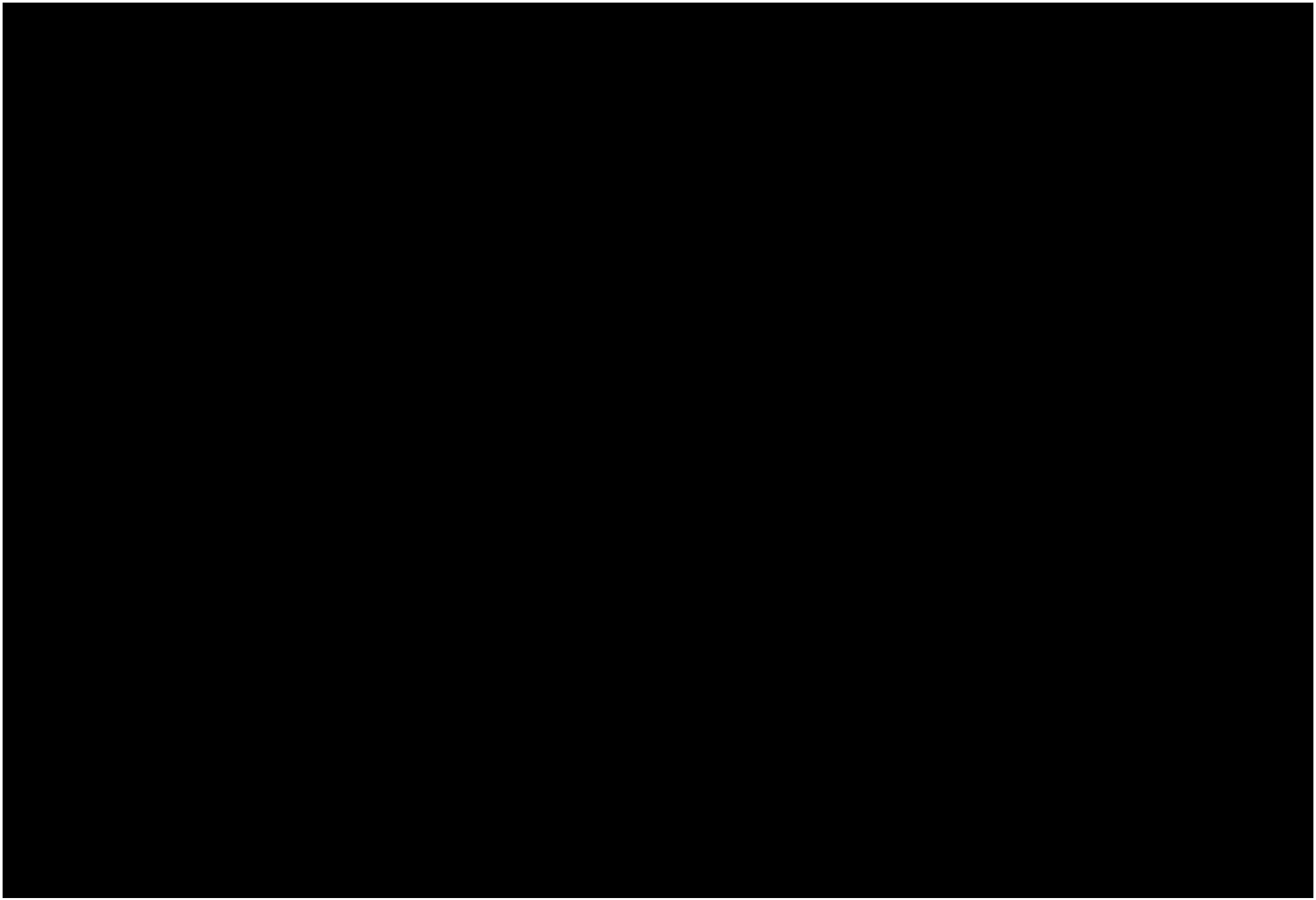
Date of Off Peak Day - 02/17/2021



Member Forecasted Off Peak Demand Day for March 2021

United Power, Inc.

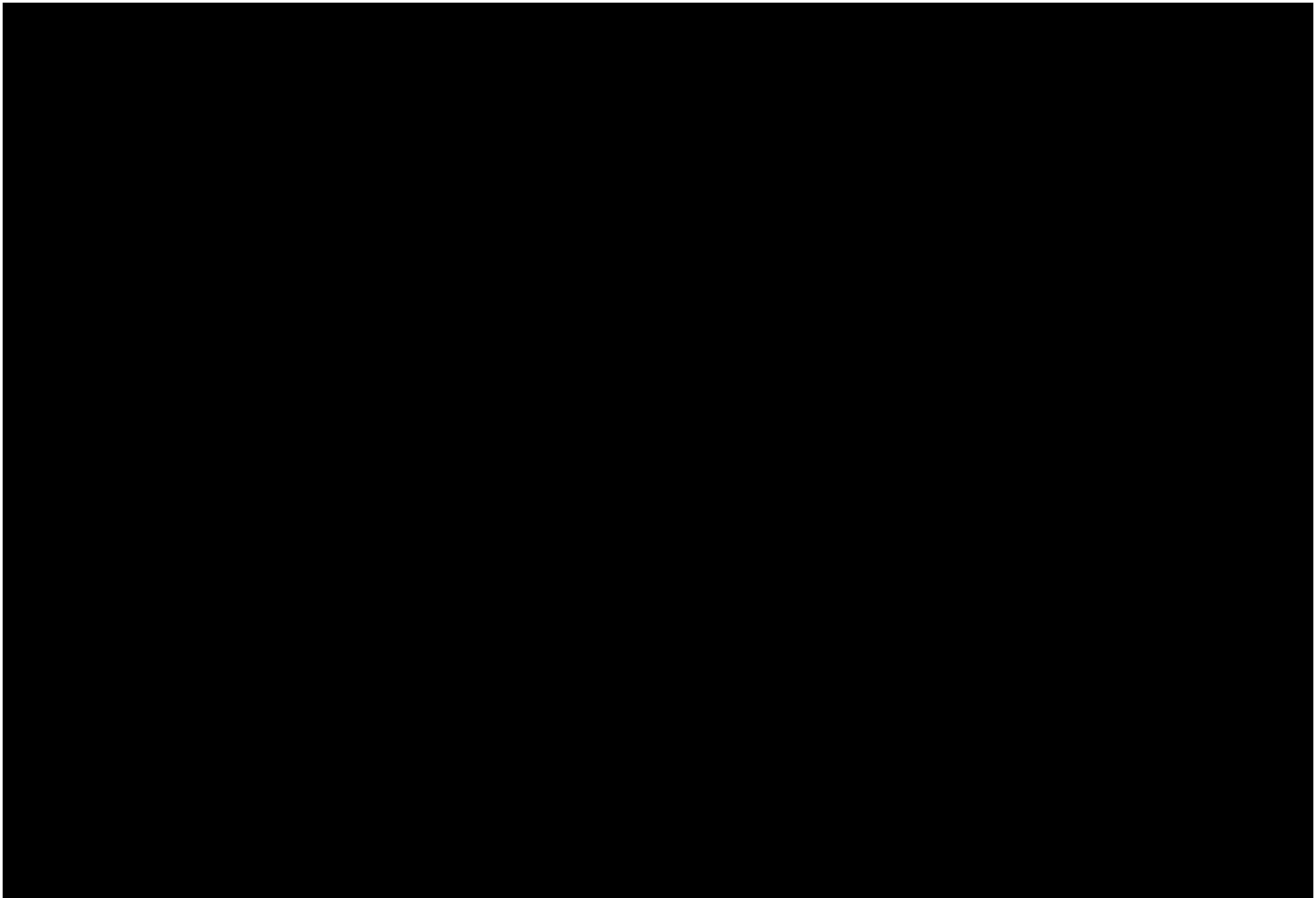
Date of Off Peak Day - 03/19/2021



Member Forecasted Off Peak Demand Day for April 2021

United Power, Inc.

Date of Off Peak Day - 04/07/2021



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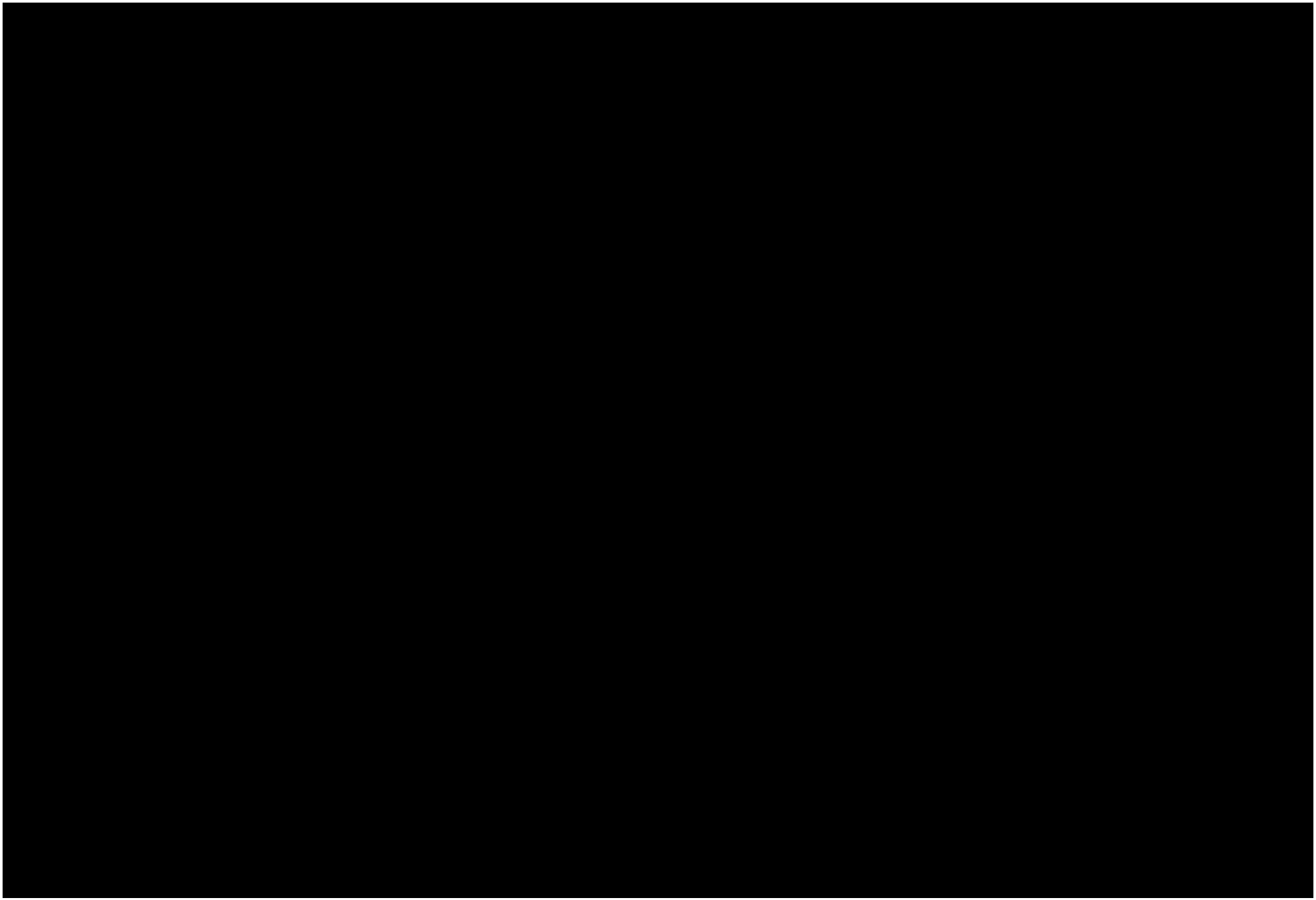
Member Forecasted Off Peak Demand Day for May 2021

United Power, Inc.

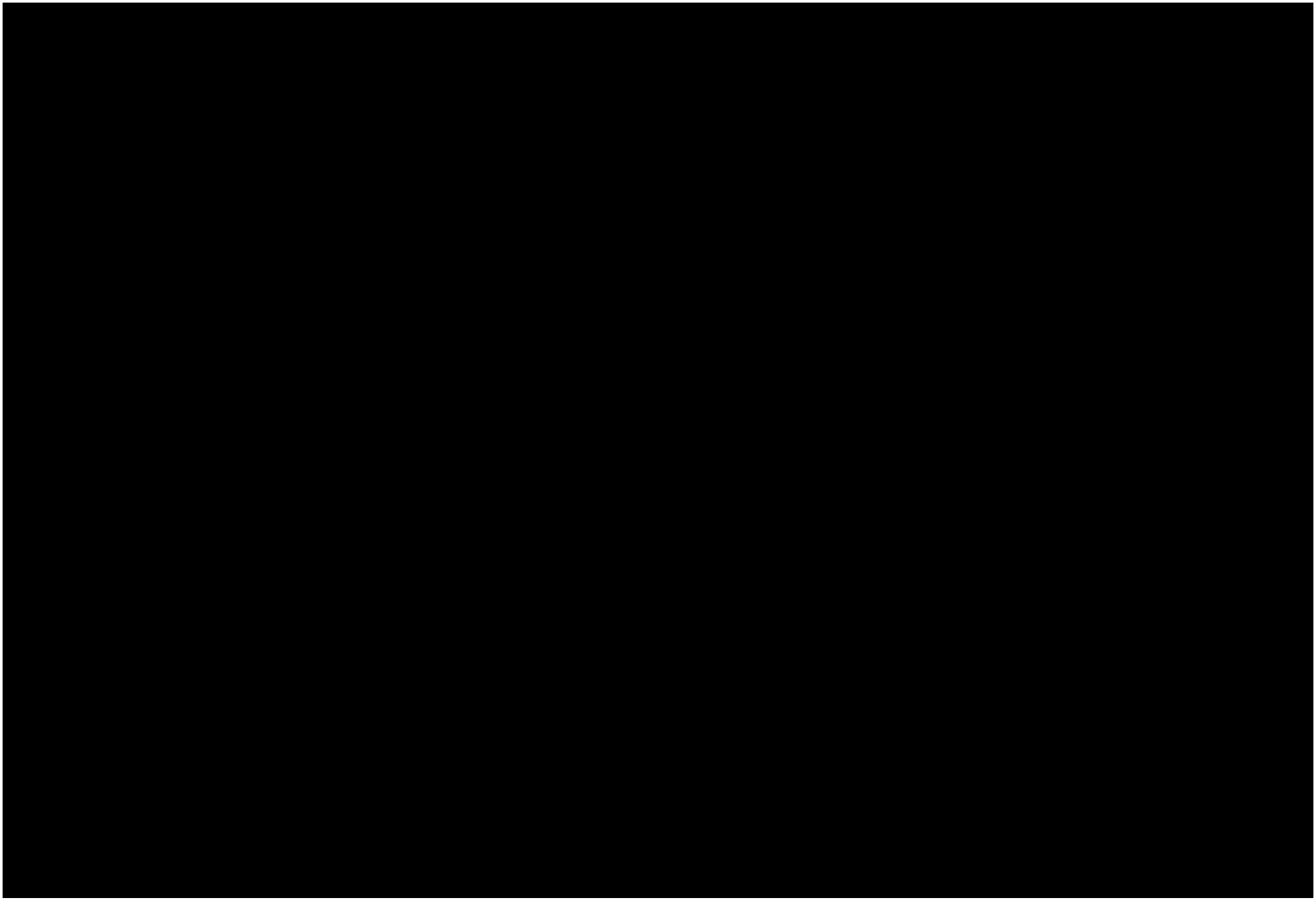
Date of Off Peak Day - 05/25/2021



Member Forecasted Off Peak Demand Day for June 2021

United Power, Inc.

Date of Off Peak Day - 06/12/2021



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Member Forecasted Off Peak Demand Day for July 2021

United Power, Inc.

Date of Off Peak Day - 07/04/2021

[redacted]

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Member Forecasted Off Peak Demand Day for August 2021

United Power, Inc.

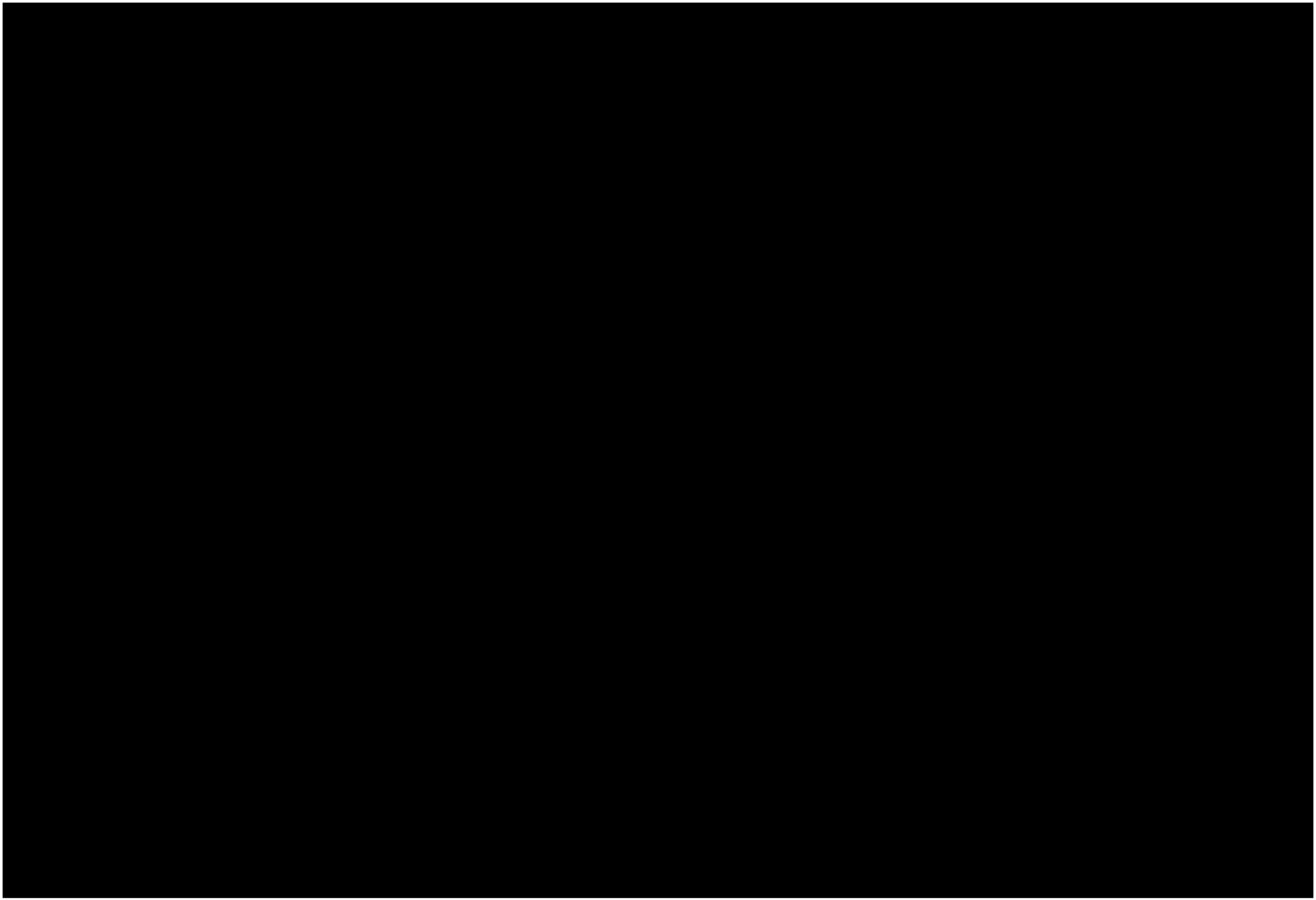
Date of Off Peak Day - 08/08/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

United Power, Inc.

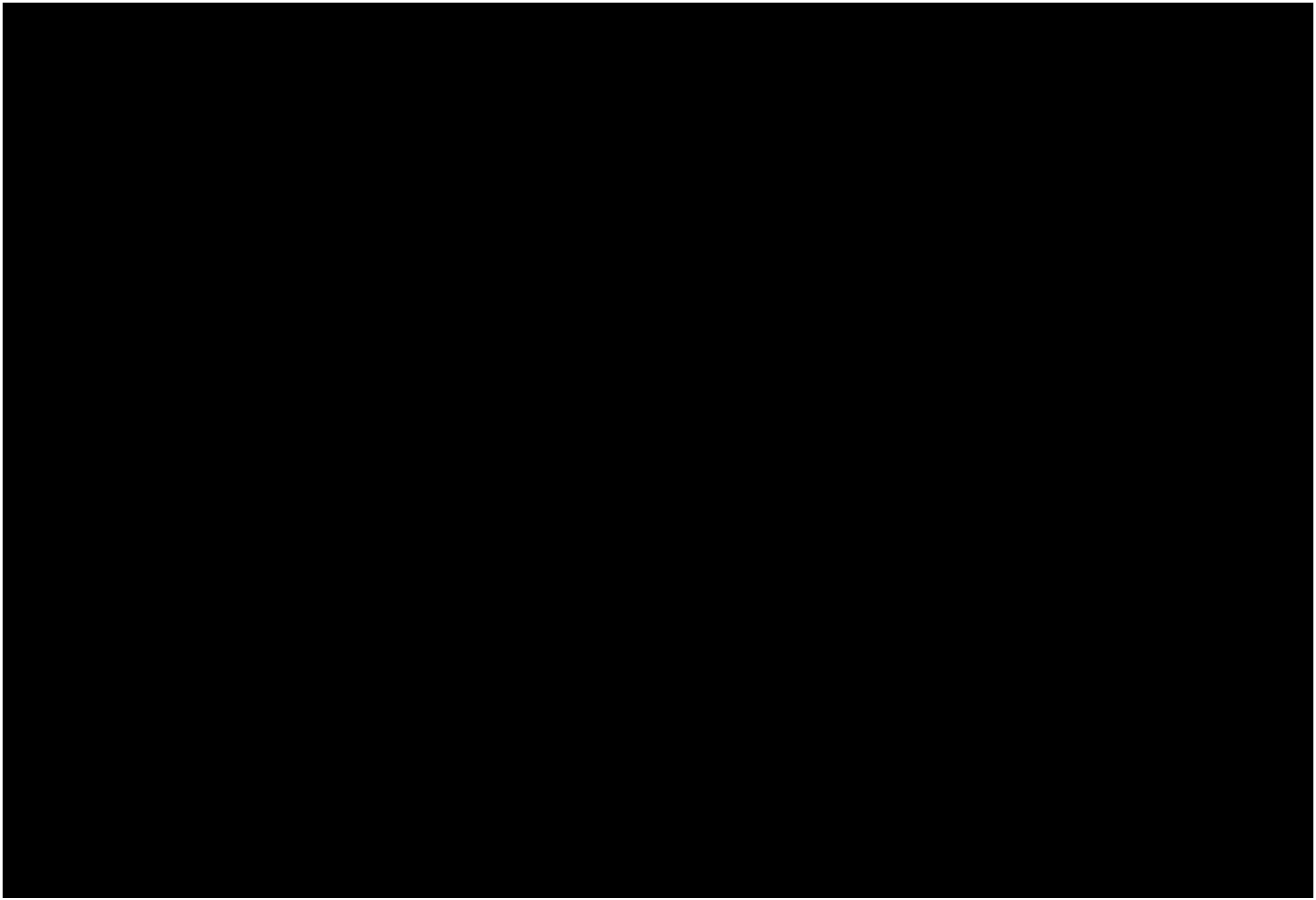
Date of Off Peak Day - 09/20/2021



Member Forecasted Off Peak Demand Day for October 2021

United Power, Inc.

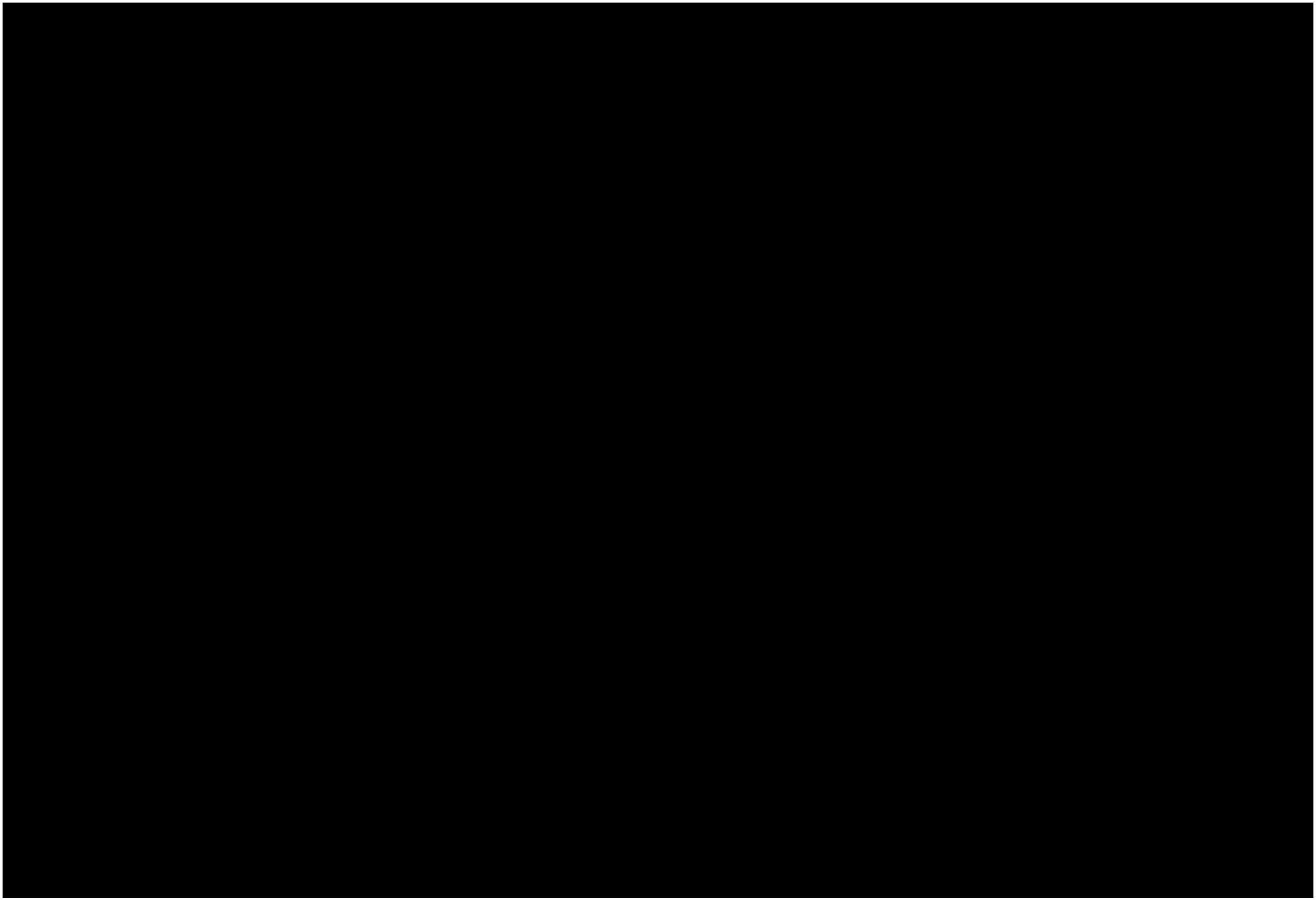
Date of Off Peak Day - 10/11/2021



Member Forecasted Off Peak Demand Day for November 2021

United Power, Inc.

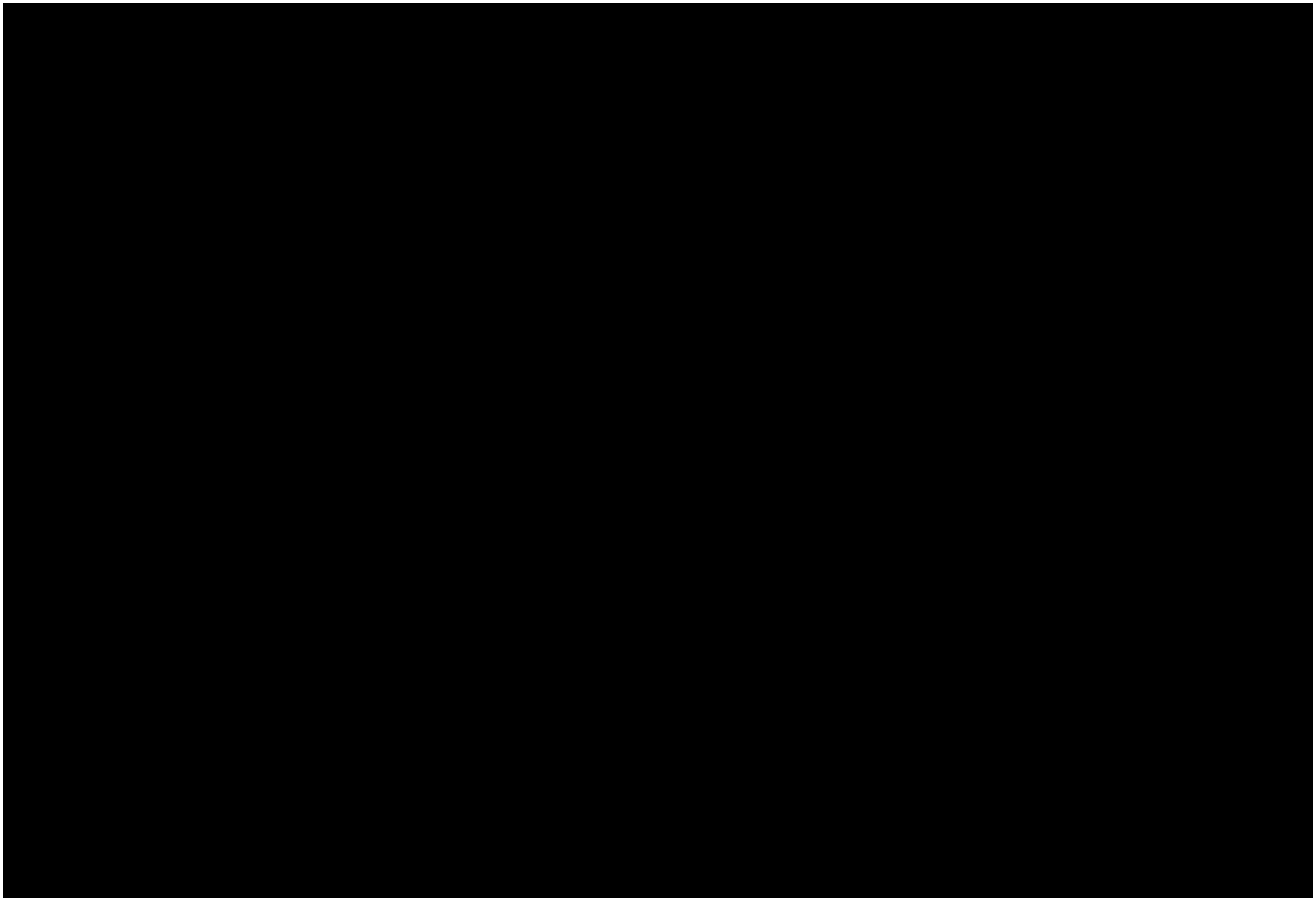
Date of Off Peak Day - 11/05/2021



Member Forecasted Off Peak Demand Day for December 2021

United Power, Inc.

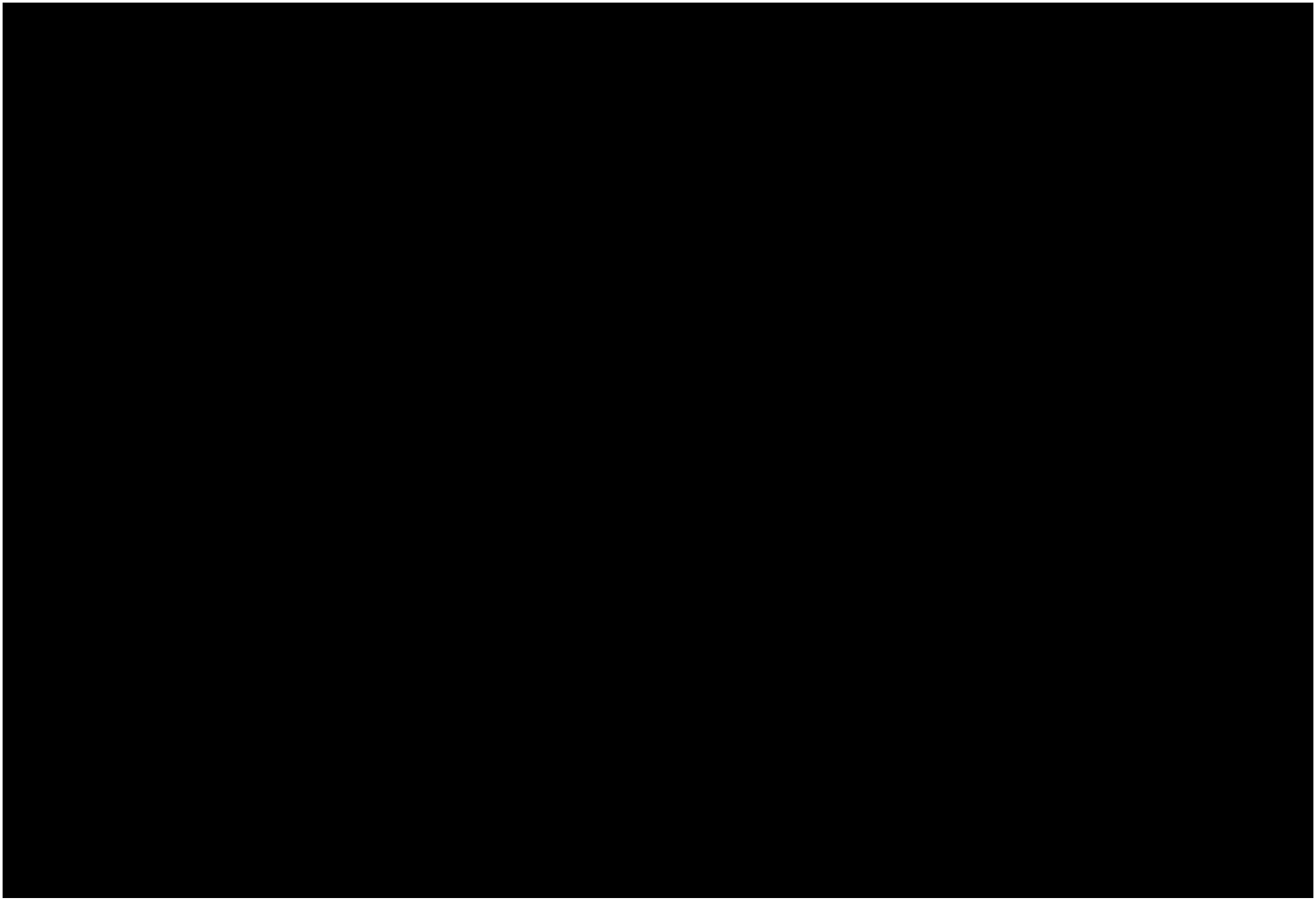
Date of Off Peak Day - 12/02/2021



Member Forecasted Off Peak Demand Day for January 2021

Wheat Belt Public Power District

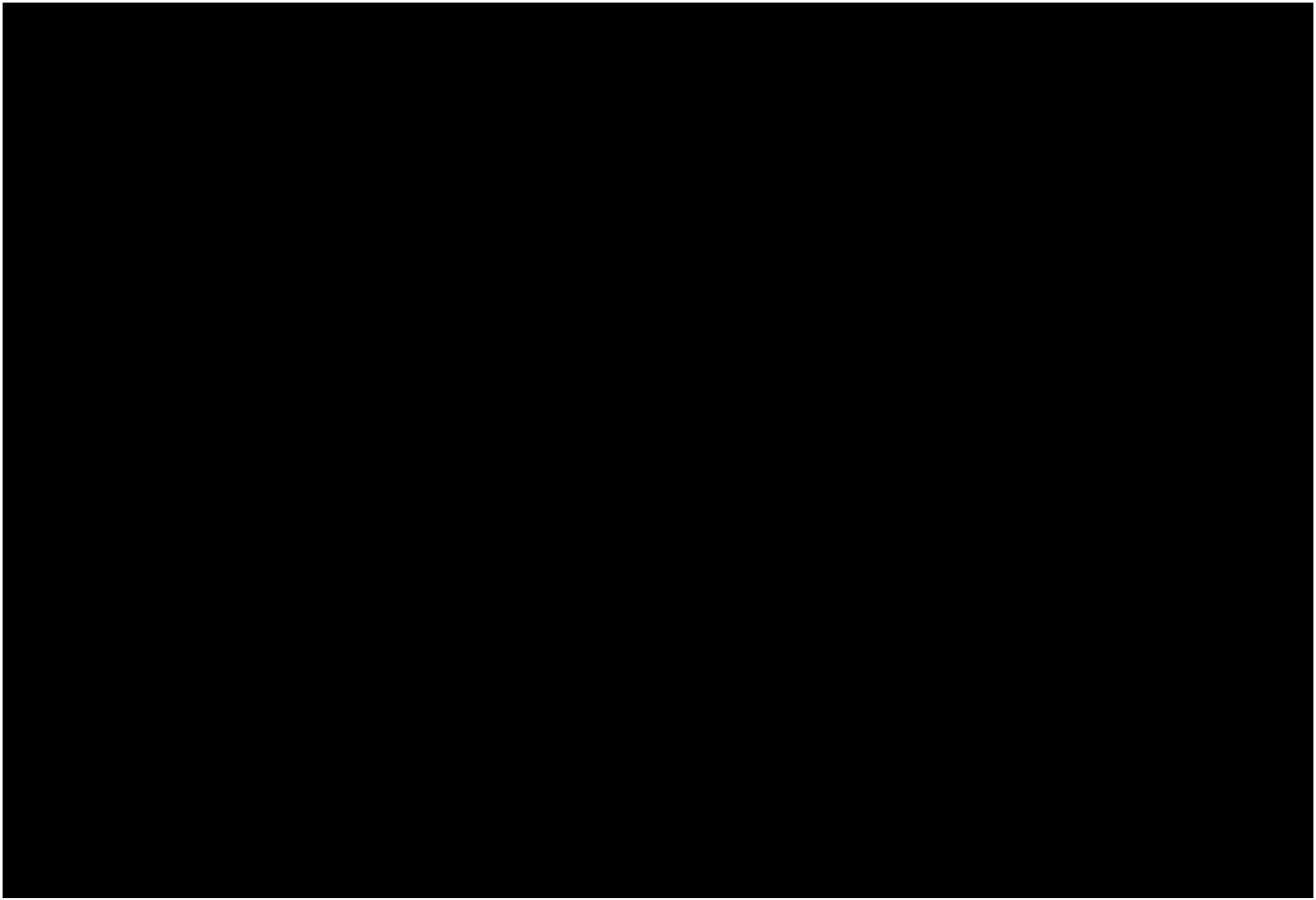
Date of Off Peak Day - 01/19/2021



Member Forecasted Off Peak Demand Day for February 2021

Wheat Belt Public Power District

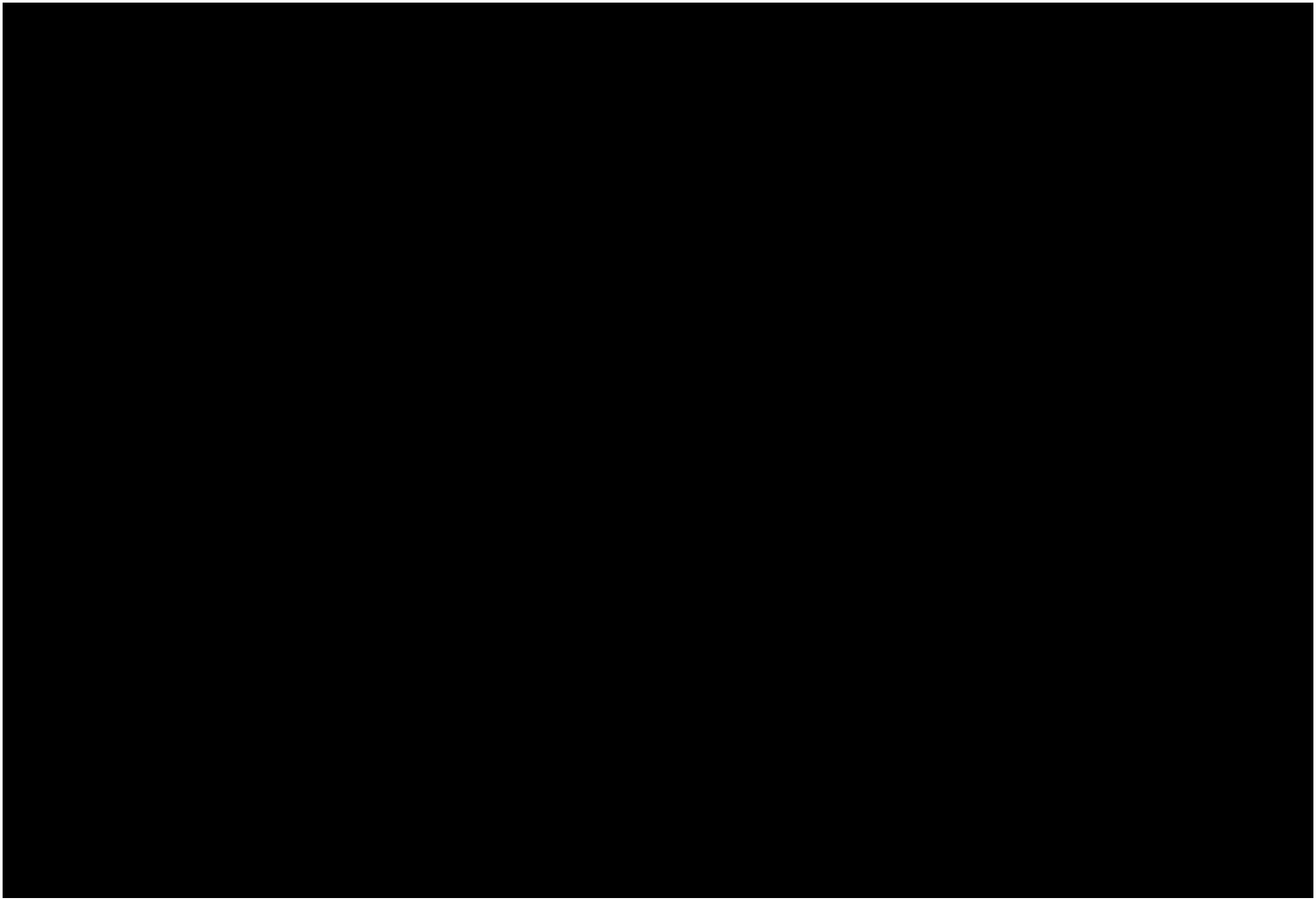
Date of Off Peak Day - 02/16/2021



Member Forecasted Off Peak Demand Day for March 2021

Wheat Belt Public Power District

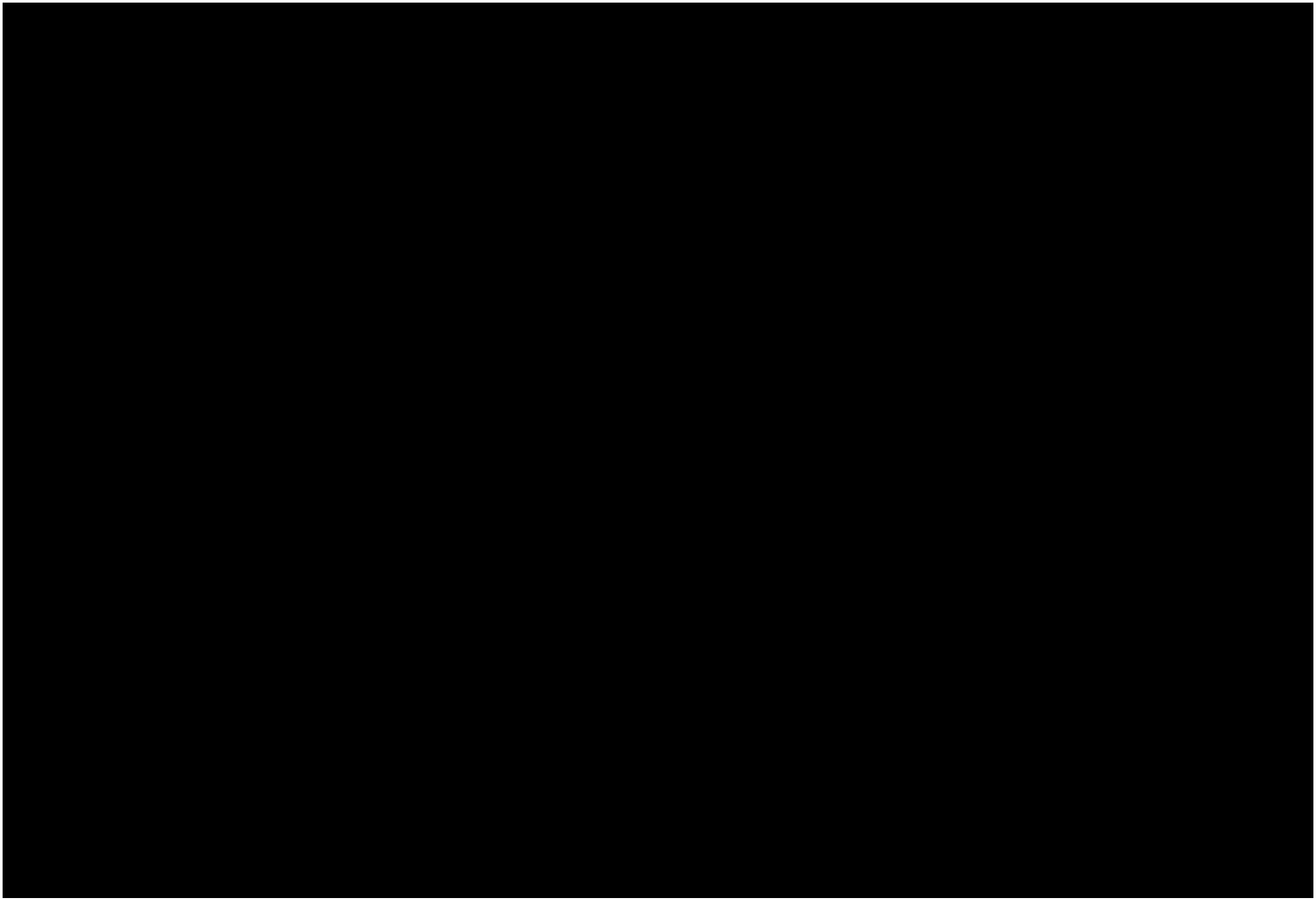
Date of Off Peak Day - 03/19/2021



Member Forecasted Off Peak Demand Day for April 2021

Wheat Belt Public Power District

Date of Off Peak Day - 04/10/2021



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Member Forecasted Off Peak Demand Day for May 2021

Wheat Belt Public Power District

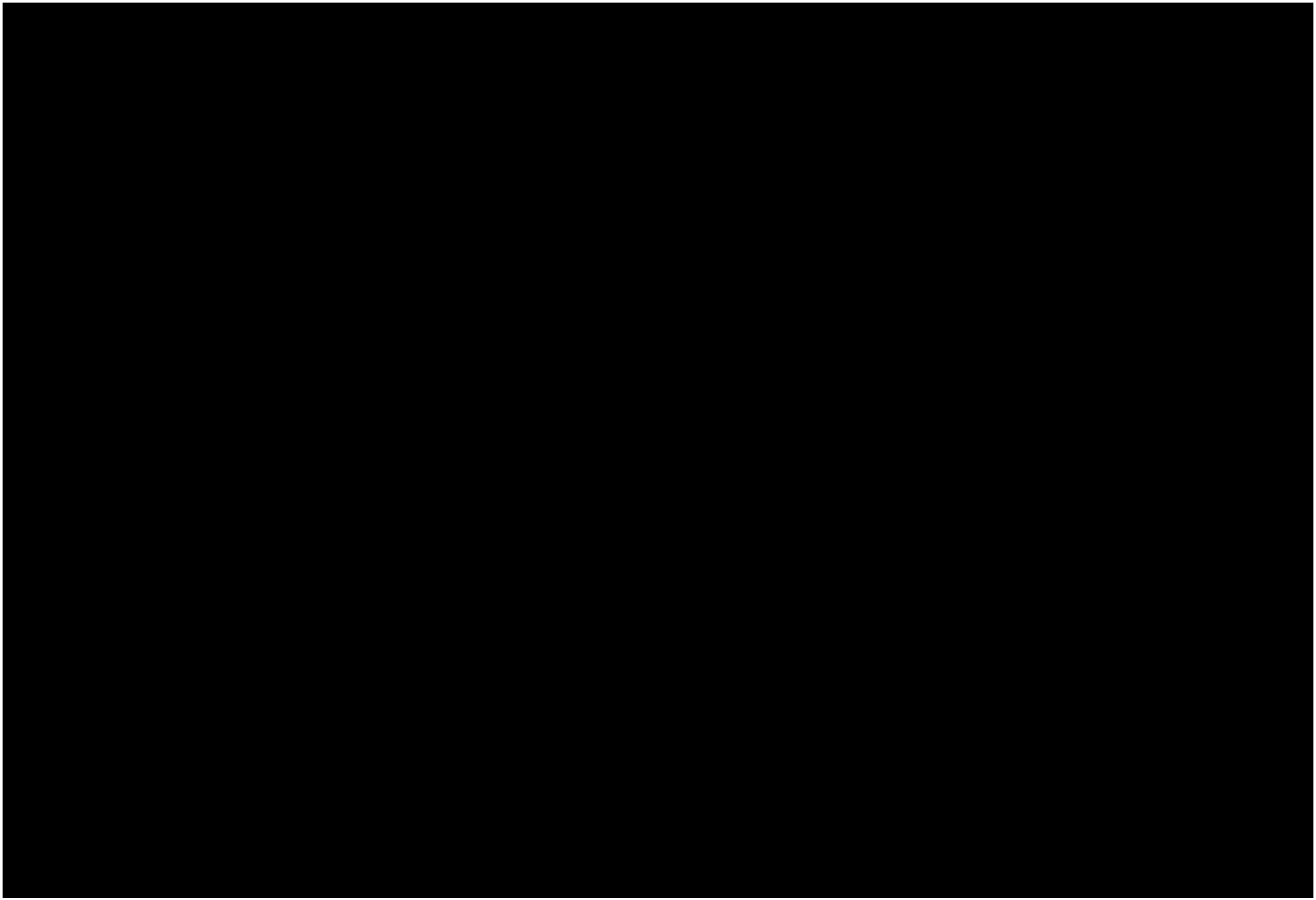
Date of Off Peak Day - 05/22/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Wheat Belt Public Power District

Date of Off Peak Day - 06/21/2021



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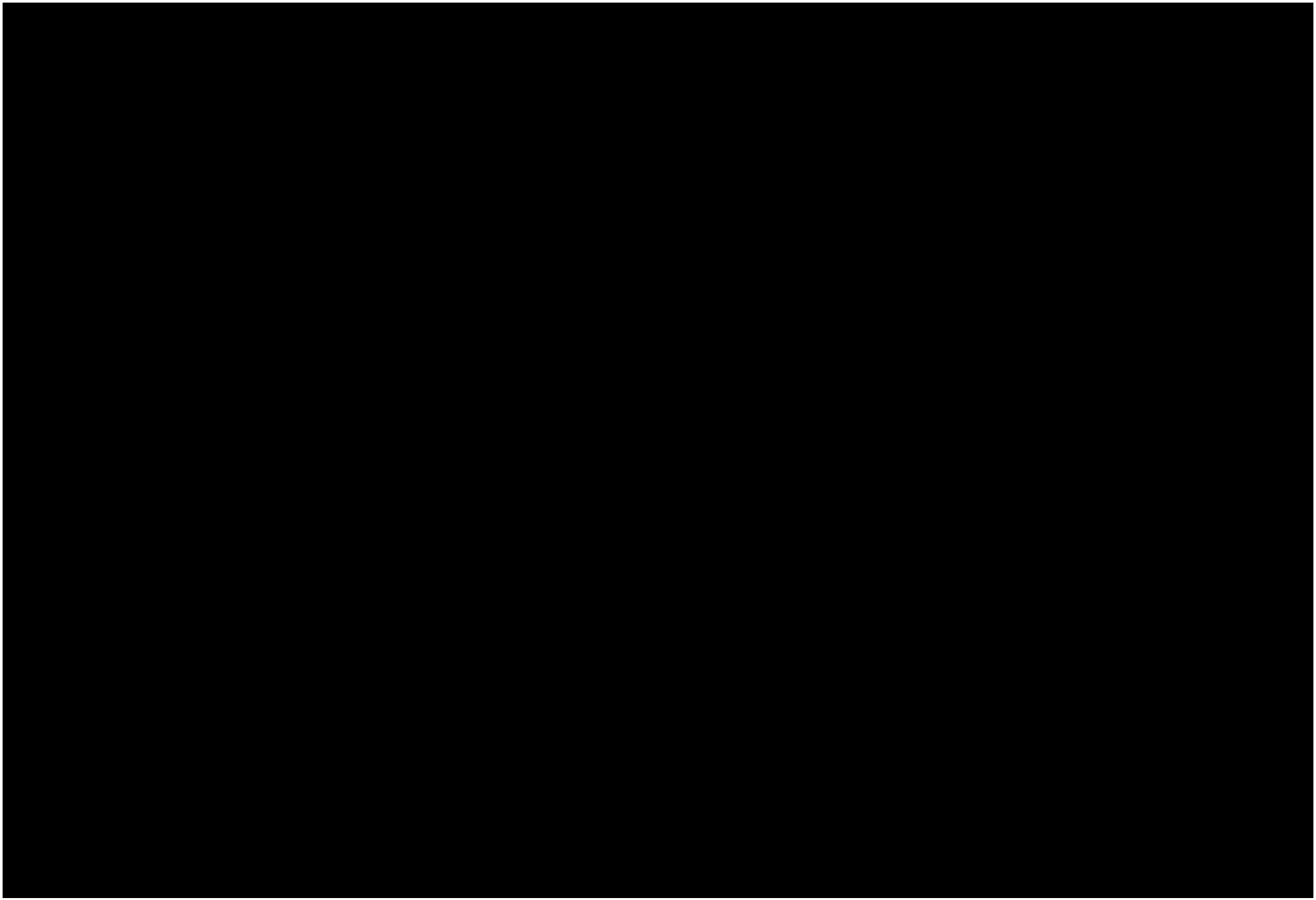
Member Forecasted Off Peak Demand Day for July 2021

Wheat Belt Public Power District

Date of Off Peak Day - 07/30/2021



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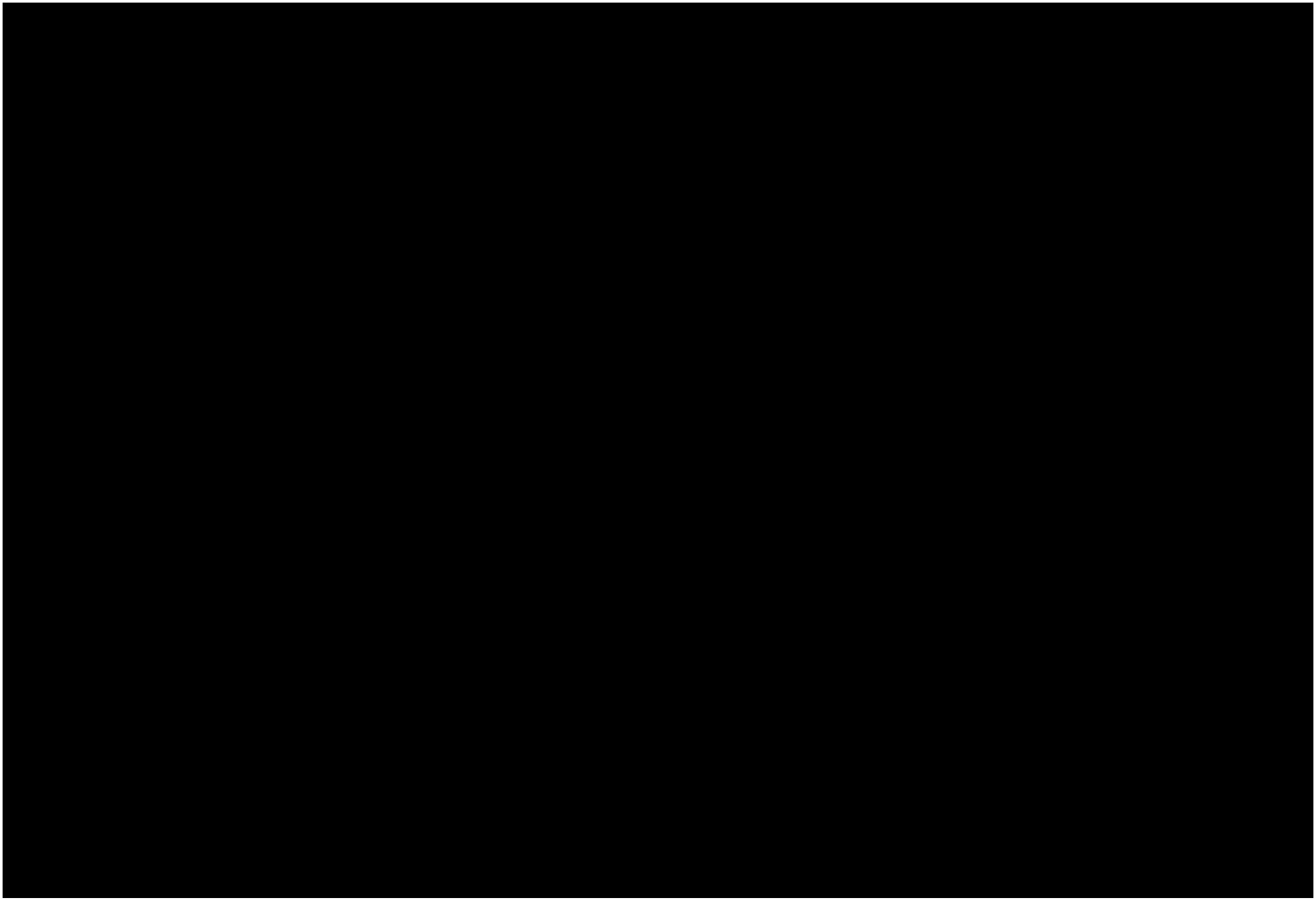
Member Forecasted Off Peak Demand Day for August 2021

Wheat Belt Public Power District

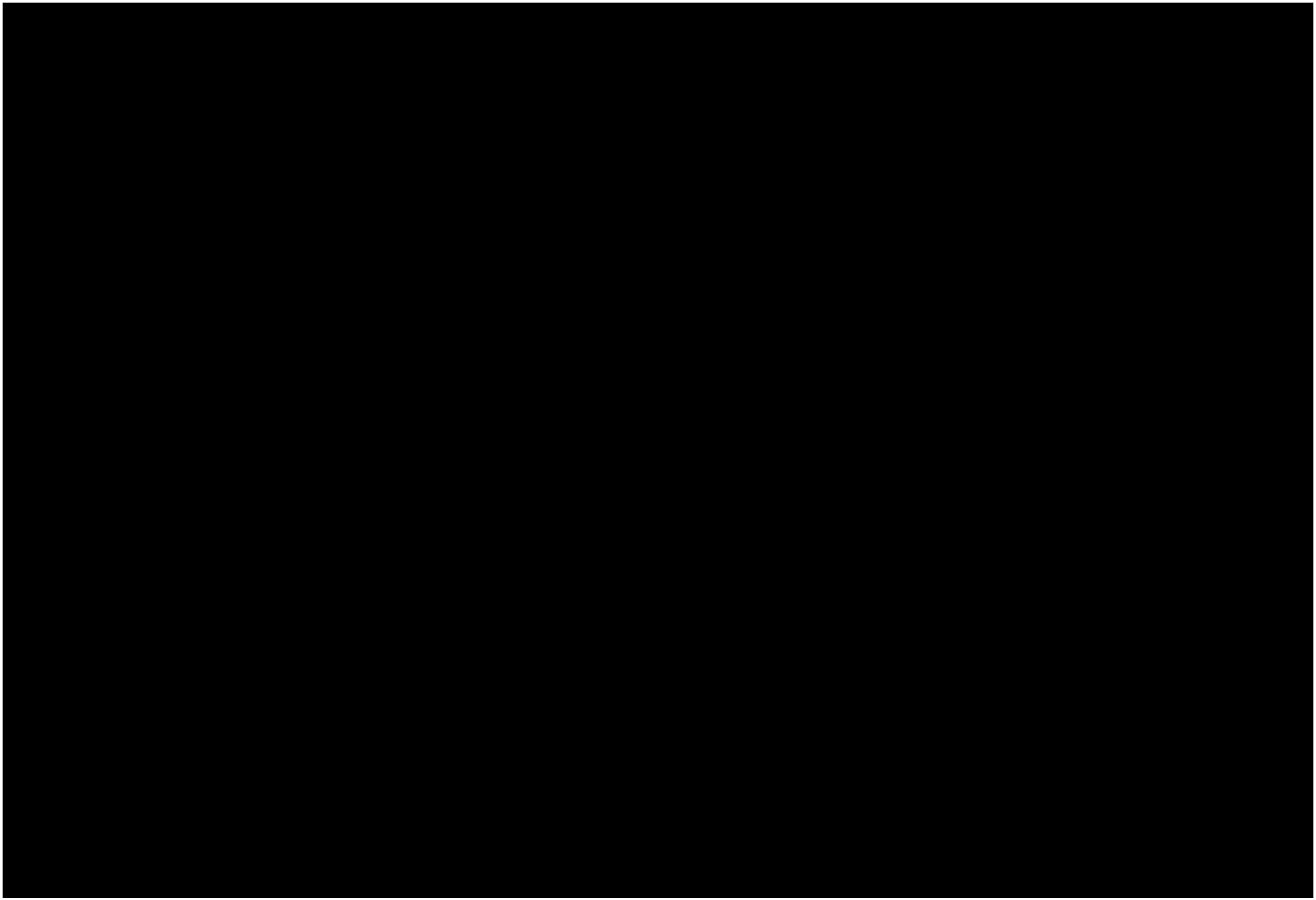
Date of Off Peak Day - 08/13/2021



Member Forecasted Off Peak Demand Day for September 2021

Wheat Belt Public Power District

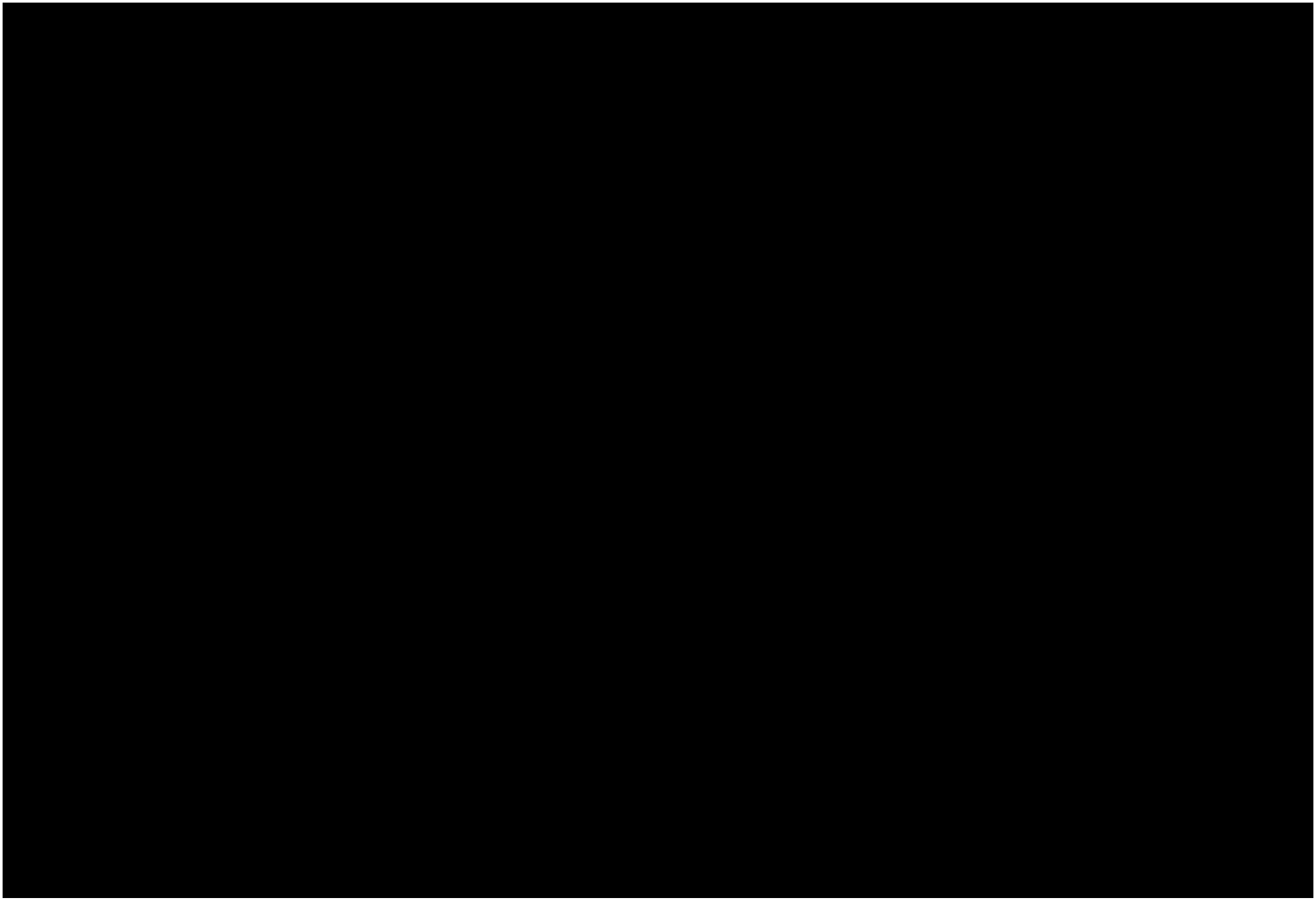
Date of Off Peak Day - 09/30/2021



Member Forecasted Off Peak Demand Day for October 2021

Wheat Belt Public Power District

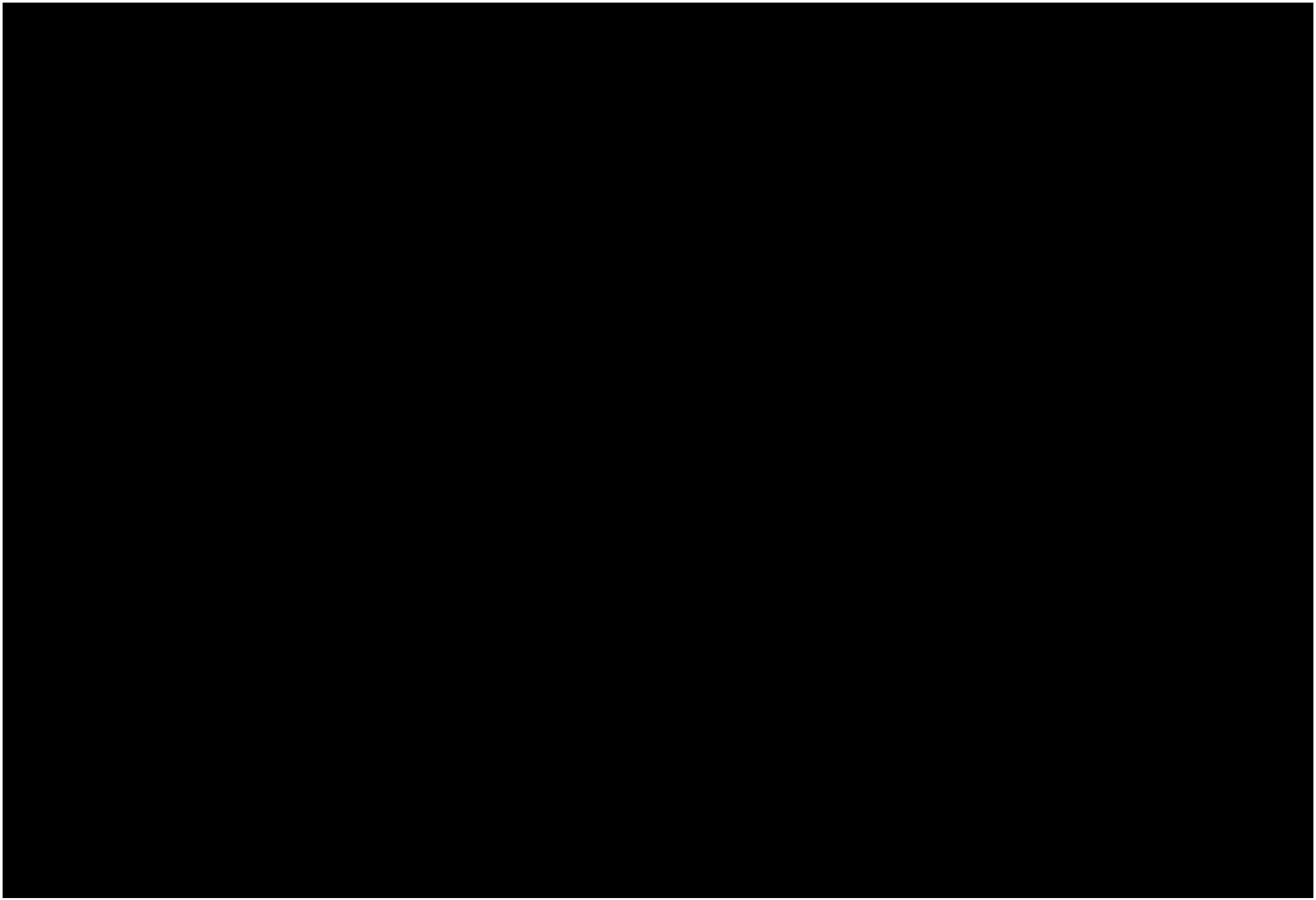
Date of Off Peak Day - 10/03/2021



Member Forecasted Off Peak Demand Day for November 2021

Wheat Belt Public Power District

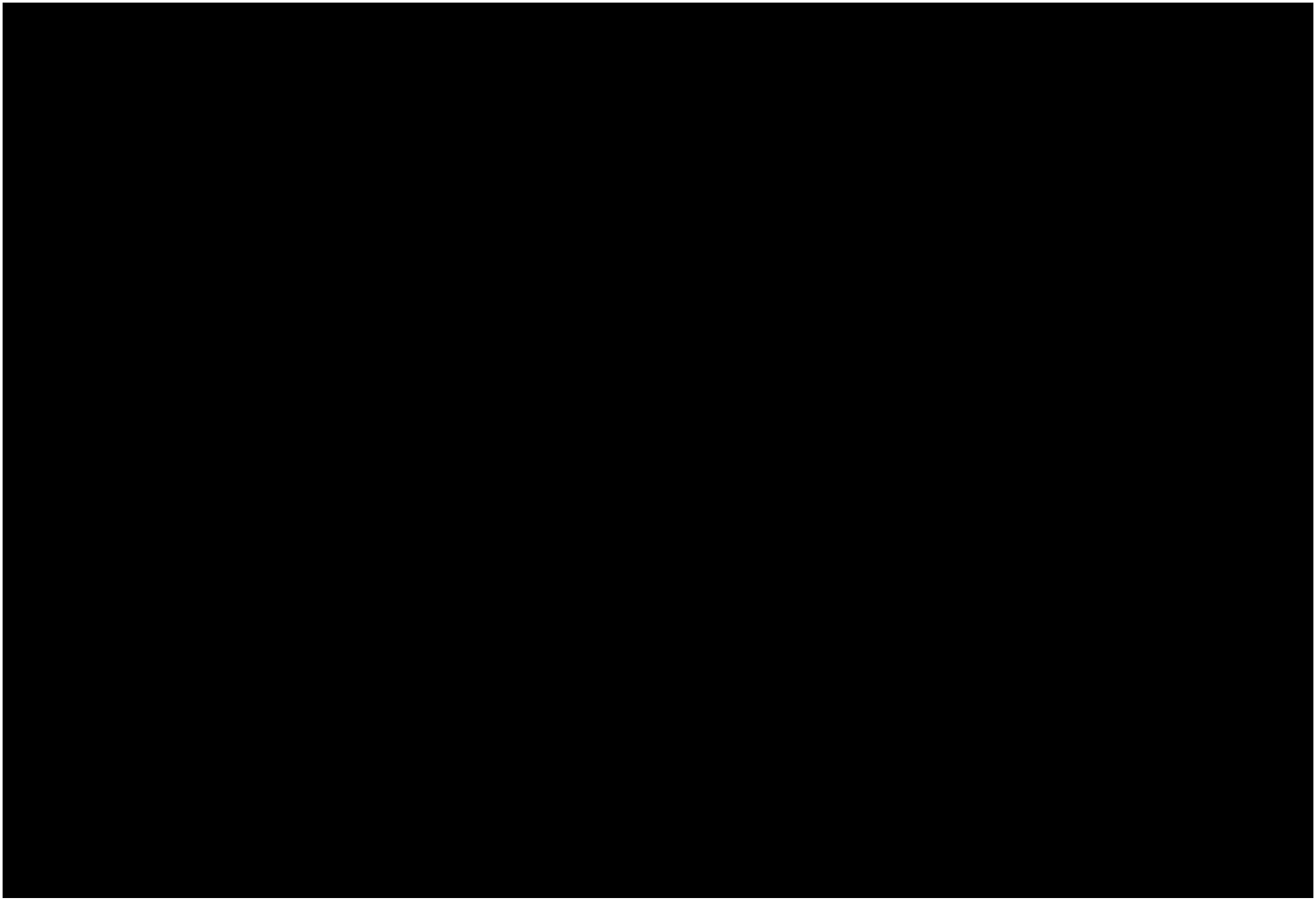
Date of Off Peak Day - 11/30/2021



Member Forecasted Off Peak Demand Day for December 2021

Wheat Belt Public Power District

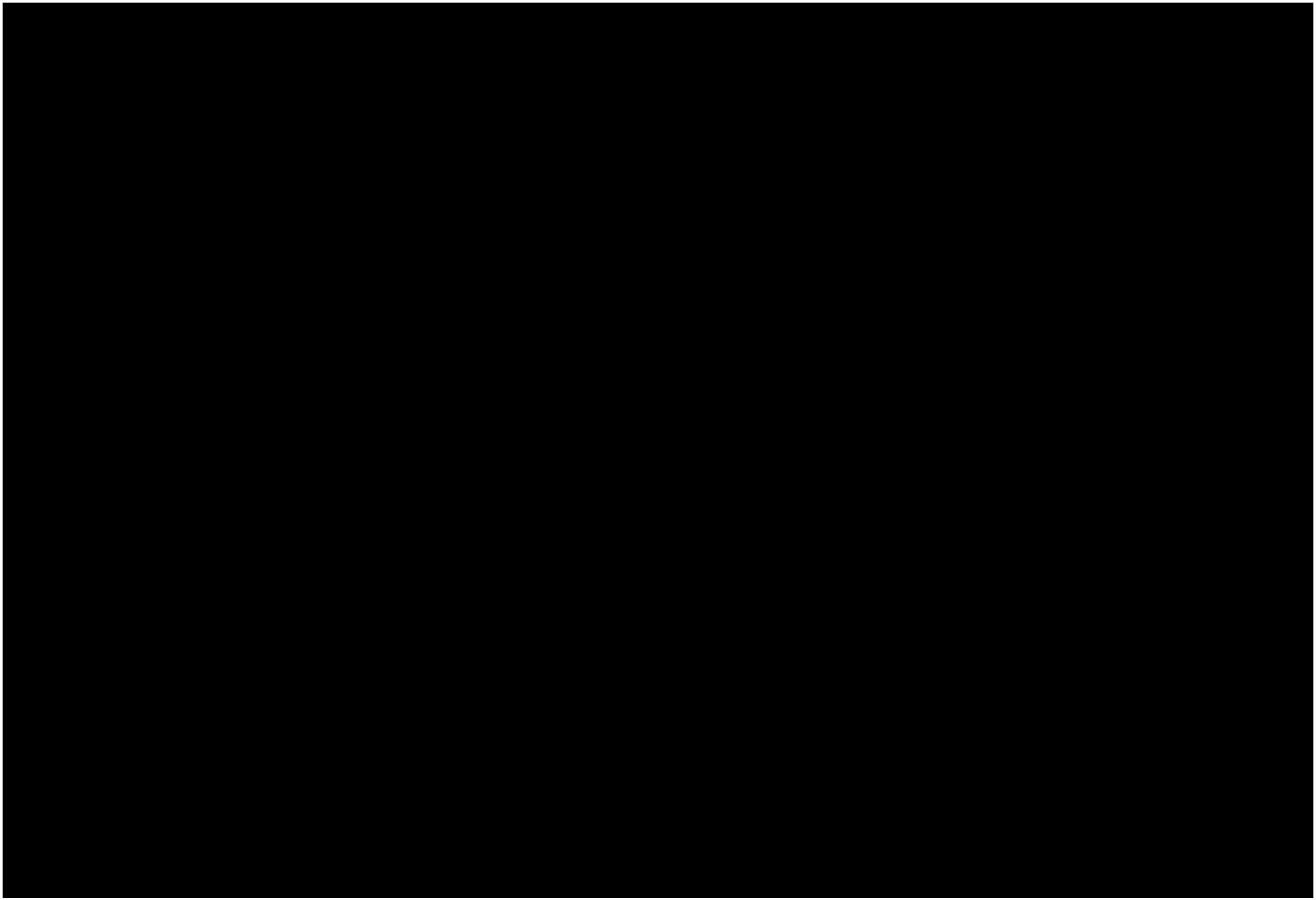
Date of Off Peak Day - 12/11/2021



Member Forecasted Off Peak Demand Day for January 2021

Wheatland Rural Electric Association, Inc.

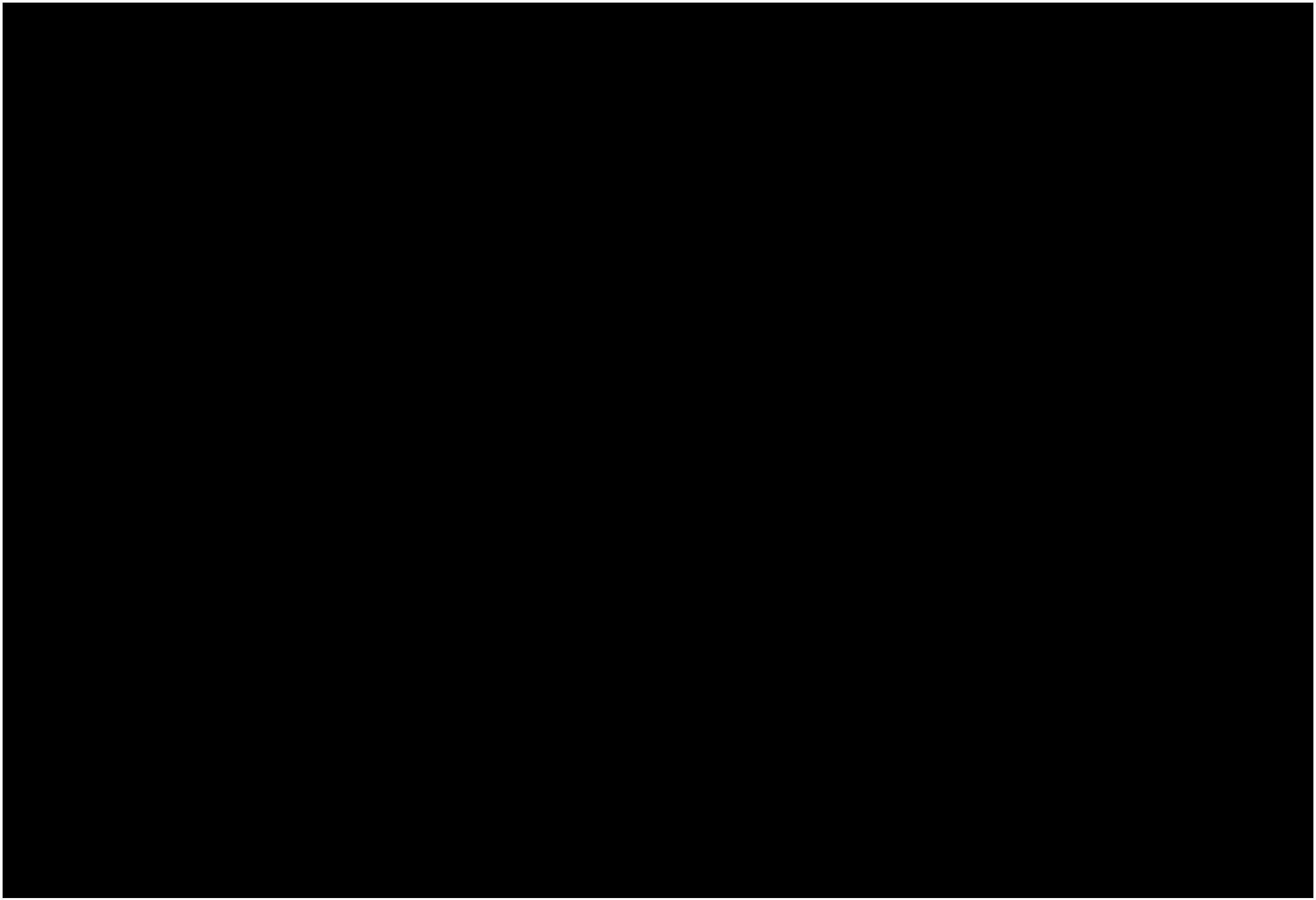
Date of Off Peak Day - 01/17/2021



Member Forecasted Off Peak Demand Day for February 2021

Wheatland Rural Electric Association, Inc.

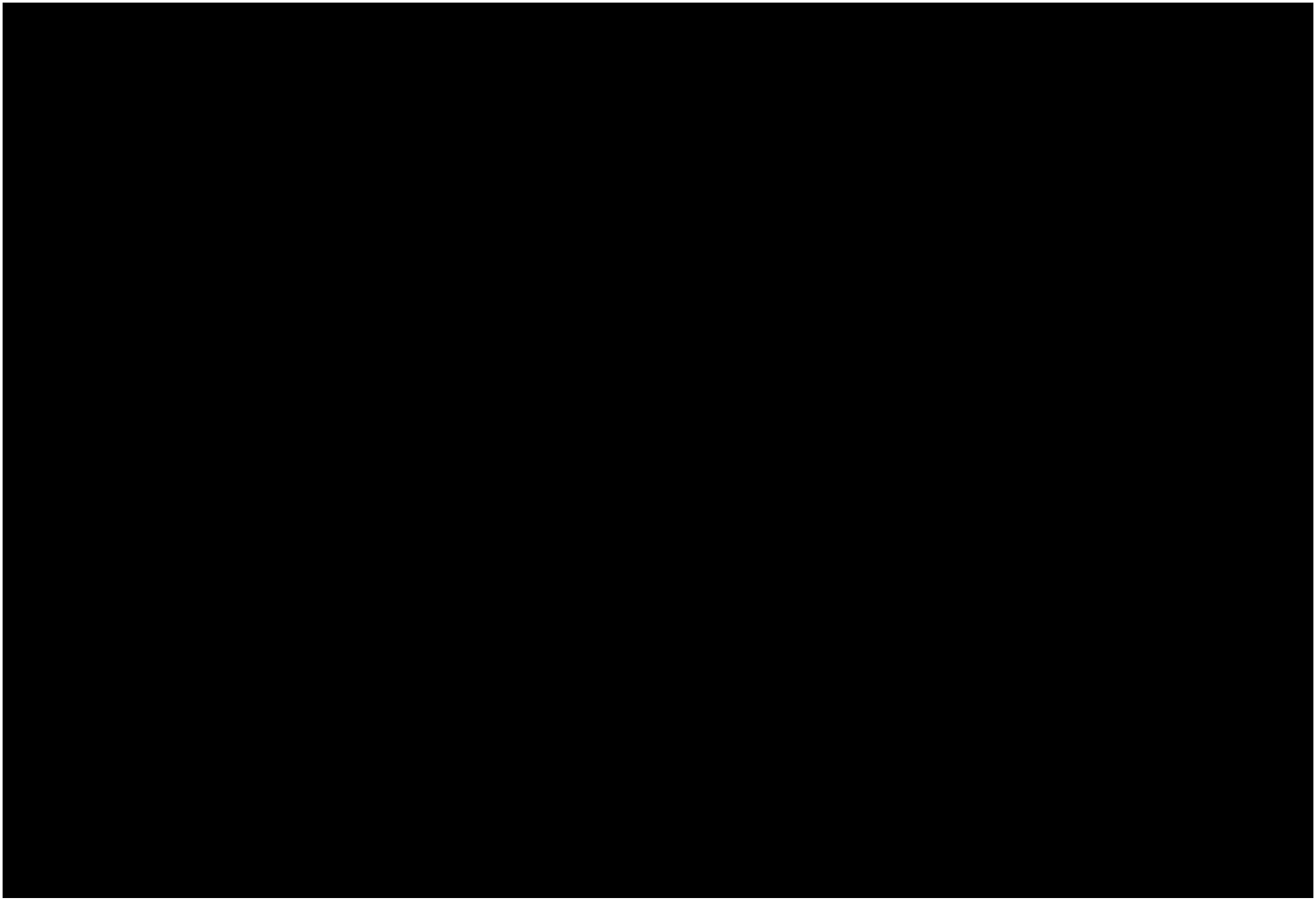
Date of Off Peak Day - 02/09/2021



Member Forecasted Off Peak Demand Day for March 2021

Wheatland Rural Electric Association, Inc.

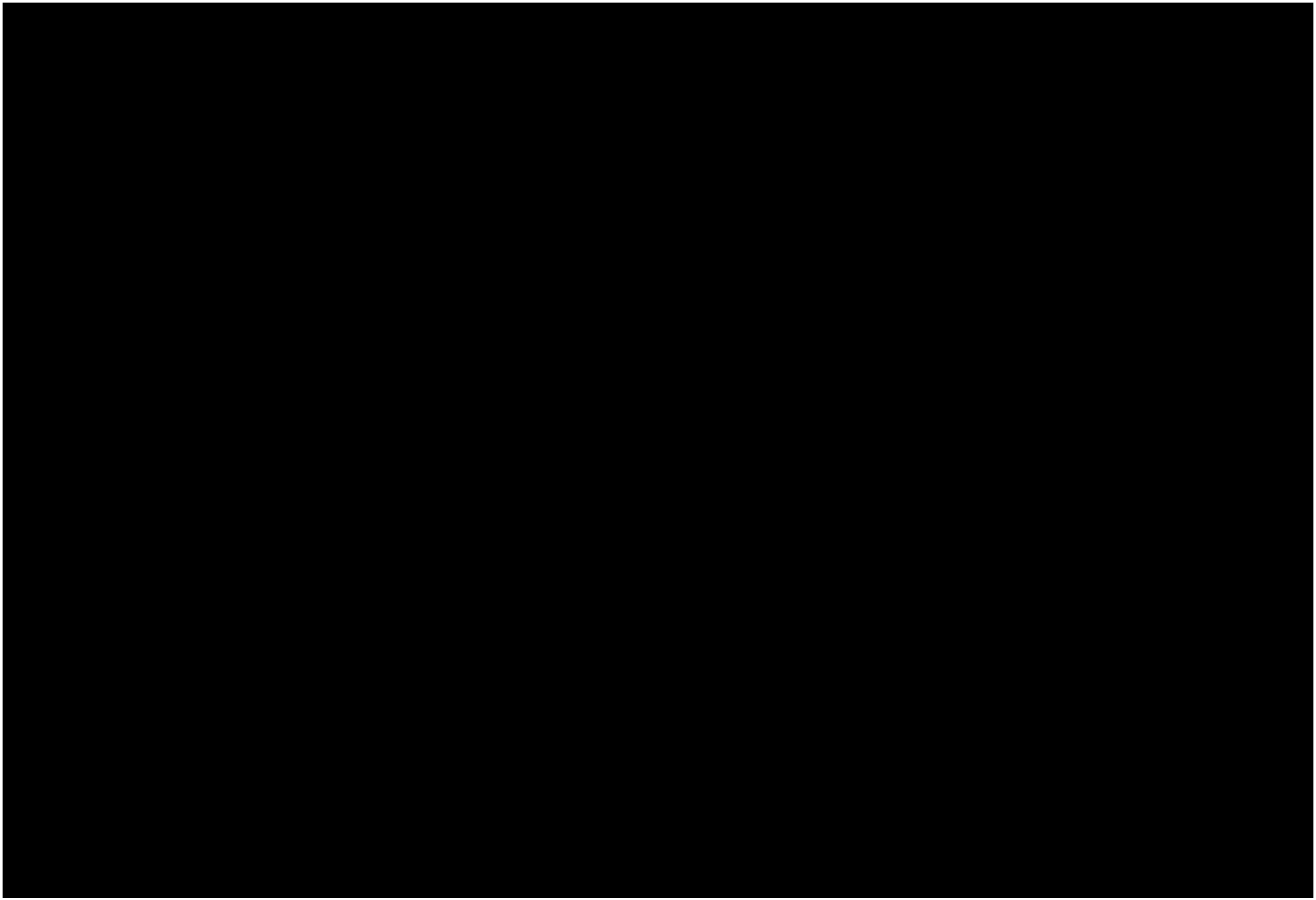
Date of Off Peak Day - 03/14/2021



Member Forecasted Off Peak Demand Day for April 2021

Wheatland Rural Electric Association, Inc.

Date of Off Peak Day - 04/29/2021



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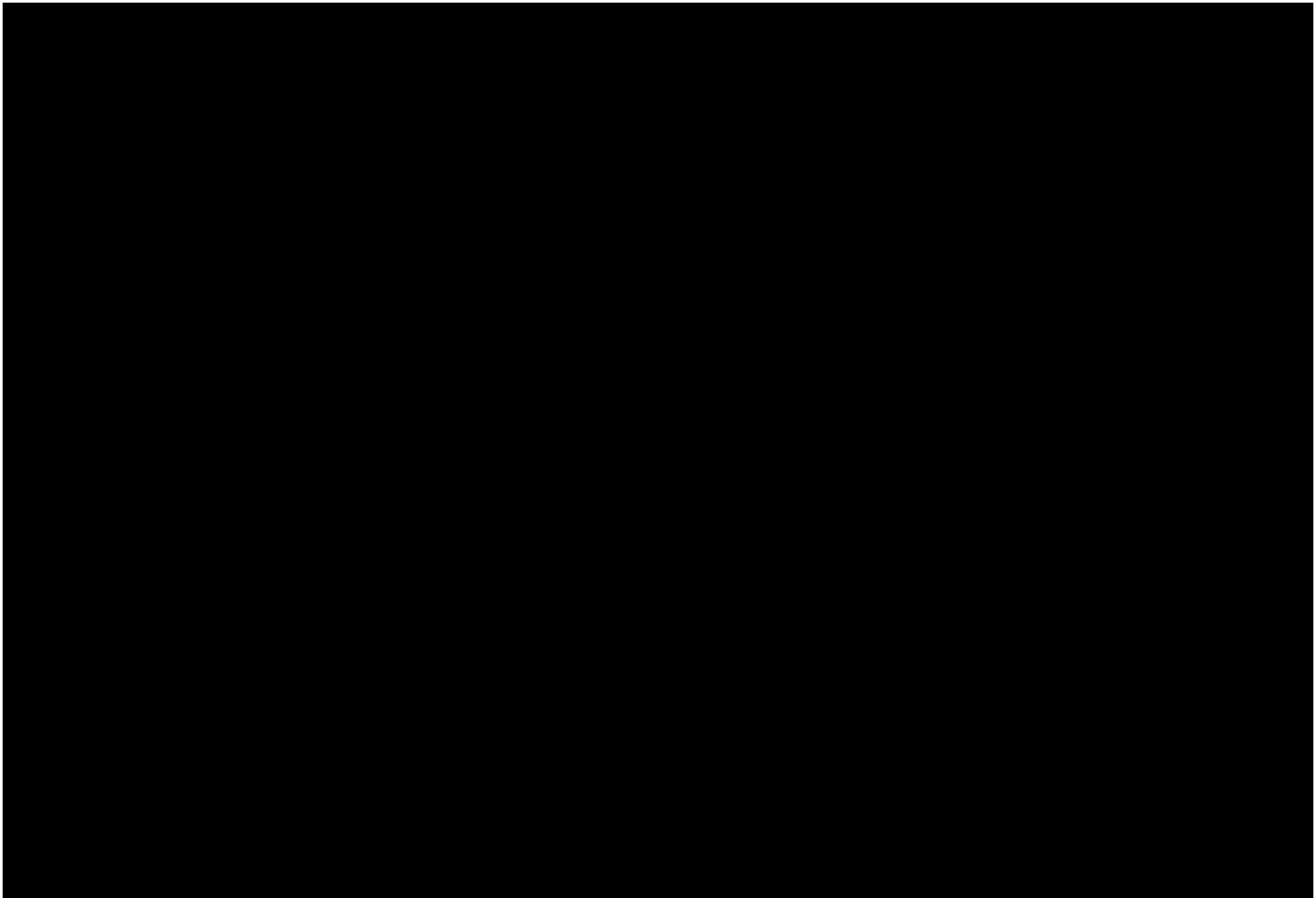
Member Forecasted Off Peak Demand Day for May 2021

Wheatland Rural Electric Association, Inc.

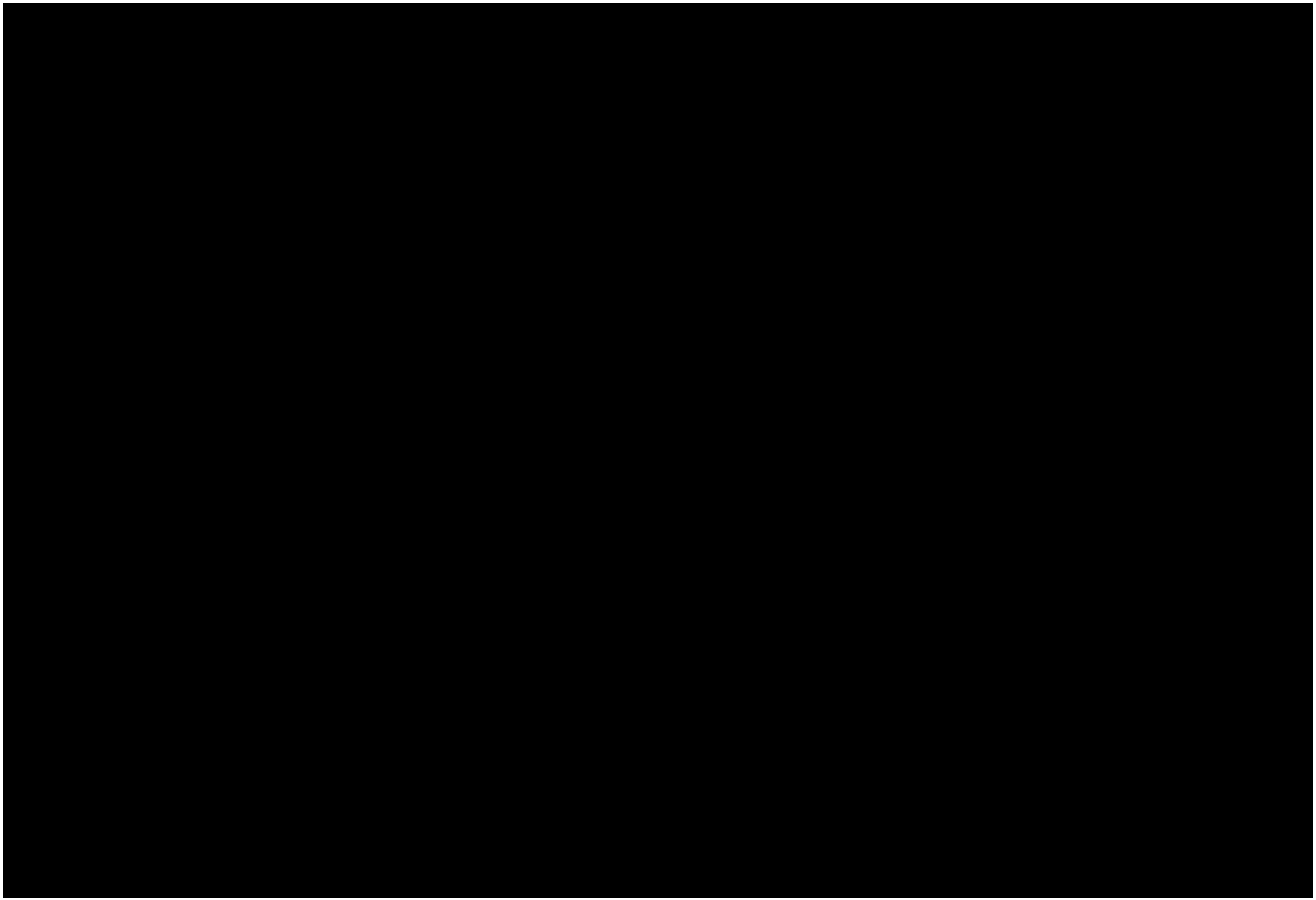
Date of Off Peak Day - 05/22/2021



Member Forecasted Off Peak Demand Day for June 2021

Wheatland Rural Electric Association, Inc.

Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Wheatland Rural Electric Association, Inc.

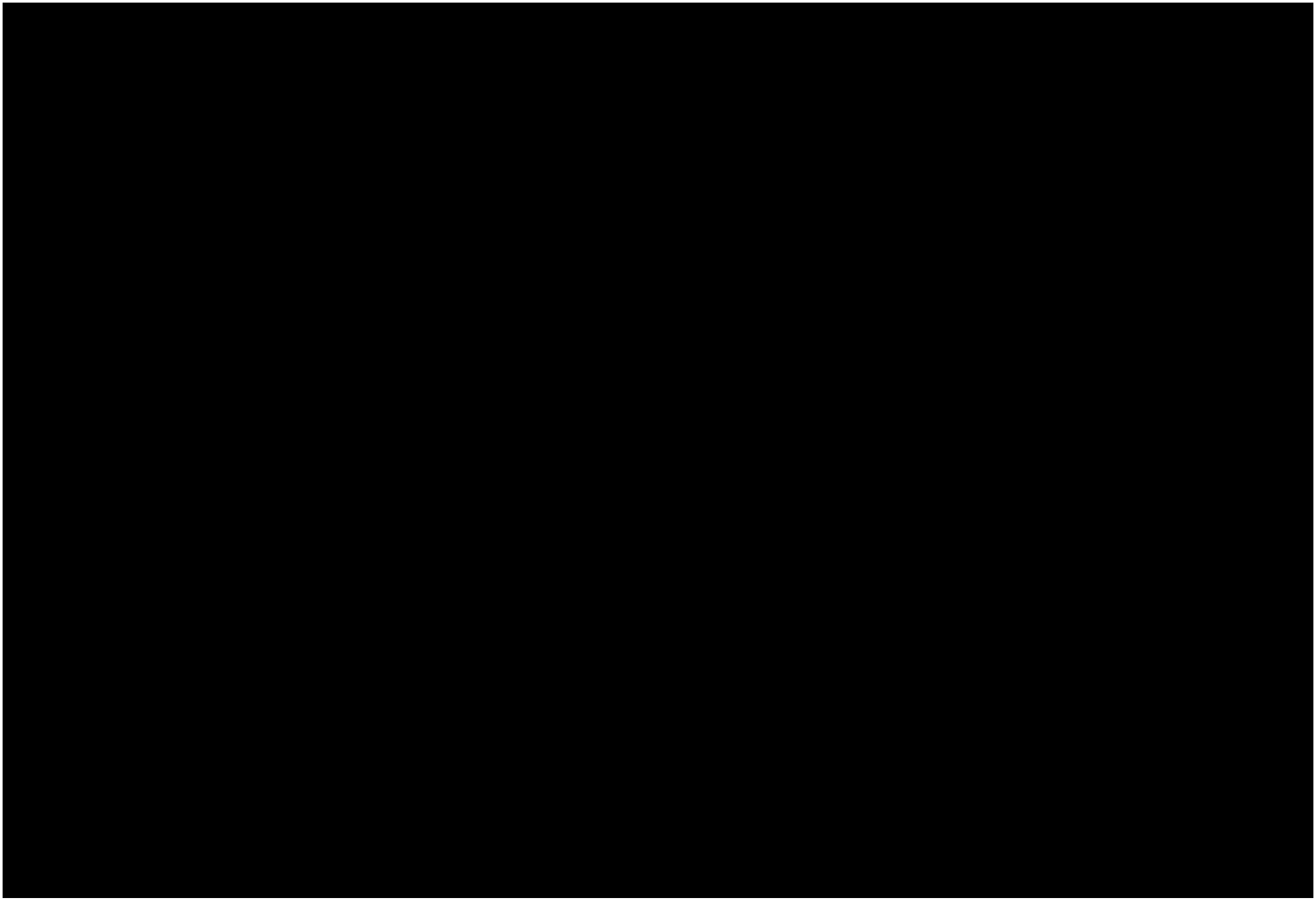
Date of Off Peak Day - 07/05/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Wheatland Rural Electric Association, Inc.

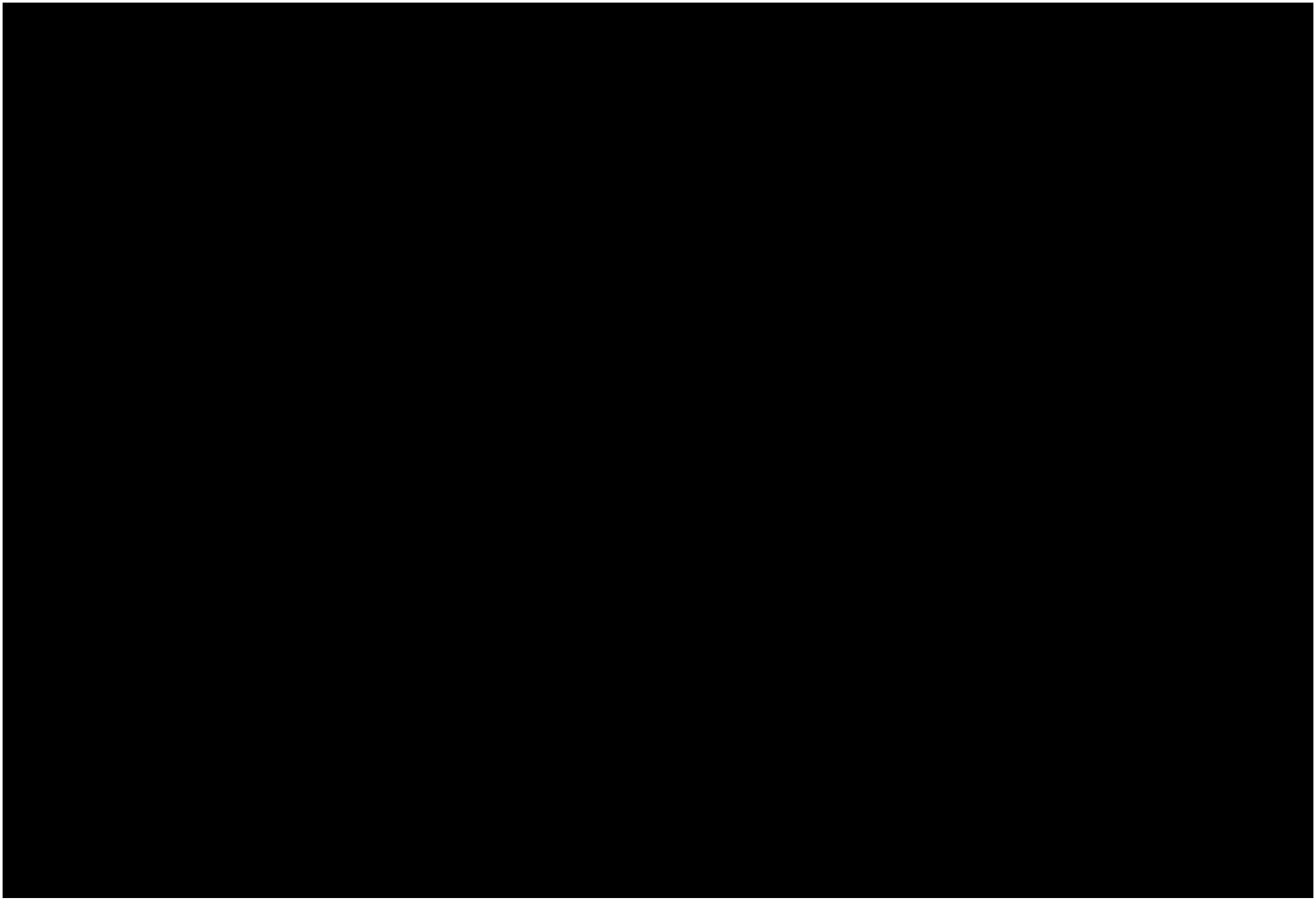
Date of Off Peak Day - 08/08/2021



Member Forecasted Off Peak Demand Day for September 2021

Wheatland Rural Electric Association, Inc.

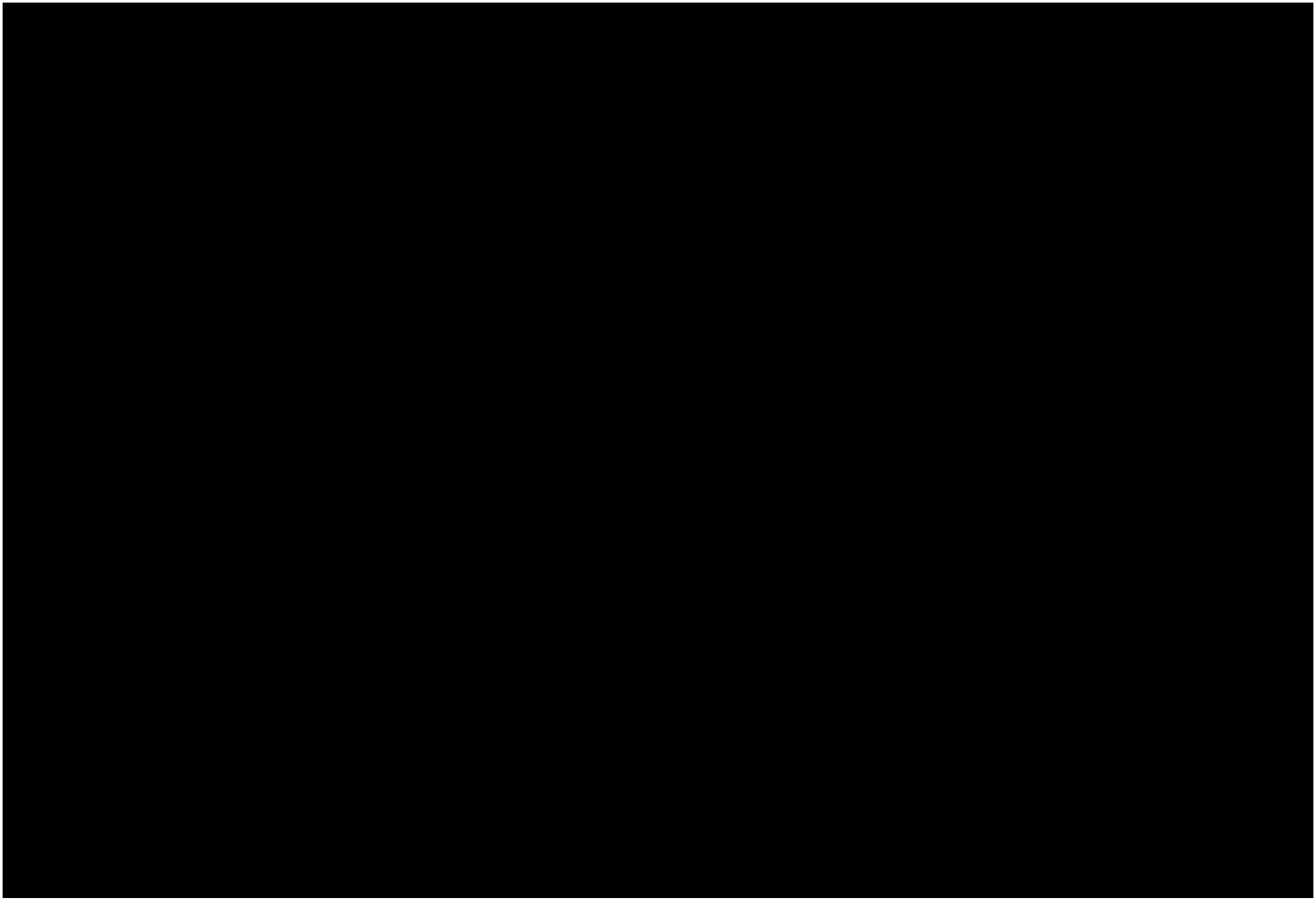
Date of Off Peak Day - 09/15/2021



Member Forecasted Off Peak Demand Day for October 2021

Wheatland Rural Electric Association, Inc.

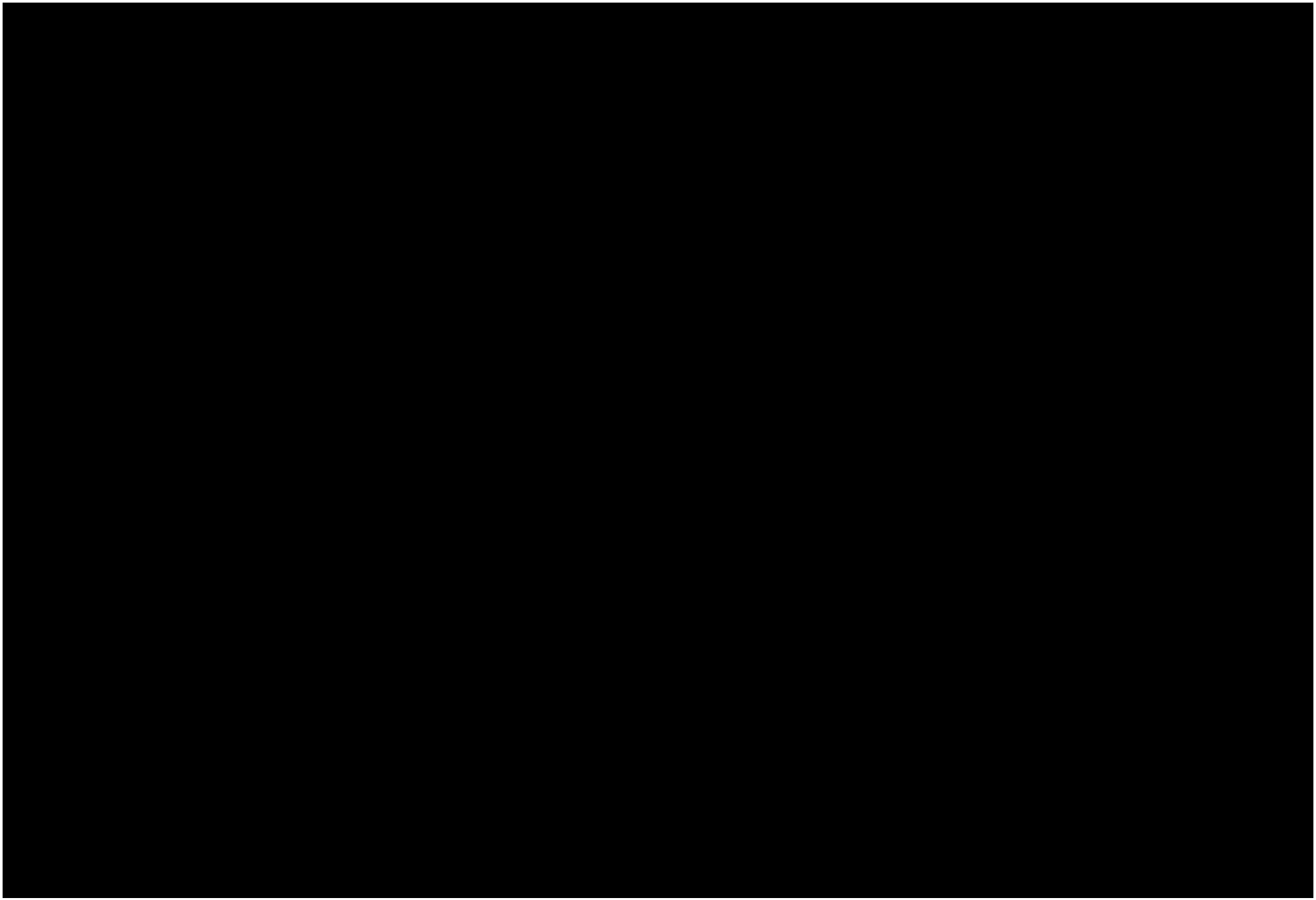
Date of Off Peak Day - 10/01/2021



Member Forecasted Off Peak Demand Day for November 2021

Wheatland Rural Electric Association, Inc.

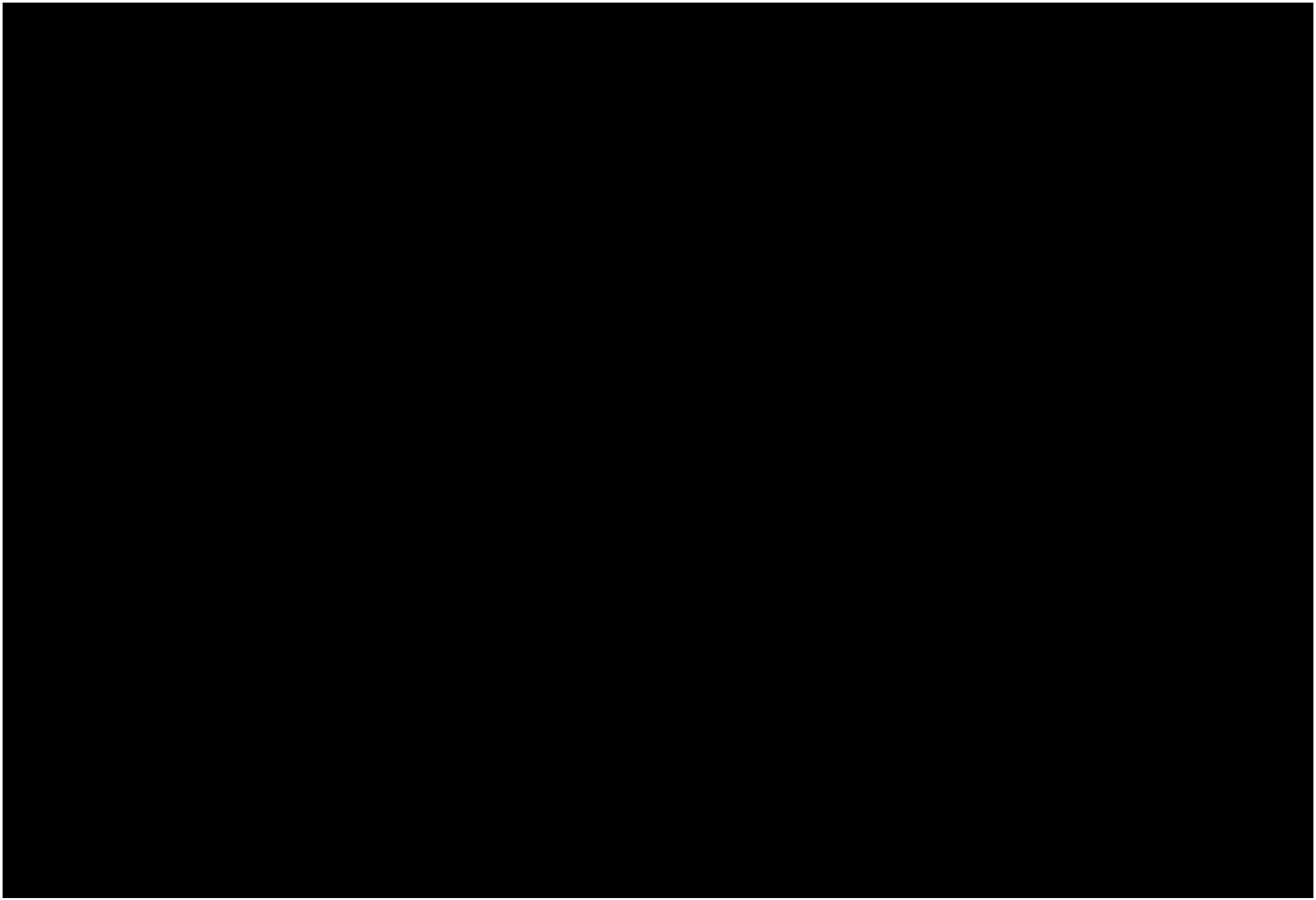
Date of Off Peak Day - 11/04/2021



Member Forecasted Off Peak Demand Day for December 2021

Wheatland Rural Electric Association, Inc.

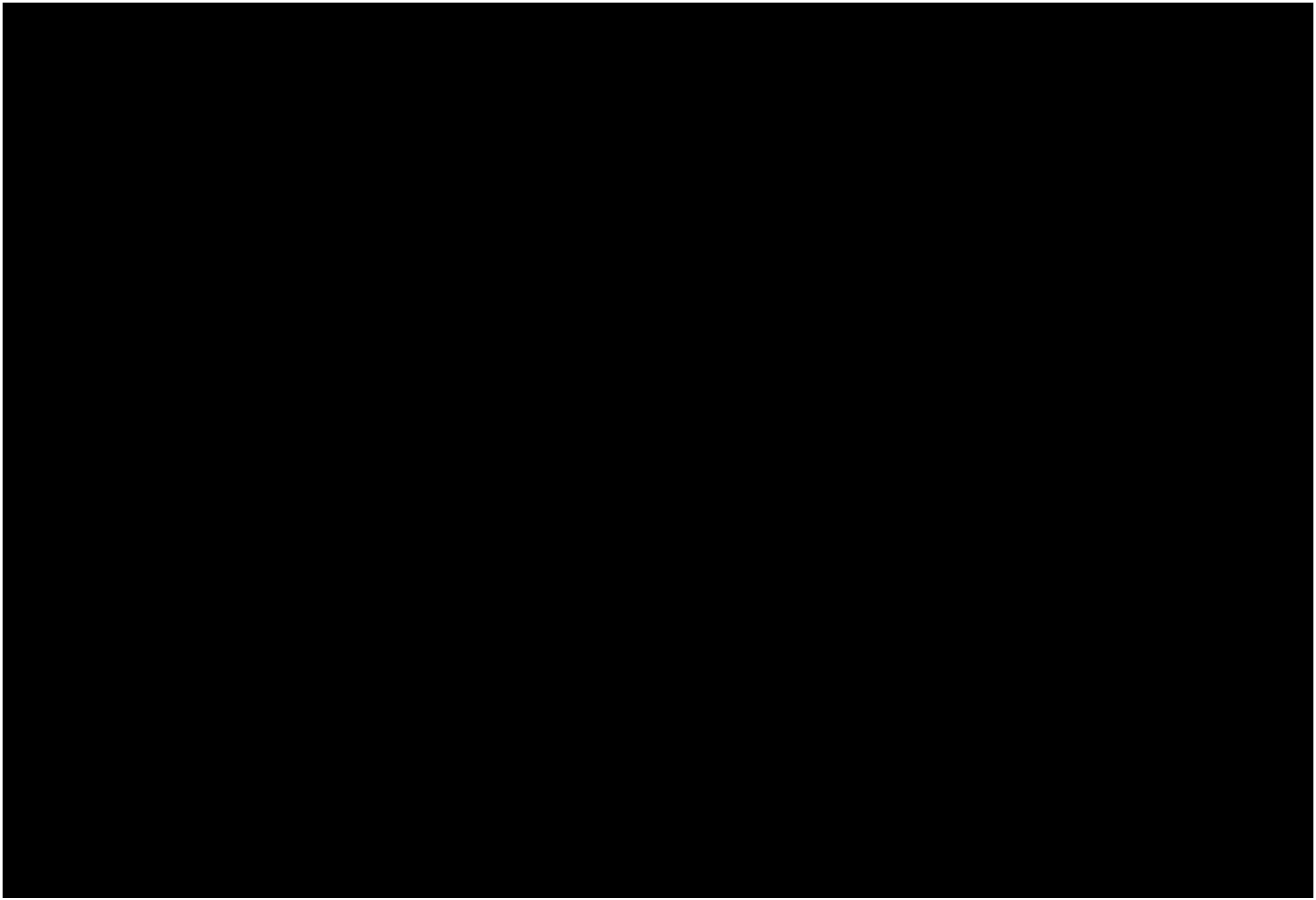
Date of Off Peak Day - 12/01/2021



Member Forecasted Off Peak Demand Day for January 2021

White River Electric Association, Inc.

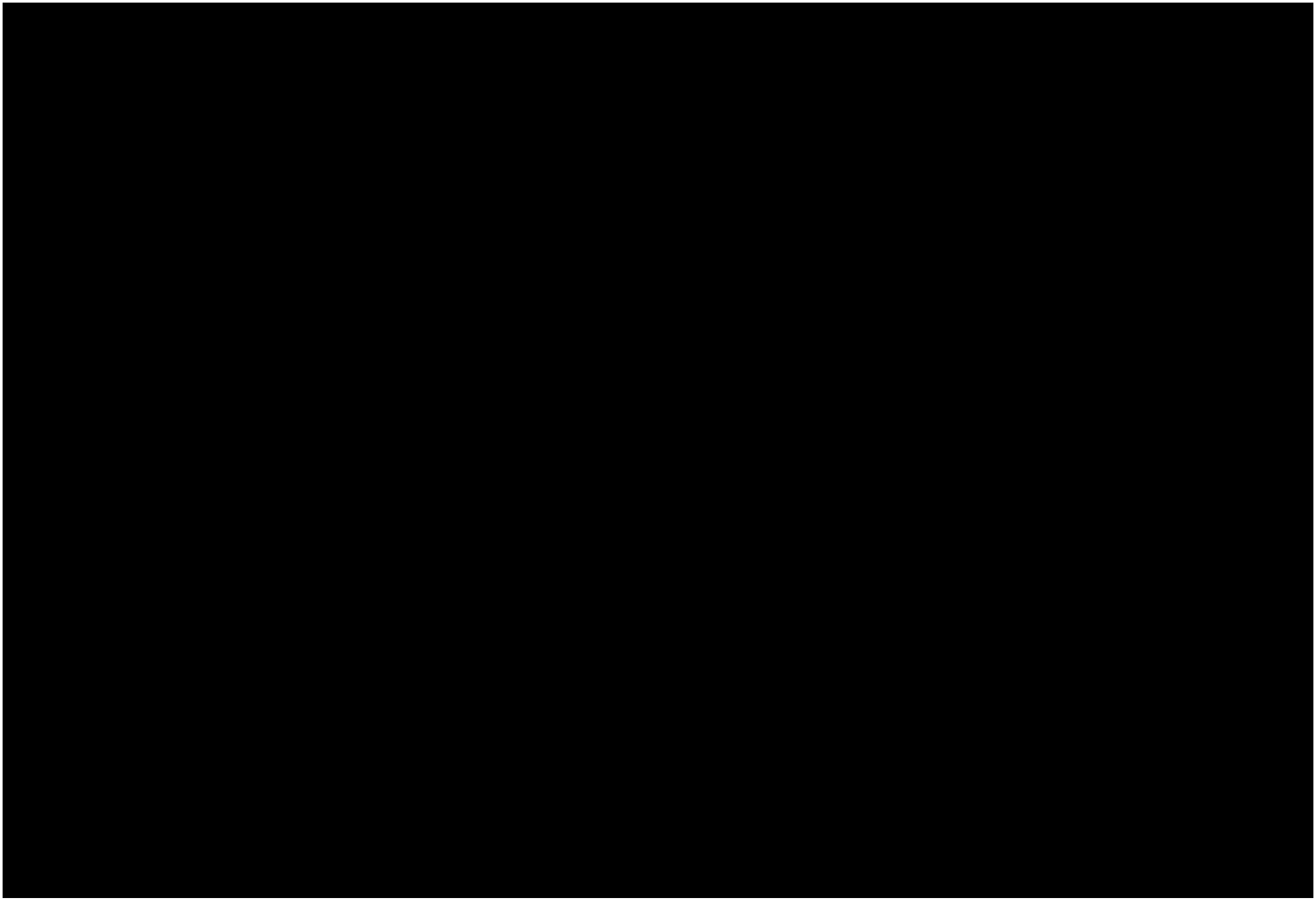
Date of Off Peak Day - 01/06/2021



Member Forecasted Off Peak Demand Day for February 2021

White River Electric Association, Inc.

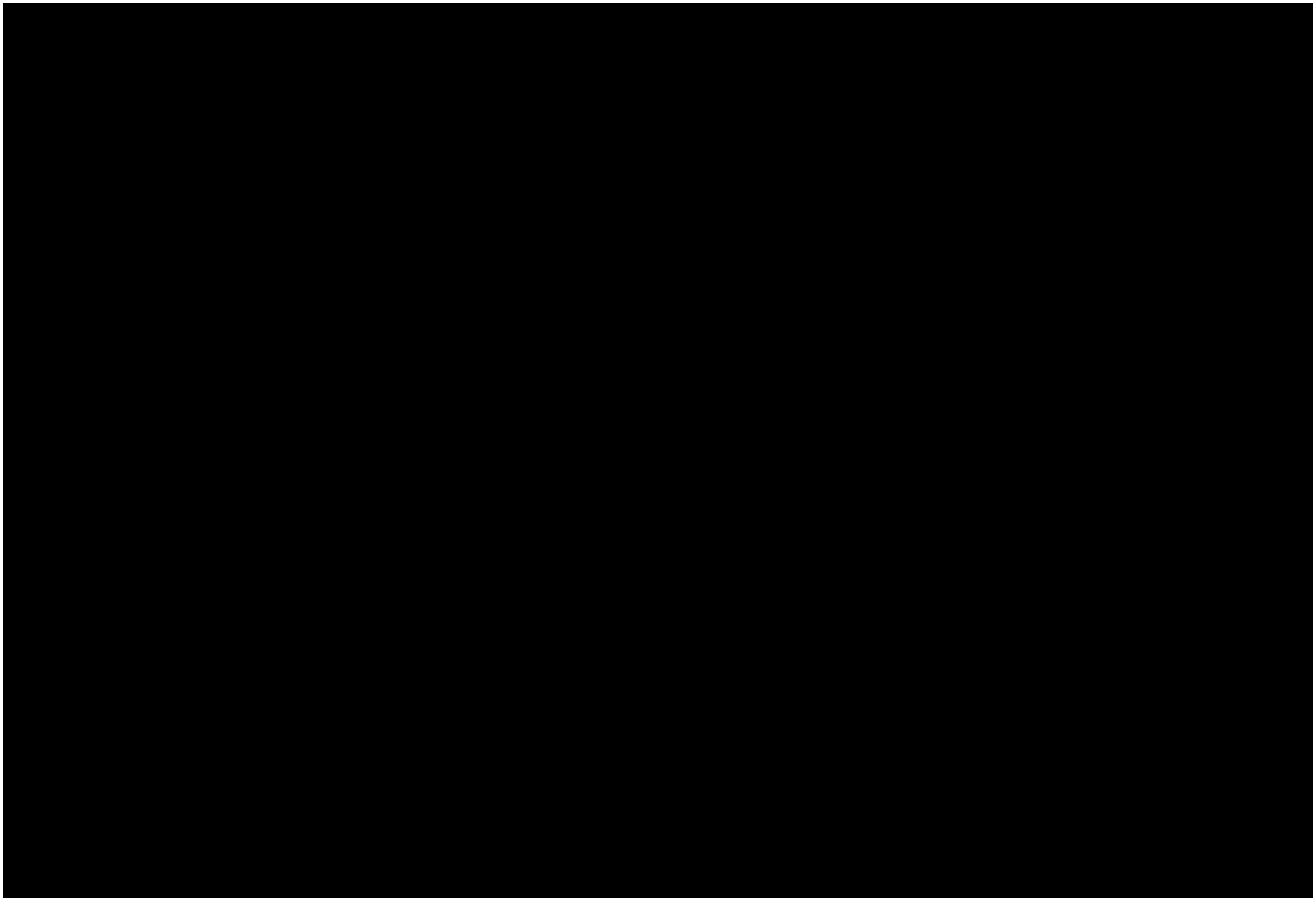
Date of Off Peak Day - 02/11/2021



Member Forecasted Off Peak Demand Day for March 2021

White River Electric Association, Inc.

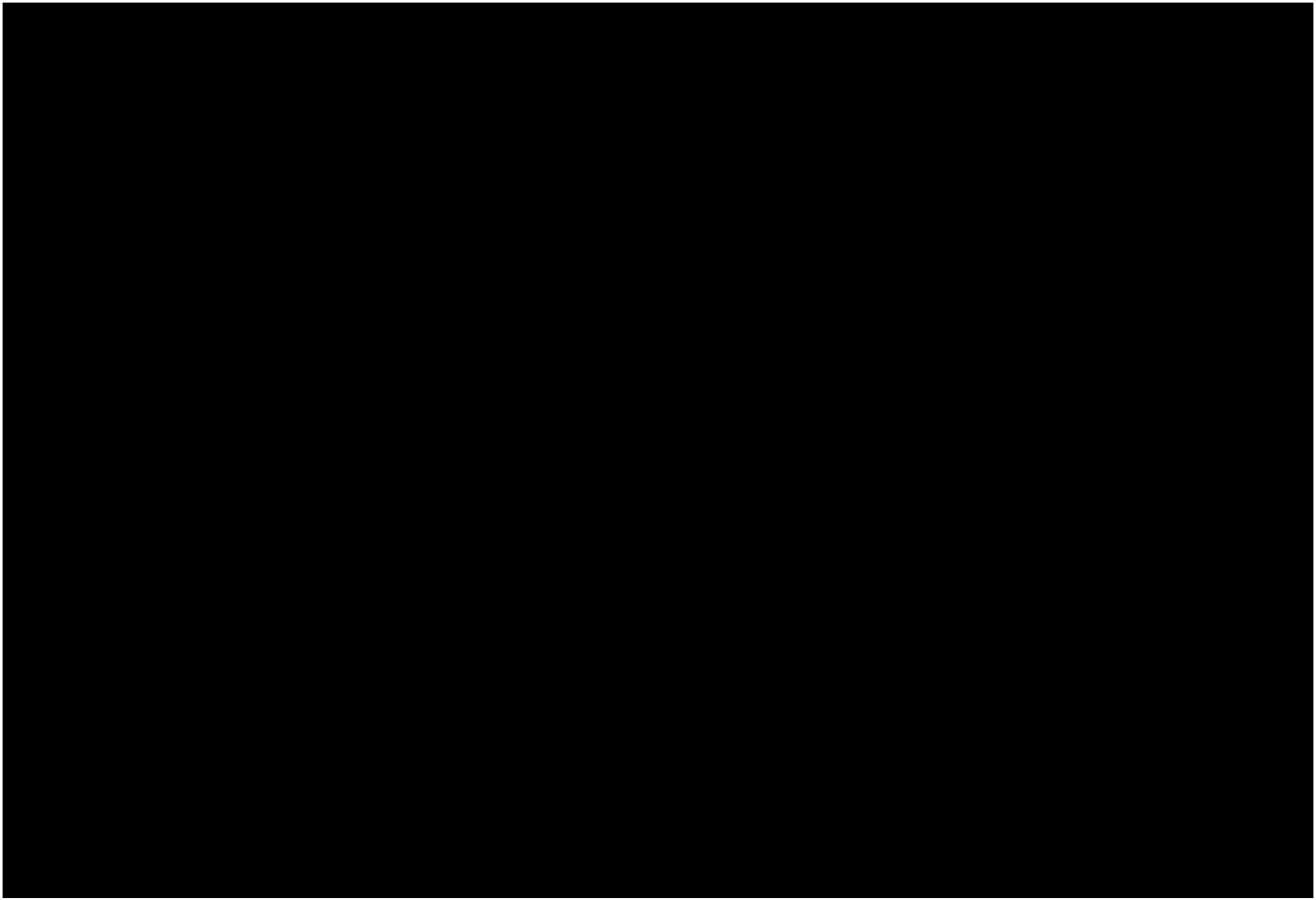
Date of Off Peak Day - 03/09/2021



Member Forecasted Off Peak Demand Day for April 2021

White River Electric Association, Inc.

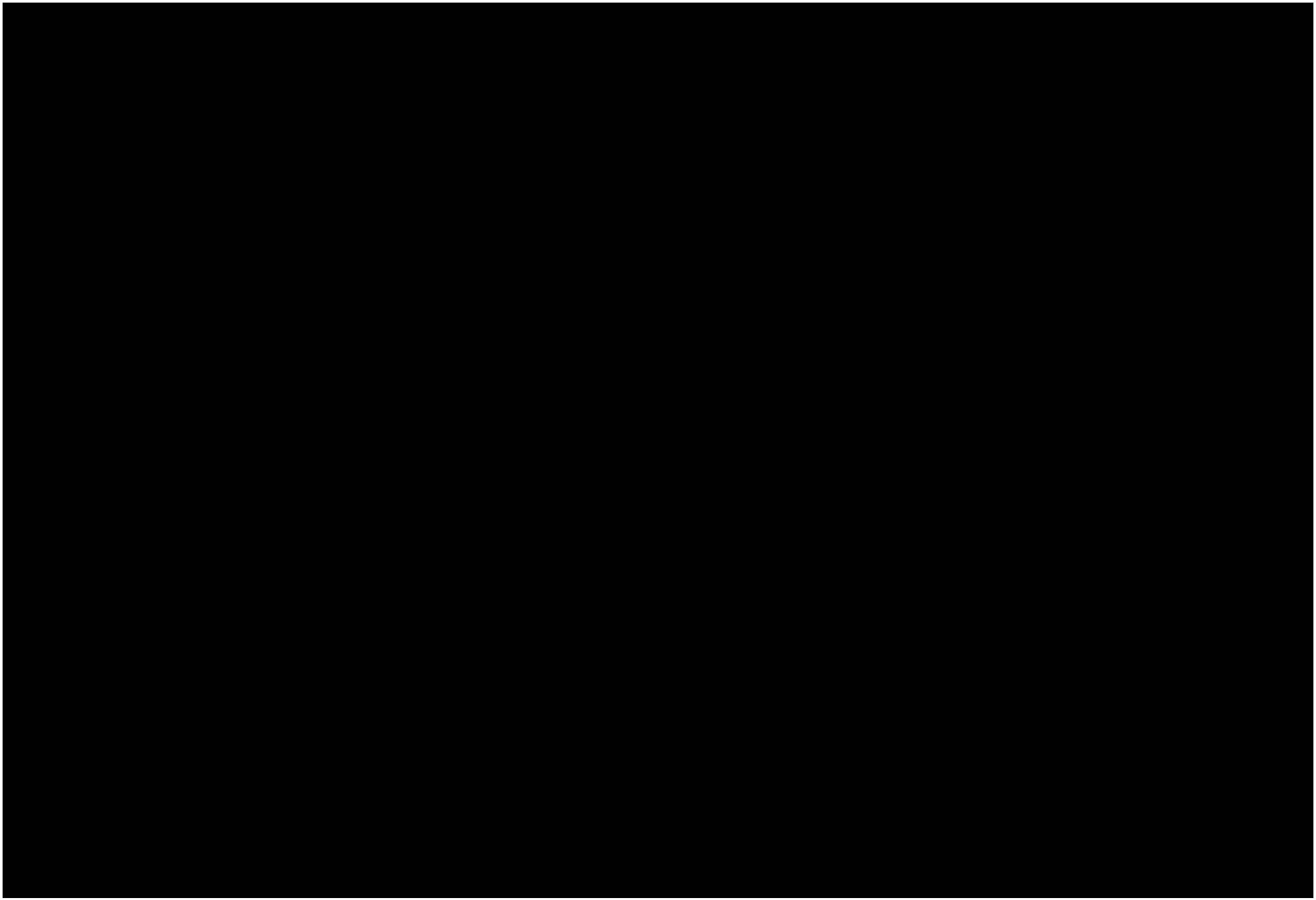
Date of Off Peak Day - 04/28/2021



Member Forecasted Off Peak Demand Day for May 2021

White River Electric Association, Inc.

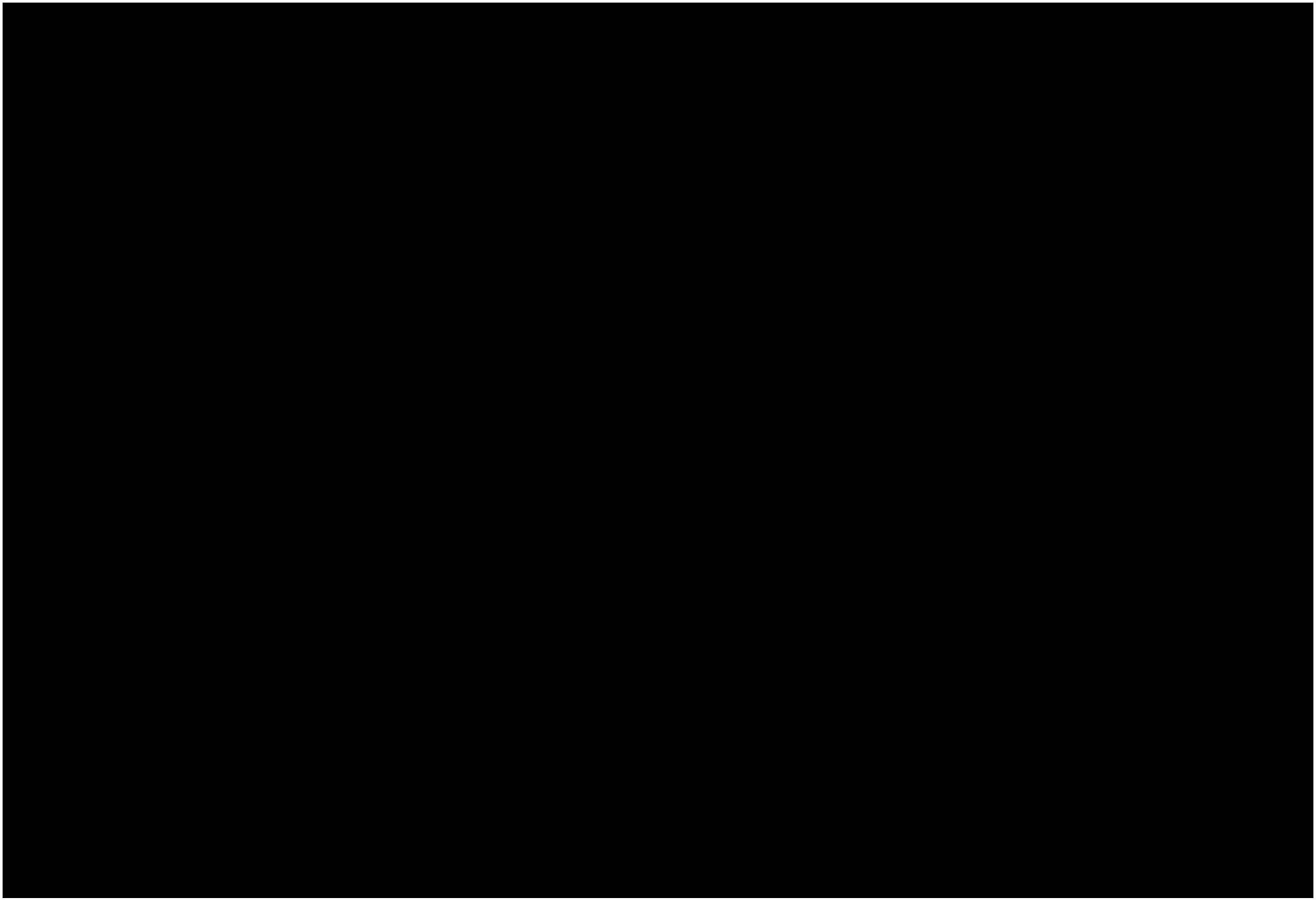
Date of Off Peak Day - 05/17/2021



Member Forecasted Off Peak Demand Day for June 2021

White River Electric Association, Inc.

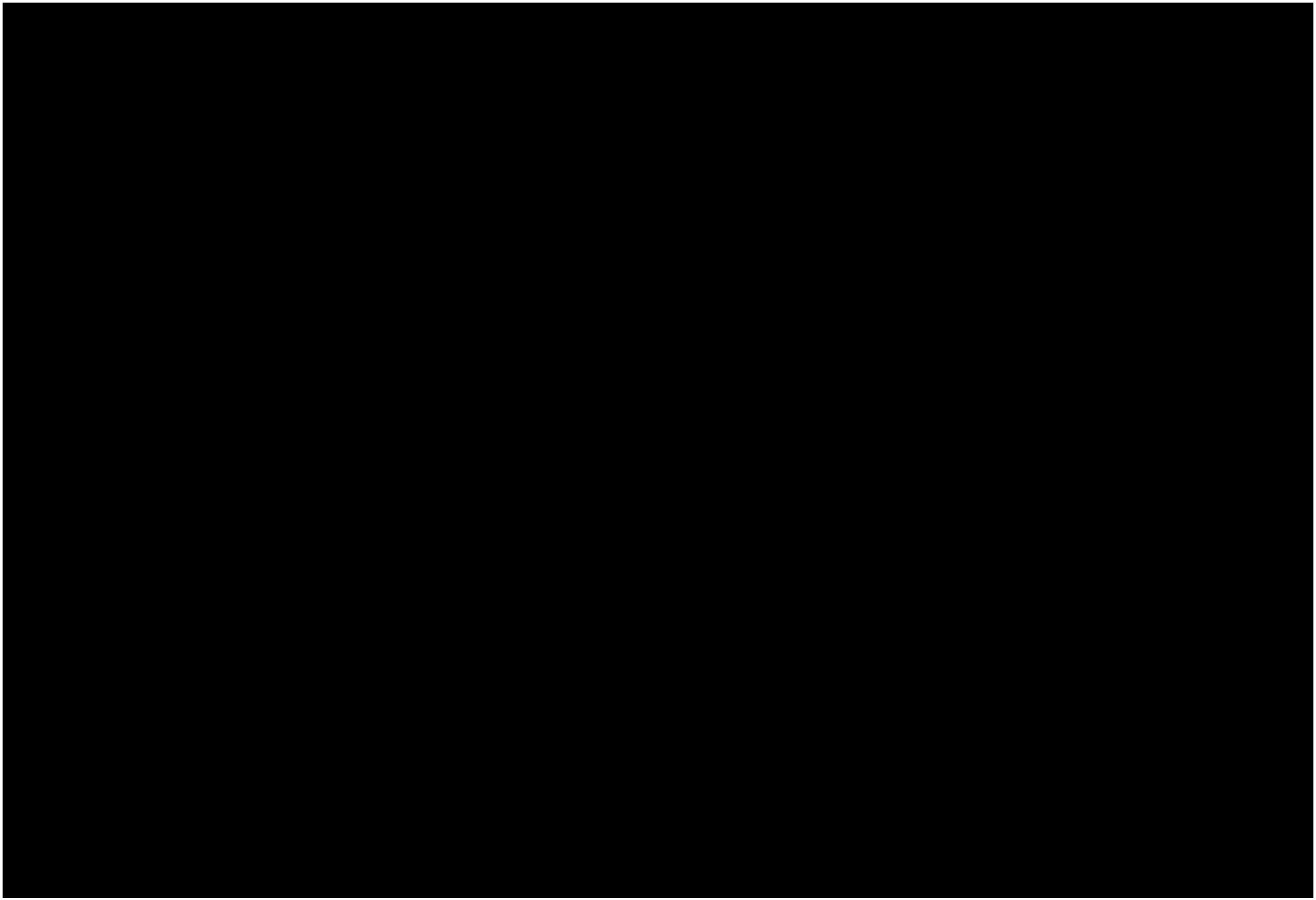
Date of Off Peak Day - 06/22/2021



Member Forecasted Off Peak Demand Day for July 2021

White River Electric Association, Inc.

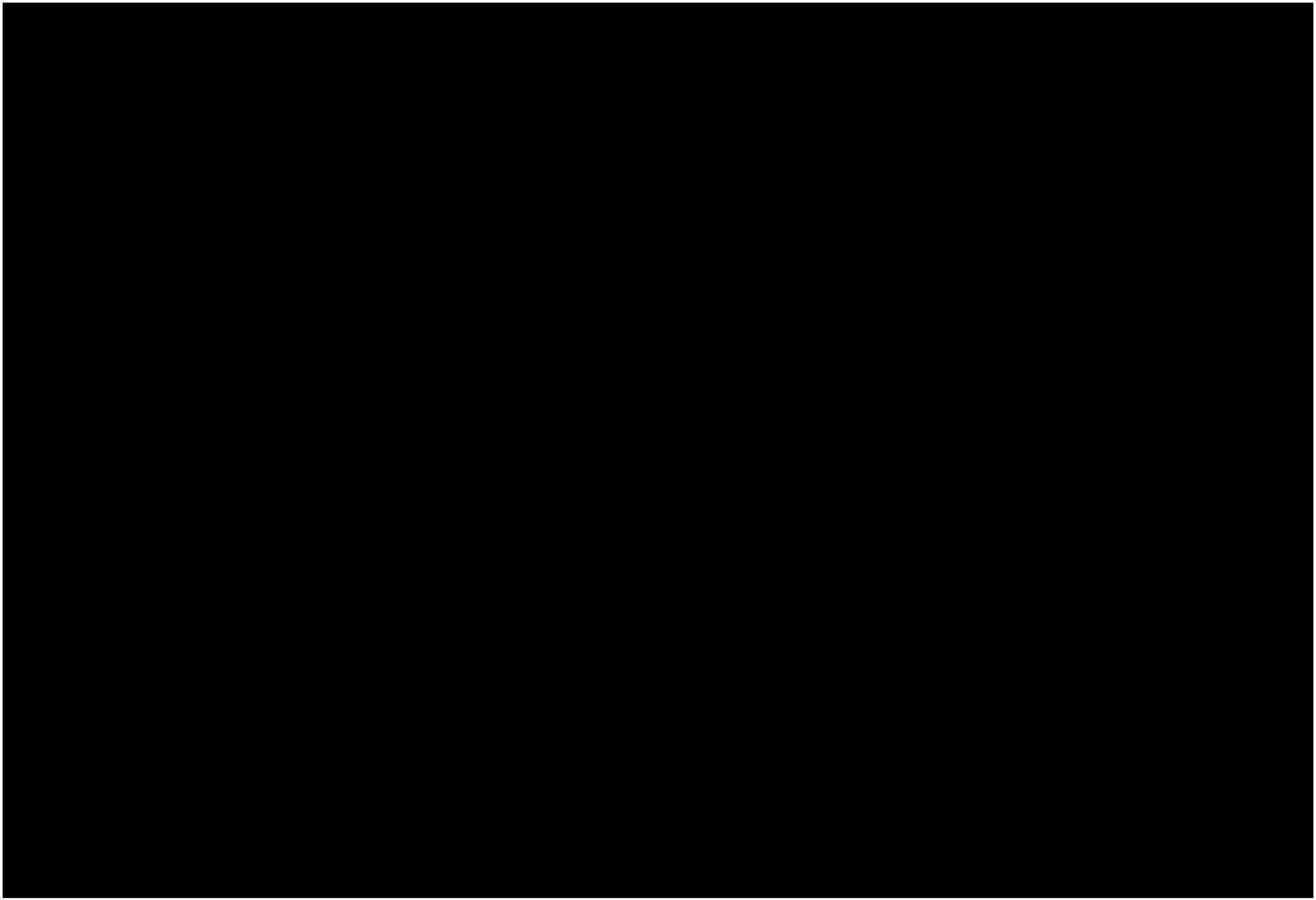
Date of Off Peak Day - 07/20/2021



Member Forecasted Off Peak Demand Day for August 2021

White River Electric Association, Inc.

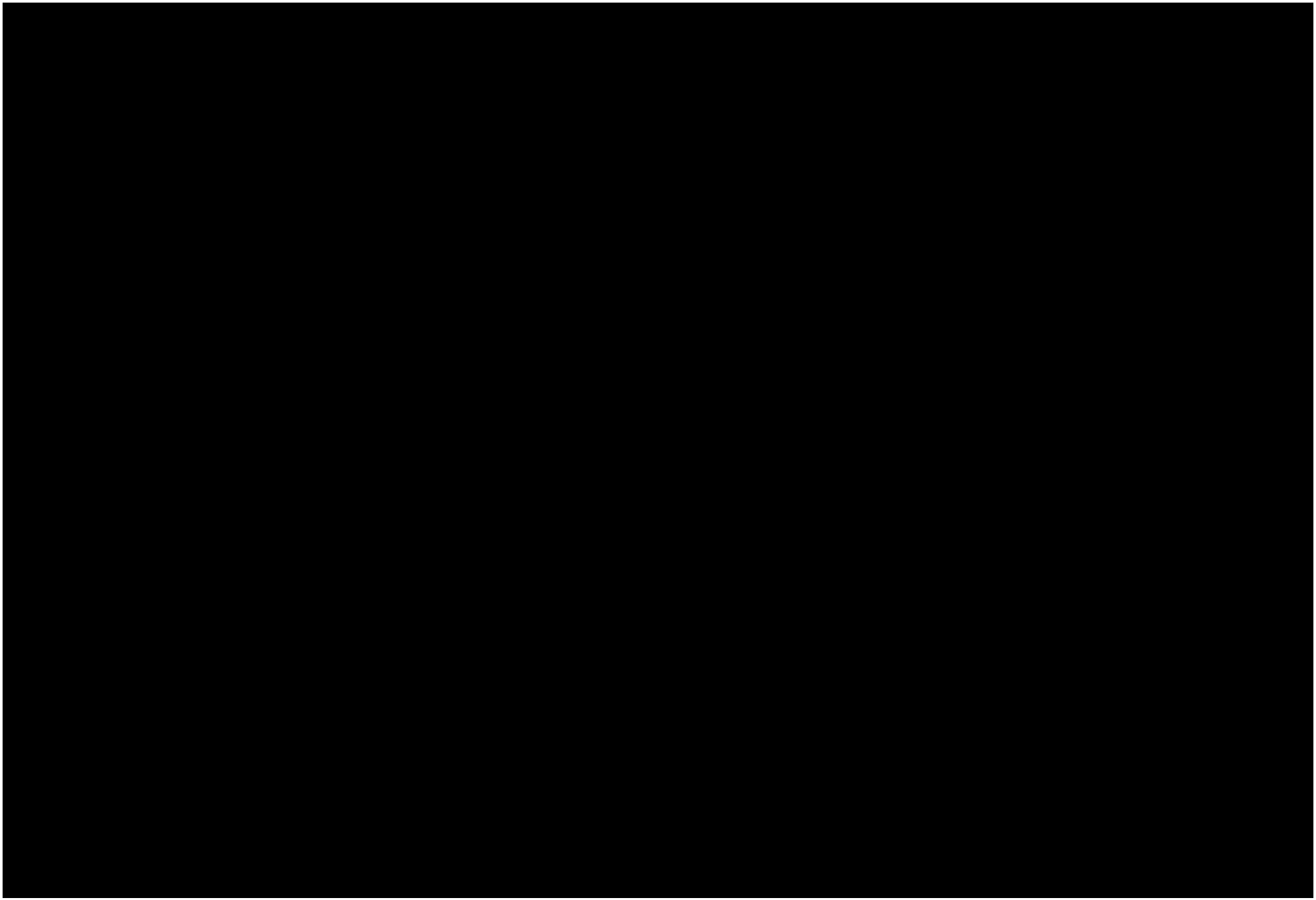
Date of Off Peak Day - 08/03/2021



Member Forecasted Off Peak Demand Day for September 2021

White River Electric Association, Inc.

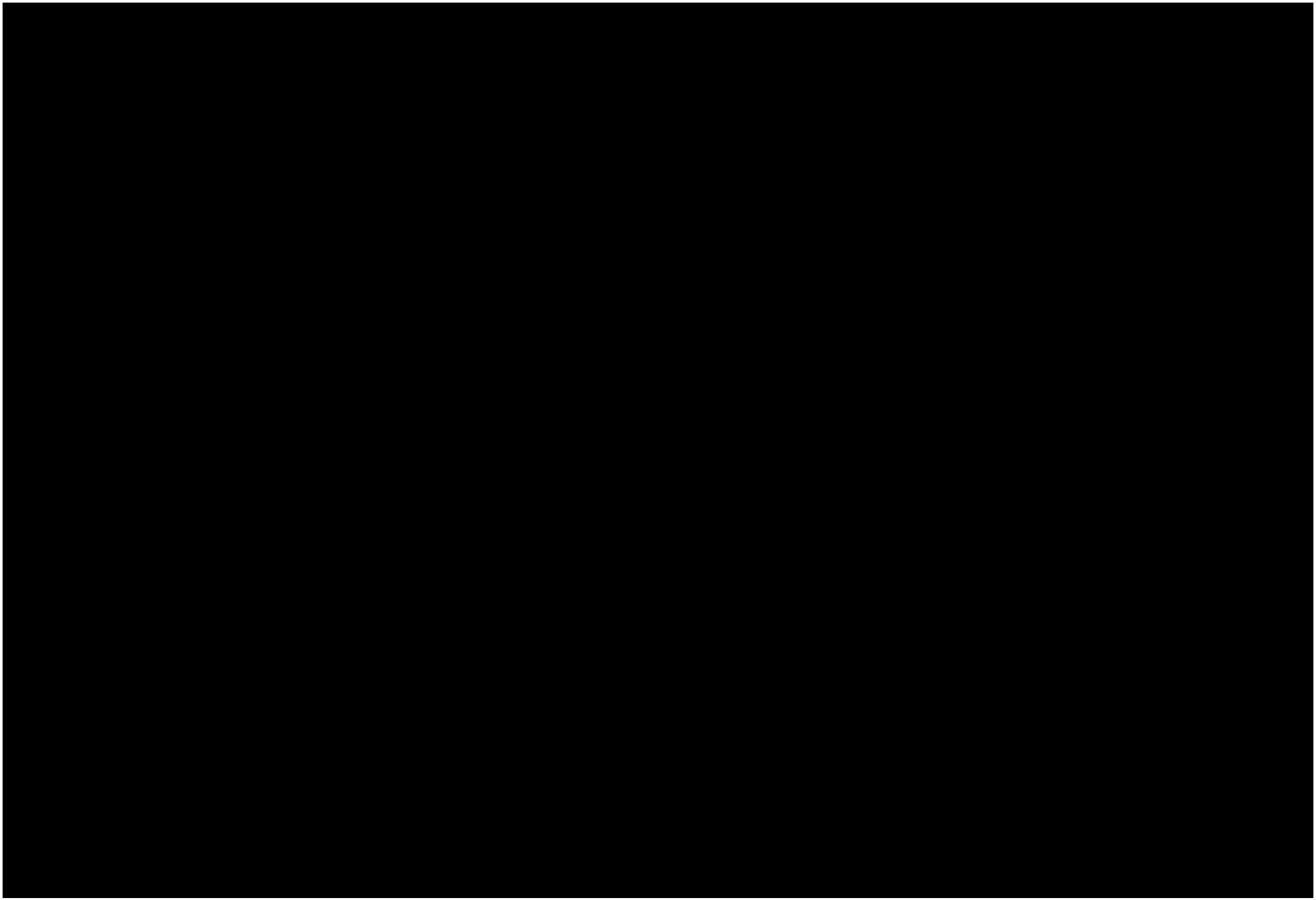
Date of Off Peak Day - 09/02/2021



Member Forecasted Off Peak Demand Day for October 2021

White River Electric Association, Inc.

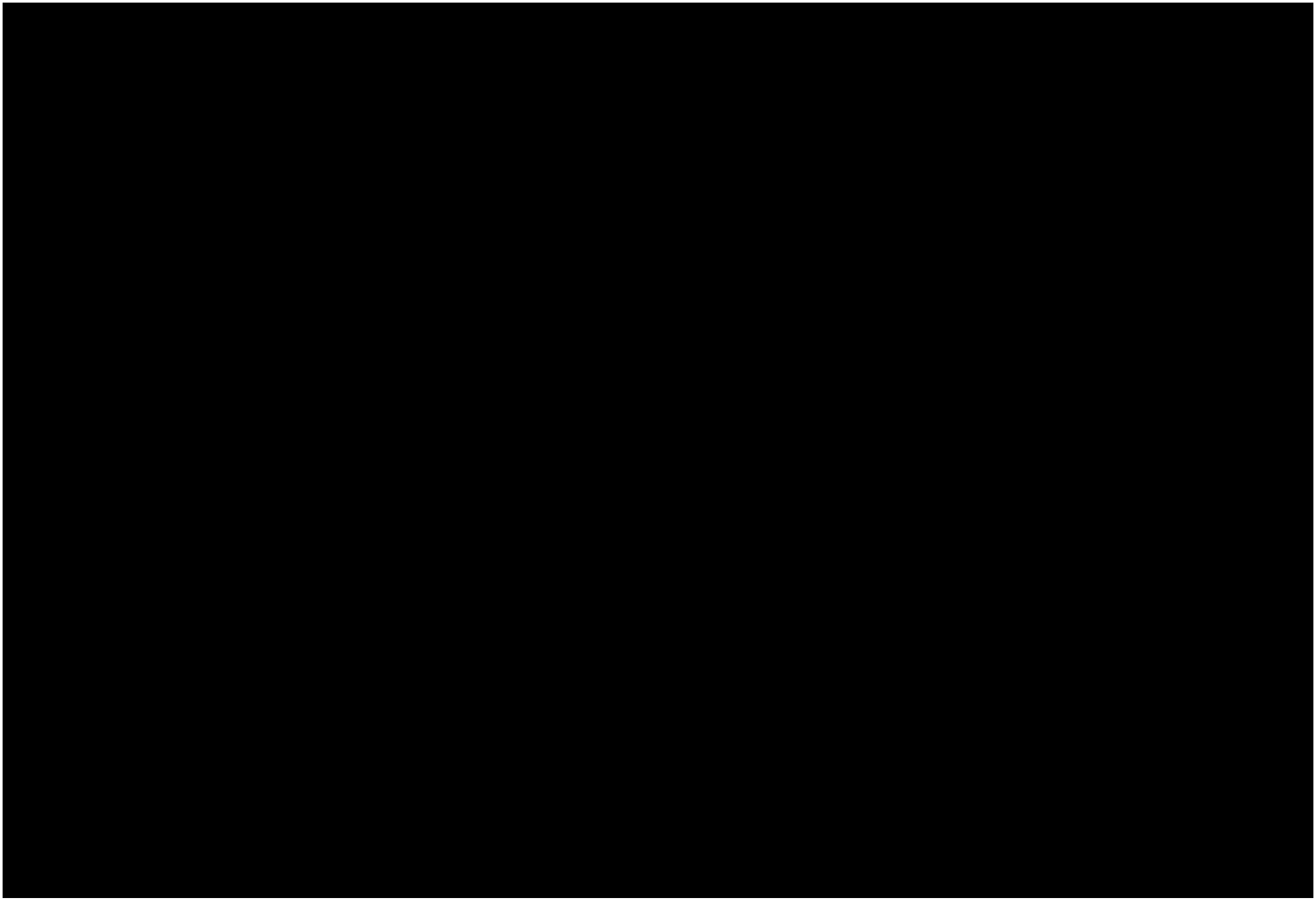
Date of Off Peak Day - 10/21/2021



Member Forecasted Off Peak Demand Day for November 2021

White River Electric Association, Inc.

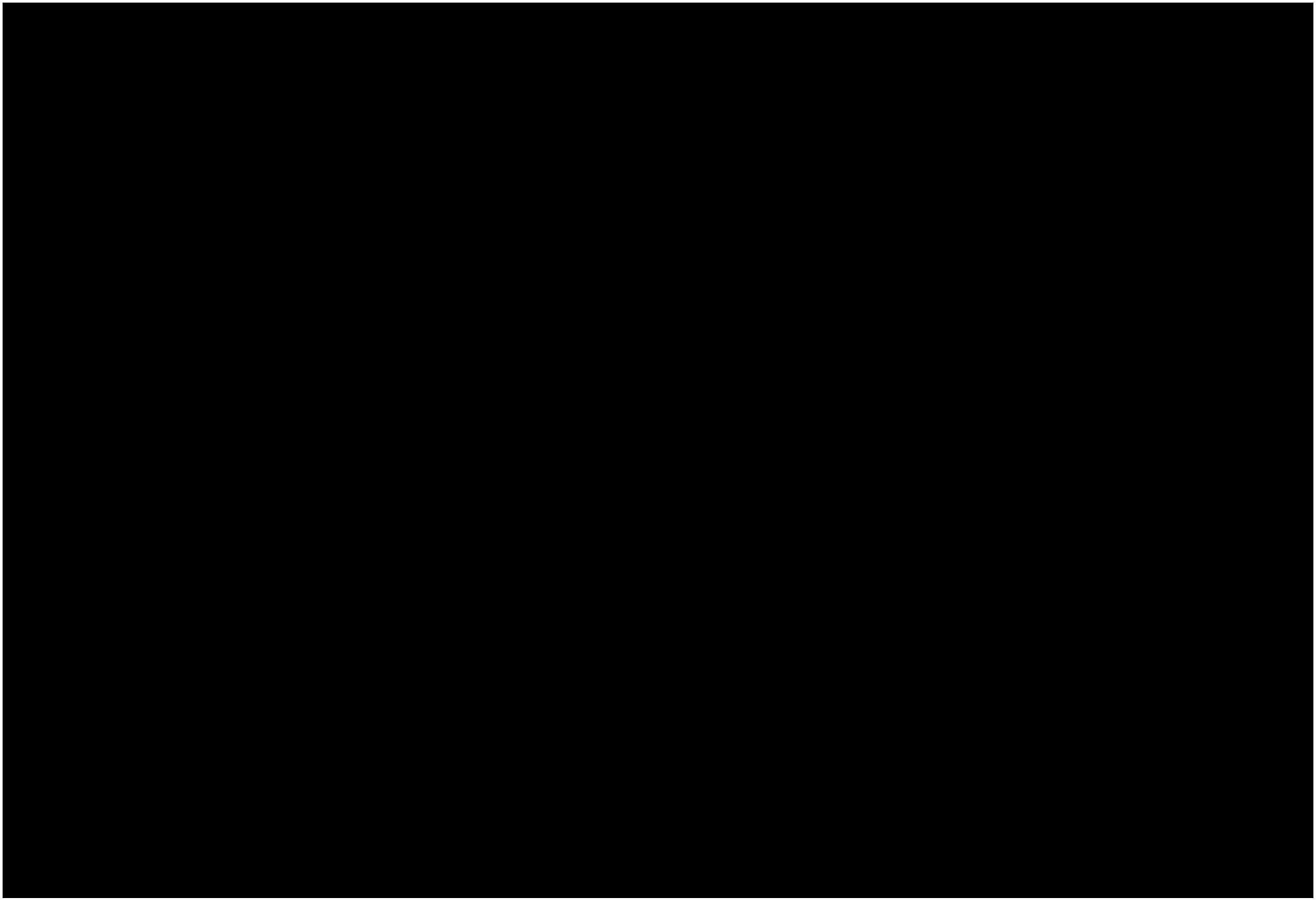
Date of Off Peak Day - 11/12/2021



Member Forecasted Off Peak Demand Day for December 2021

White River Electric Association, Inc.

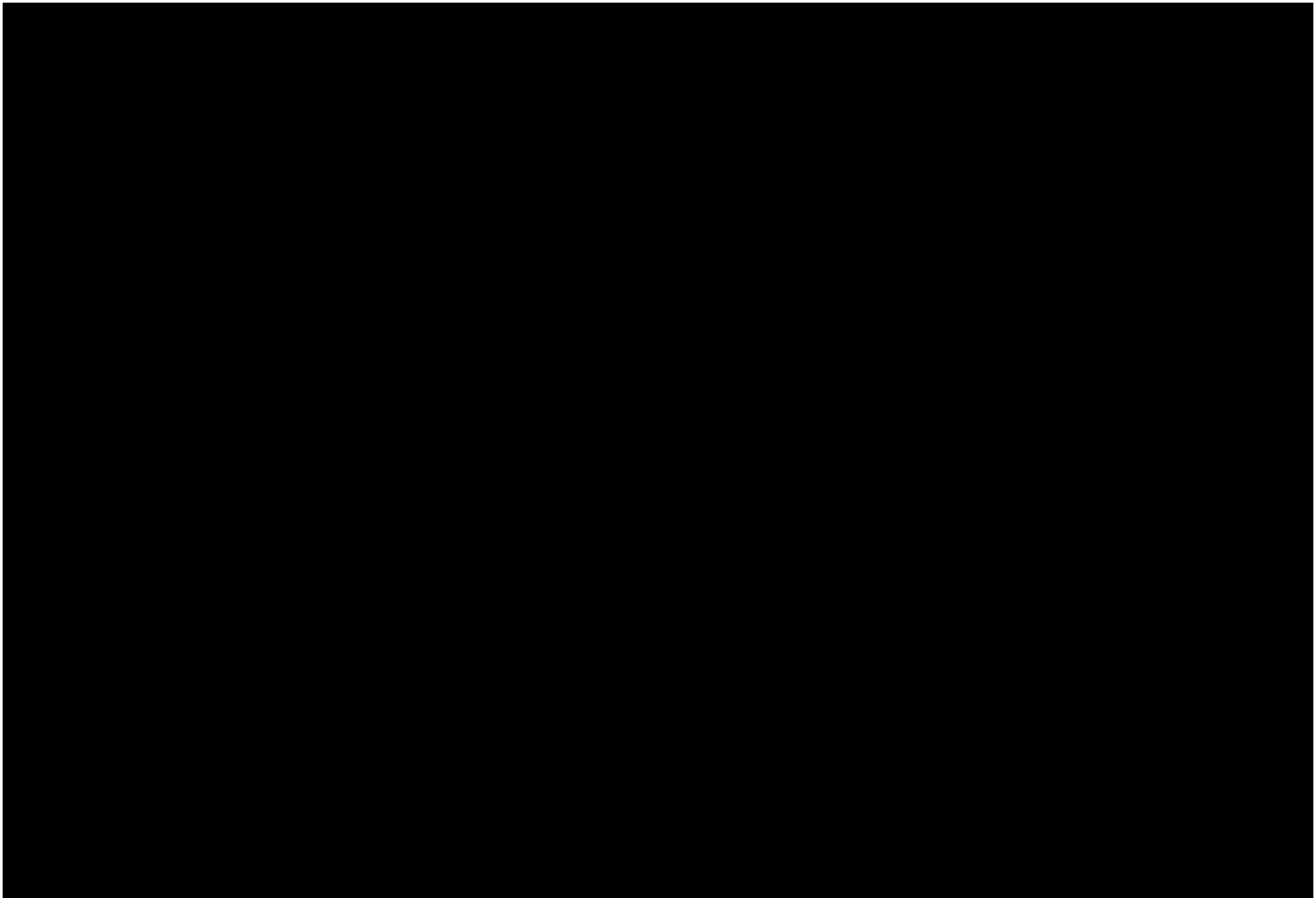
Date of Off Peak Day - 12/03/2021



Member Forecasted Off Peak Demand Day for January 2021

Wyrulec Company

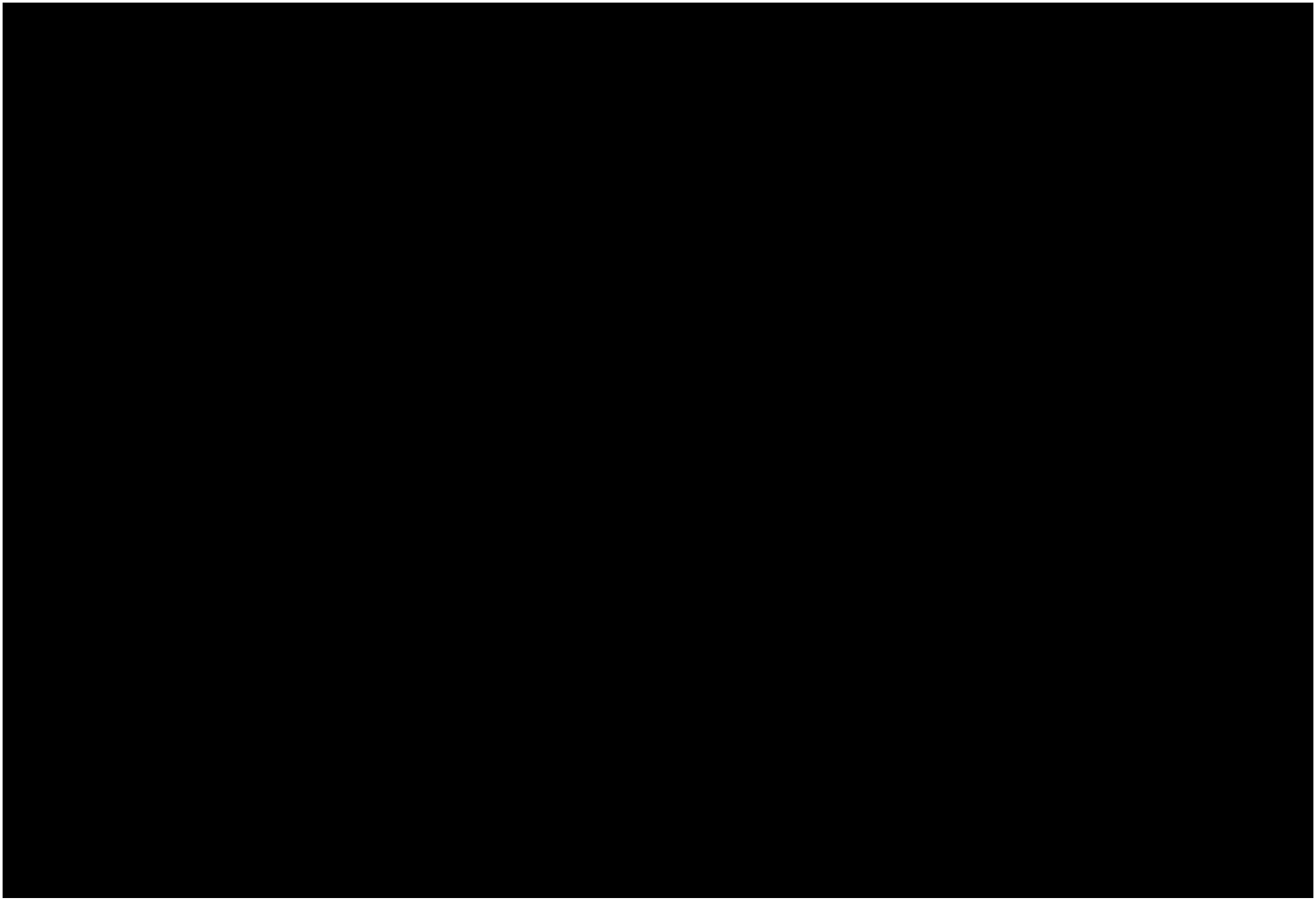
Date of Off Peak Day - 01/01/2021



Member Forecasted Off Peak Demand Day for February 2021

Wyrulec Company

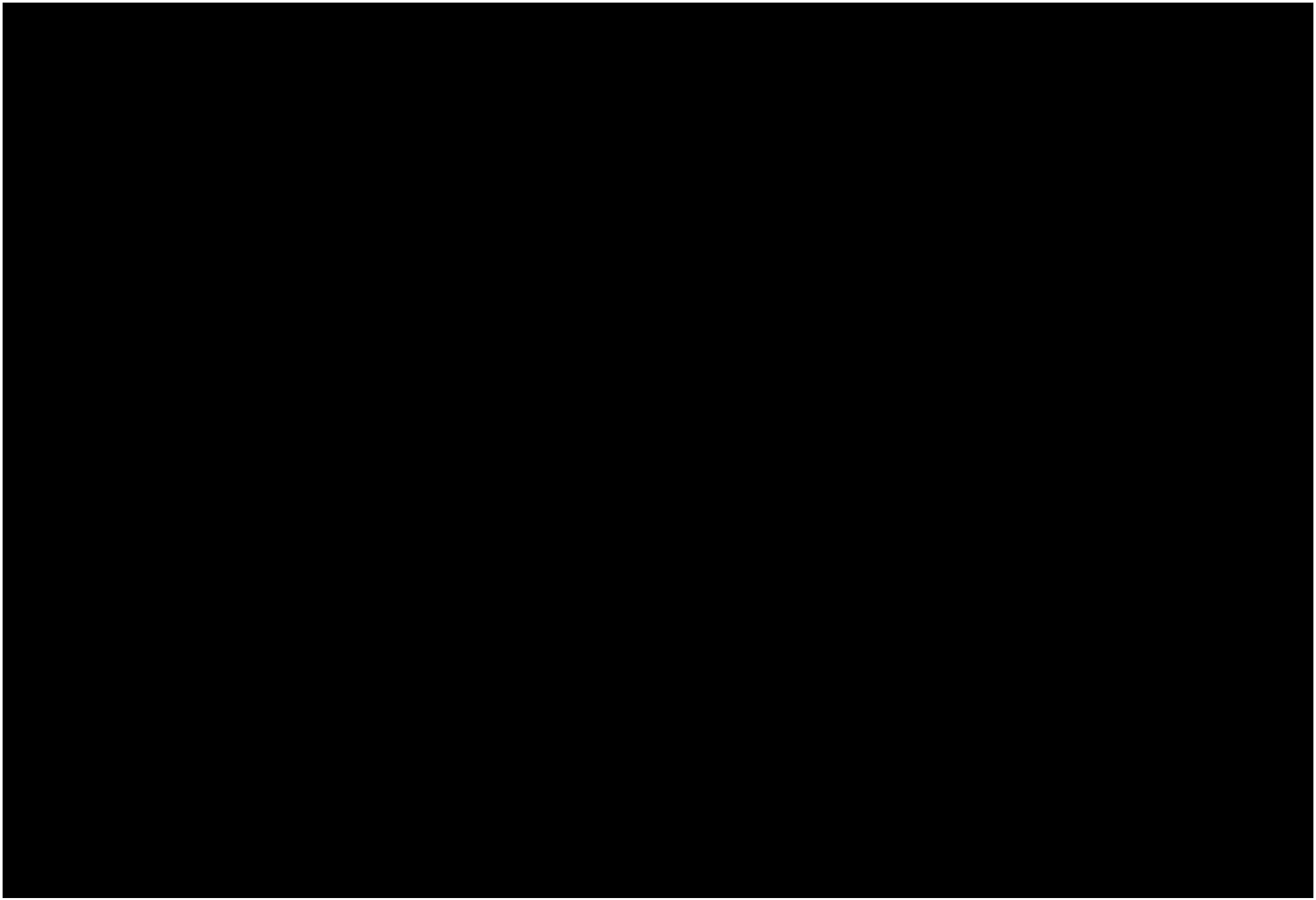
Date of Off Peak Day - 02/09/2021



Member Forecasted Off Peak Demand Day for March 2021

Wyrulec Company

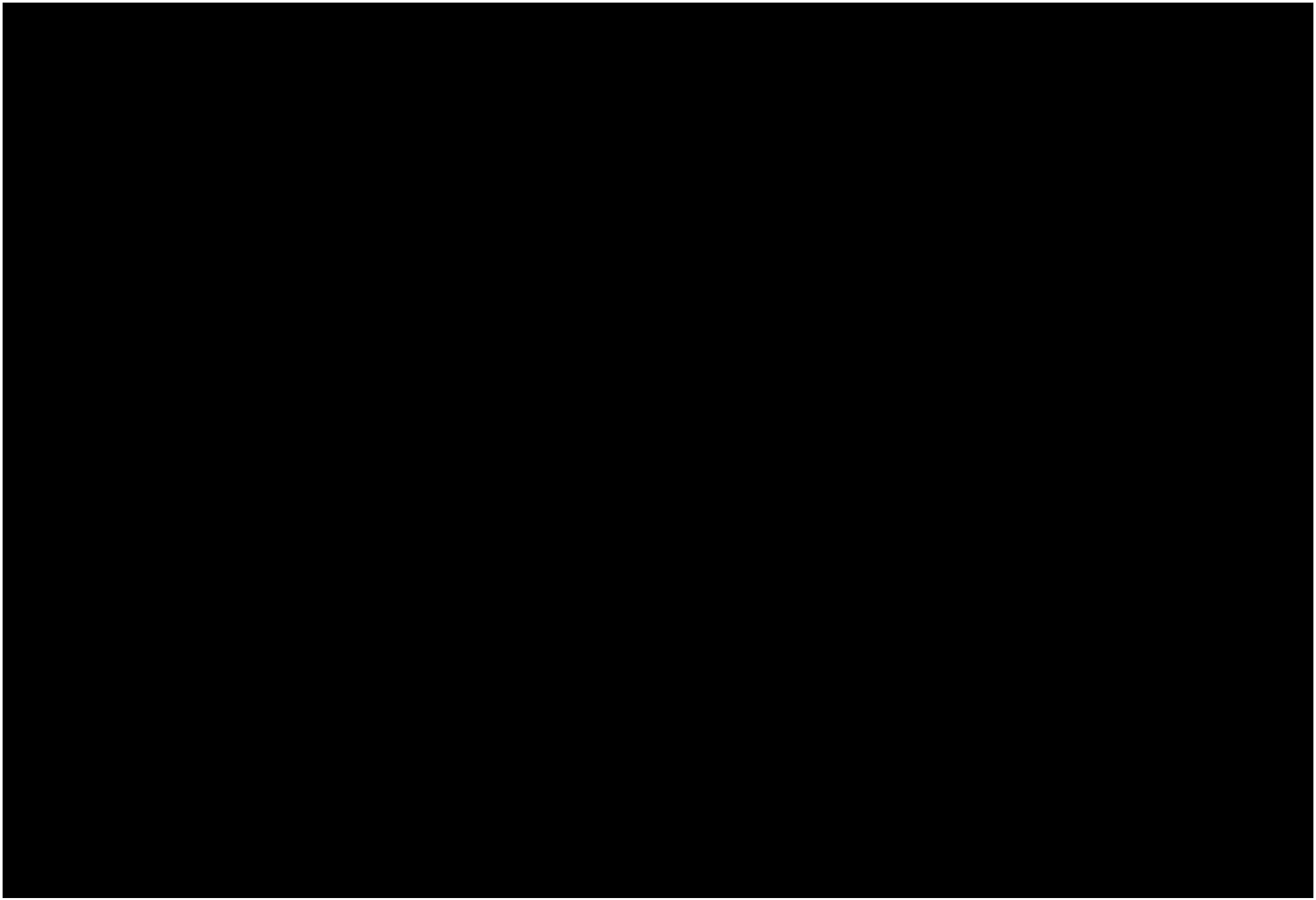
Date of Off Peak Day - 03/29/2021



Member Forecasted Off Peak Demand Day for April 2021

Wyrulec Company

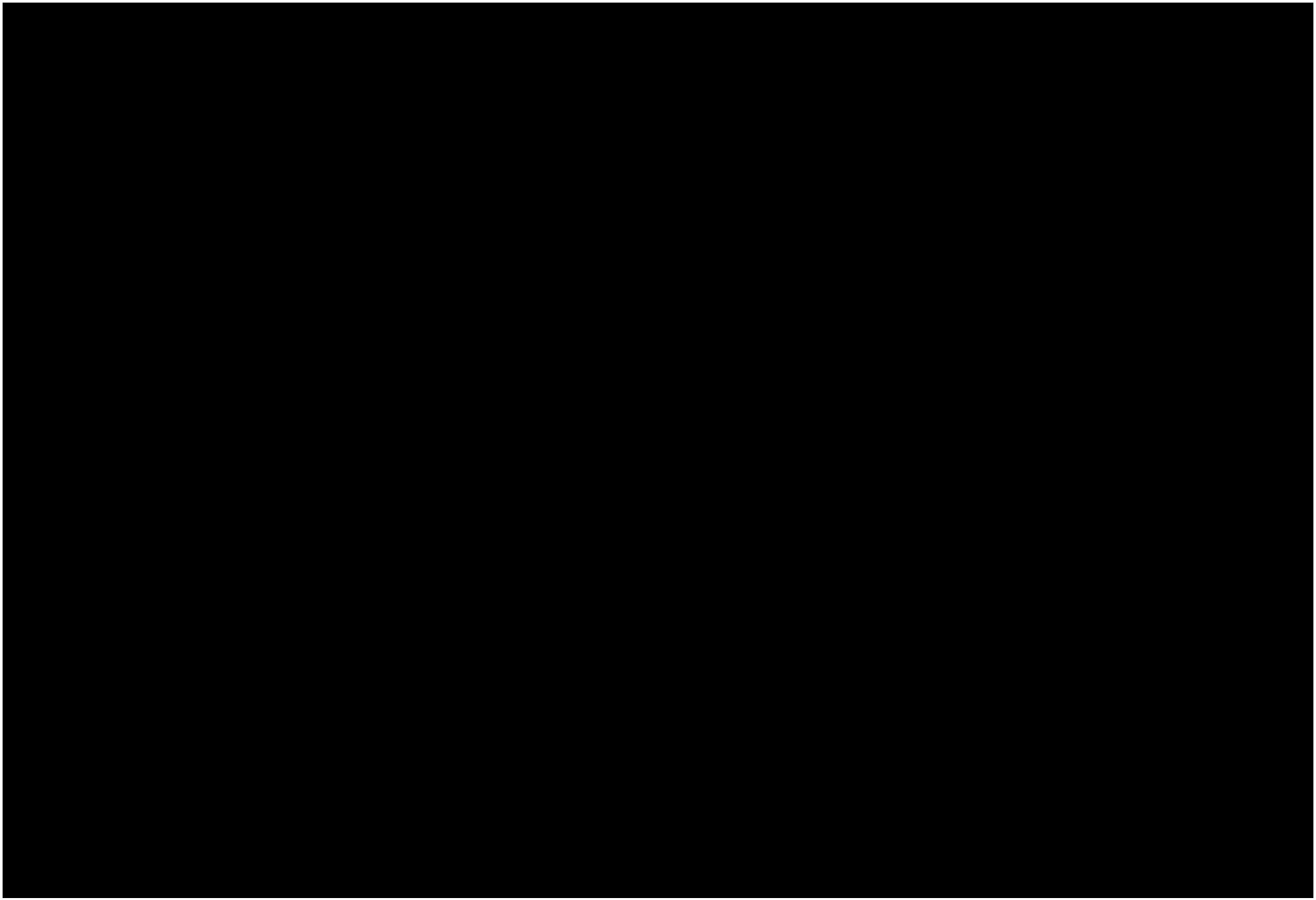
Date of Off Peak Day - 04/01/2021



Member Forecasted Off Peak Demand Day for May 2021

Wyrulec Company

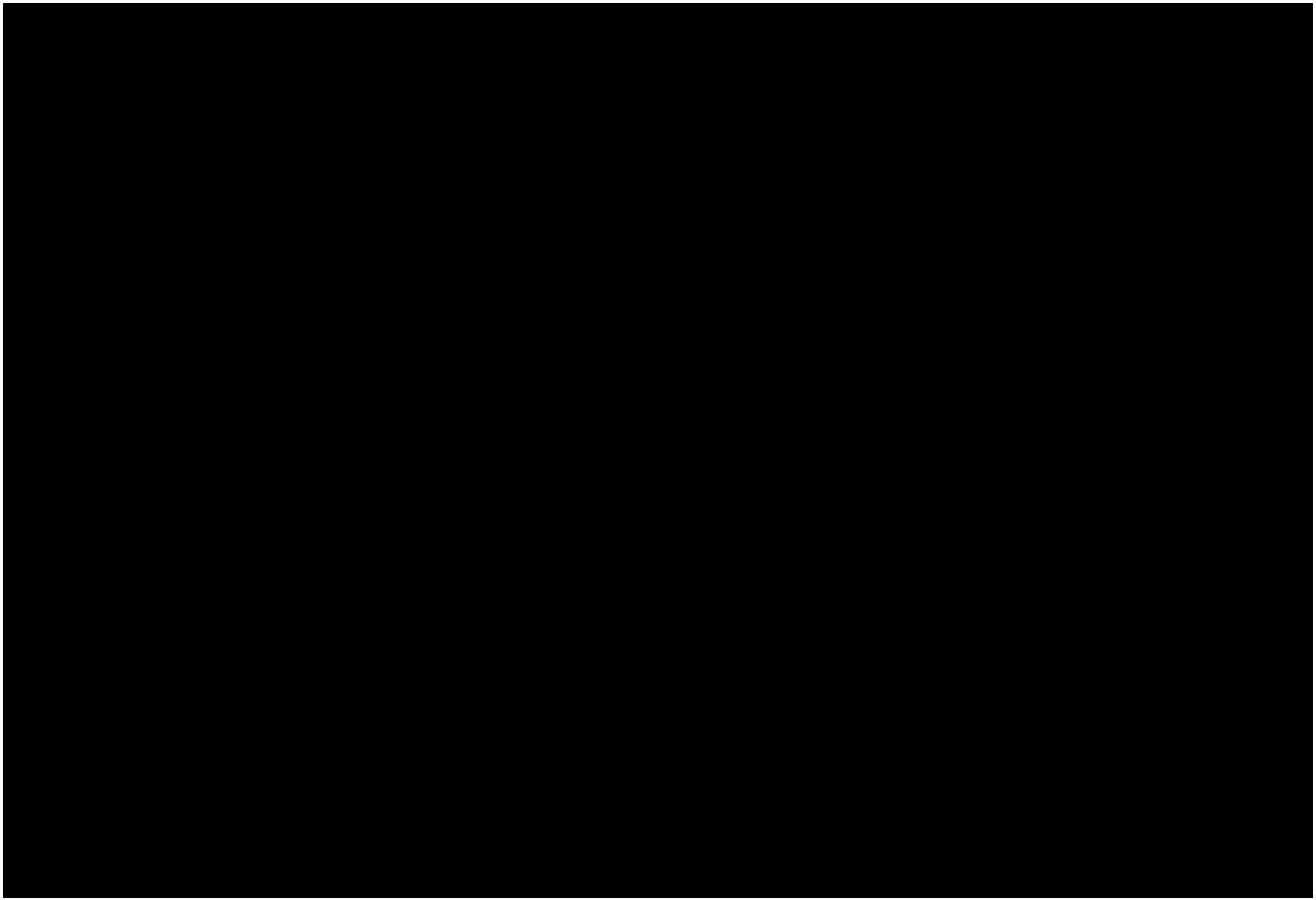
Date of Off Peak Day - 05/01/2021



Member Forecasted Off Peak Demand Day for June 2021

Wyrulec Company

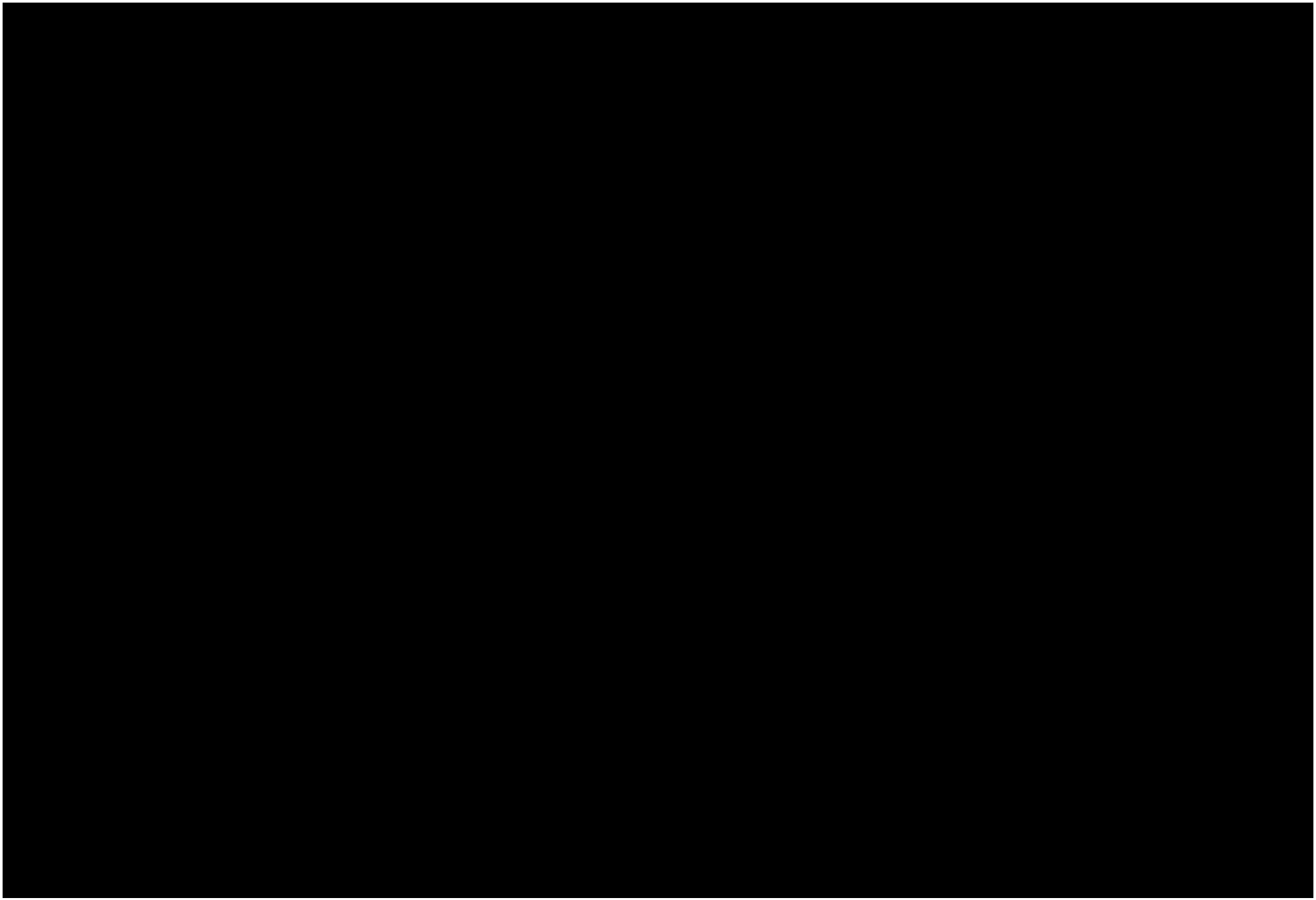
Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Wyrulec Company

Date of Off Peak Day - 07/06/2021



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Member Forecasted Off Peak Demand Day for August 2021

Wyrulec Company

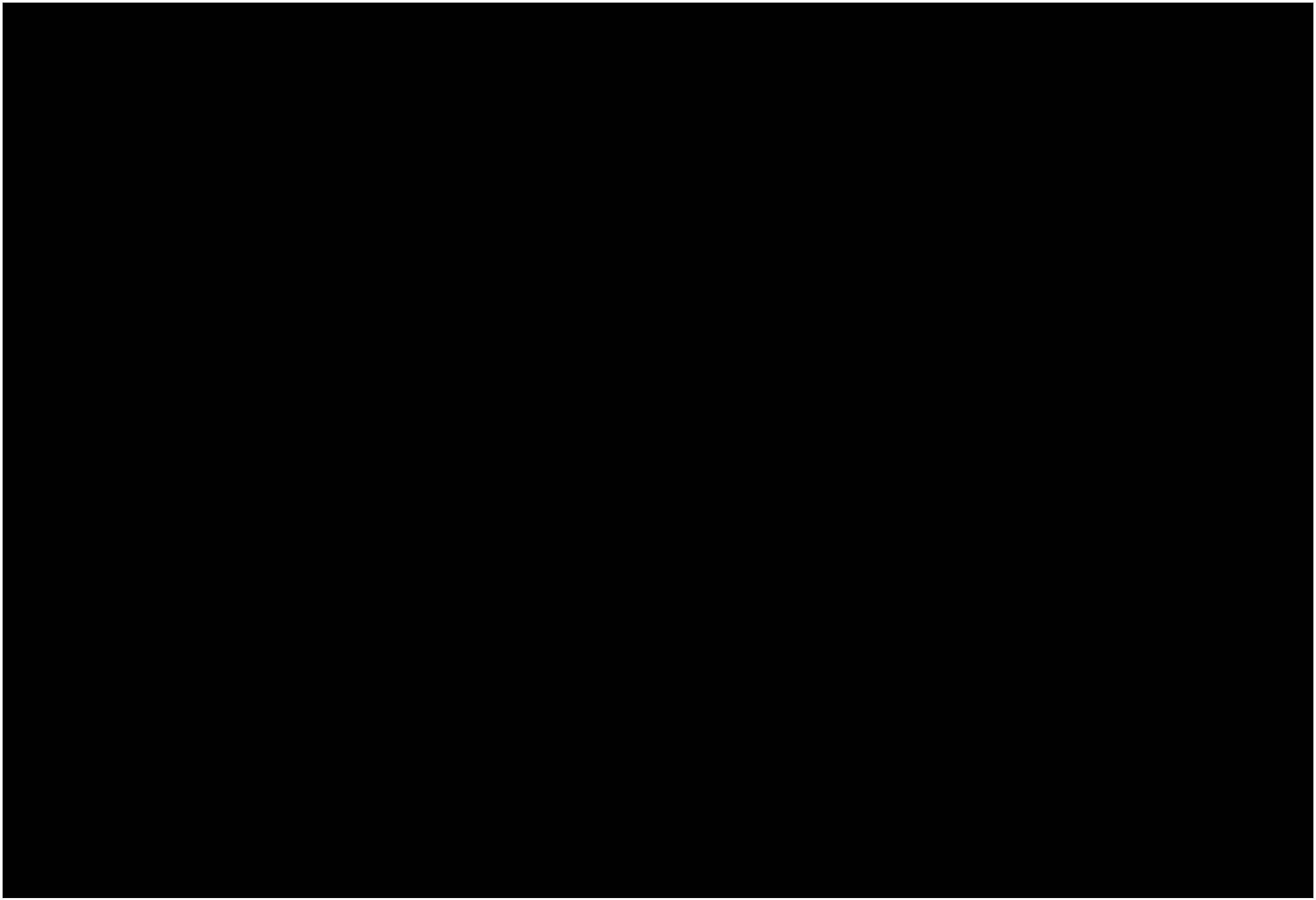
Date of Off Peak Day - 08/13/2021

[redacted]

Member Forecasted Off Peak Demand Day for September 2021

Wyrulec Company

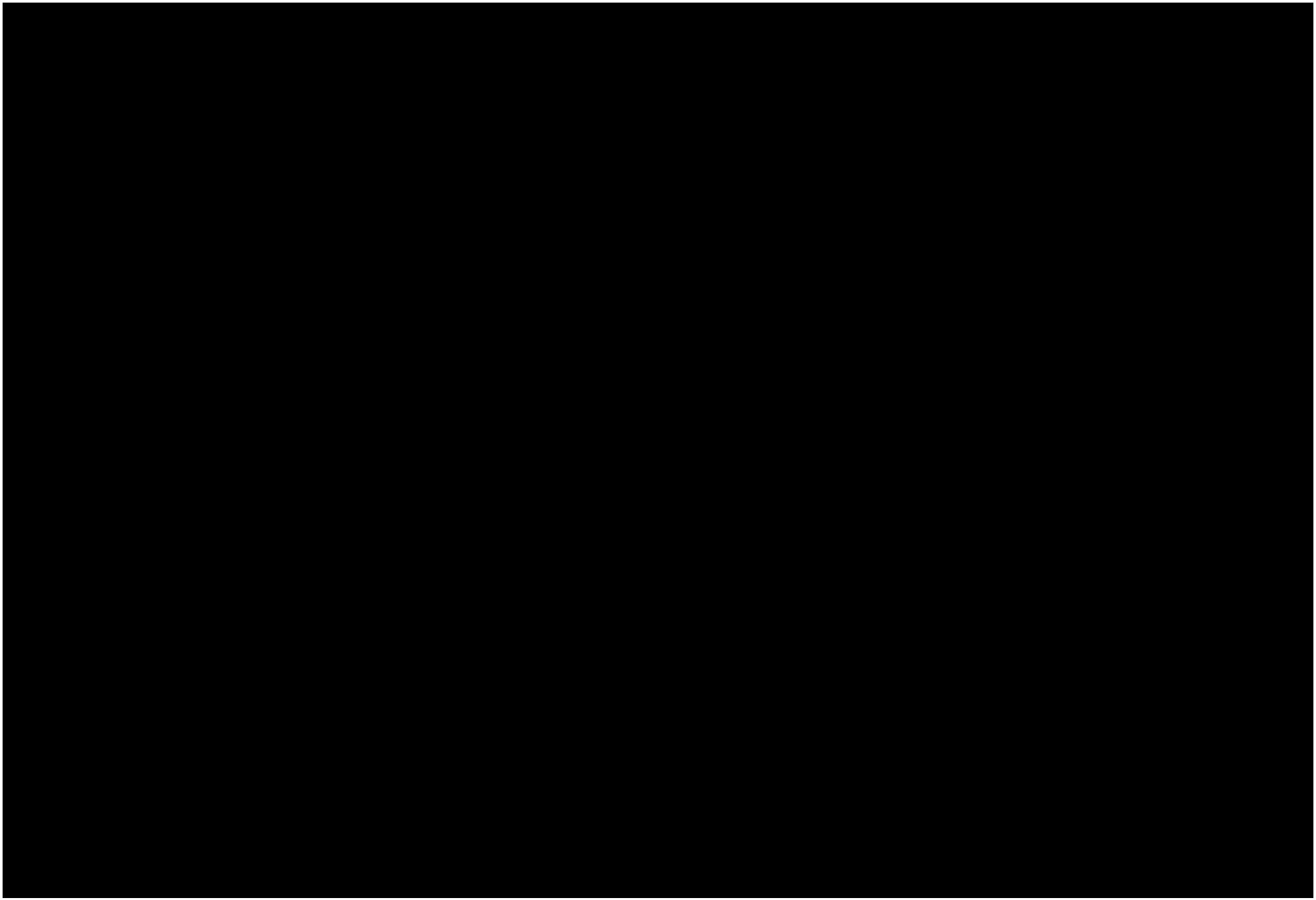
Date of Off Peak Day - 09/18/2021



Member Forecasted Off Peak Demand Day for October 2021

Wyrulec Company

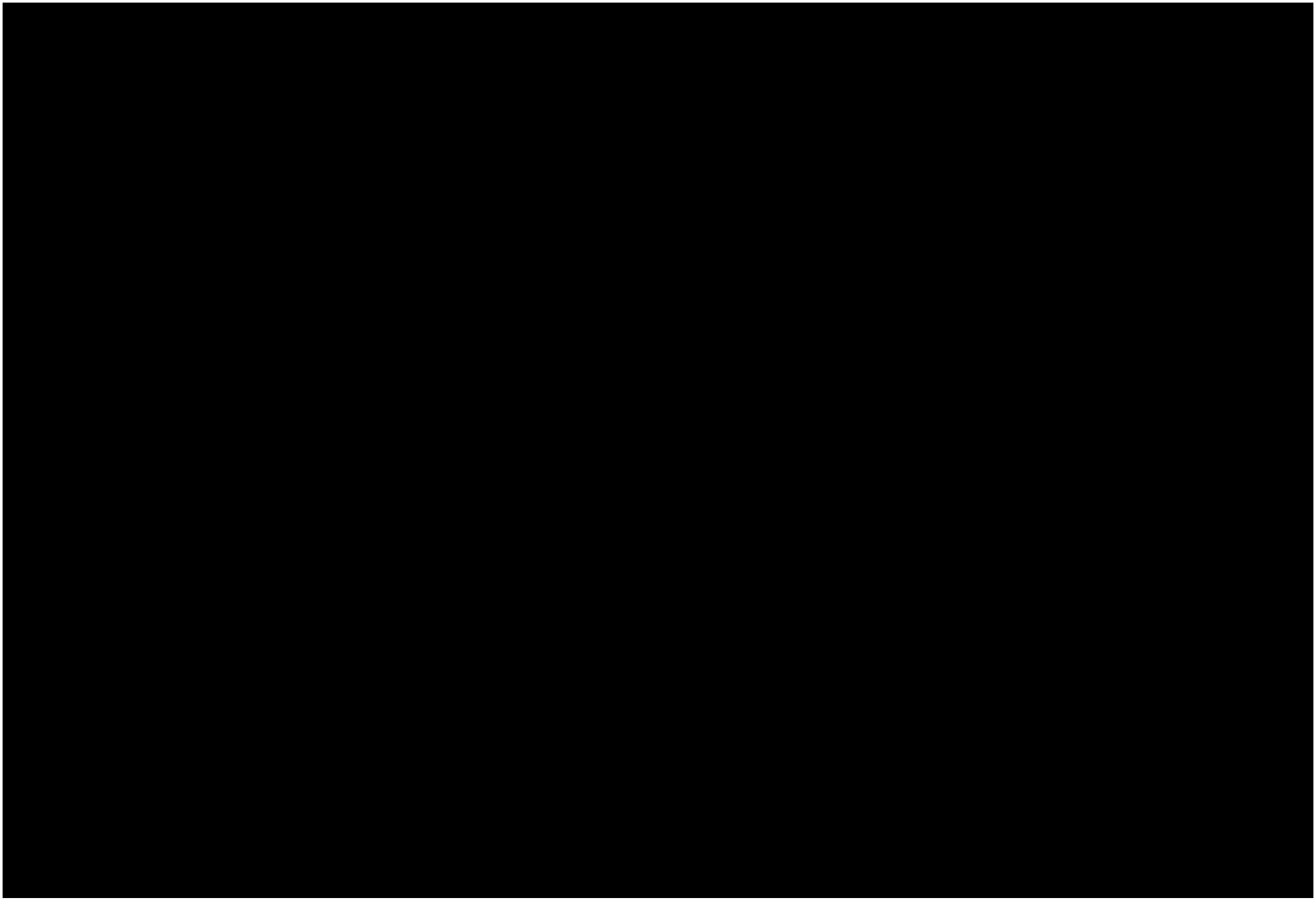
Date of Off Peak Day - 10/08/2021



Member Forecasted Off Peak Demand Day for November 2021

Wyrulec Company

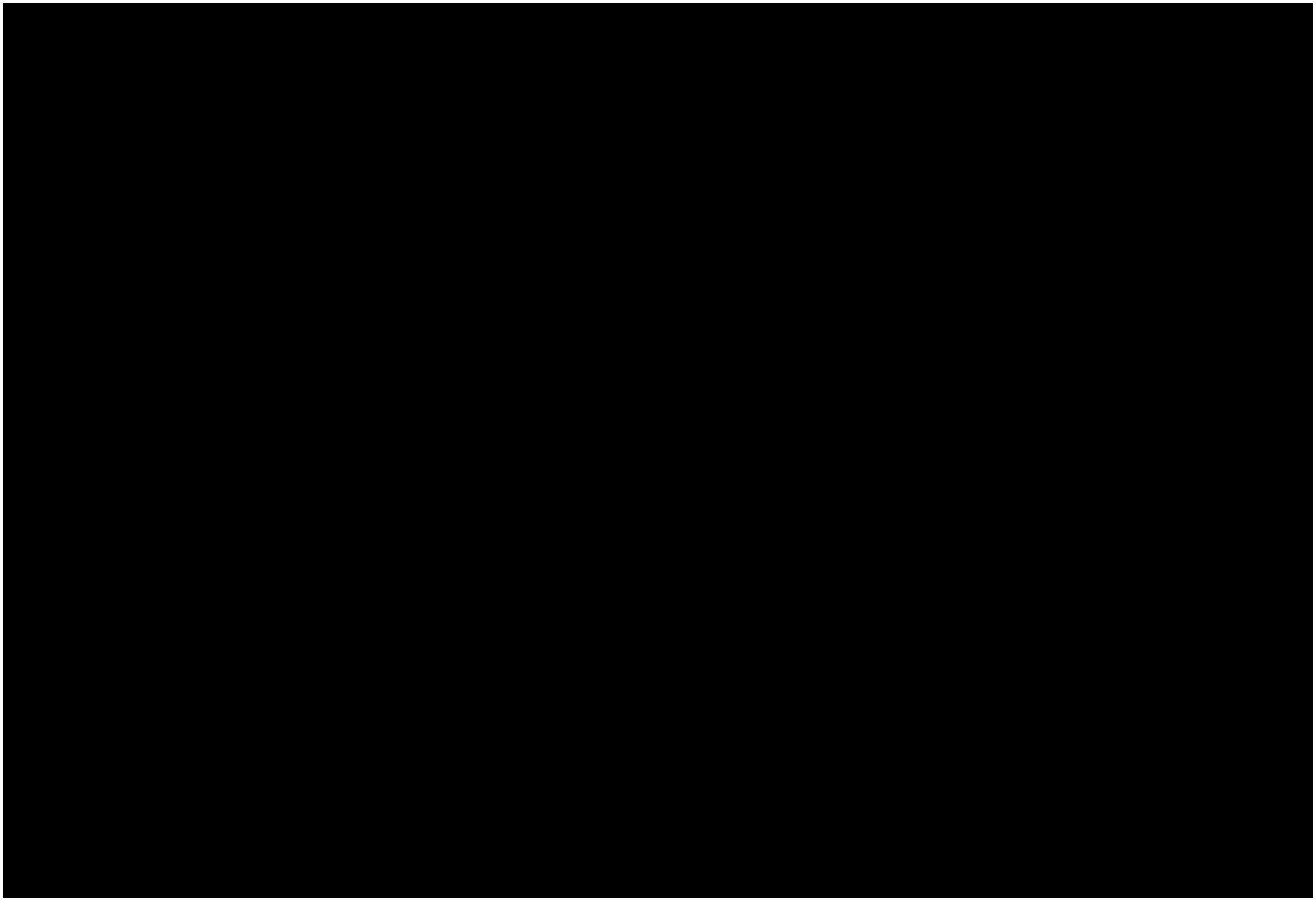
Date of Off Peak Day - 11/25/2021



Member Forecasted Off Peak Demand Day for December 2021

Wyrulec Company

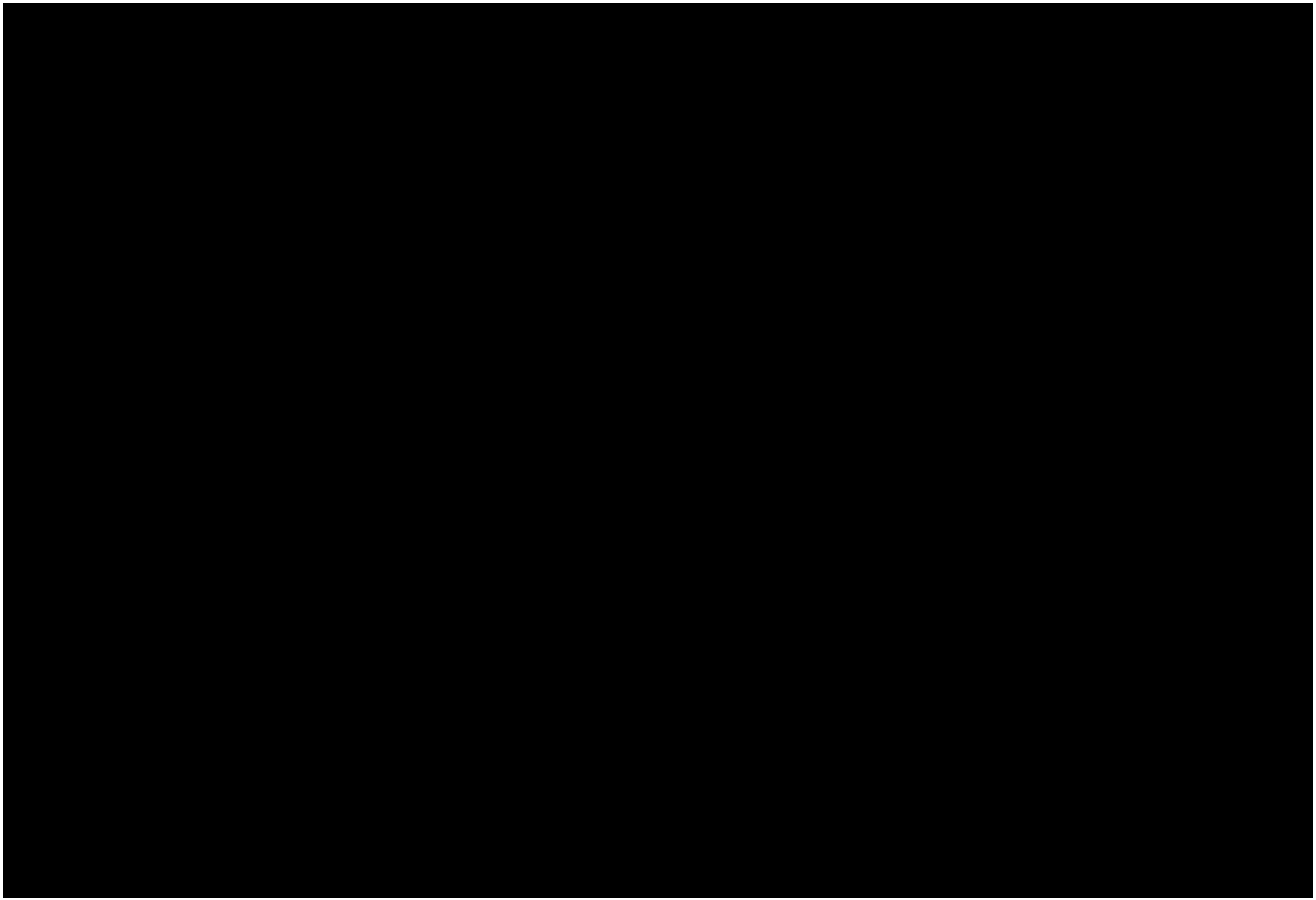
Date of Off Peak Day - 12/01/2021



Member Forecasted Off Peak Demand Day for January 2021

Y-W Electric Association, Inc.

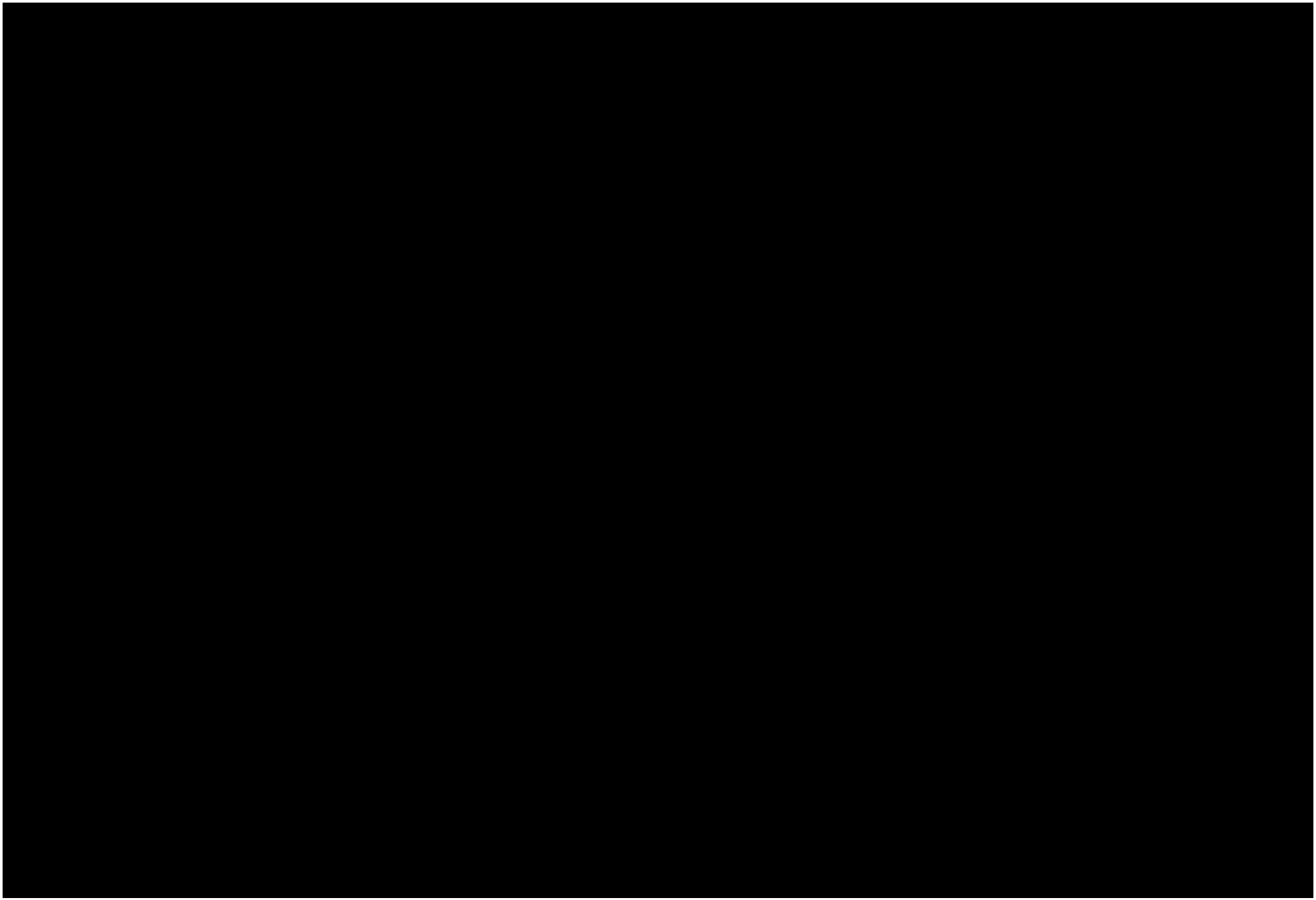
Date of Off Peak Day - 01/31/2021



Member Forecasted Off Peak Demand Day for February 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 02/11/2021



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Member Forecasted Off Peak Demand Day for March 2021

Y-W Electric Association, Inc.

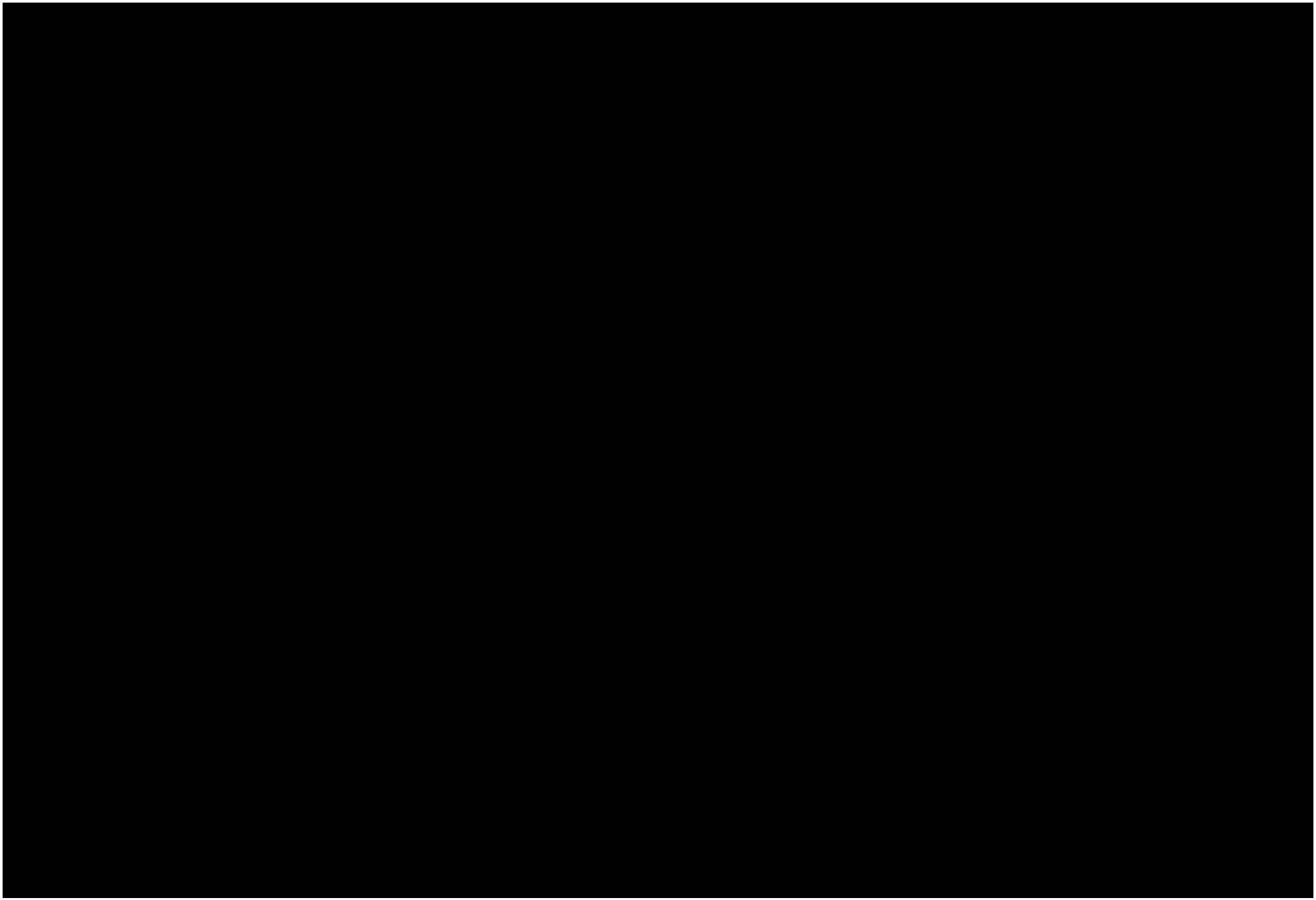
Date of Off Peak Day - 03/31/2021

[redacted]

Member Forecasted Off Peak Demand Day for April 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 04/20/2021



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Member Forecasted Off Peak Demand Day for May 2021

Y-W Electric Association, Inc.

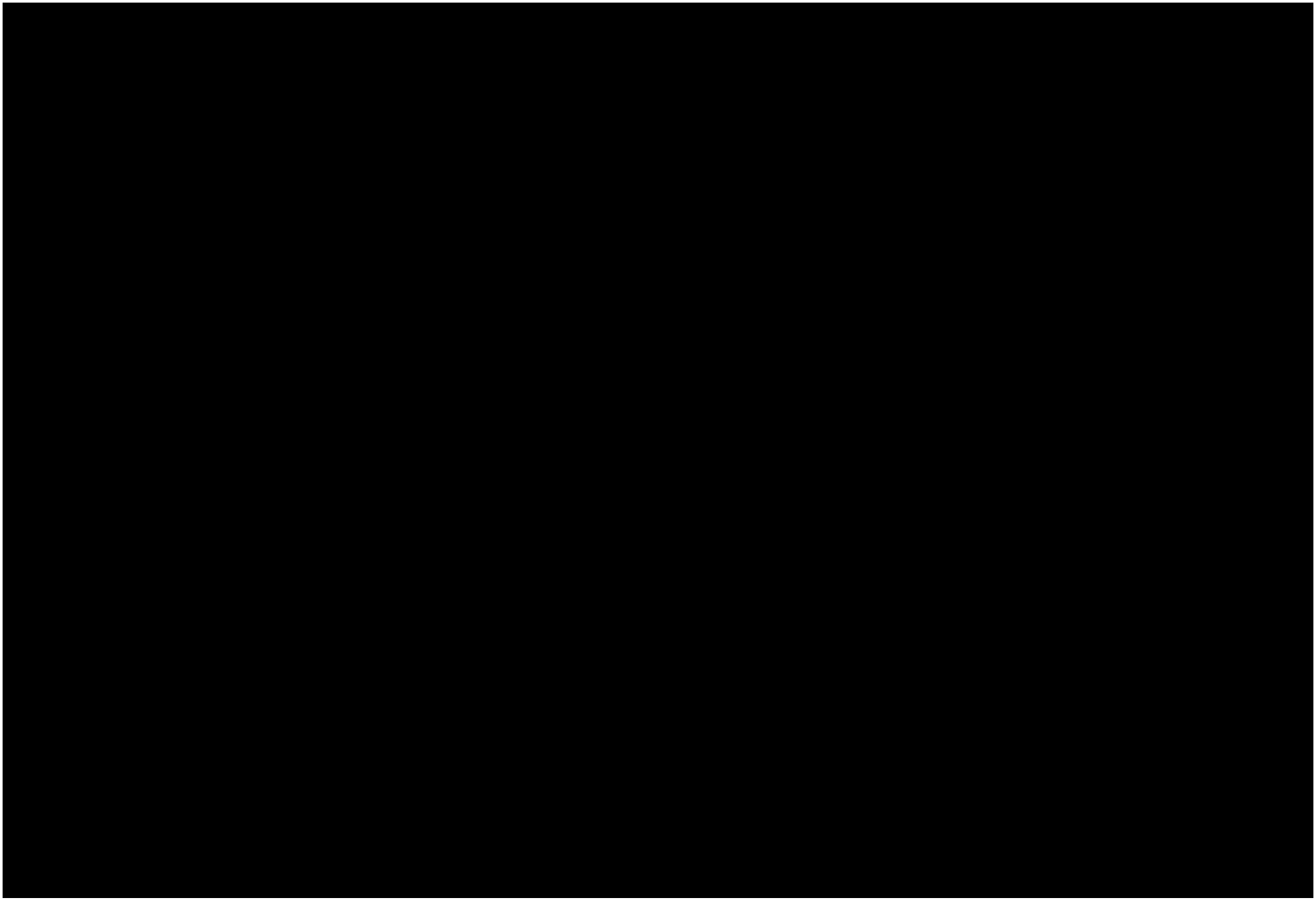
Date of Off Peak Day - 05/01/2021

[redacted]

Member Forecasted Off Peak Demand Day for June 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 06/01/2021



Member Forecasted Off Peak Demand Day for July 2021

Y-W Electric Association, Inc.

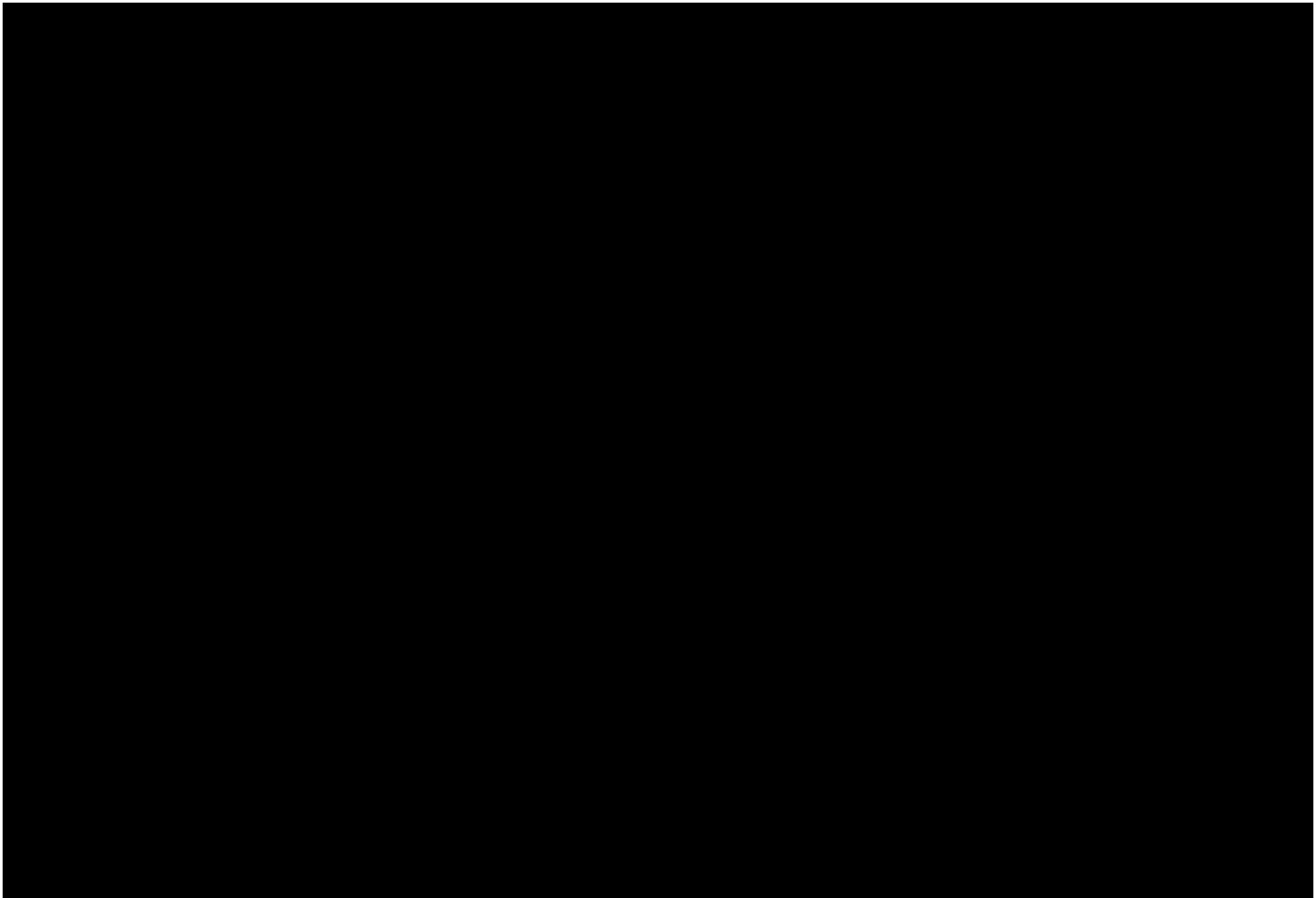
Date of Off Peak Day - 07/03/2021

[redacted]

Member Forecasted Off Peak Demand Day for August 2021

Y-W Electric Association, Inc.

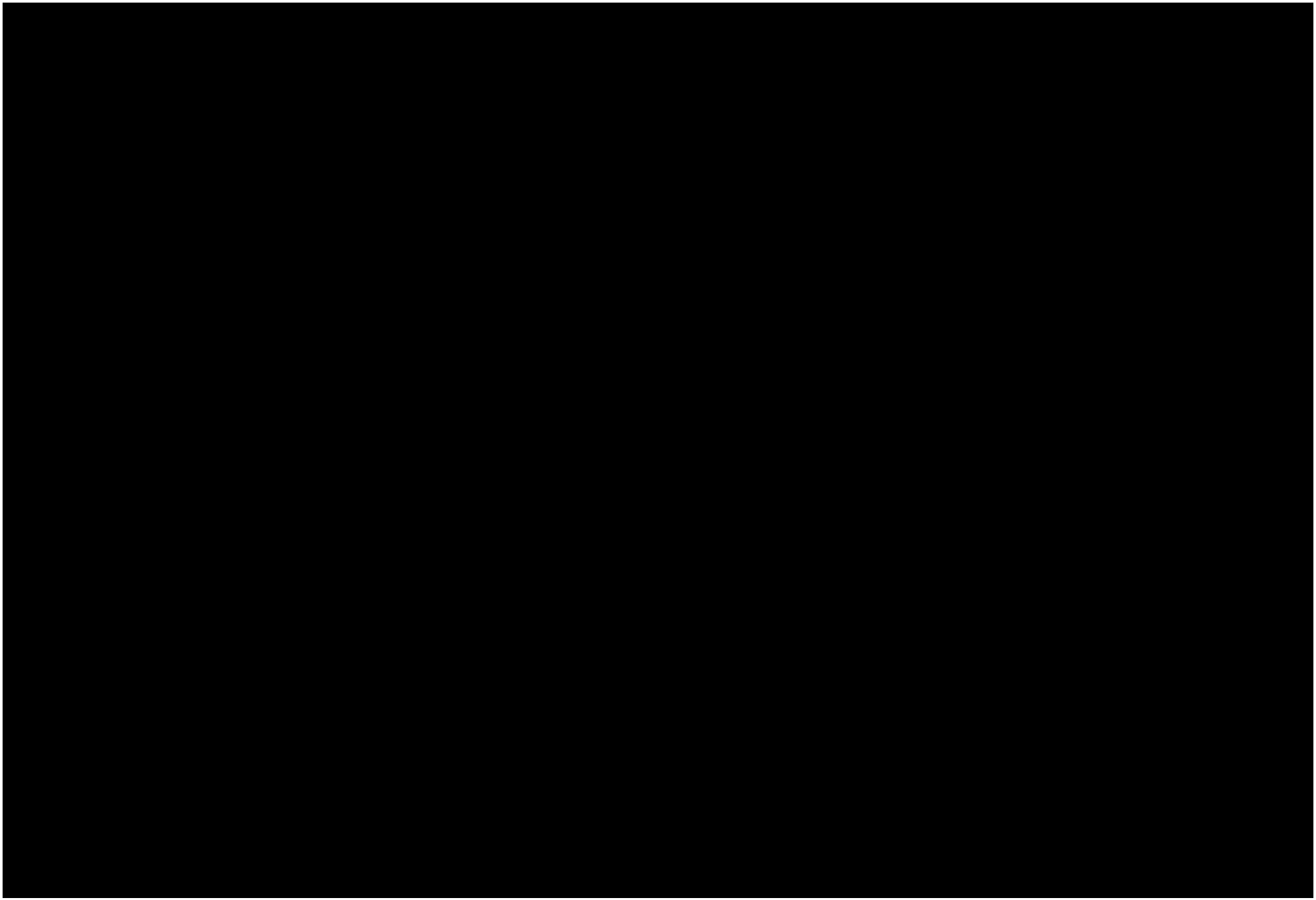
Date of Off Peak Day - 08/11/2021



Member Forecasted Off Peak Demand Day for September 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 09/30/2021



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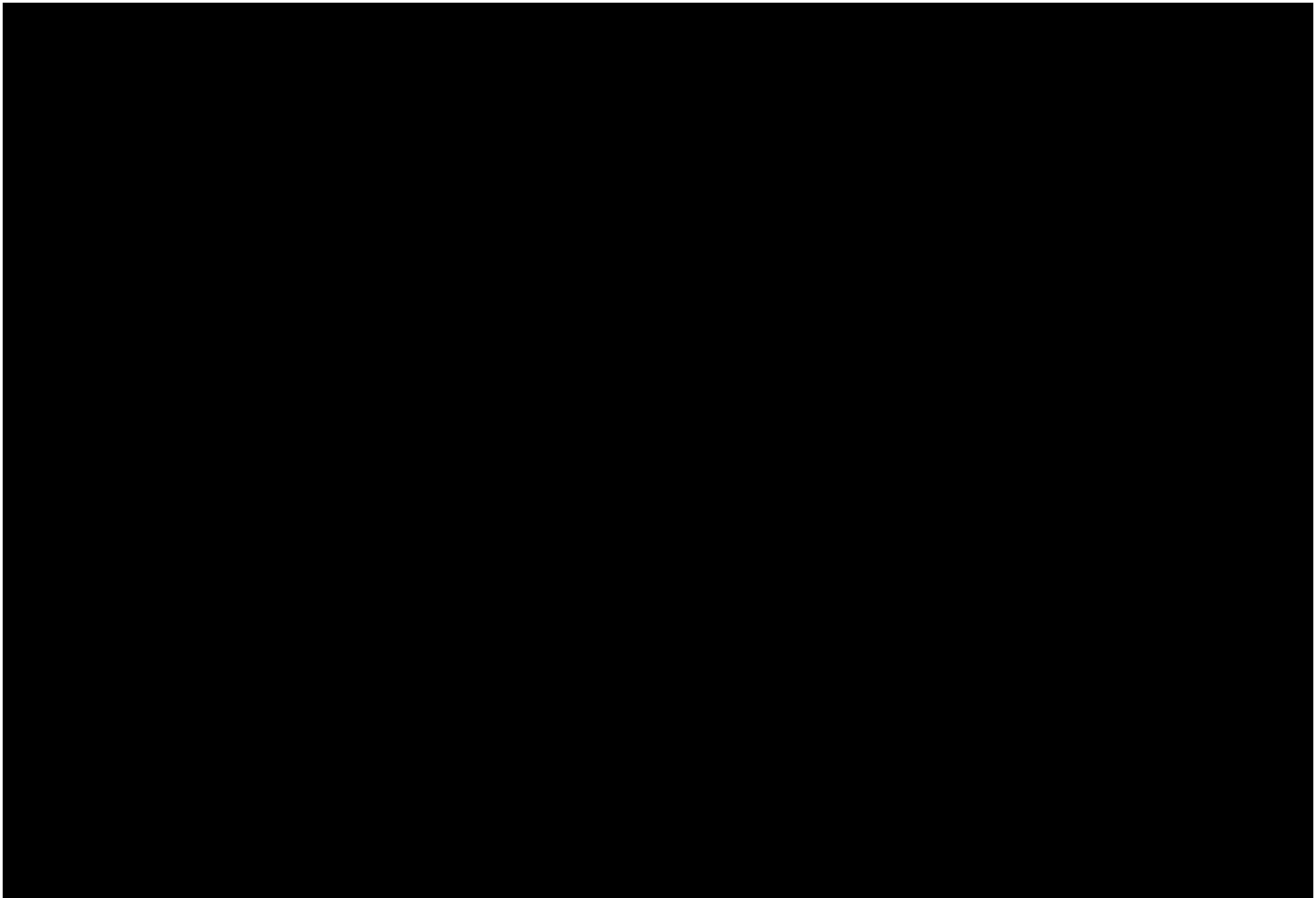
Member Forecasted Off Peak Demand Day for October 2021

Y-W Electric Association, Inc.

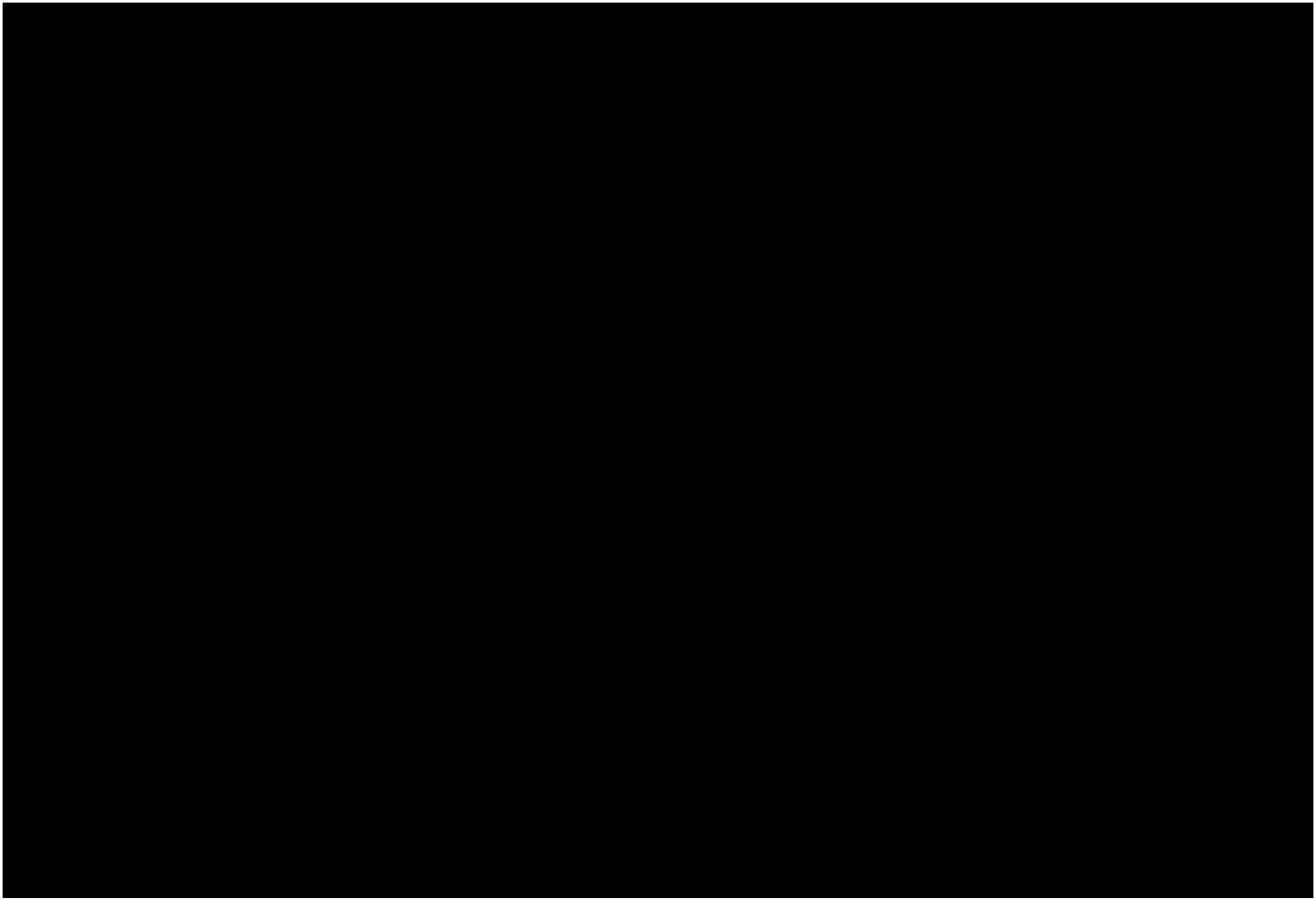
Date of Off Peak Day - 10/25/2021



Member Forecasted Off Peak Demand Day for November 2021

Y-W Electric Association, Inc.

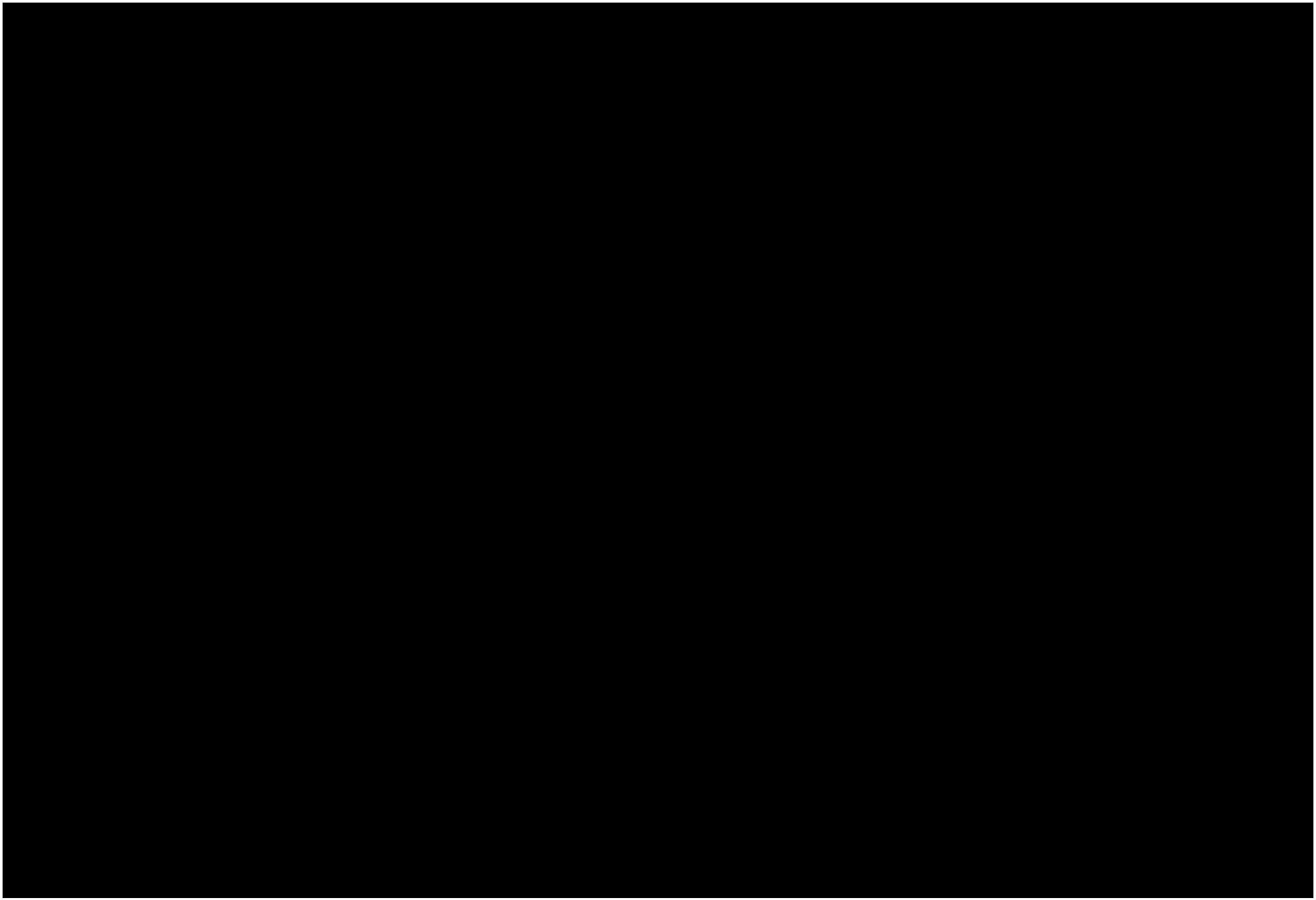
Date of Off Peak Day - 11/02/2021



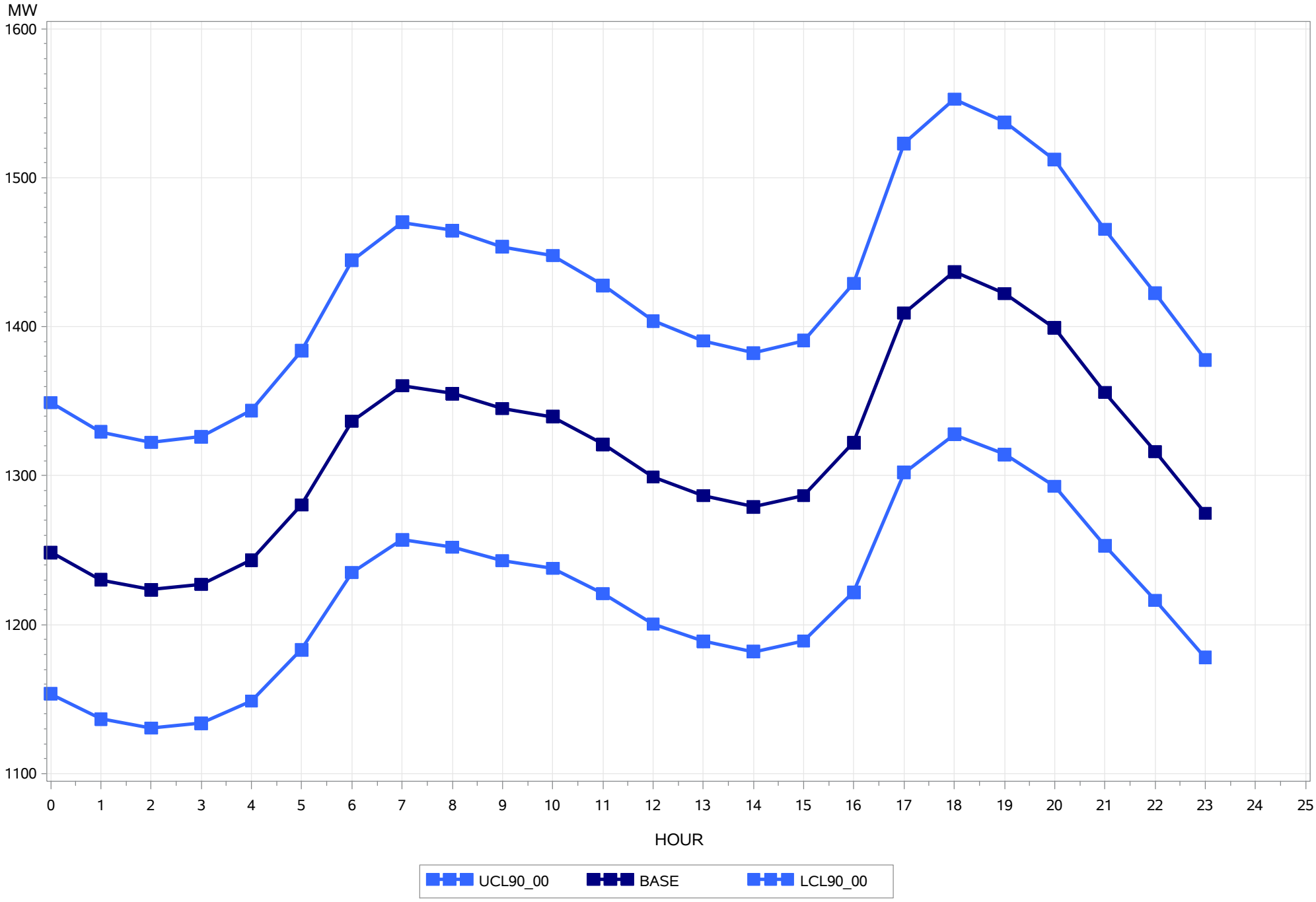
Member Forecasted Off Peak Demand Day for December 2021

Y-W Electric Association, Inc.

Date of Off Peak Day - 12/11/2021



Hourly Average Day for January 2021
STATE OF COLORADO



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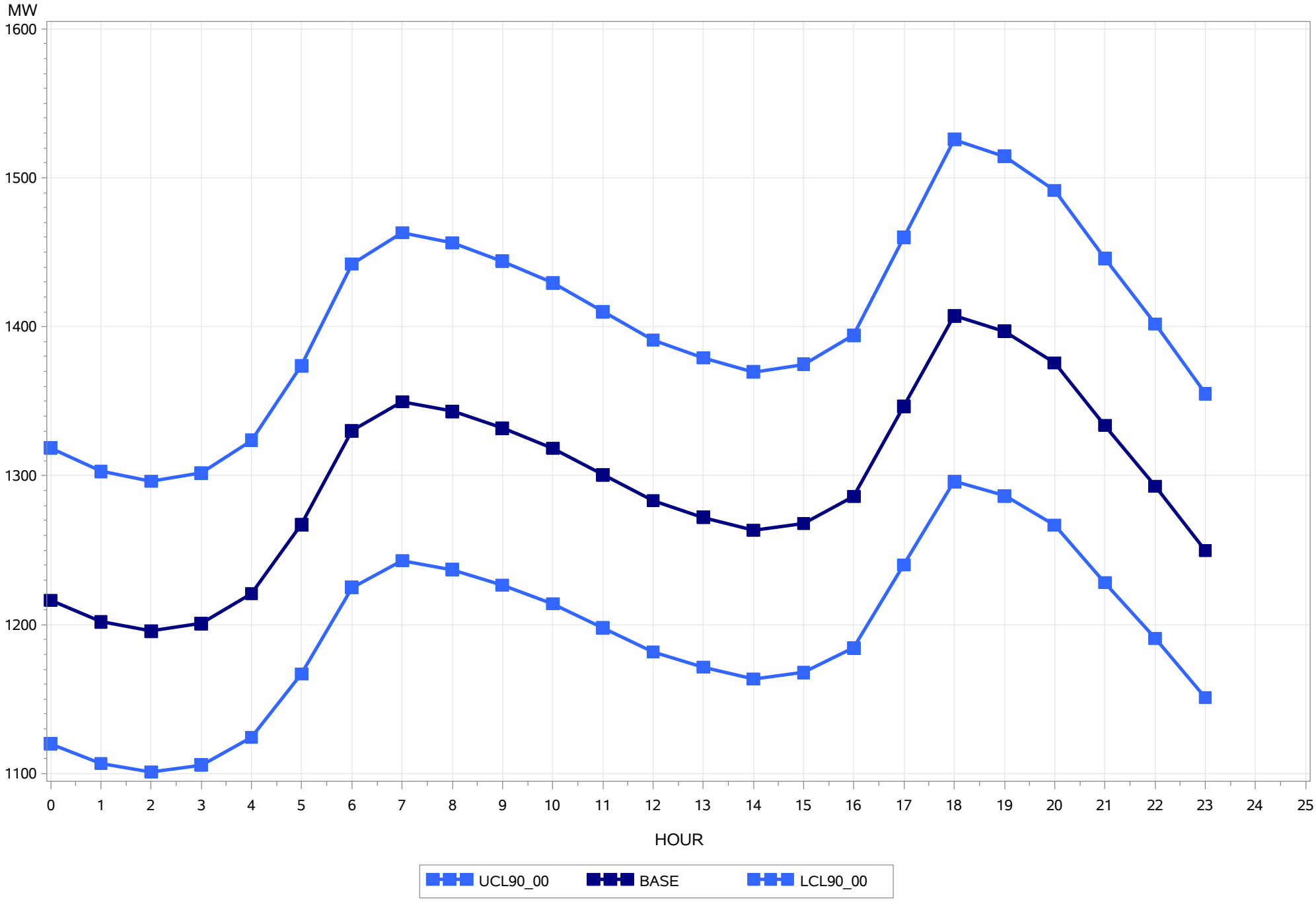
Hourly Average Day for February 2021
STATE OF COLORADO



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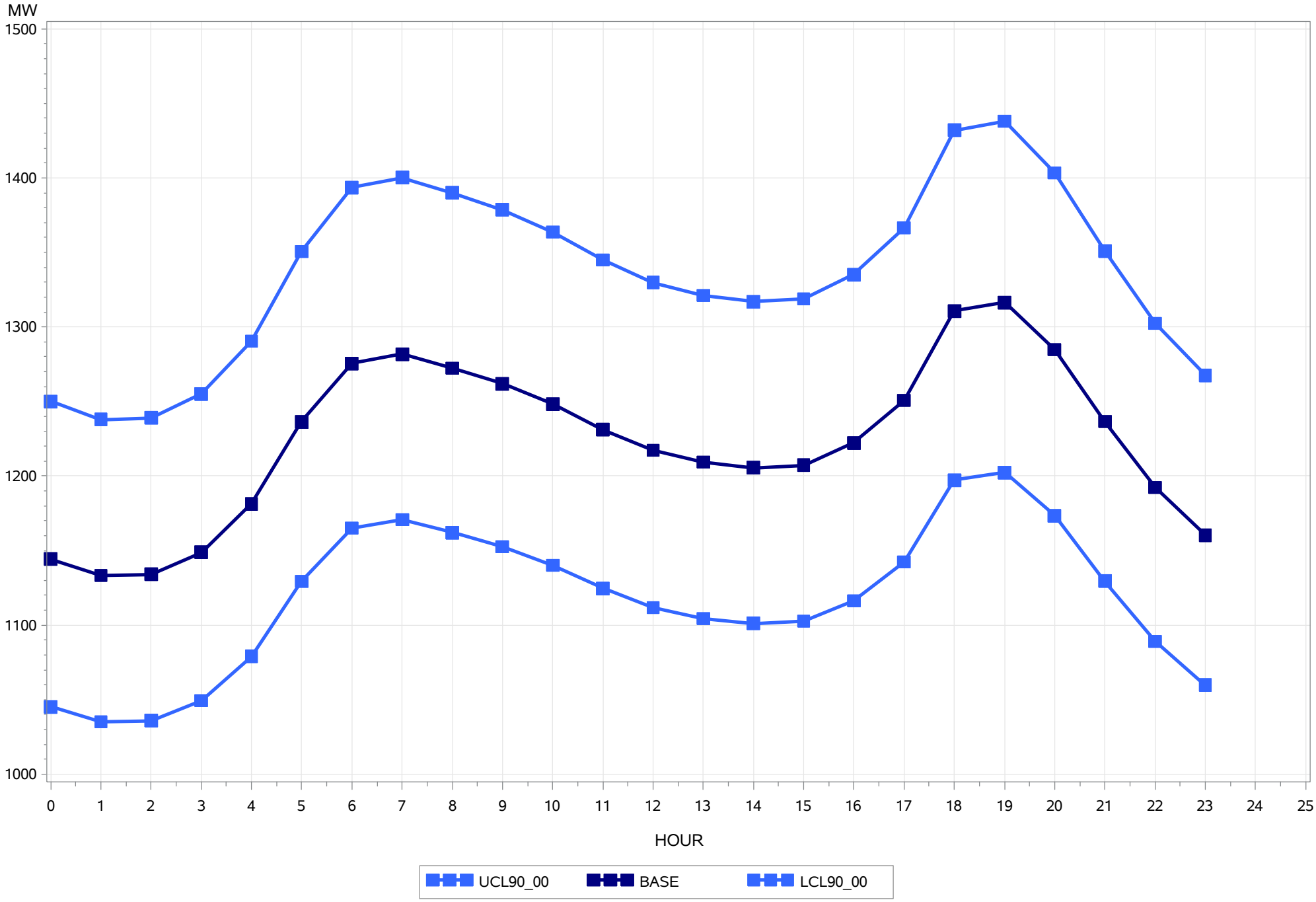
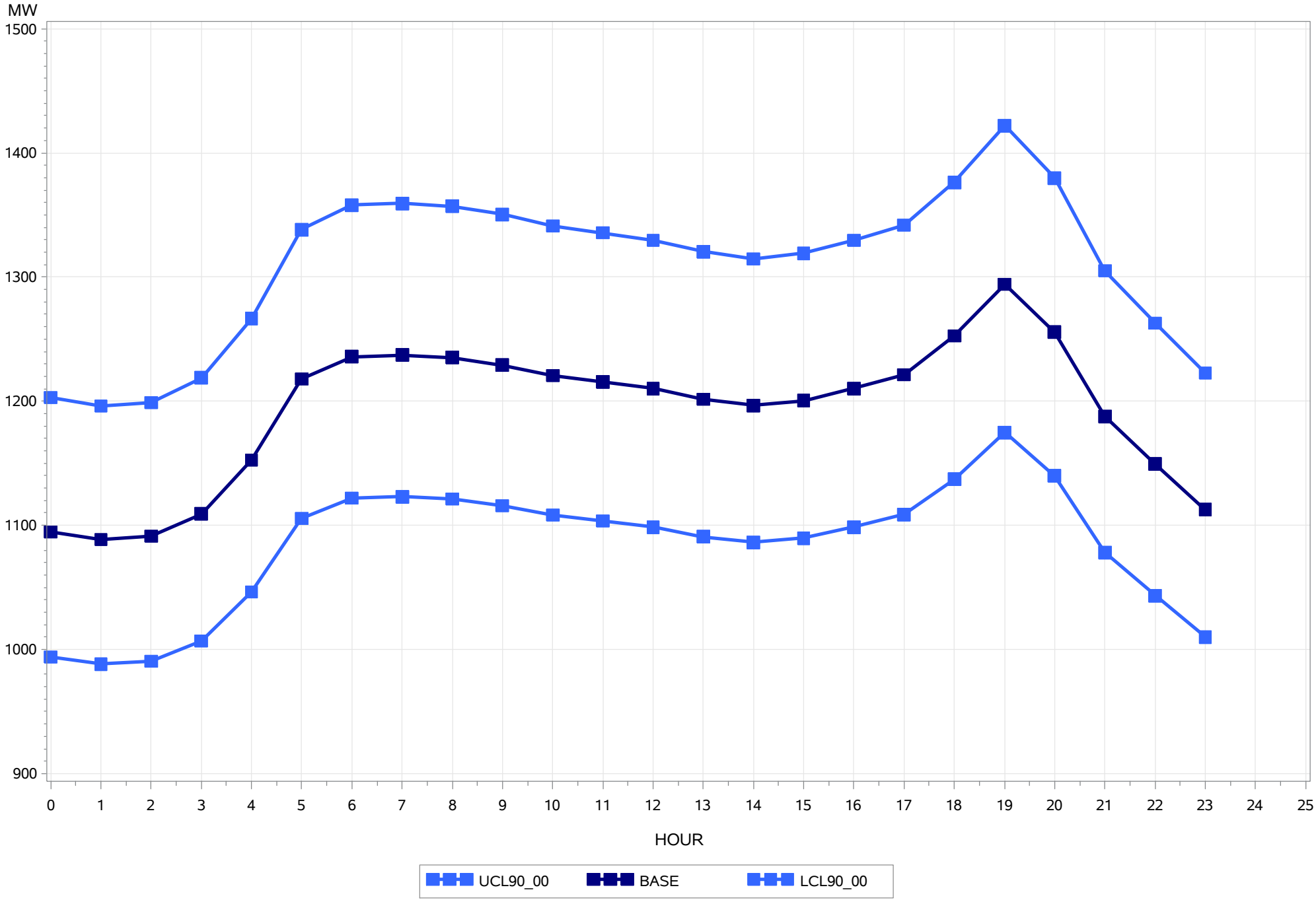
Hourly Average Day for March 2021
STATE OF COLORADO



Hourly Average Day for April 2021
STATE OF COLORADO



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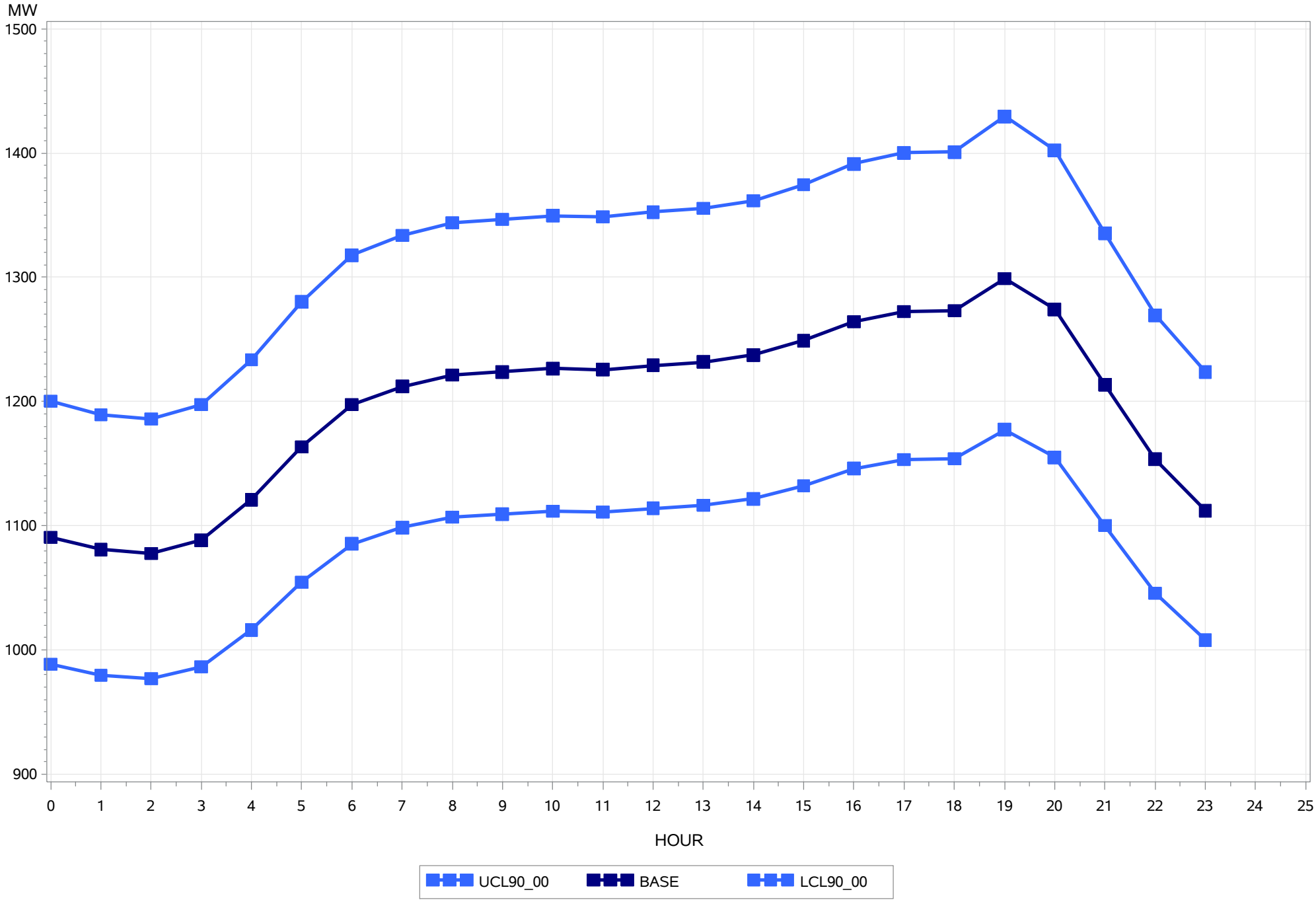
Hourly Average Day for May 2021
STATE OF COLORADO



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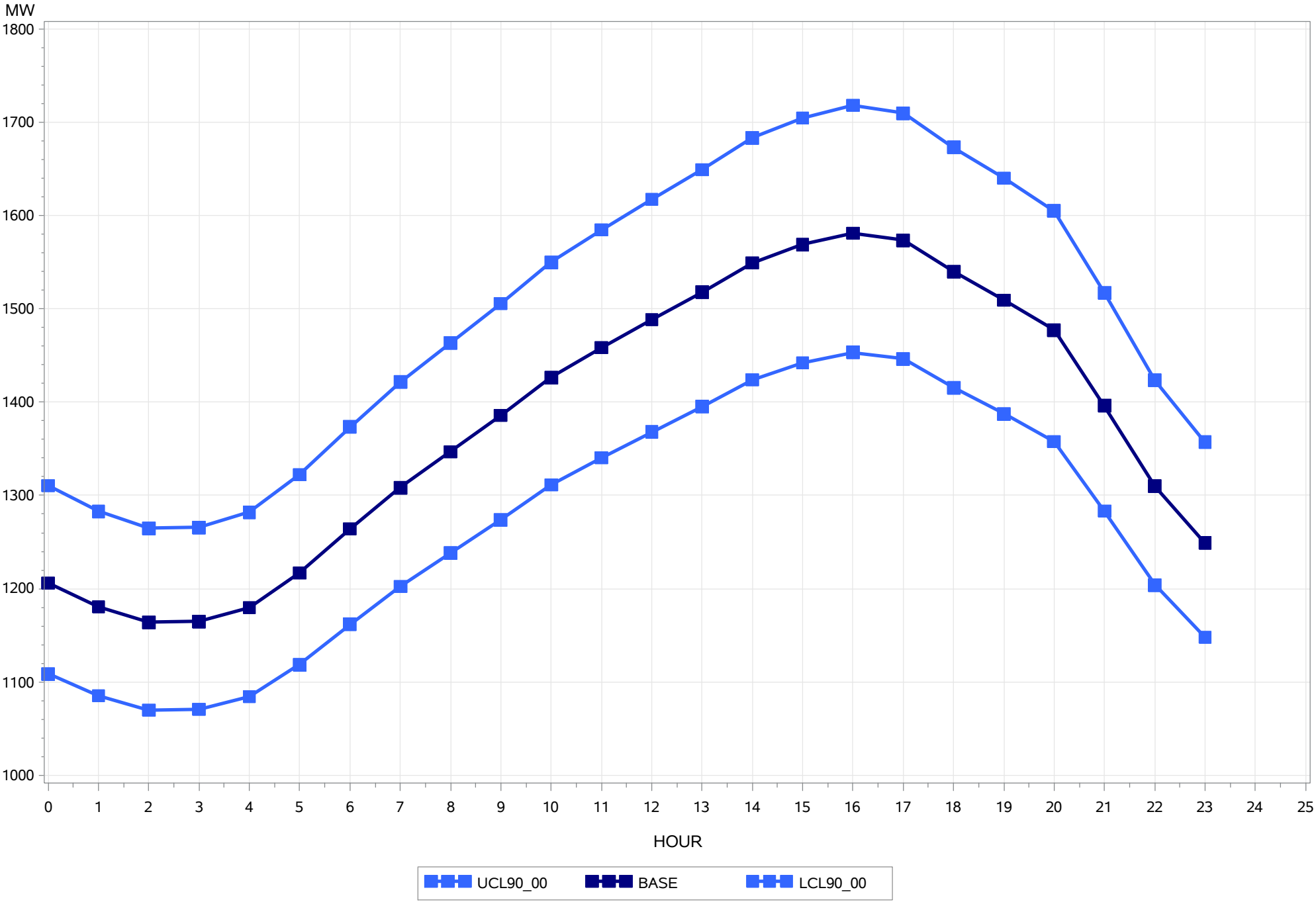
Hourly Average Day for June 2021
STATE OF COLORADO



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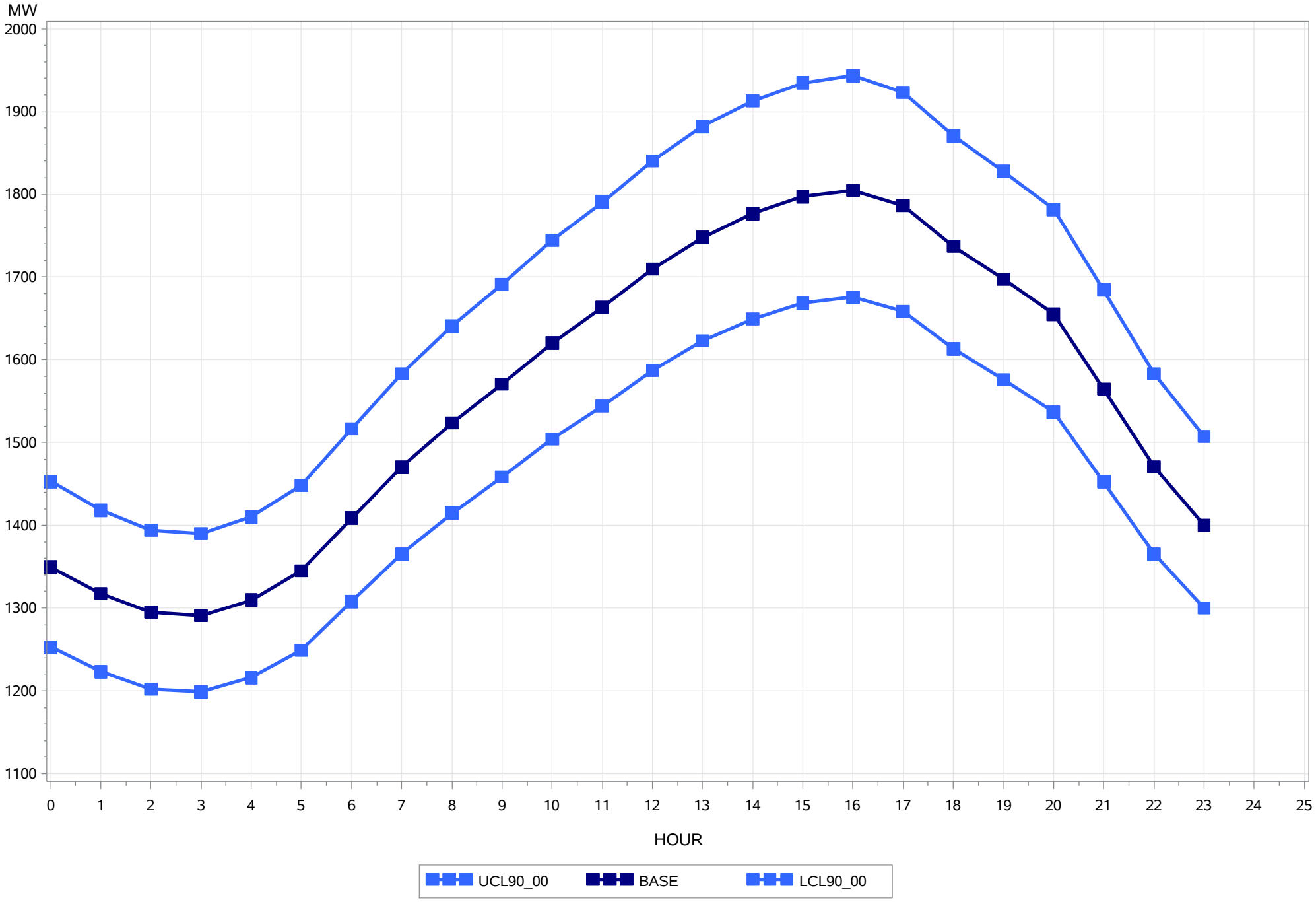
Hourly Average Day for July 2021
STATE OF COLORADO



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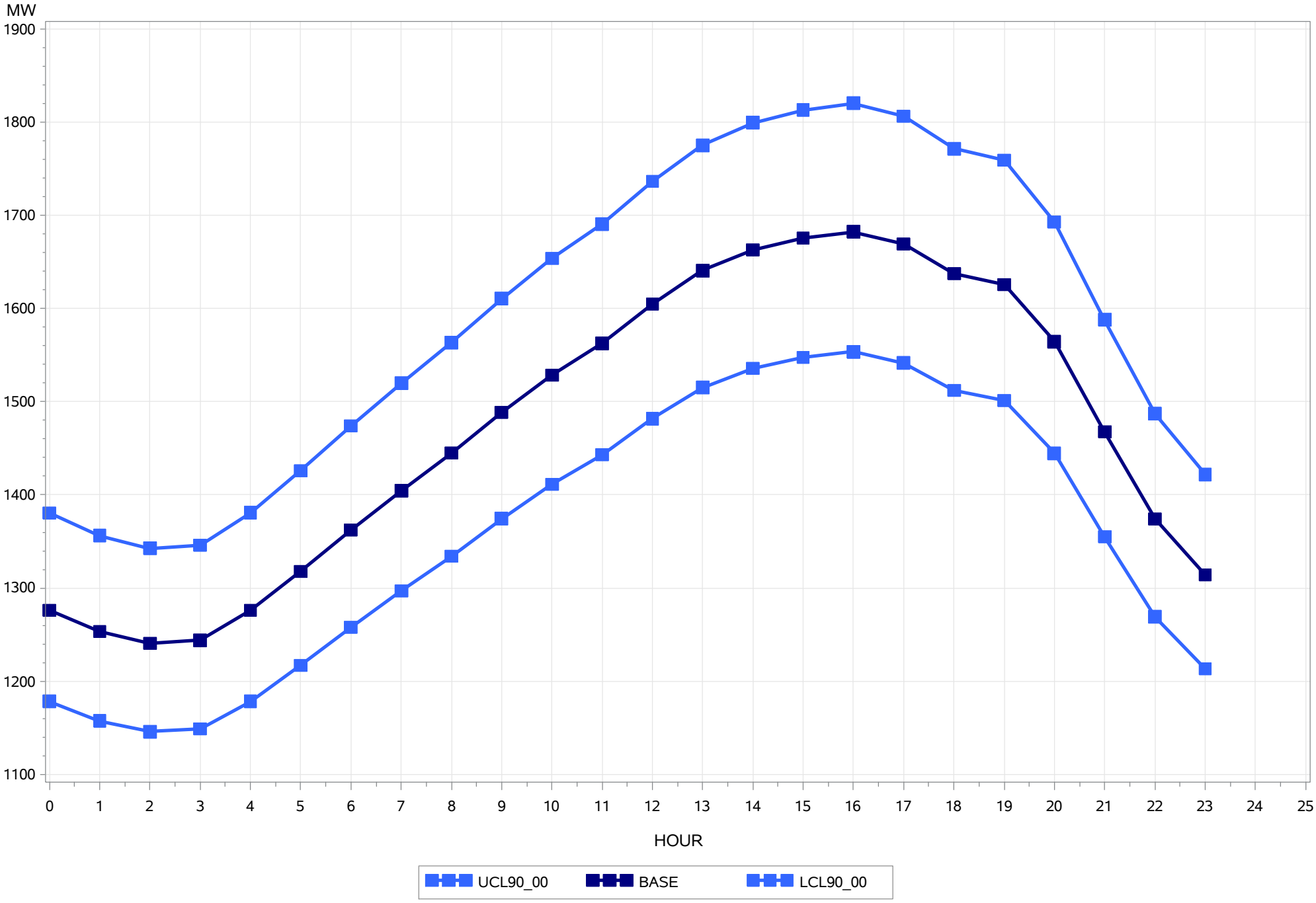
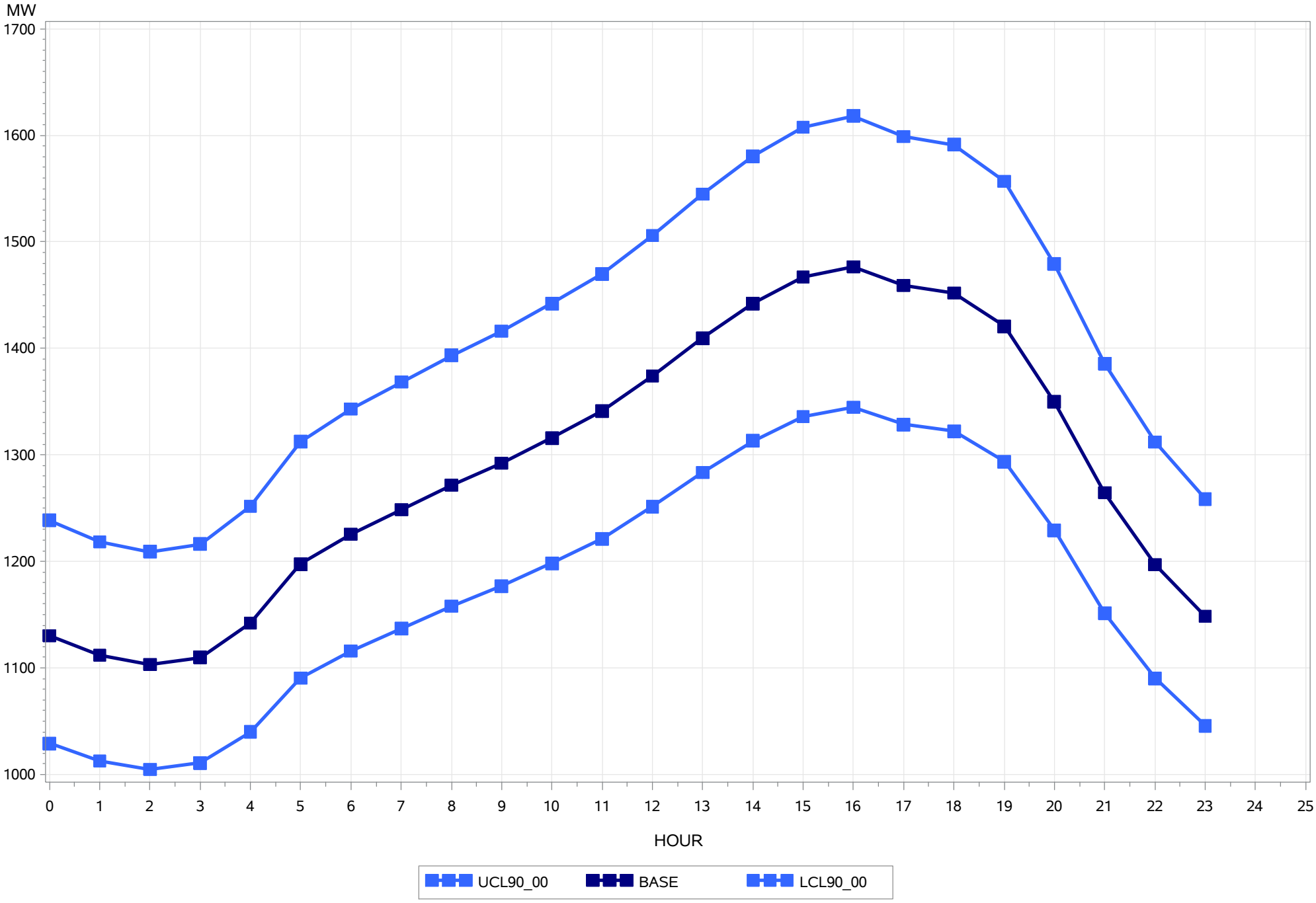
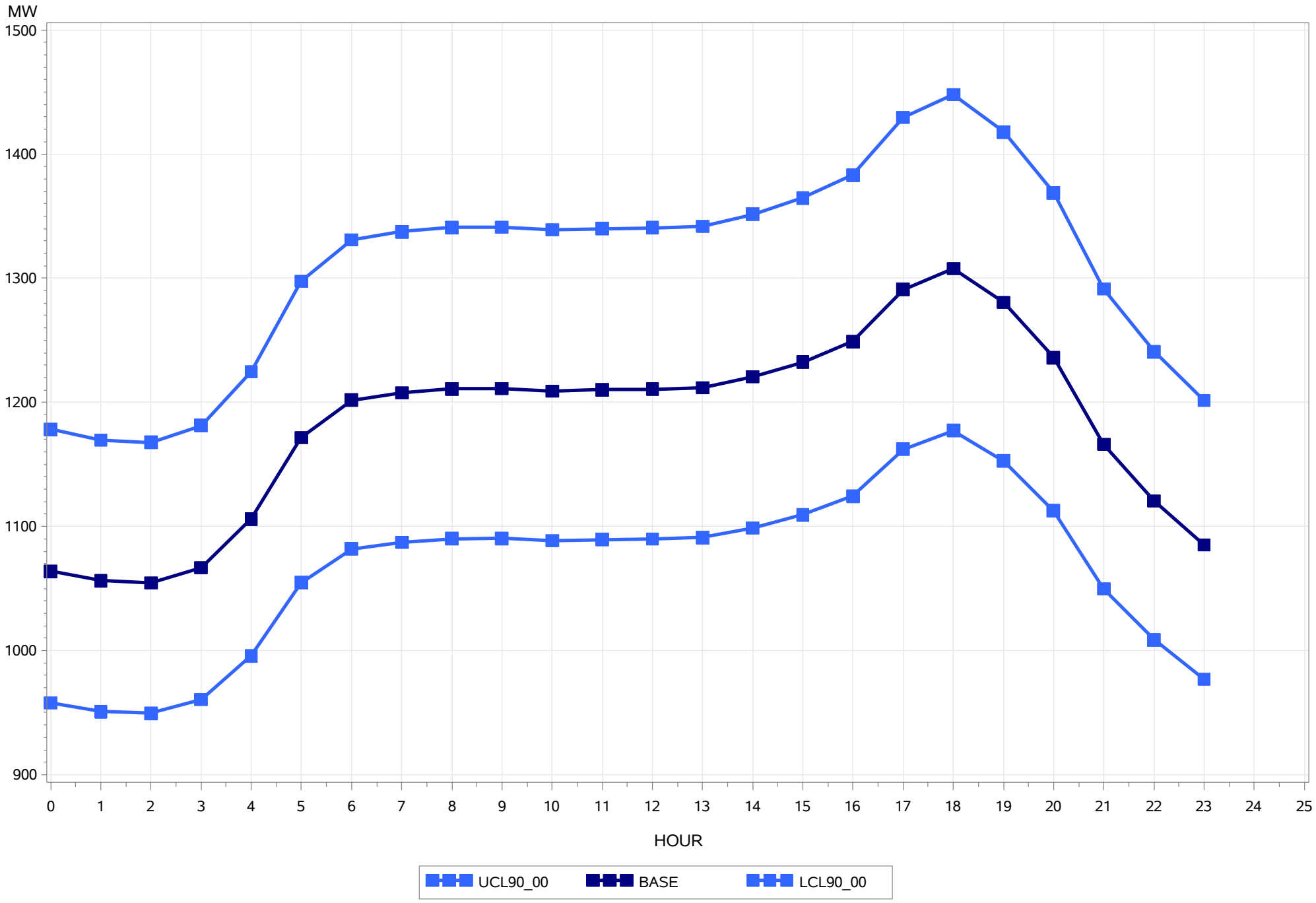
Hourly Average Day for August 2021
STATE OF COLORADO



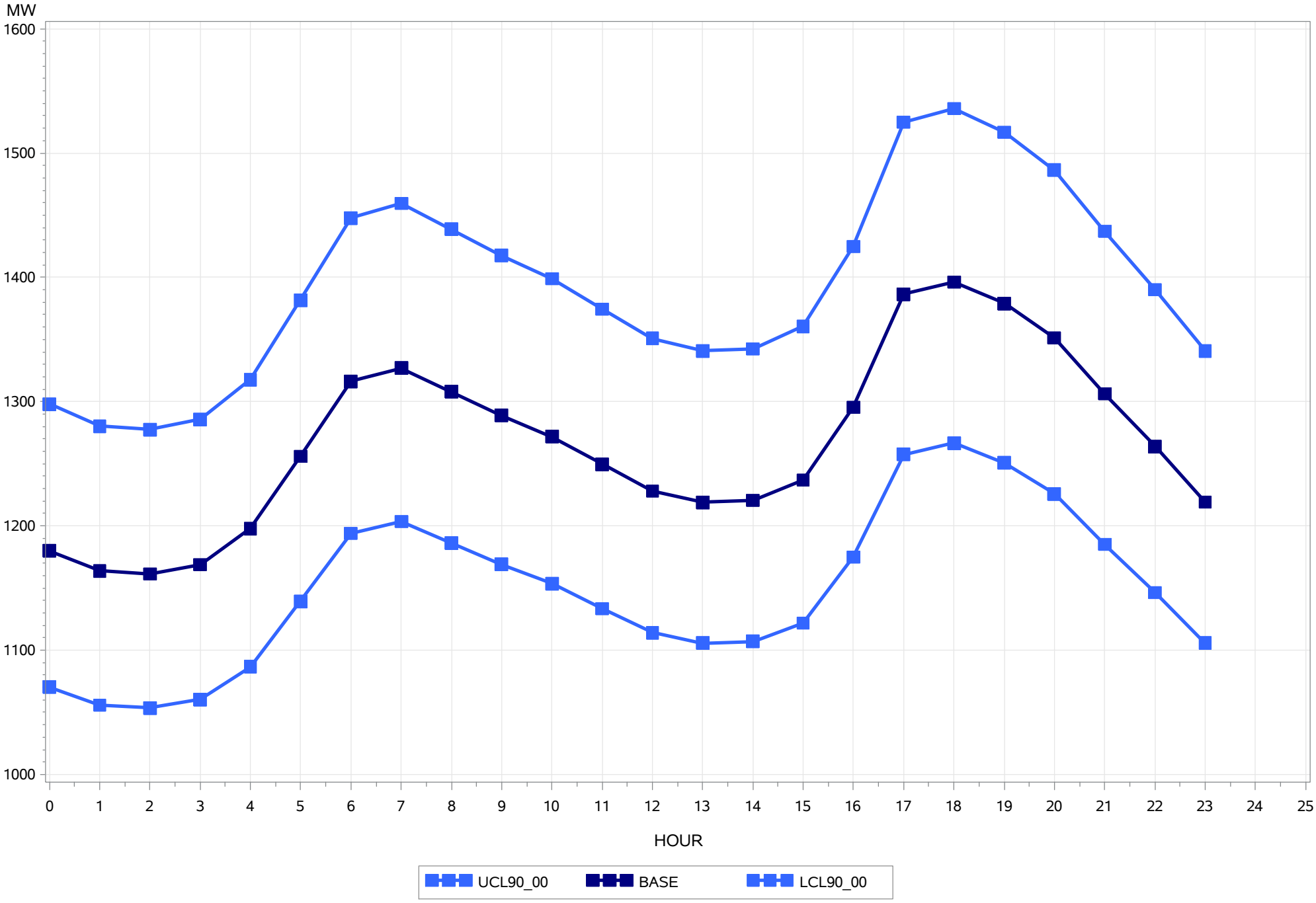
Hourly Average Day for September 2021
STATE OF COLORADO



Hourly Average Day for October 2021
STATE OF COLORADO



Hourly Average Day for November 2021
STATE OF COLORADO



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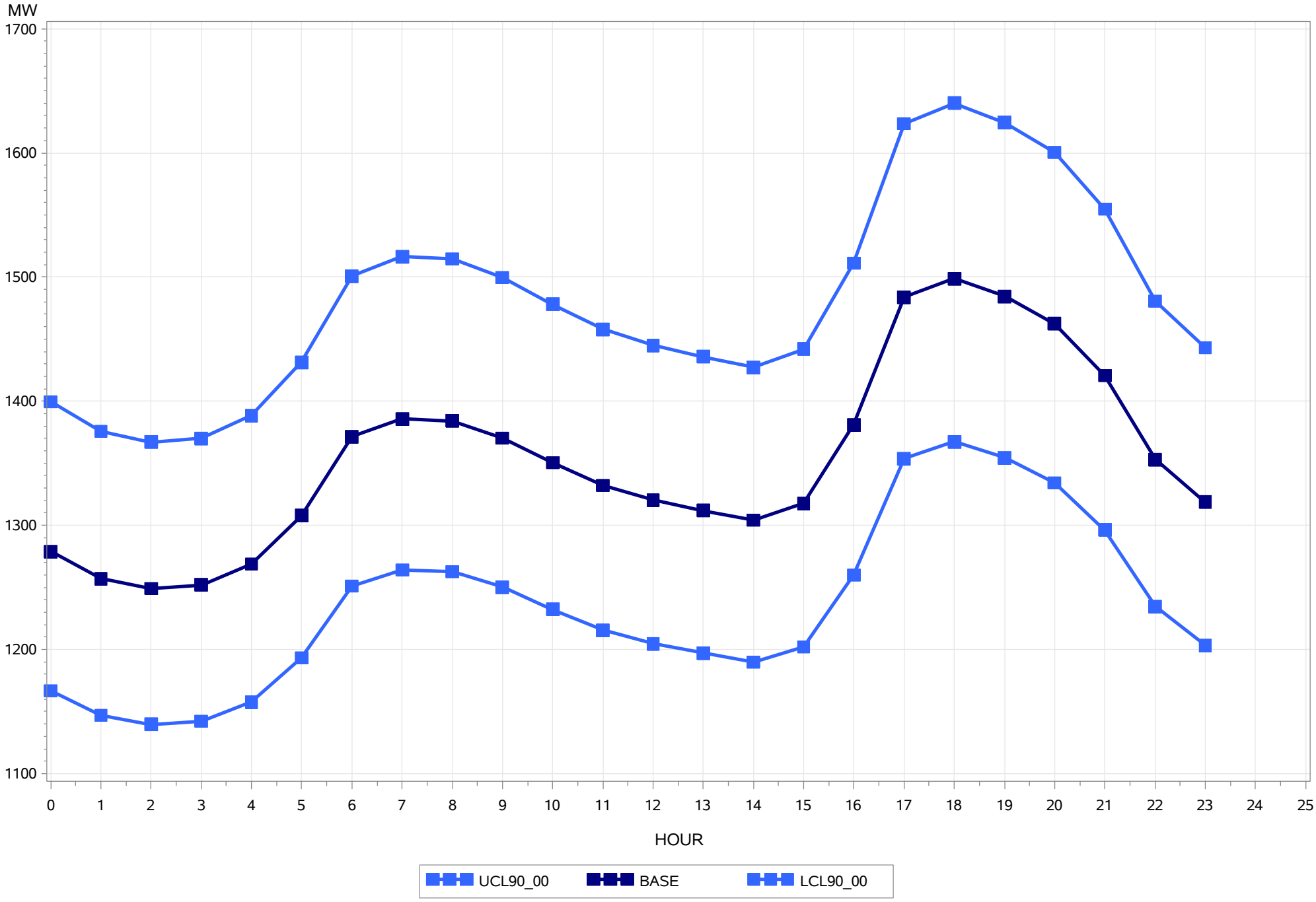
Hourly Average Day for December 2021
STATE OF COLORADO



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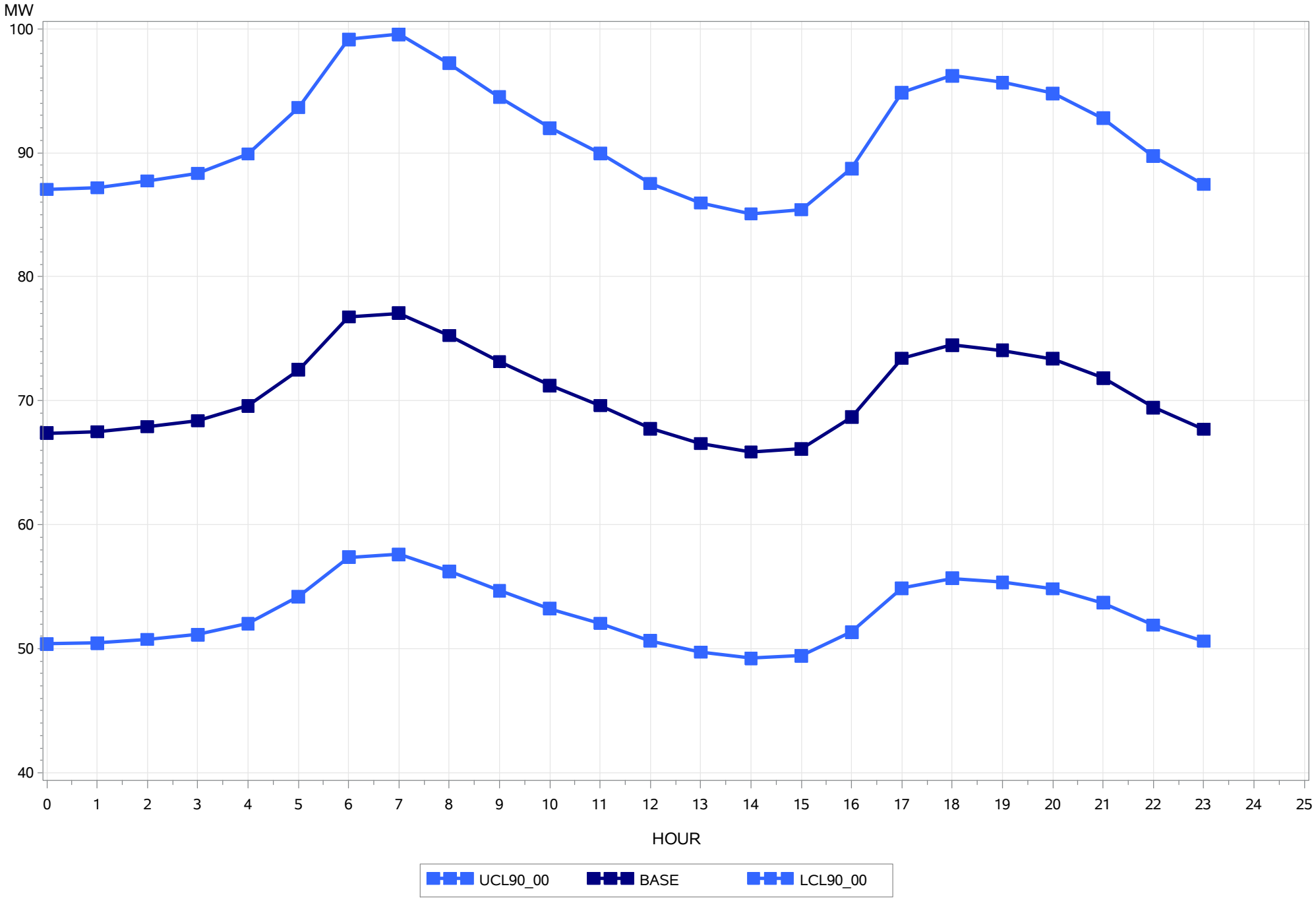
Hourly Average Day for January 2021
STATE OF NEBRASKA



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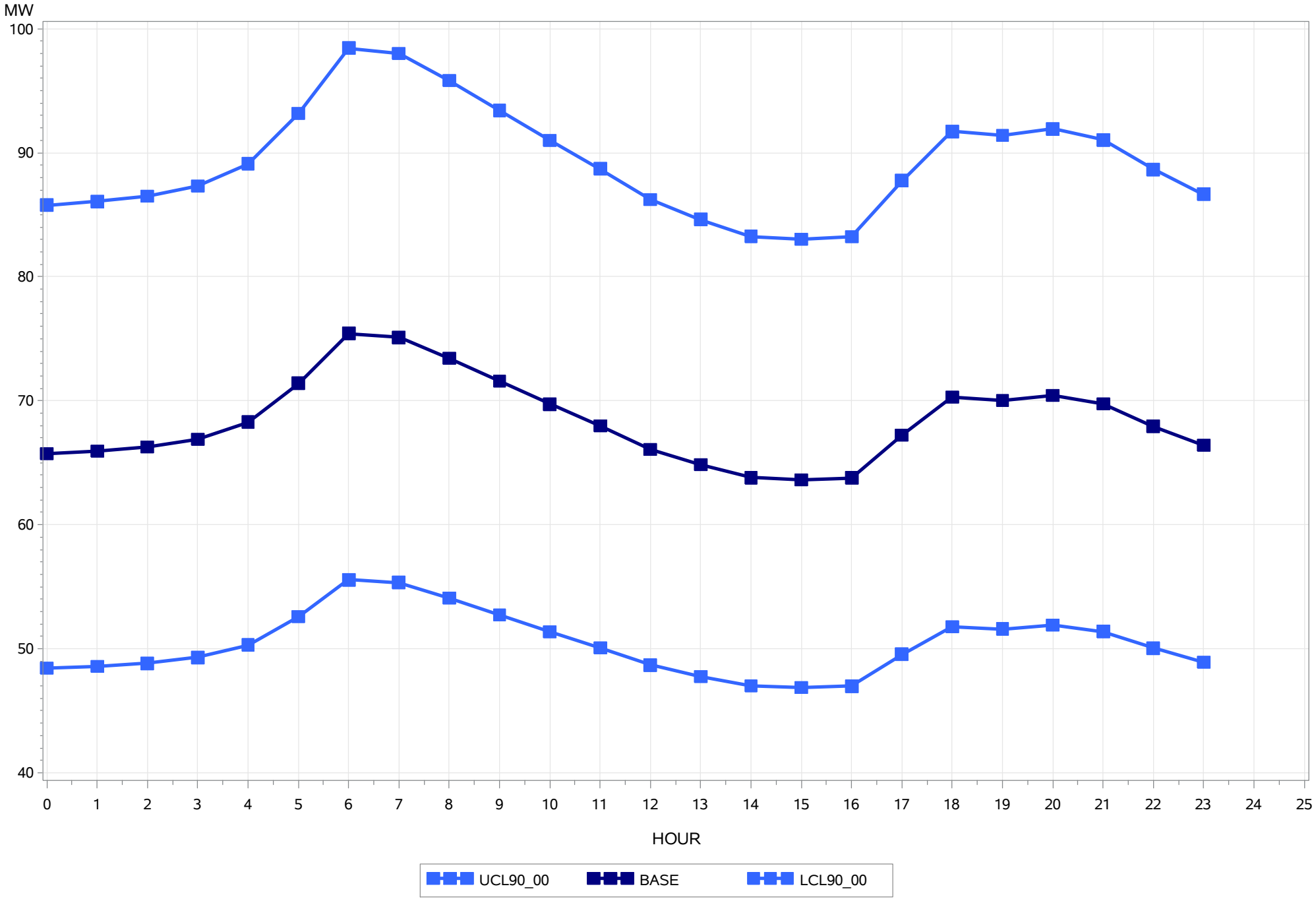
Hourly Average Day for February 2021
STATE OF NEBRASKA



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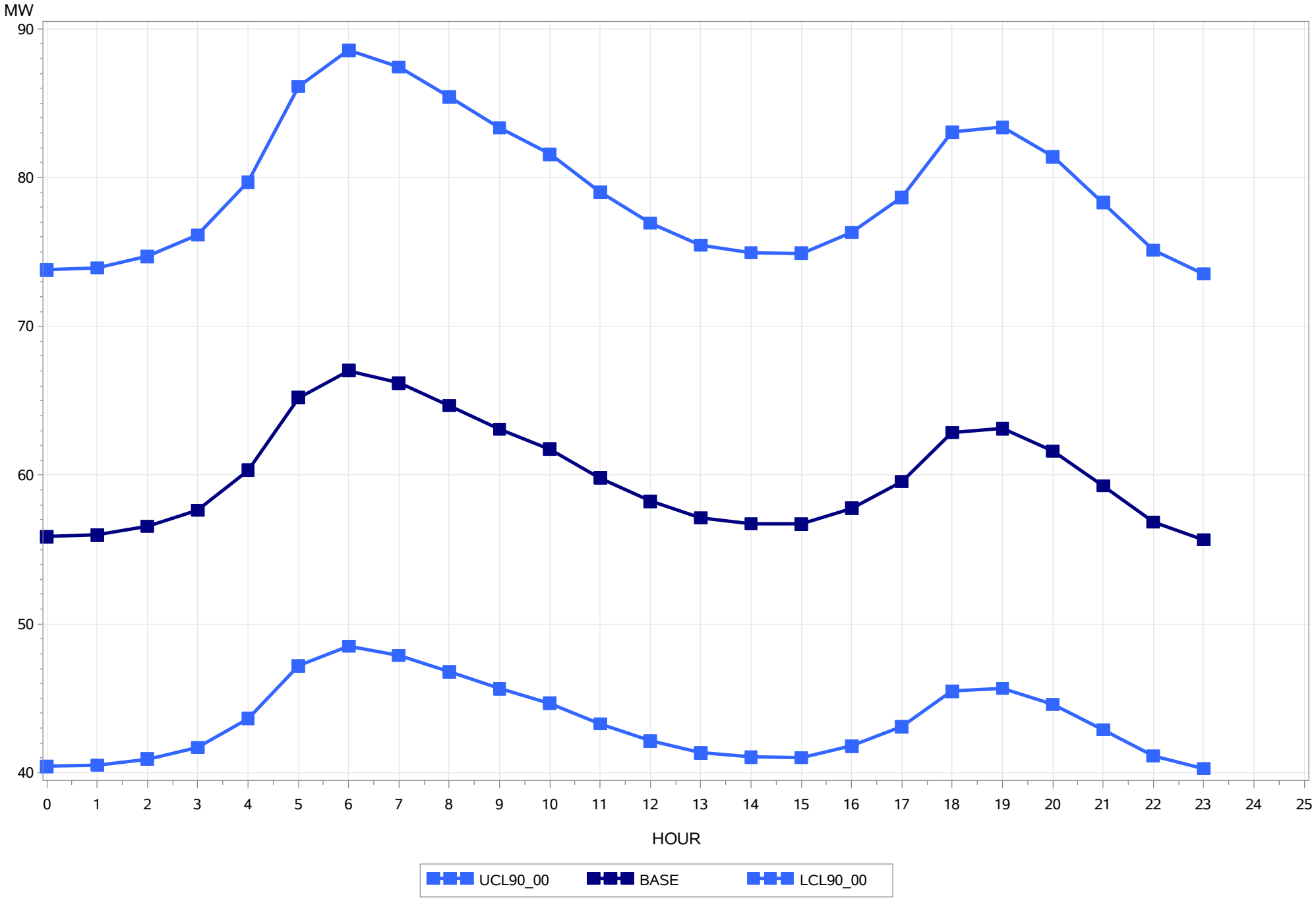
Hourly Average Day for March 2021
STATE OF NEBRASKA



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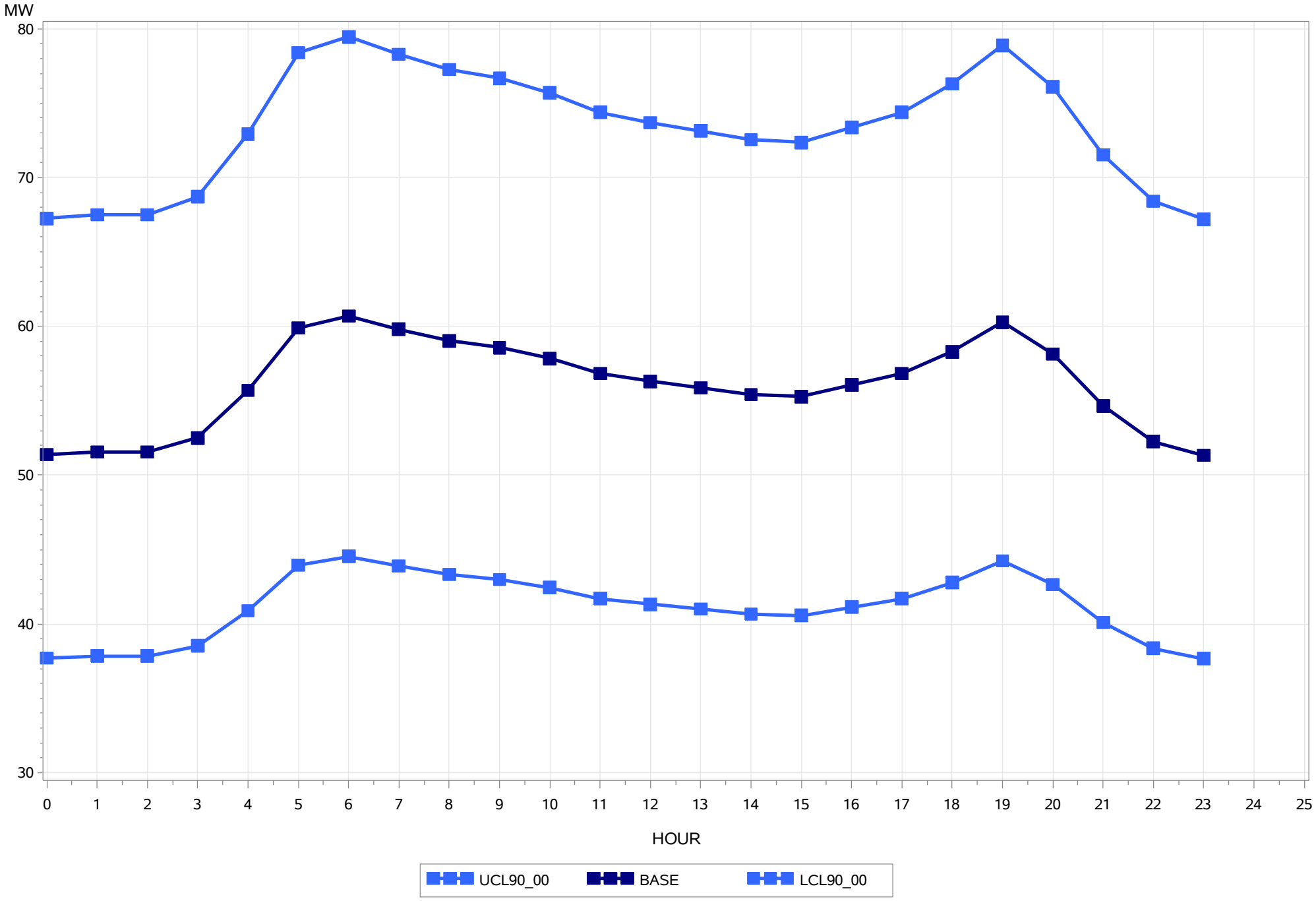
Hourly Average Day for April 2021
STATE OF NEBRASKA



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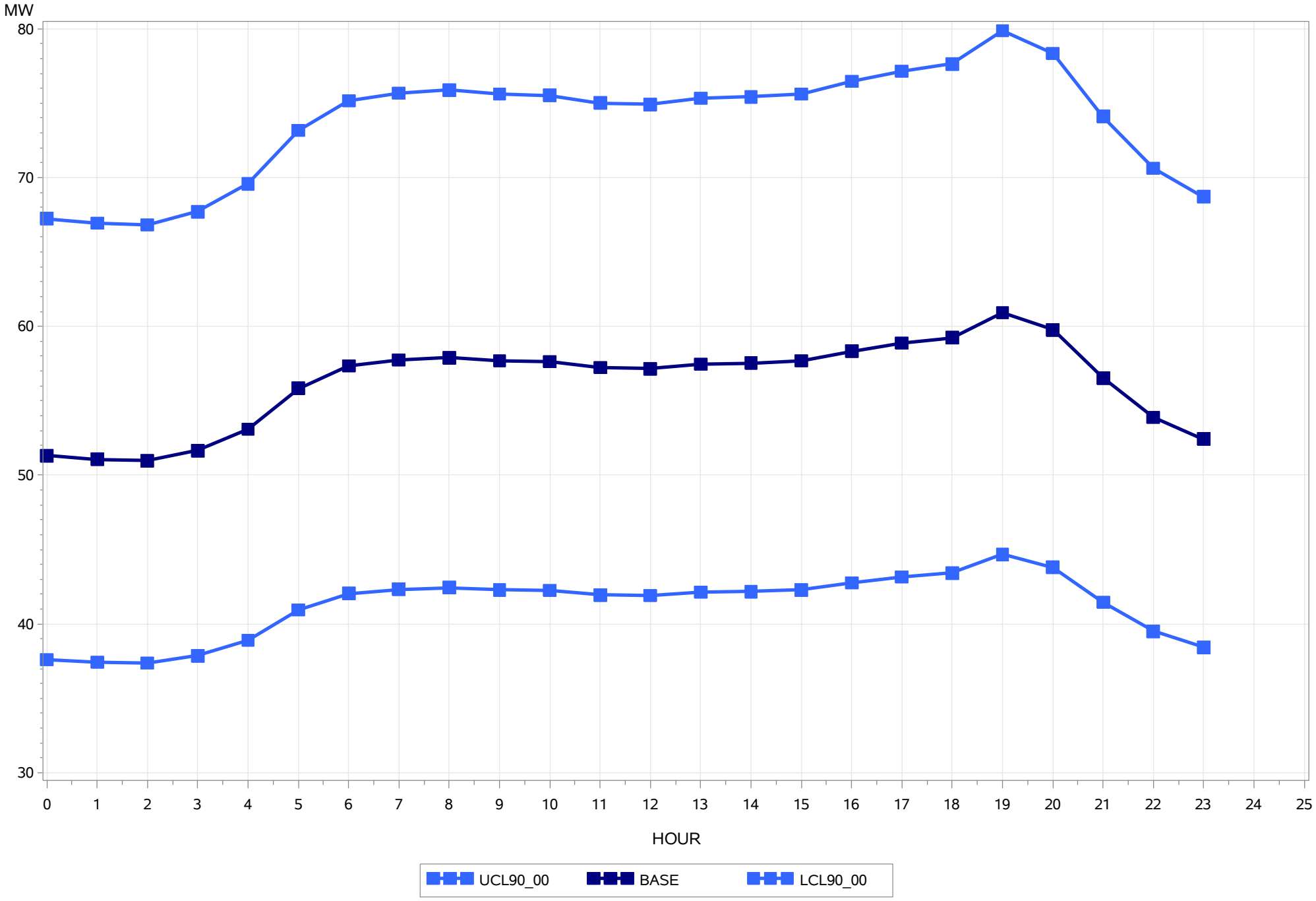
Hourly Average Day for May 2021

STATE OF NEBRASKA



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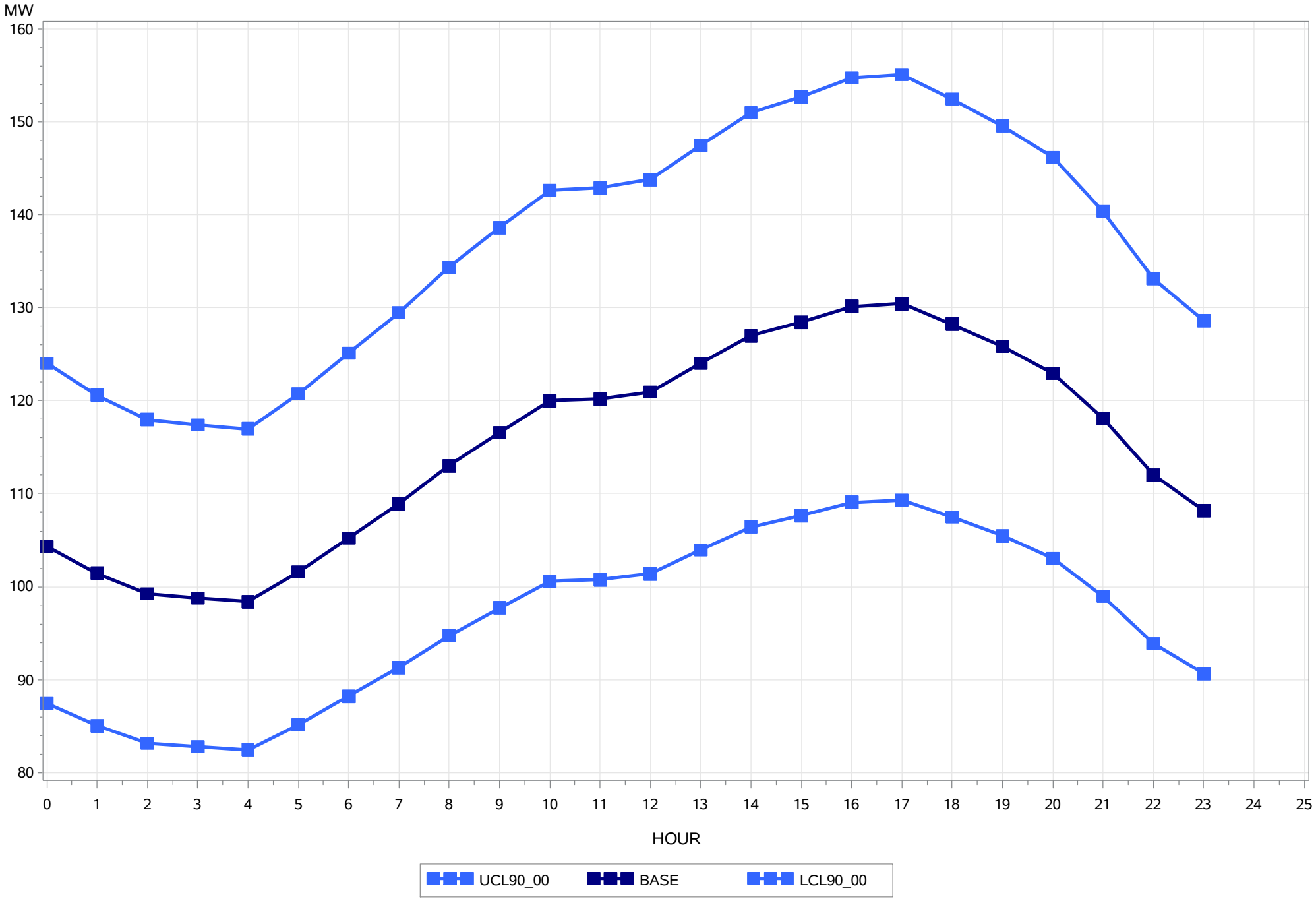
Hourly Average Day for June 2021
STATE OF NEBRASKA



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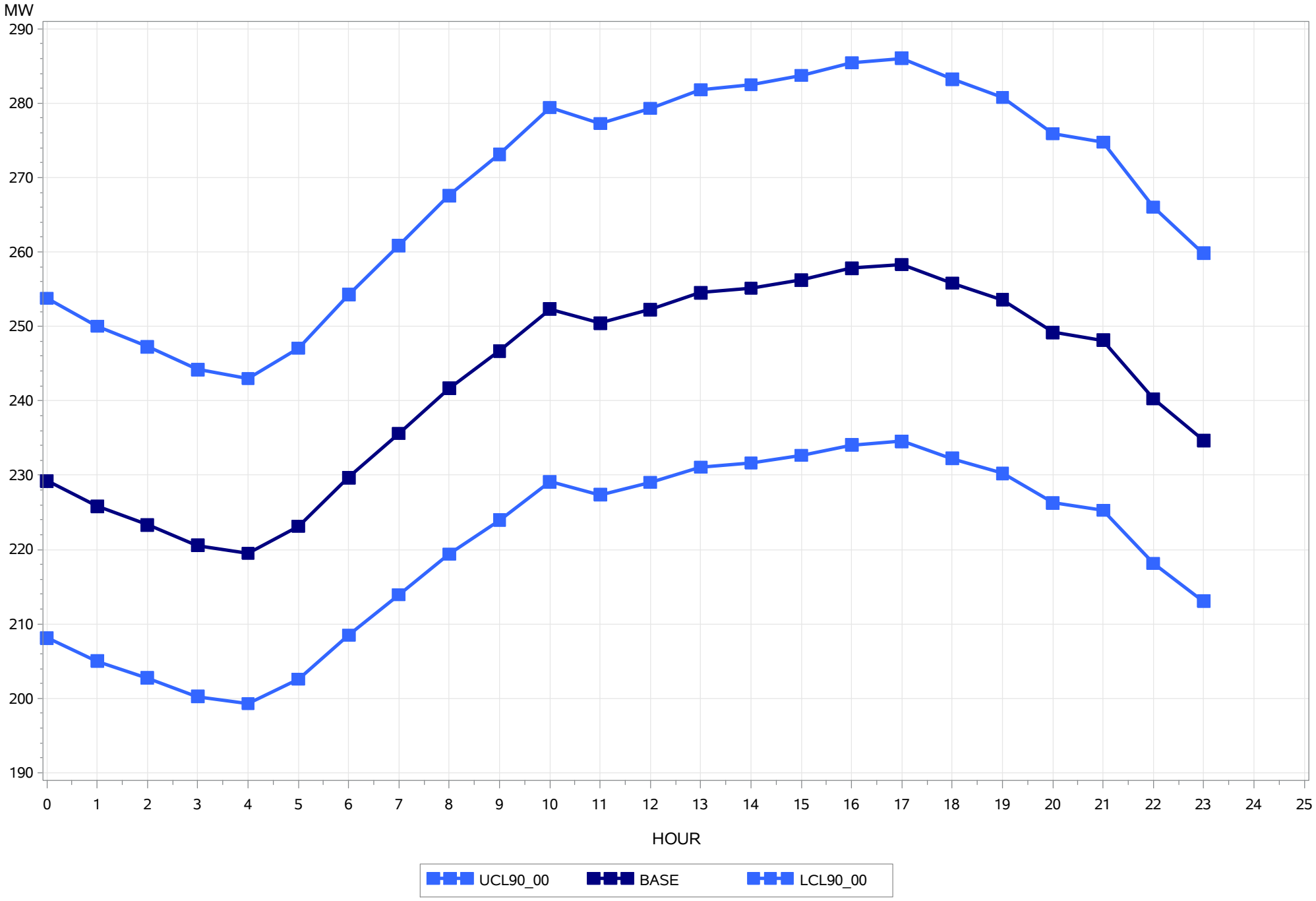
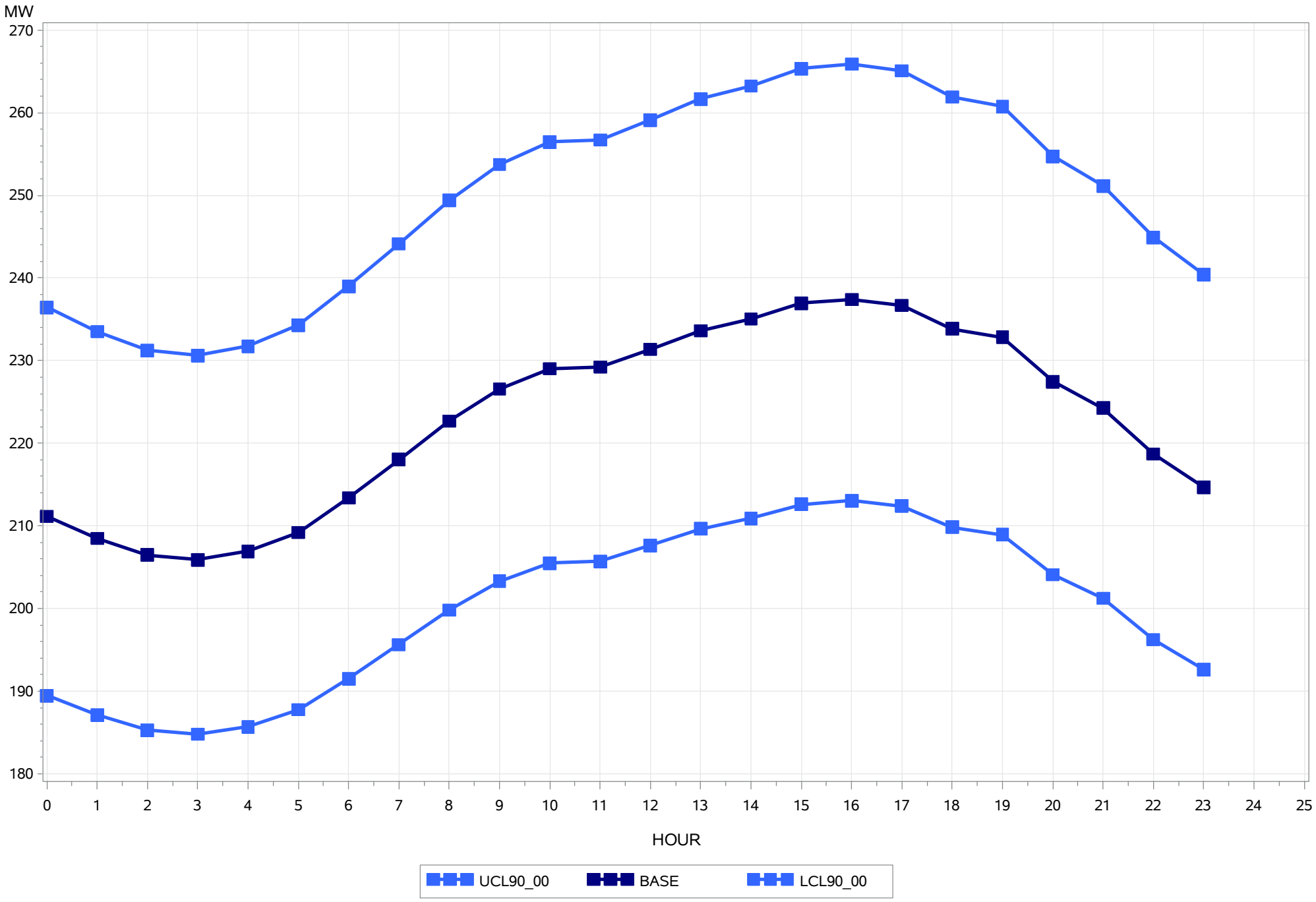
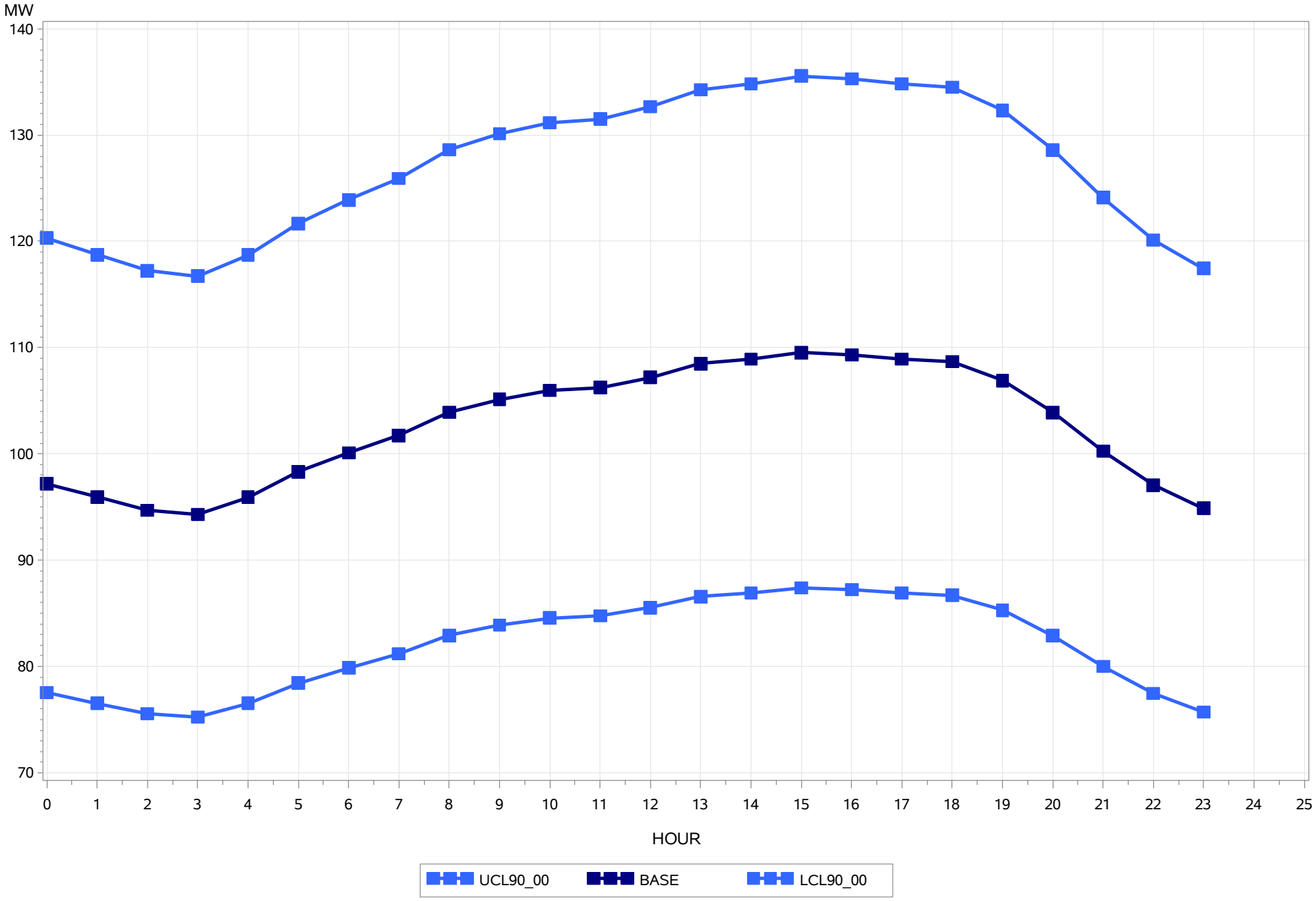
Hourly Average Day for July 2021
STATE OF NEBRASKA



Hourly Average Day for August 2021
STATE OF NEBRASKA



Hourly Average Day for September 2021
STATE OF NEBRASKA



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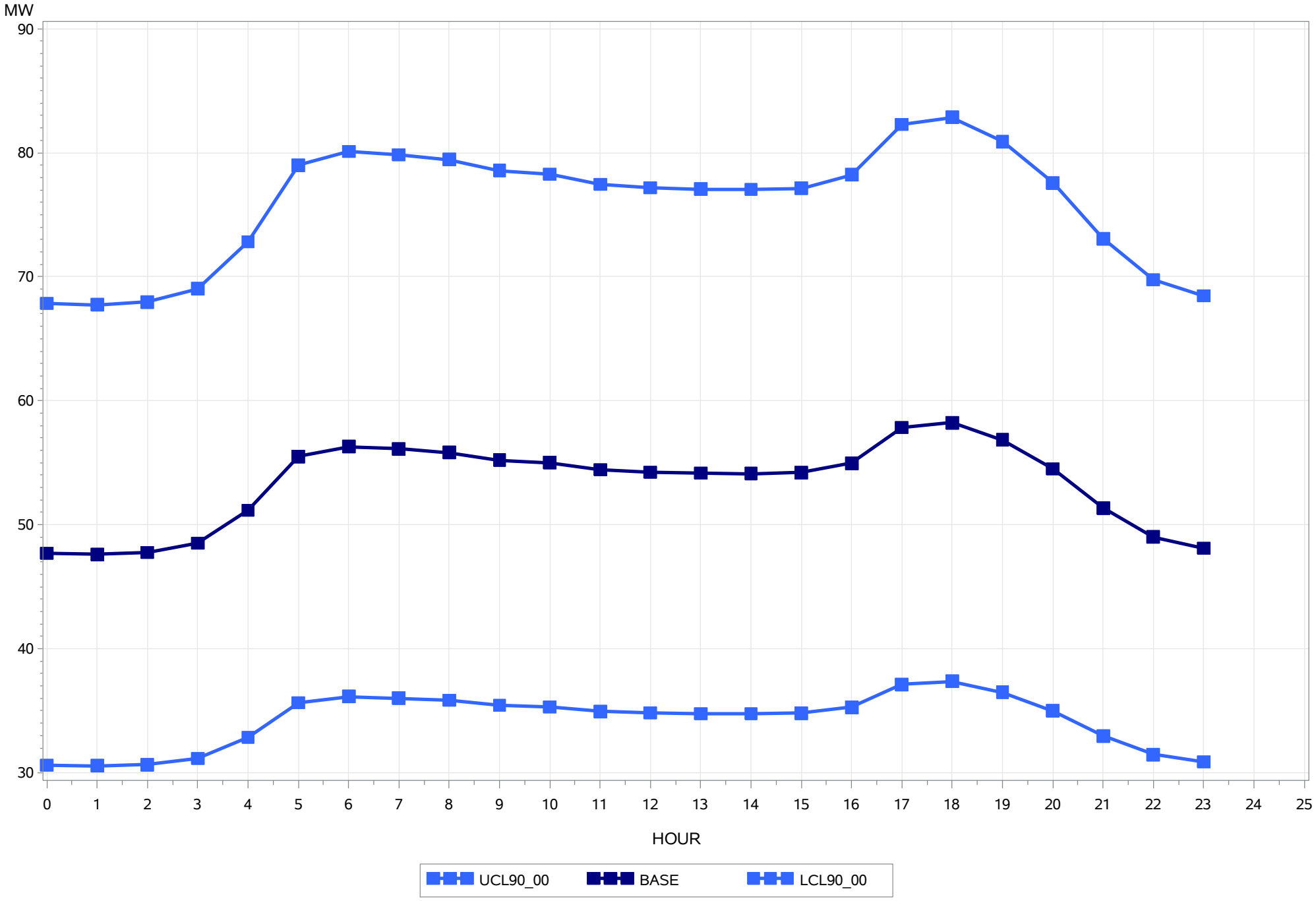
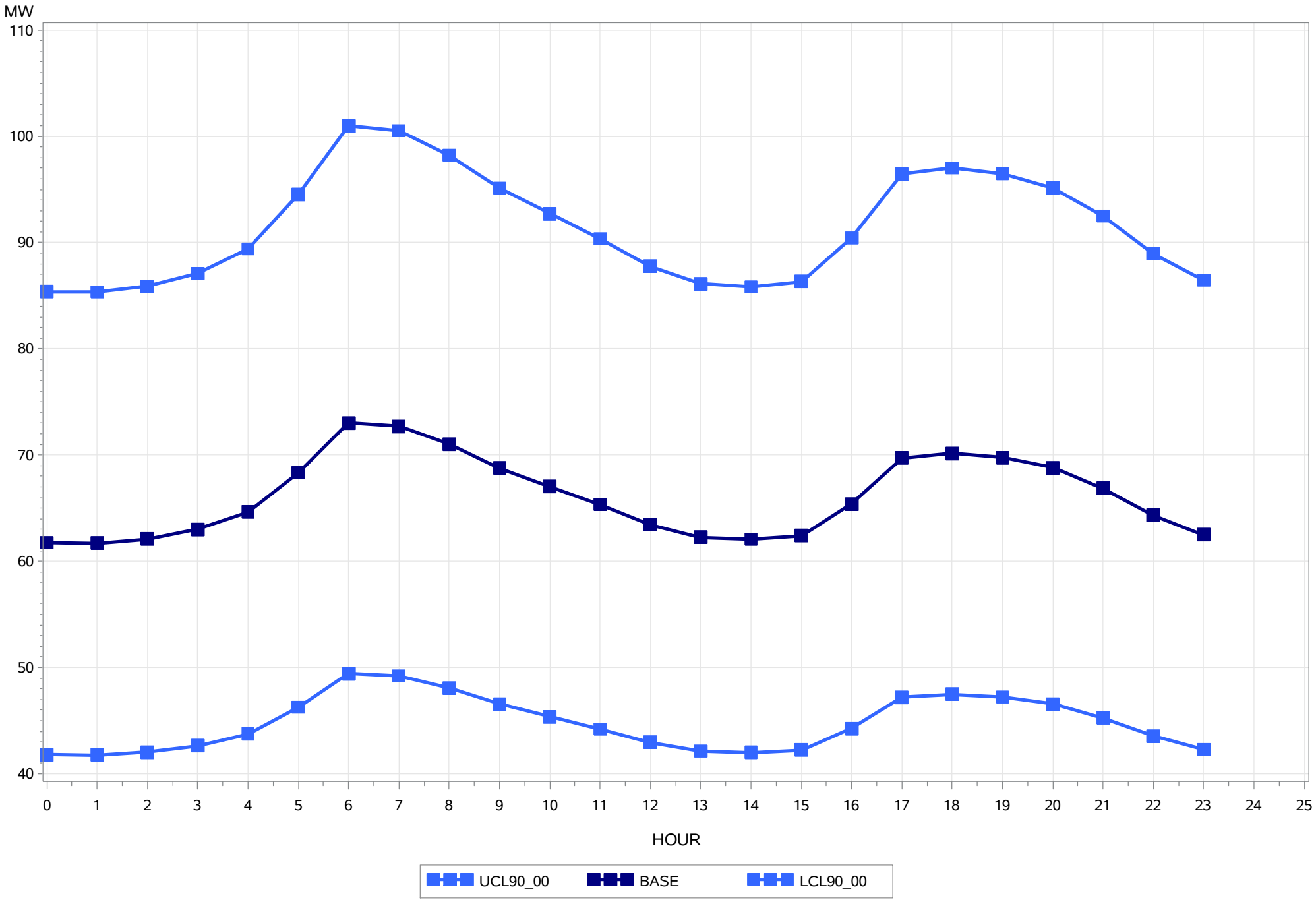
Hourly Average Day for October 2021
STATE OF NEBRASKA



Hourly Average Day for November 2021
STATE OF NEBRASKA



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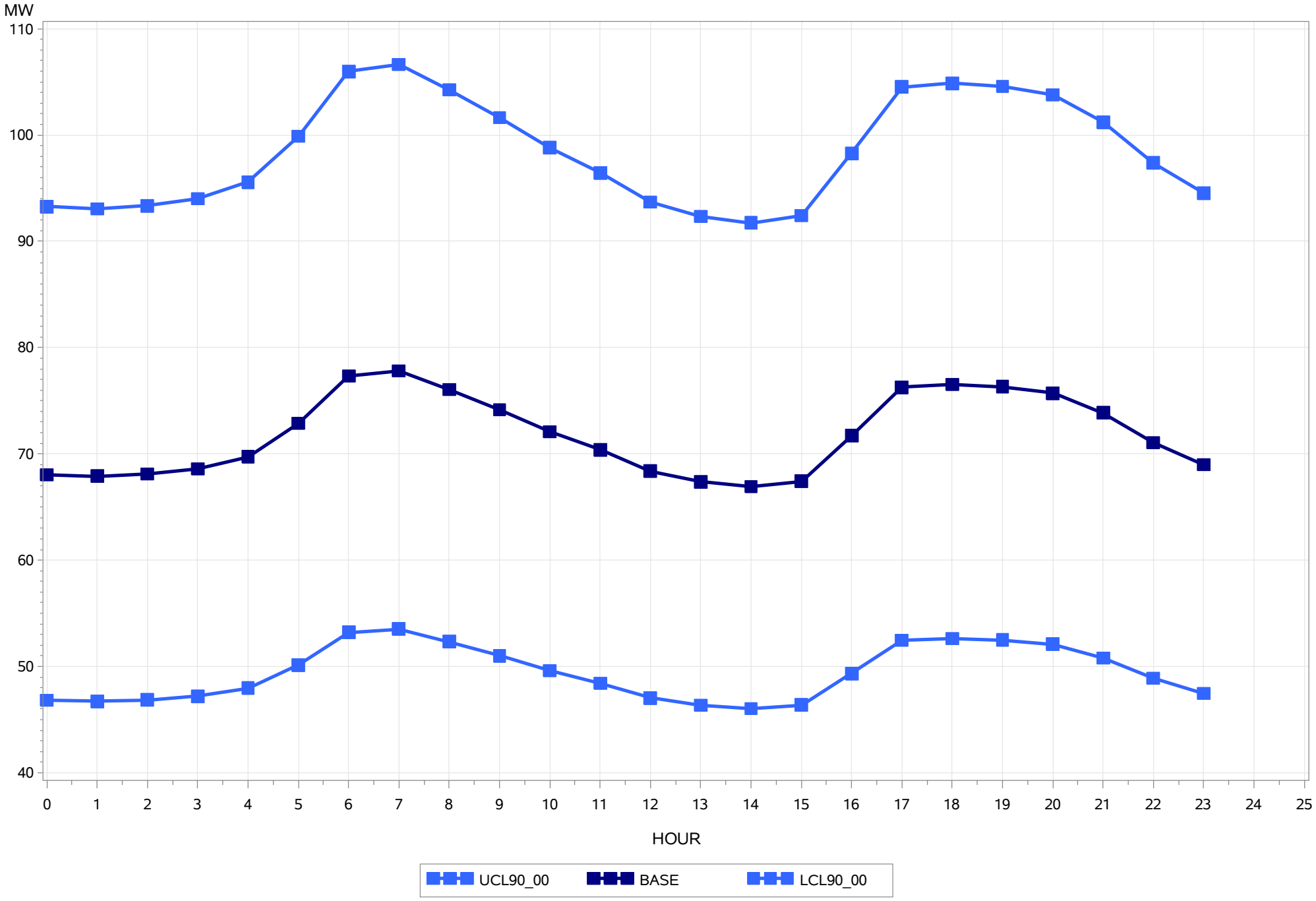
Hourly Average Day for December 2021
STATE OF NEBRASKA



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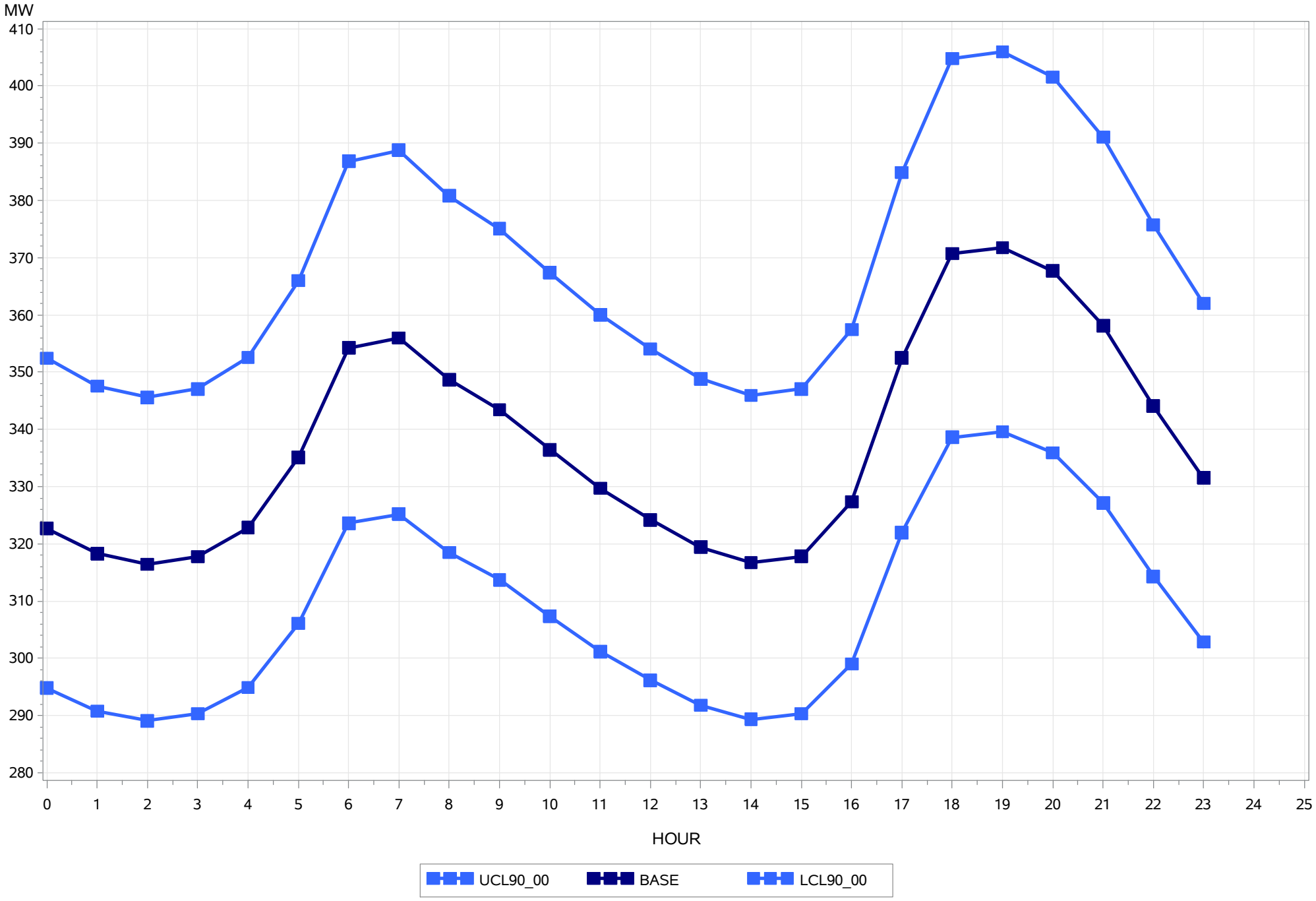
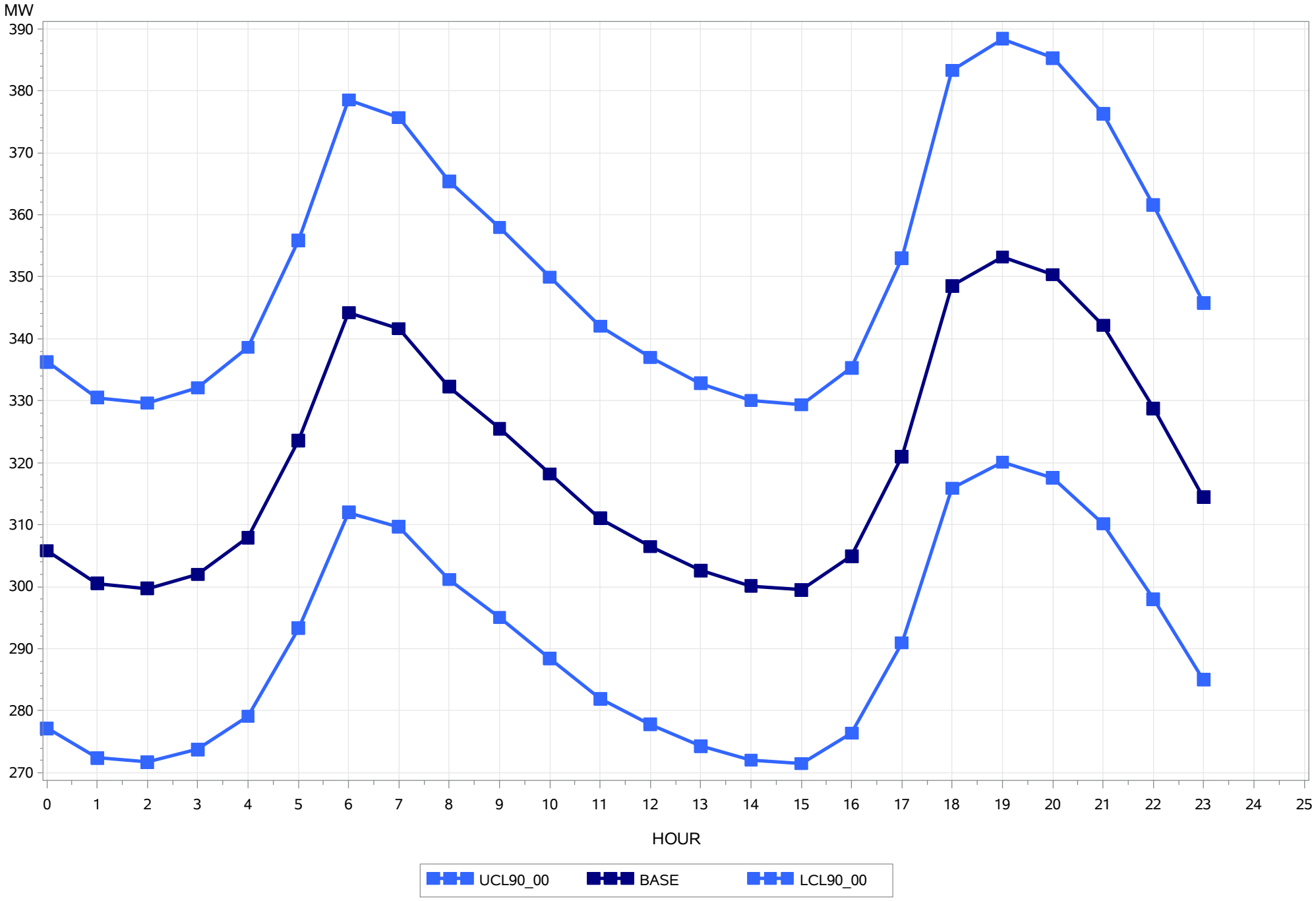
Hourly Average Day for January 2021
STATE OF NEW MEXICO



Hourly Average Day for February 2021
STATE OF NEW MEXICO



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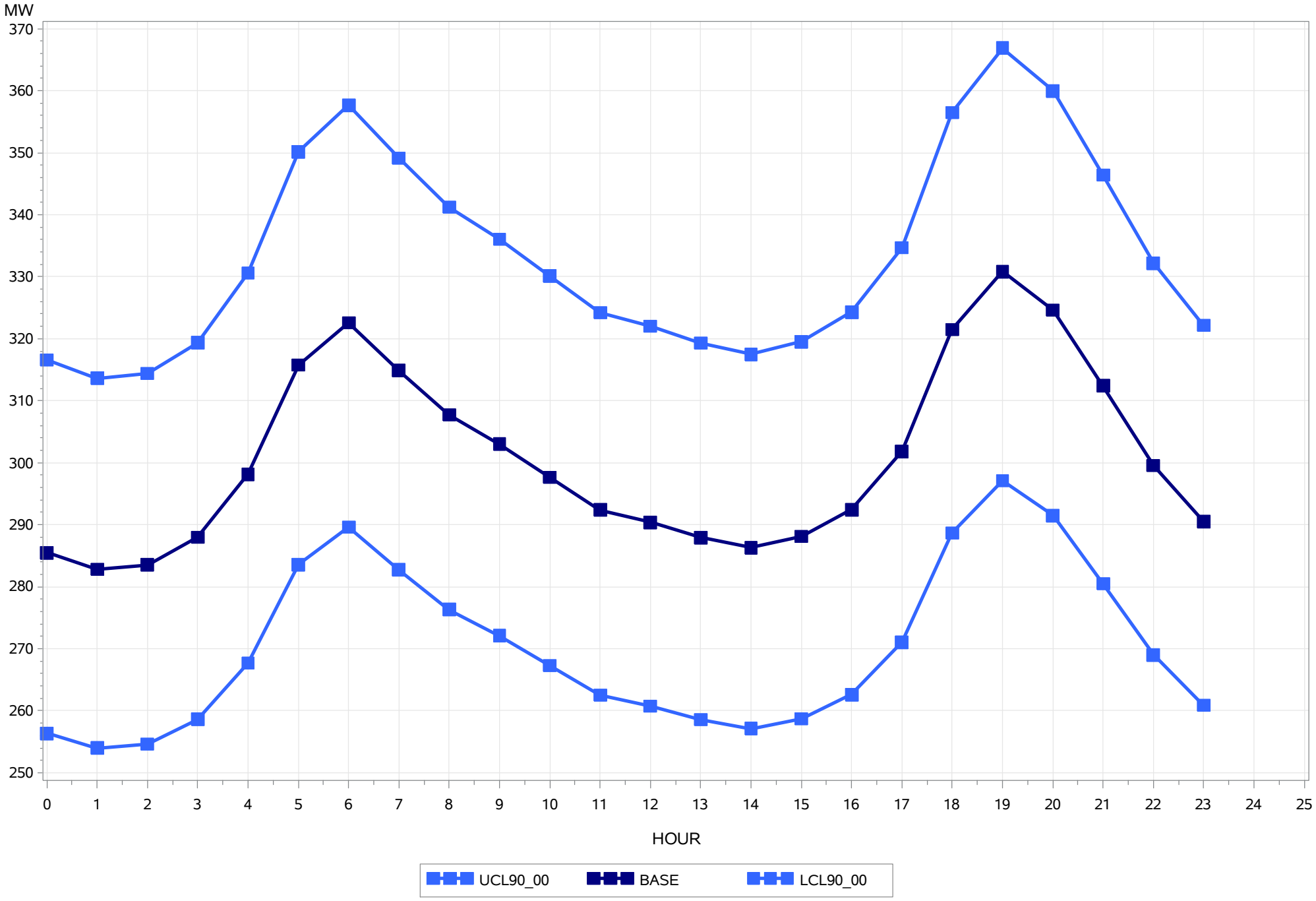
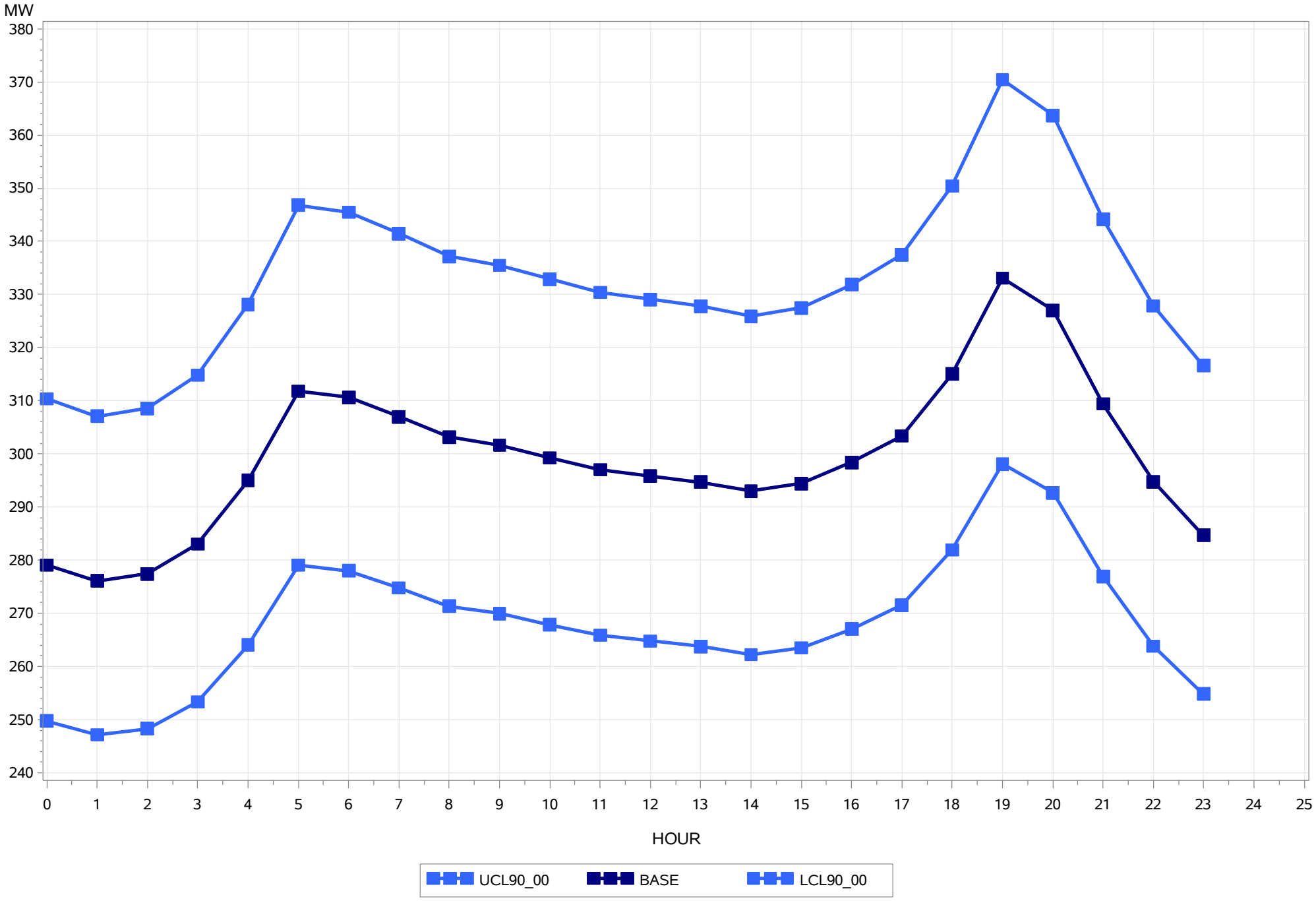
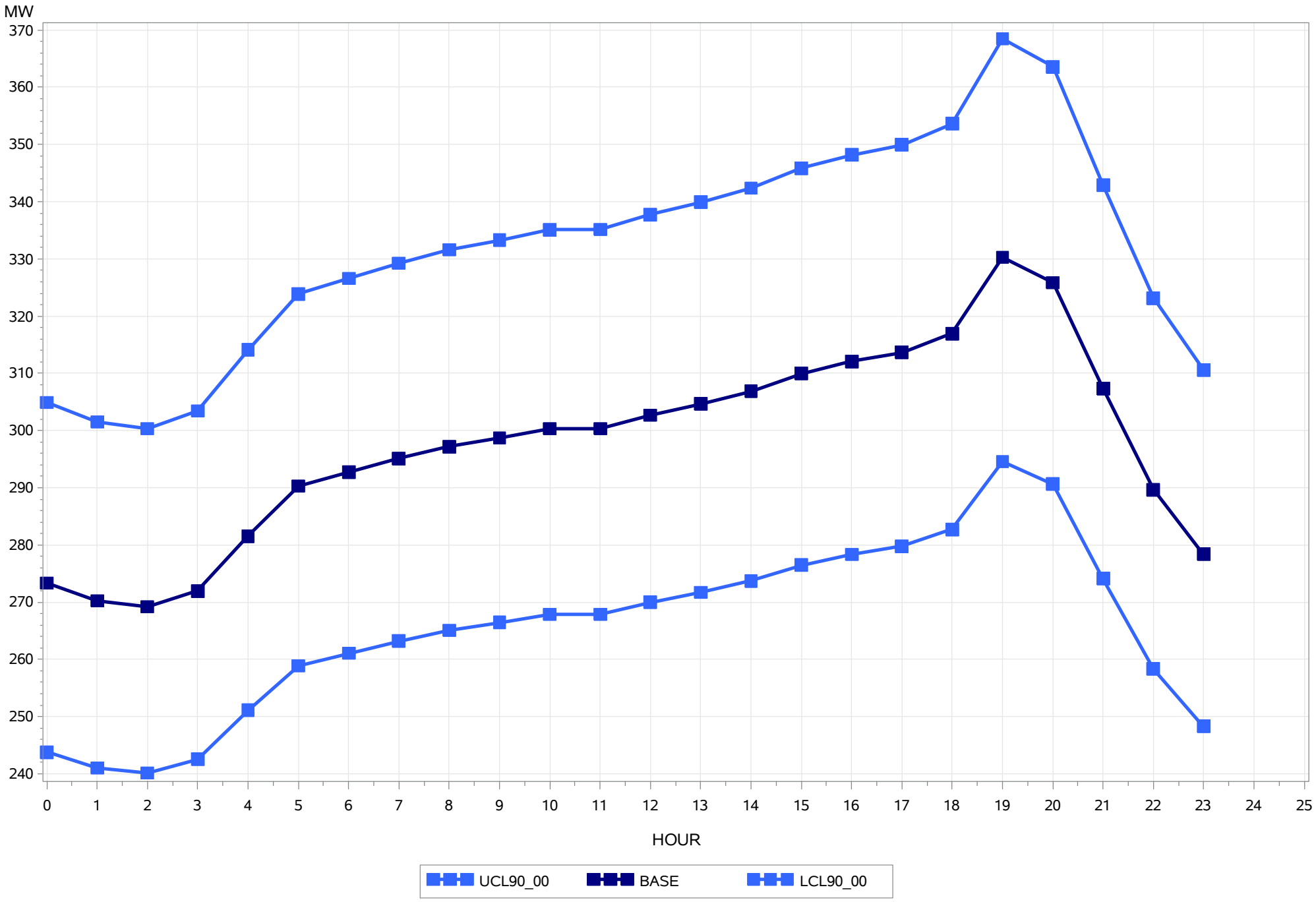
Hourly Average Day for March 2021
STATE OF NEW MEXICO



Hourly Average Day for April 2021
STATE OF NEW MEXICO



Hourly Average Day for May 2021
STATE OF NEW MEXICO



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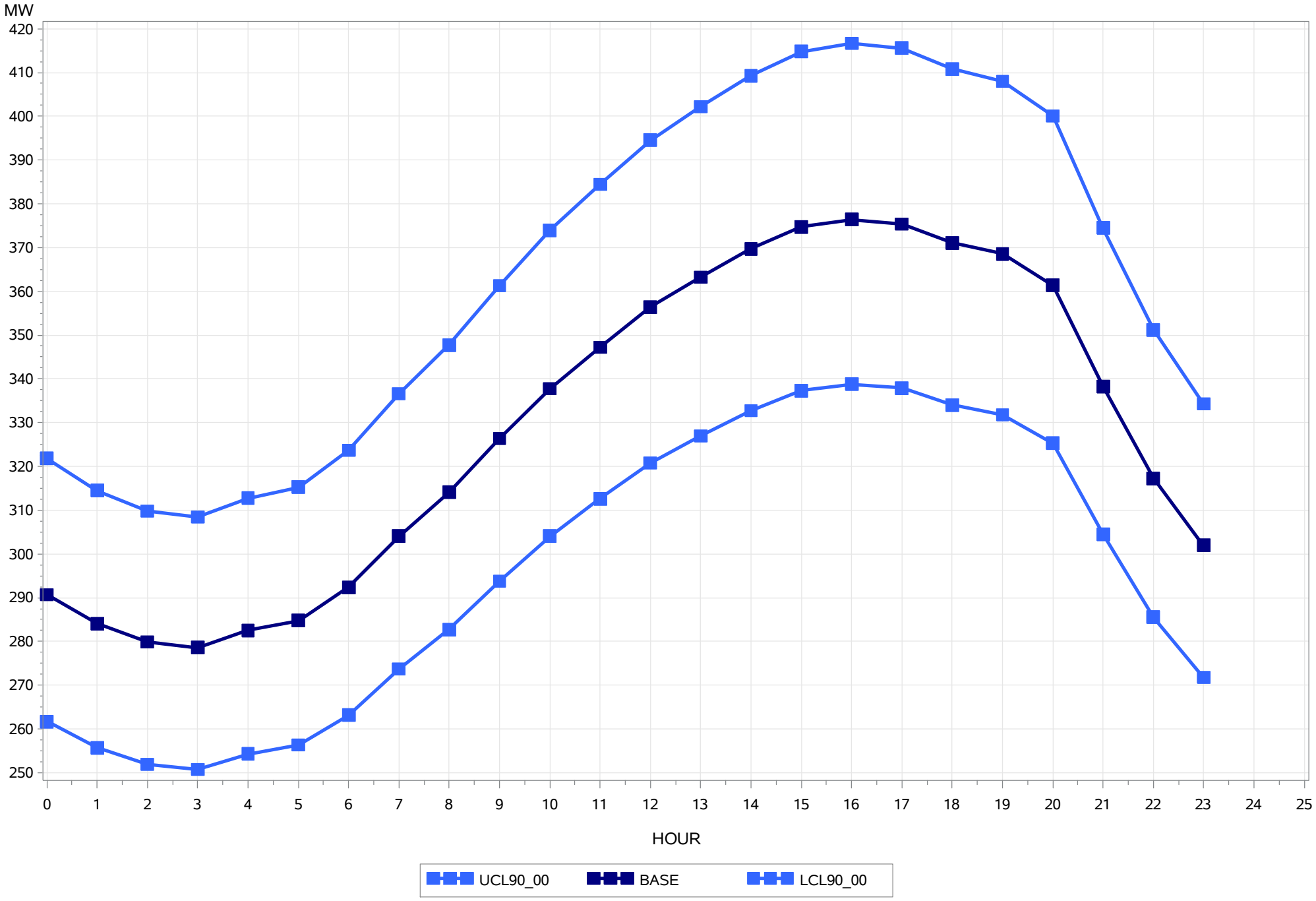
Hourly Average Day for June 2021
STATE OF NEW MEXICO



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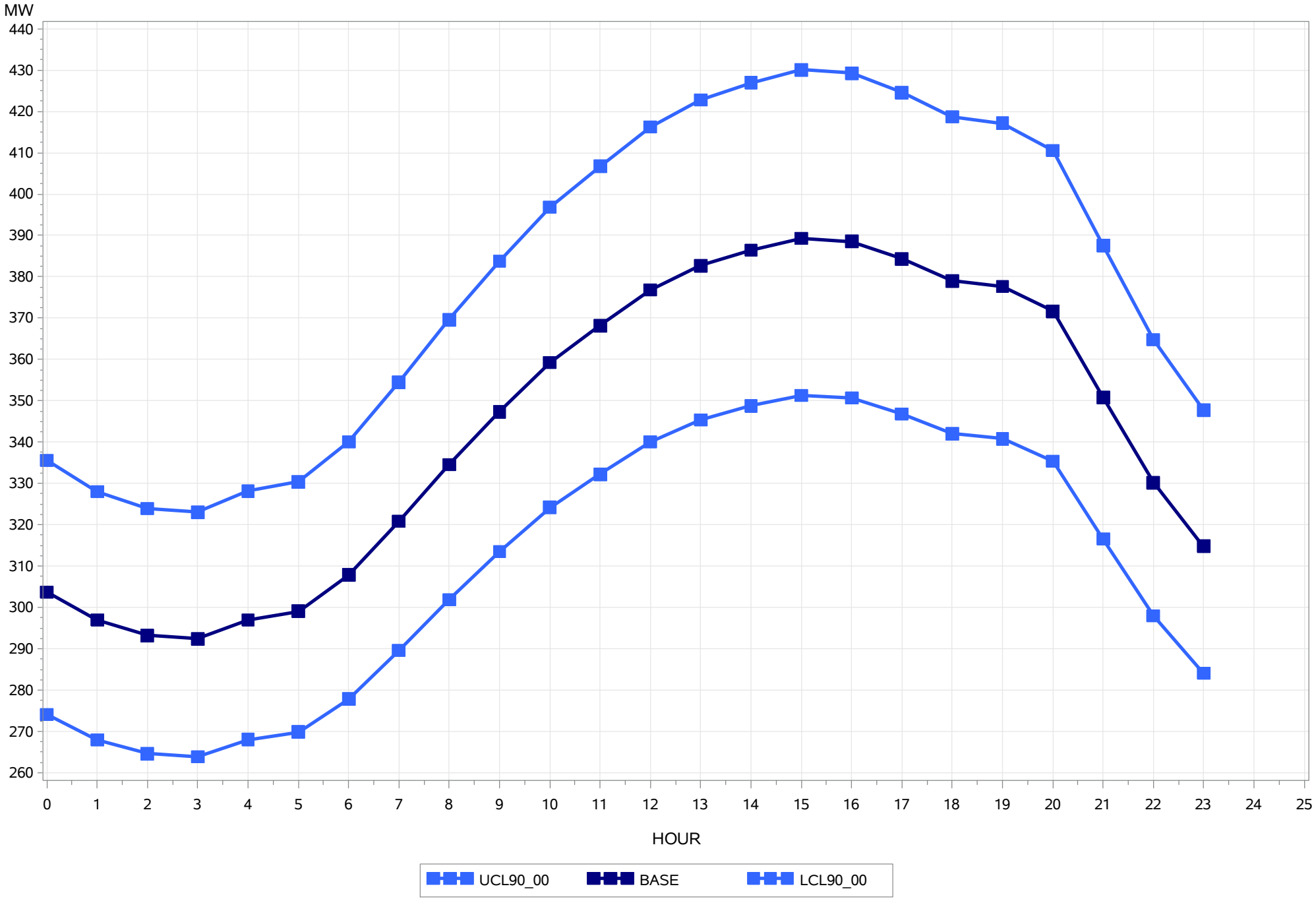
Hourly Average Day for July 2021
STATE OF NEW MEXICO



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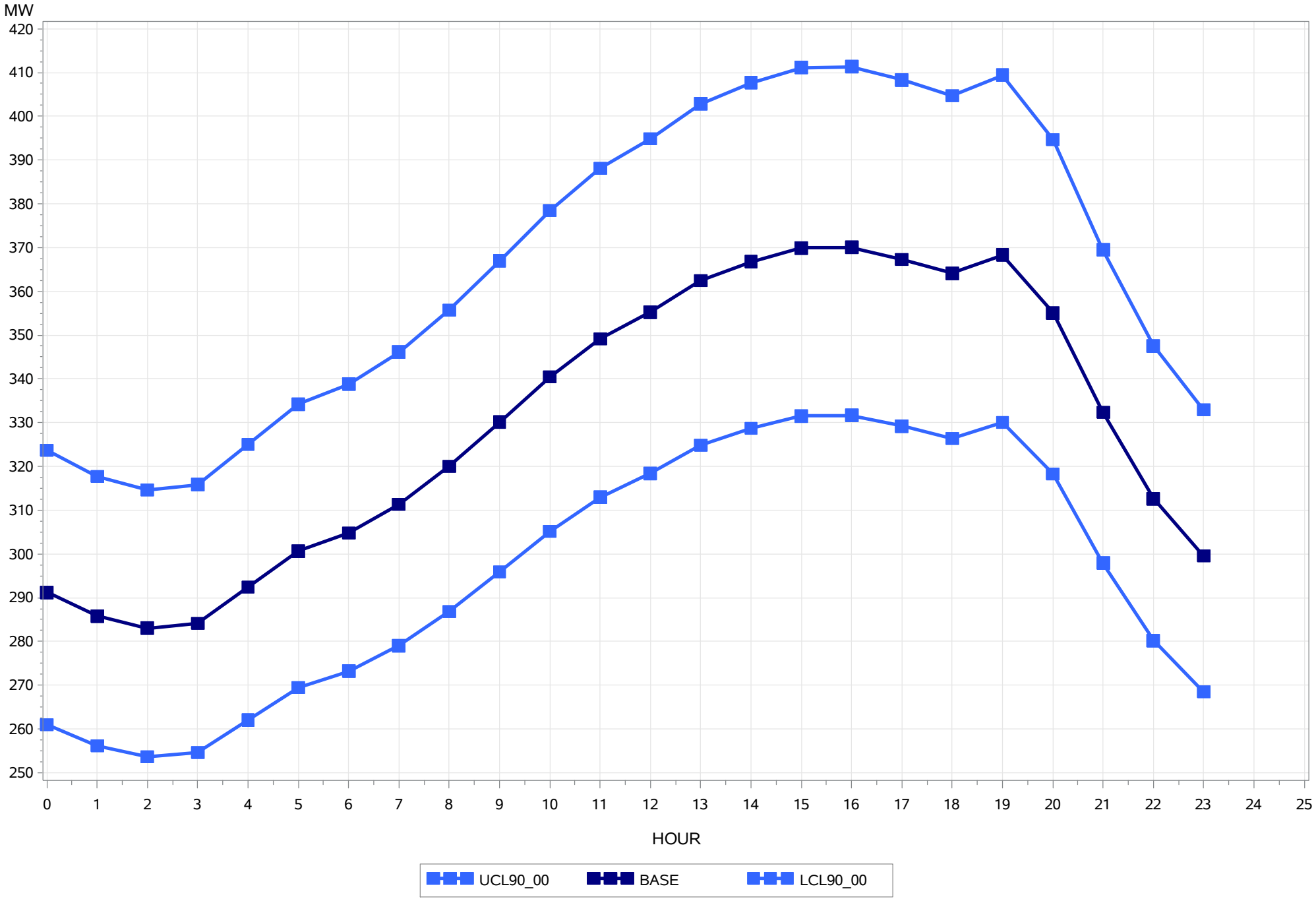
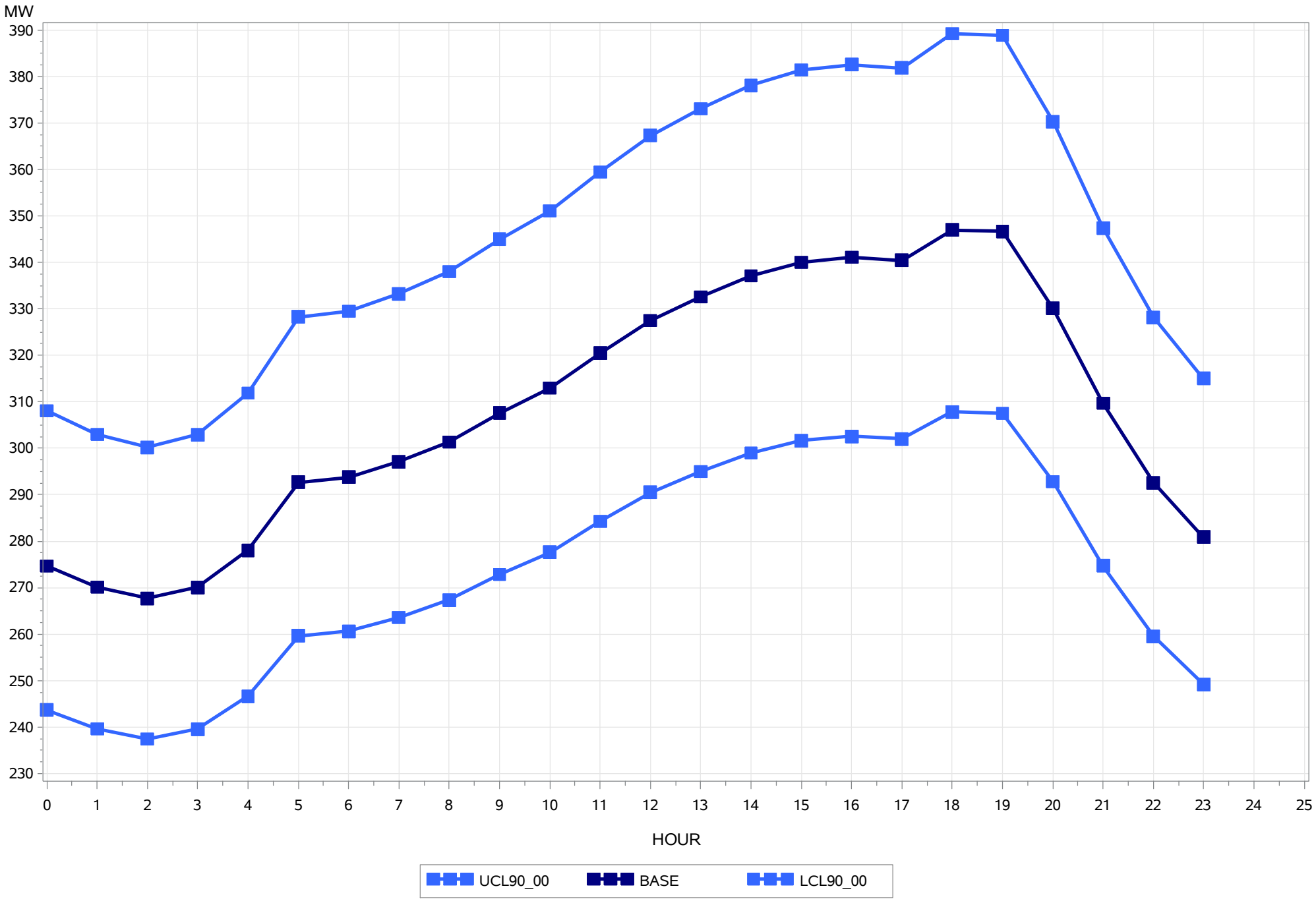
Hourly Average Day for August 2021
STATE OF NEW MEXICO



Hourly Average Day for September 2021
STATE OF NEW MEXICO



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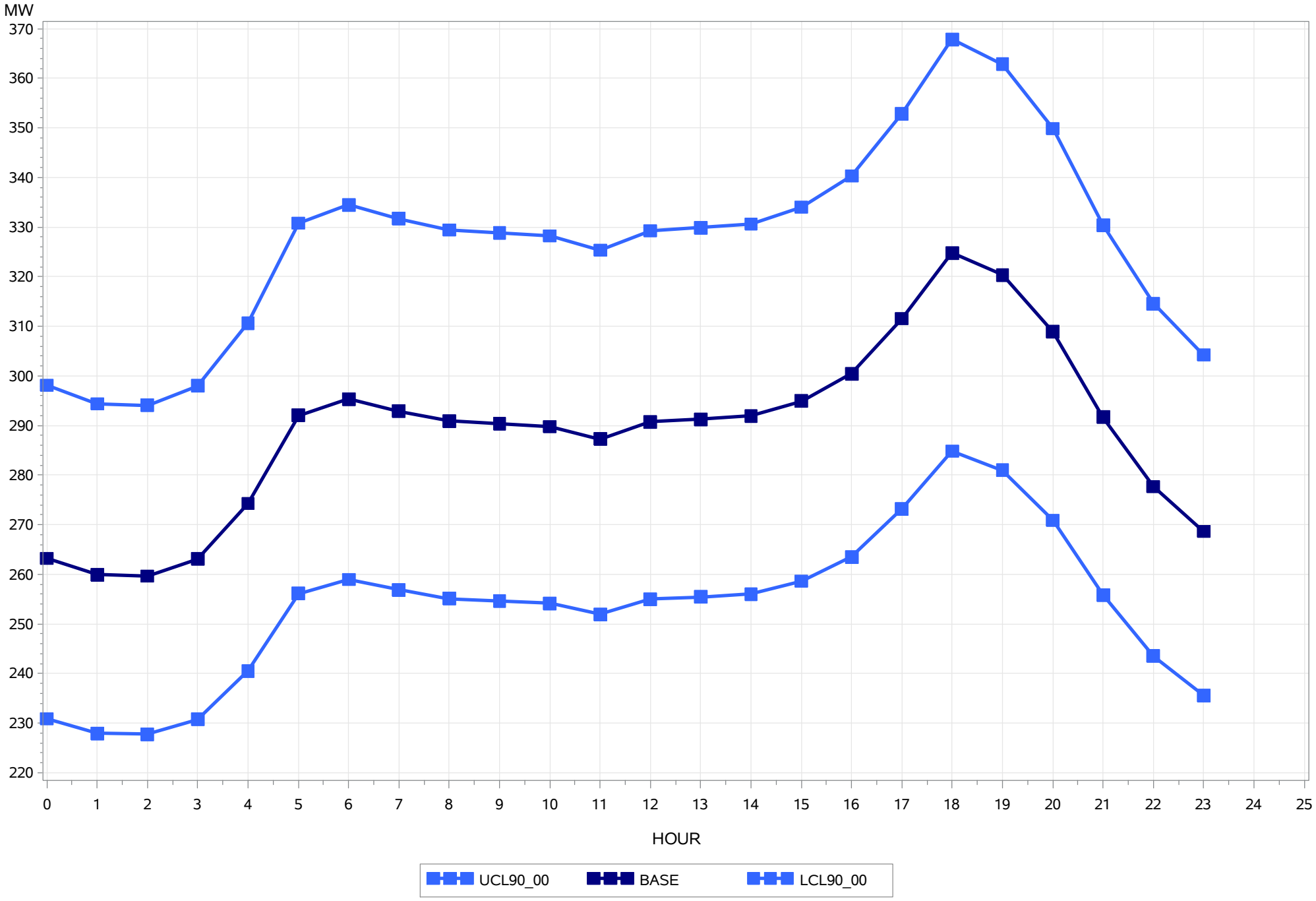
Hourly Average Day for October 2021
STATE OF NEW MEXICO



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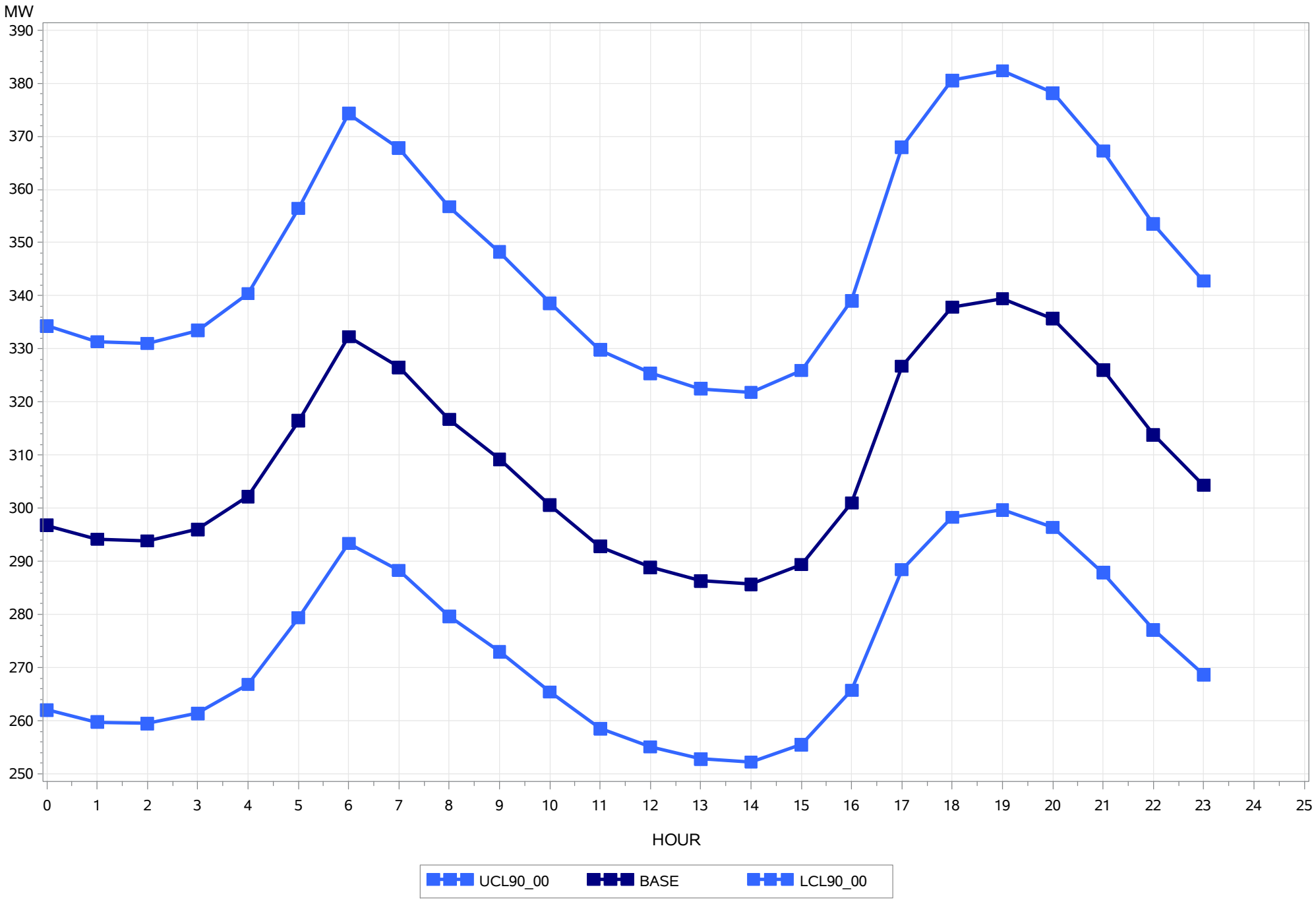
Hourly Average Day for November 2021
STATE OF NEW MEXICO



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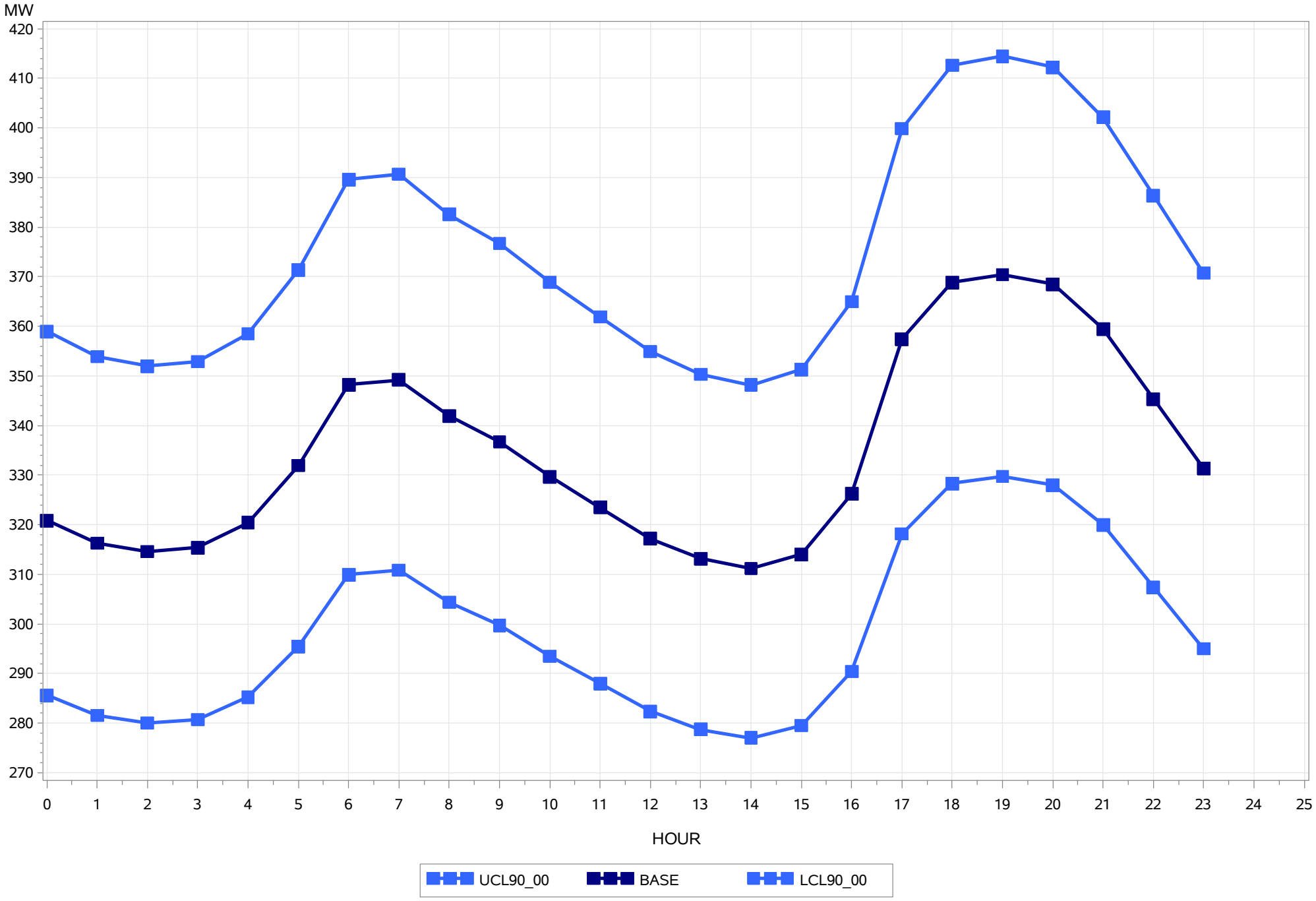
Hourly Average Day for December 2021
STATE OF NEW MEXICO



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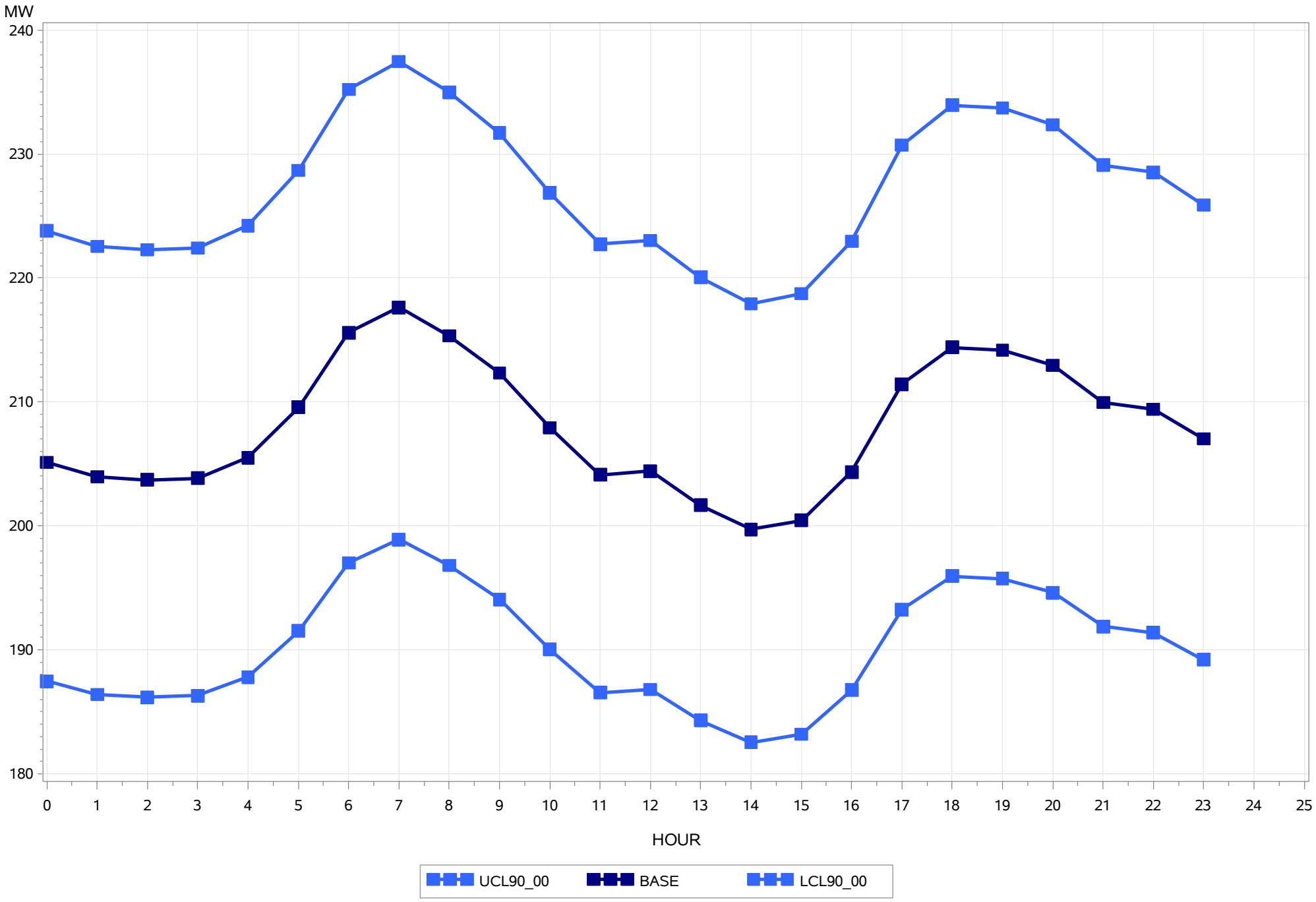
Hourly Average Day for January 2021
STATE OF WYOMING



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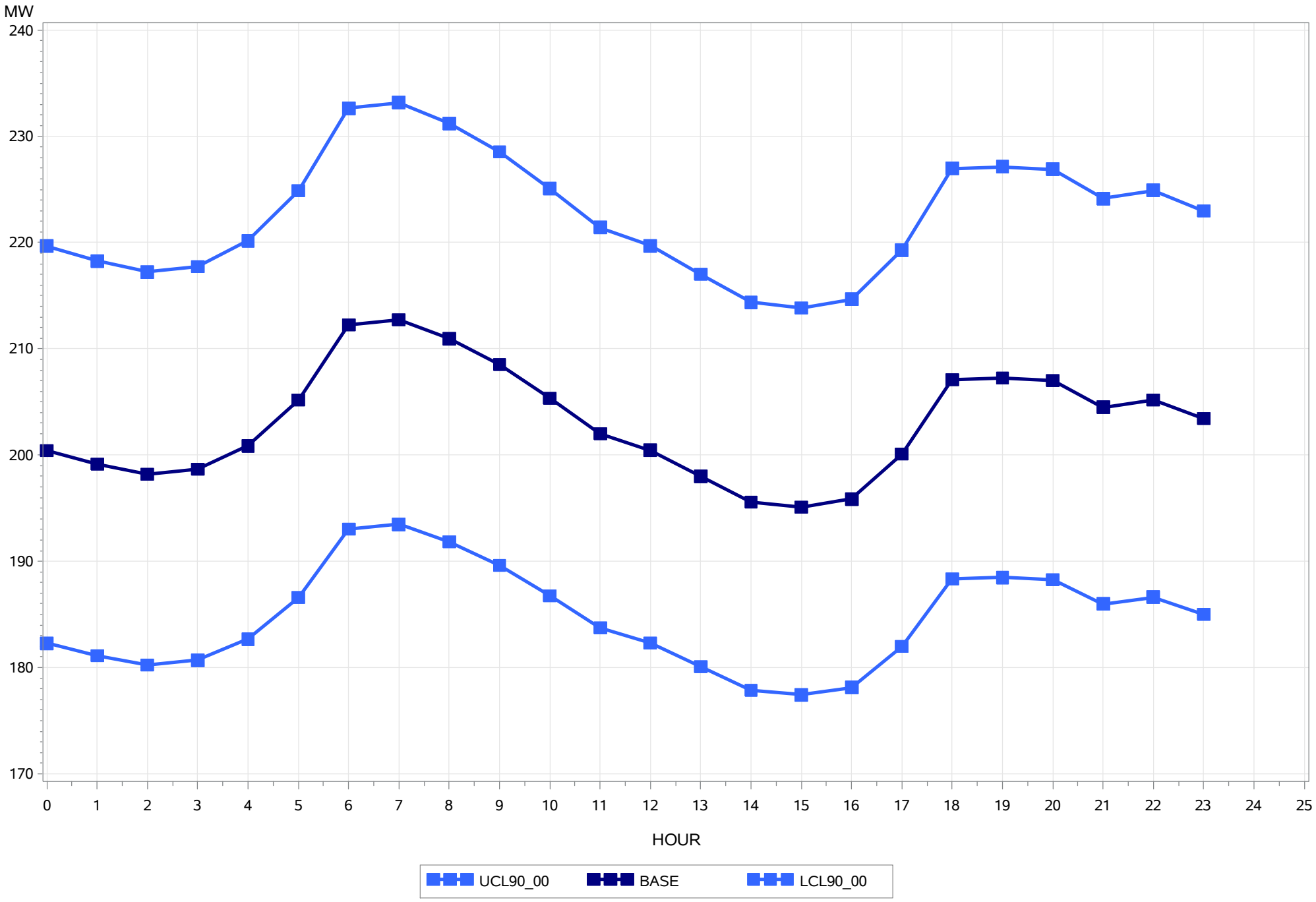
Hourly Average Day for February 2021
STATE OF WYOMING



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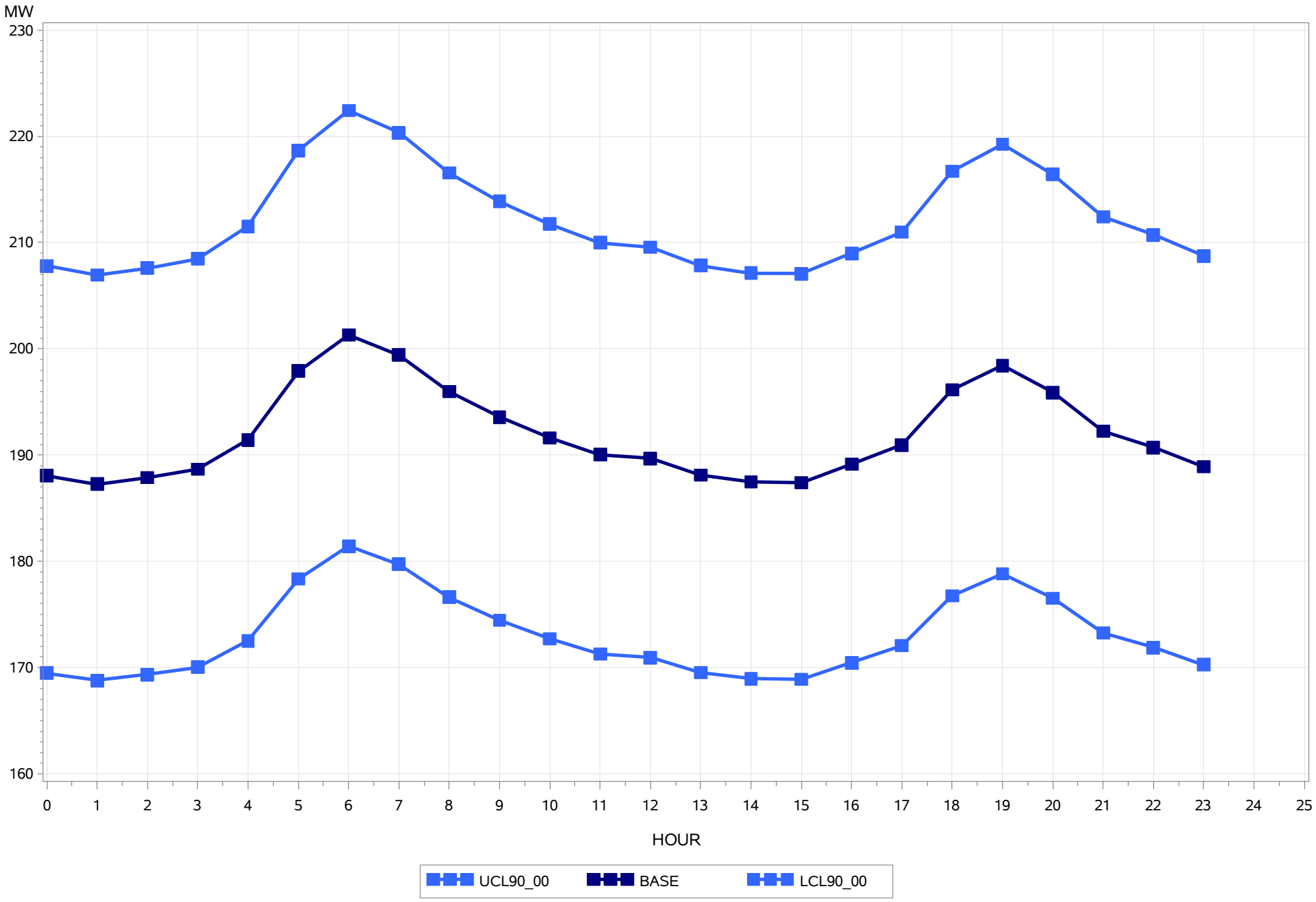
Hourly Average Day for March 2021
STATE OF WYOMING



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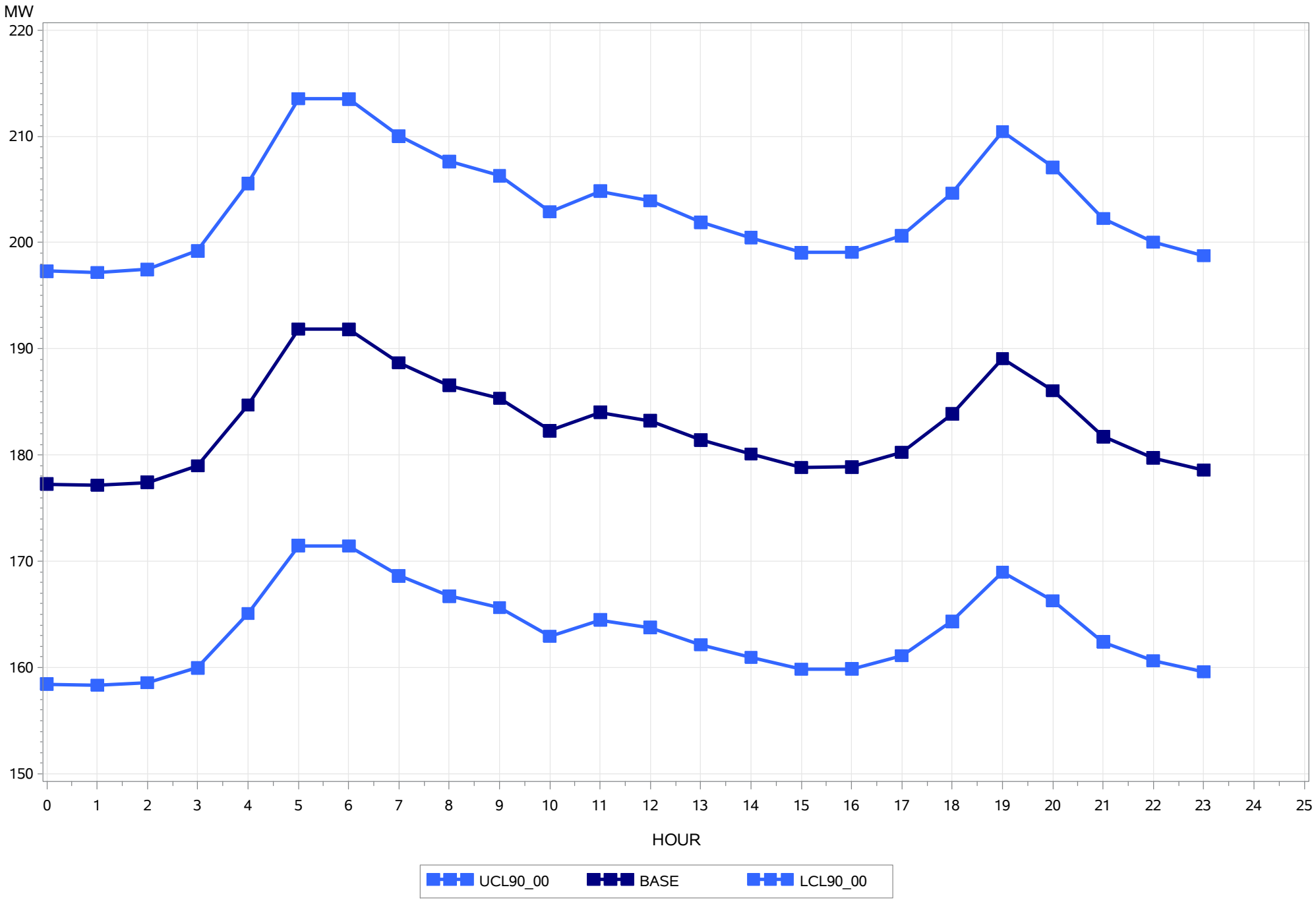
Hourly Average Day for April 2021
STATE OF WYOMING



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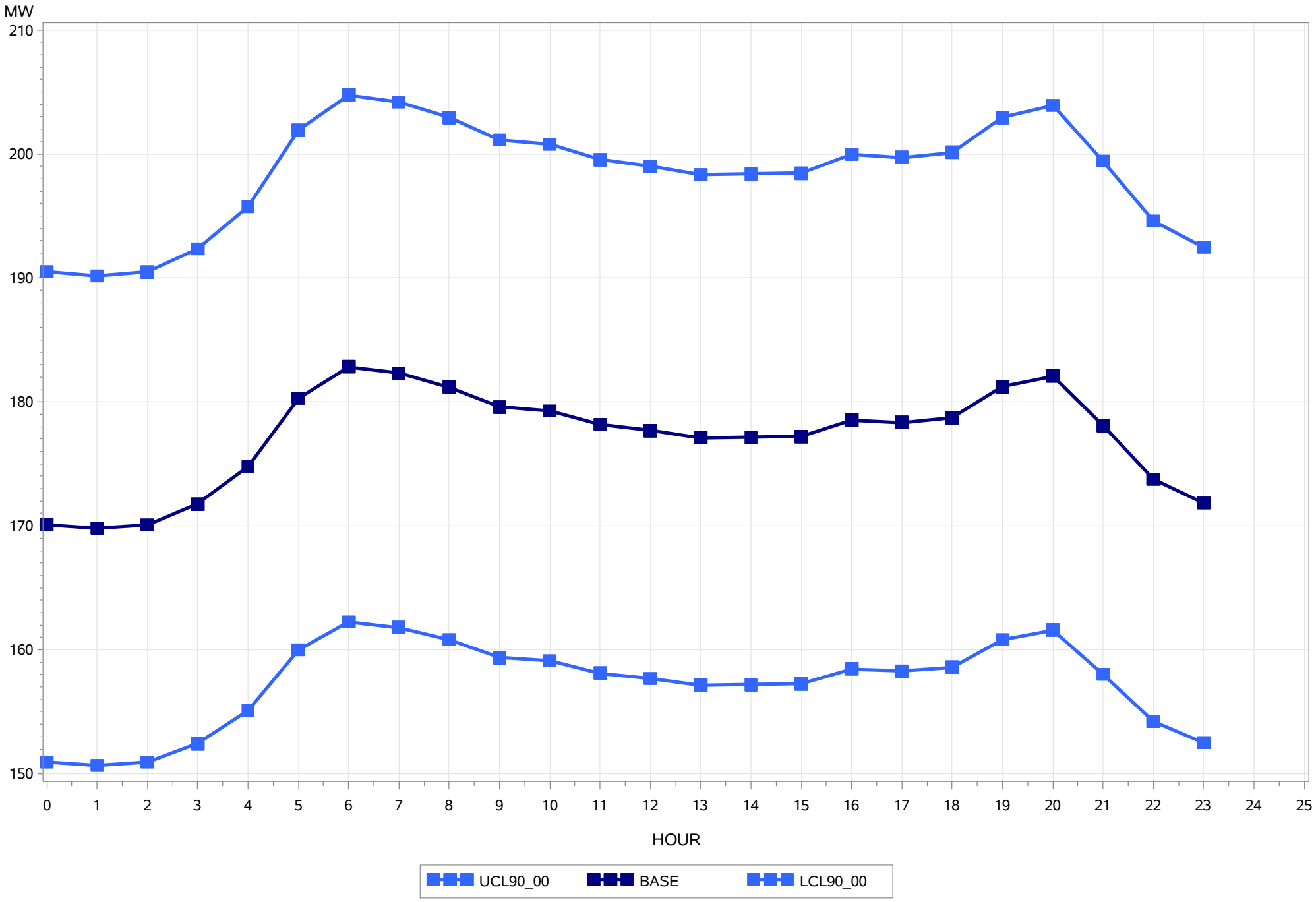
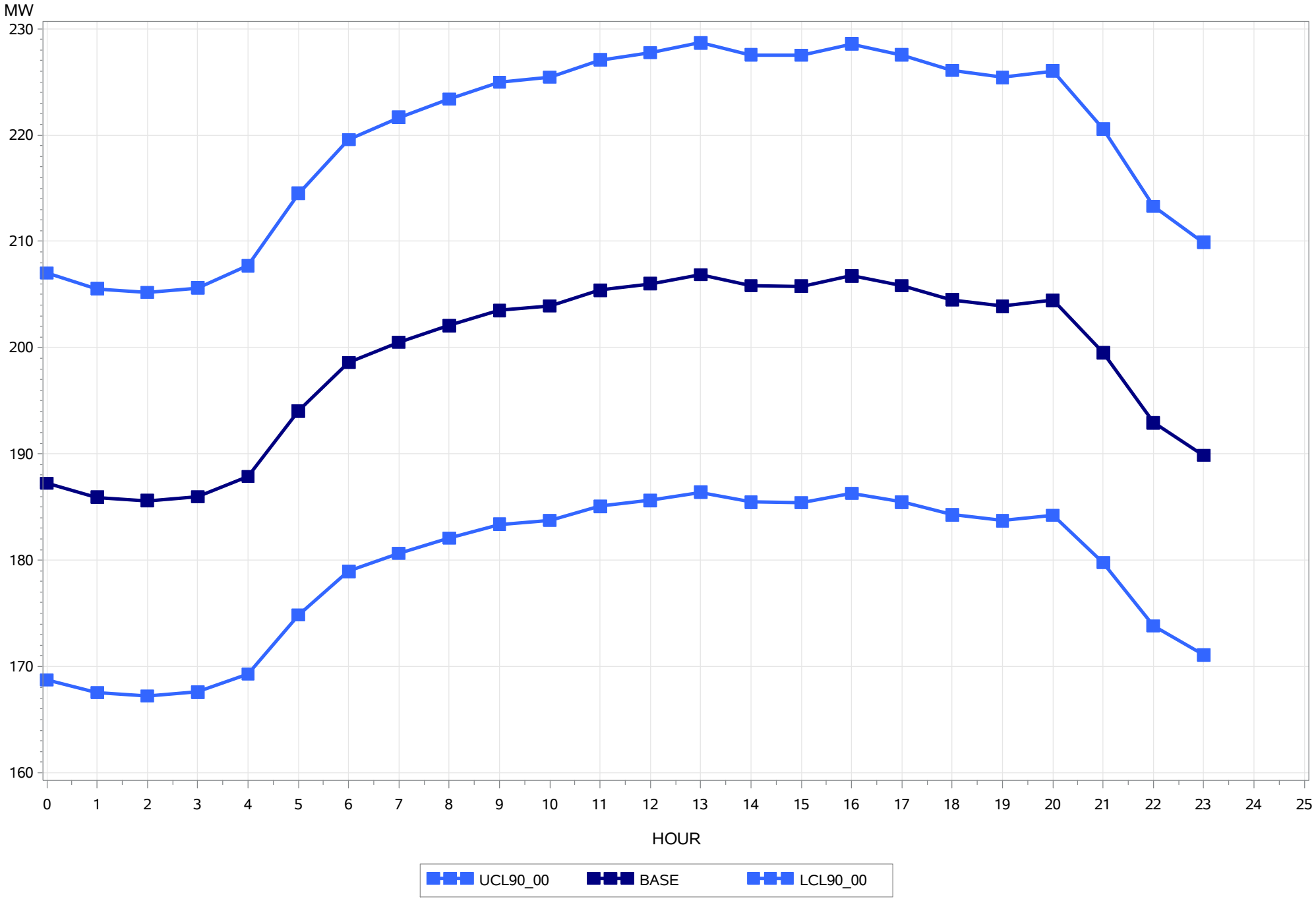
Hourly Average Day for May 2021
STATE OF WYOMING



Hourly Average Day for June 2021
STATE OF WYOMING



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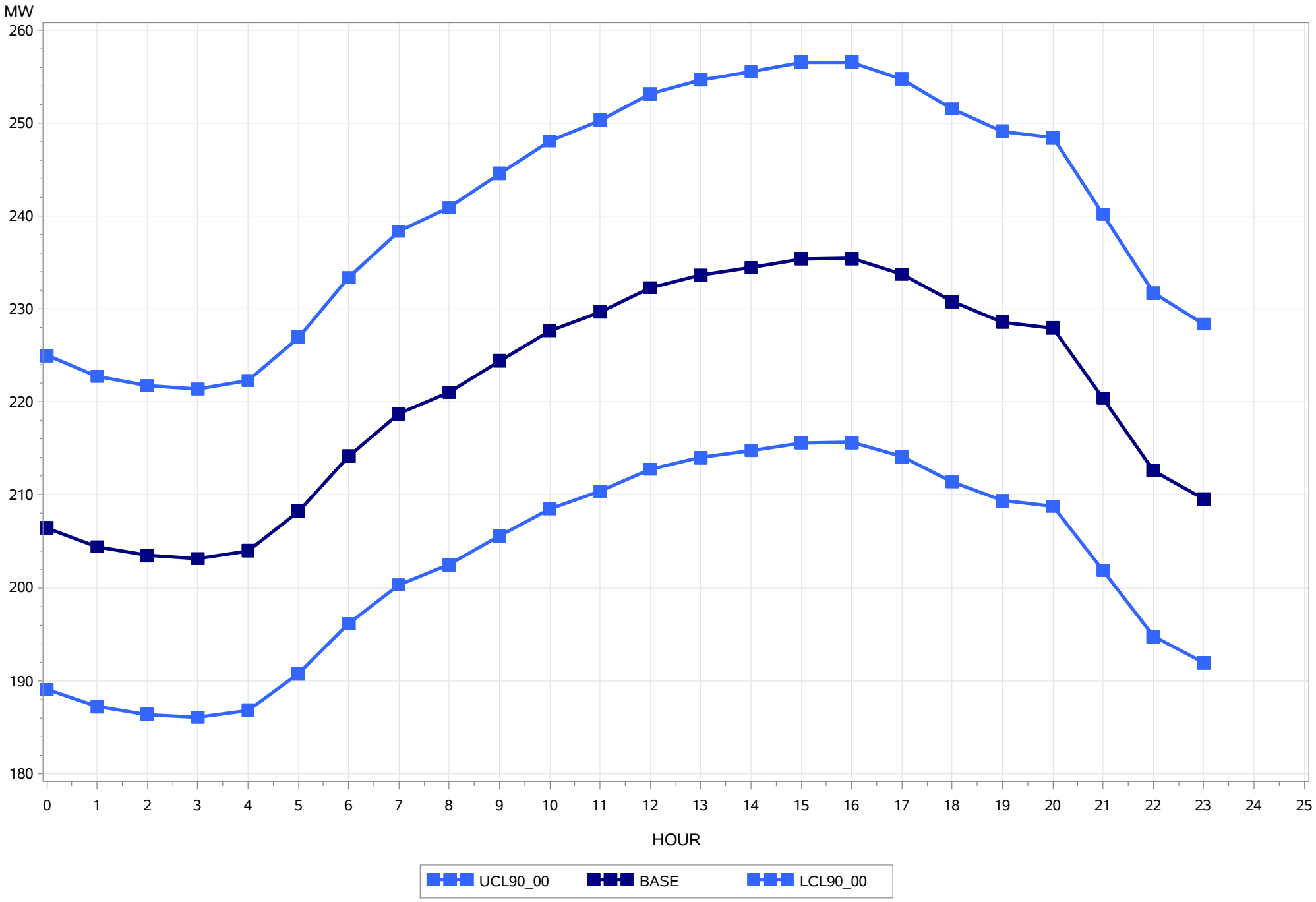
Hourly Average Day for July 2021
STATE OF WYOMING



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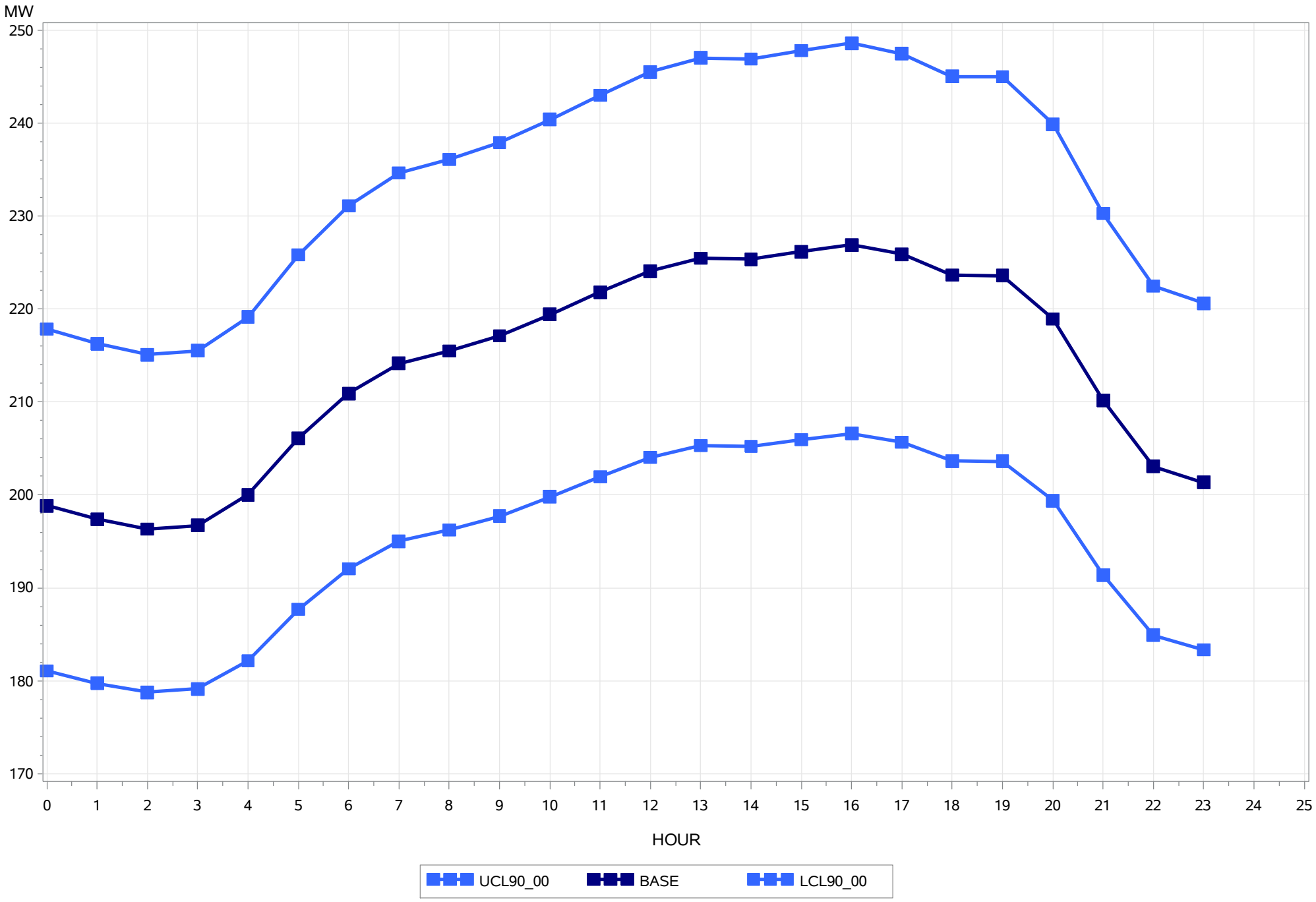
Hourly Average Day for August 2021
STATE OF WYOMING



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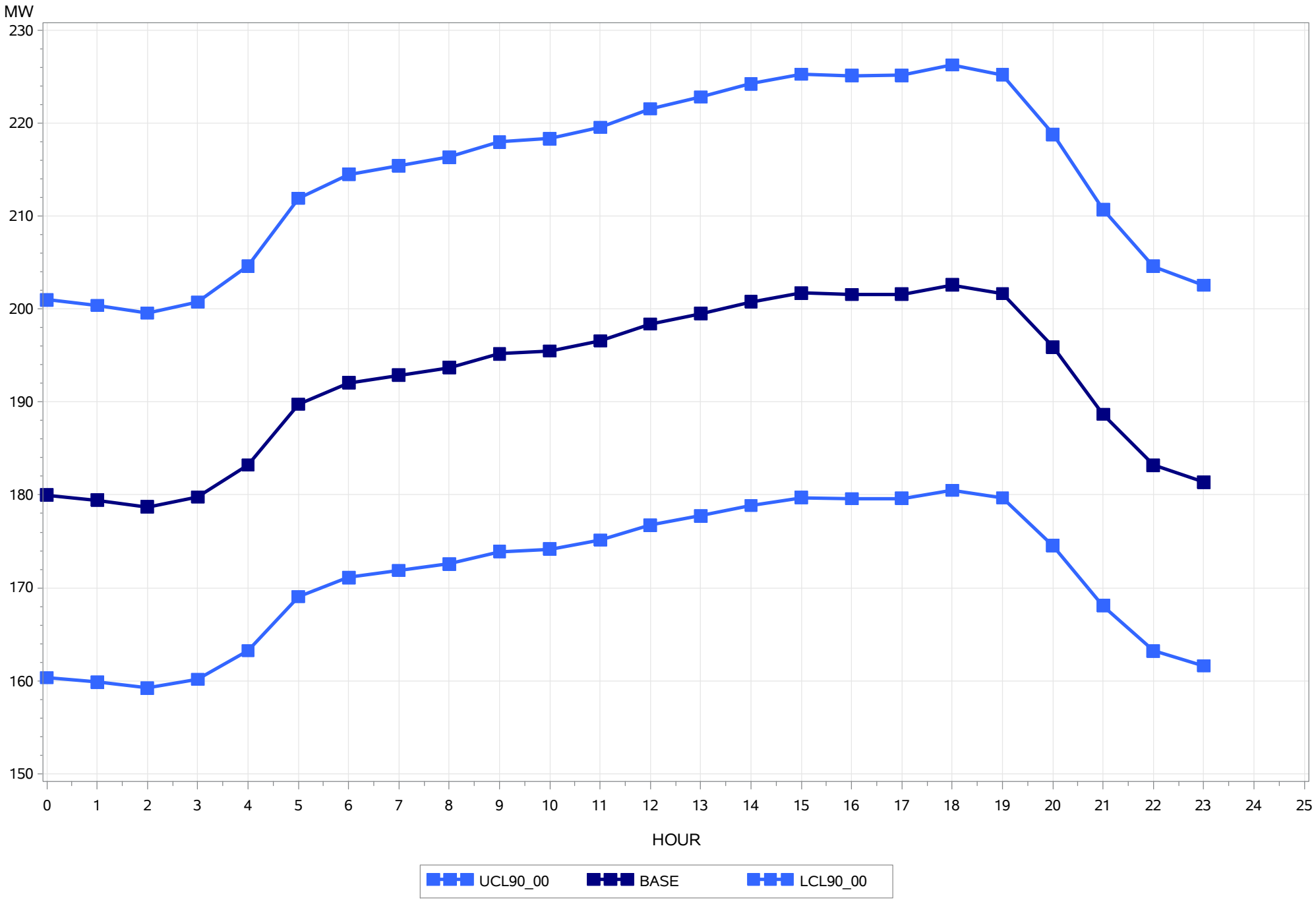
Hourly Average Day for September 2021
STATE OF WYOMING



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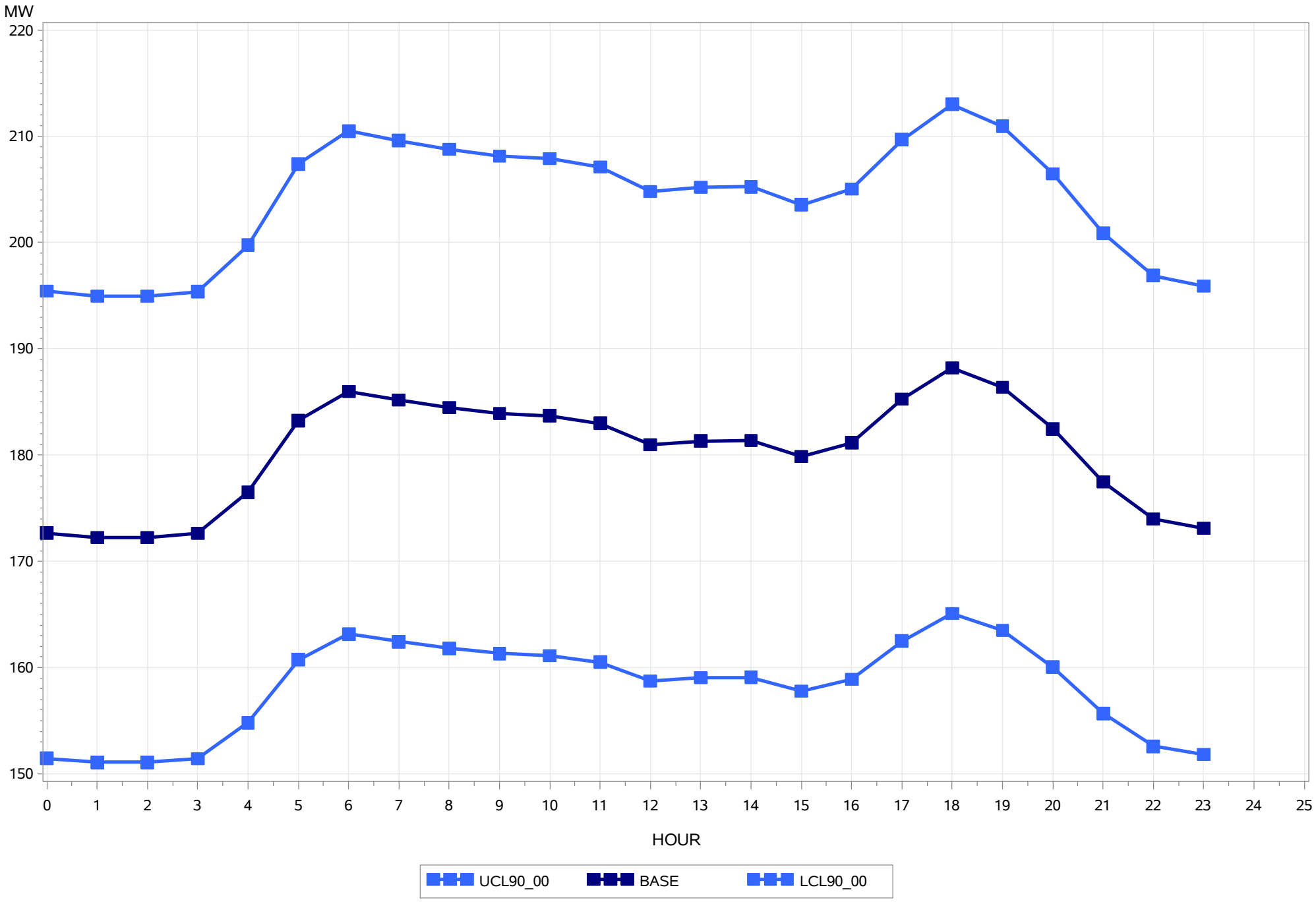
Hourly Average Day for October 2021
STATE OF WYOMING



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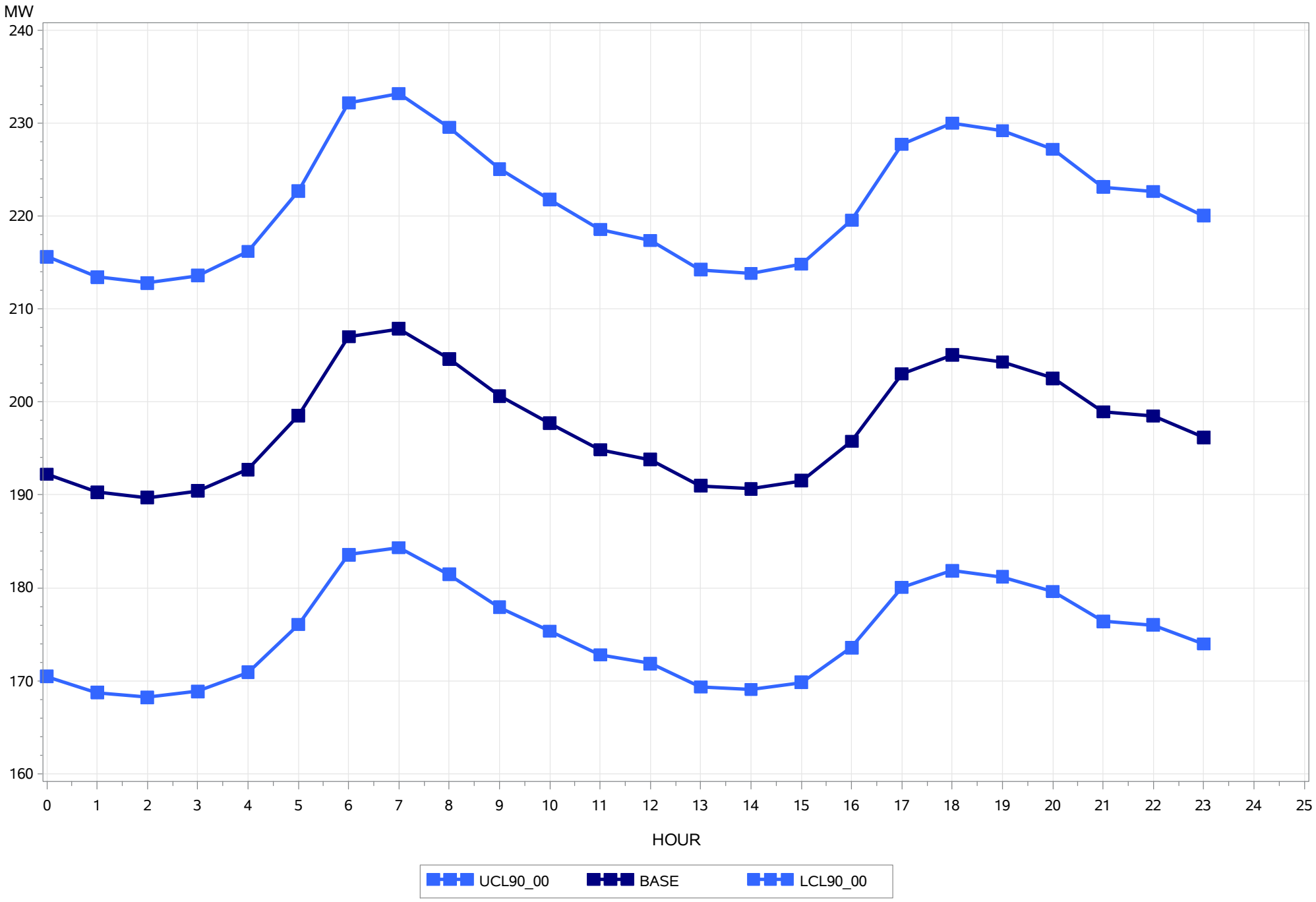
Hourly Average Day for November 2021
STATE OF WYOMING



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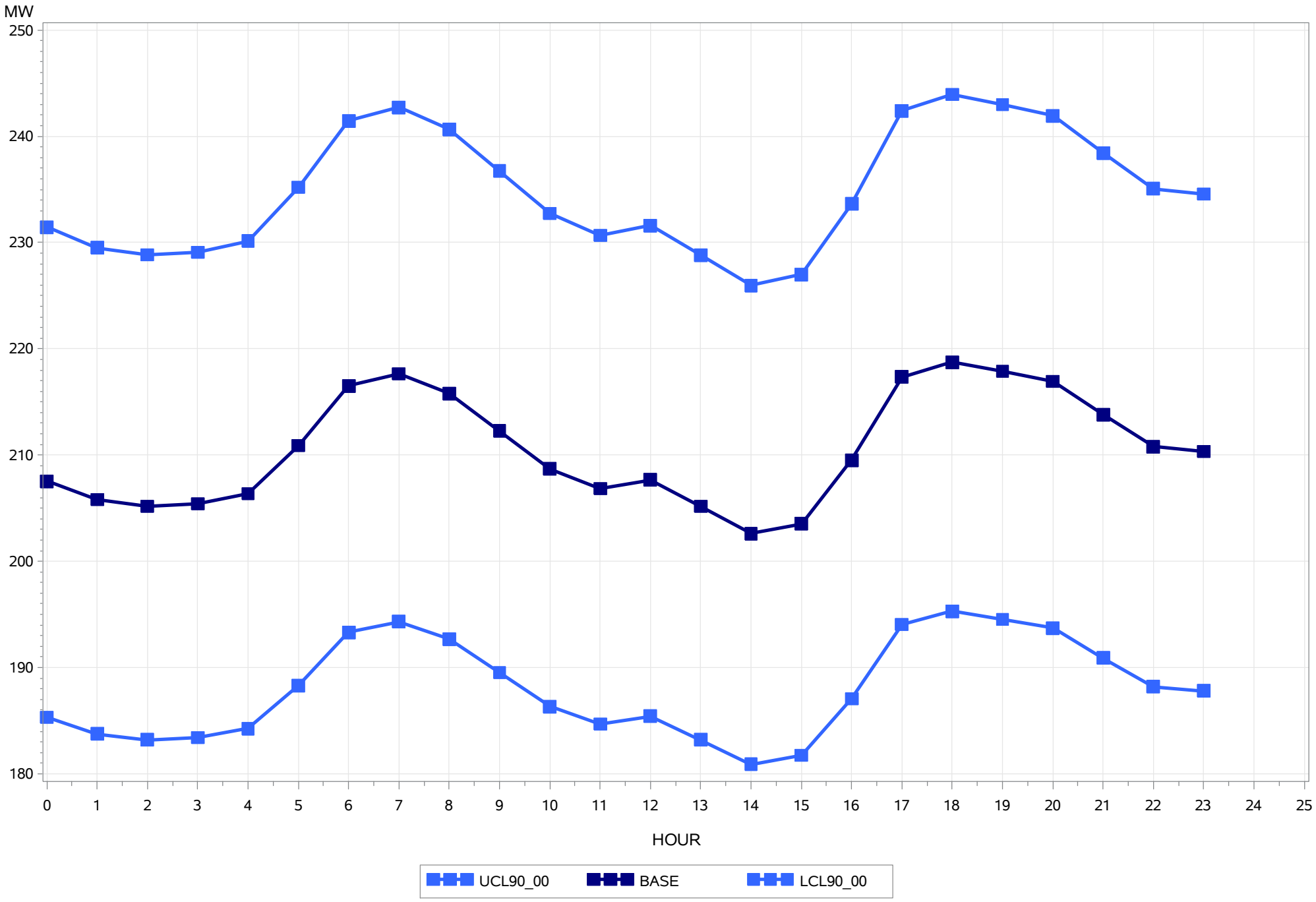
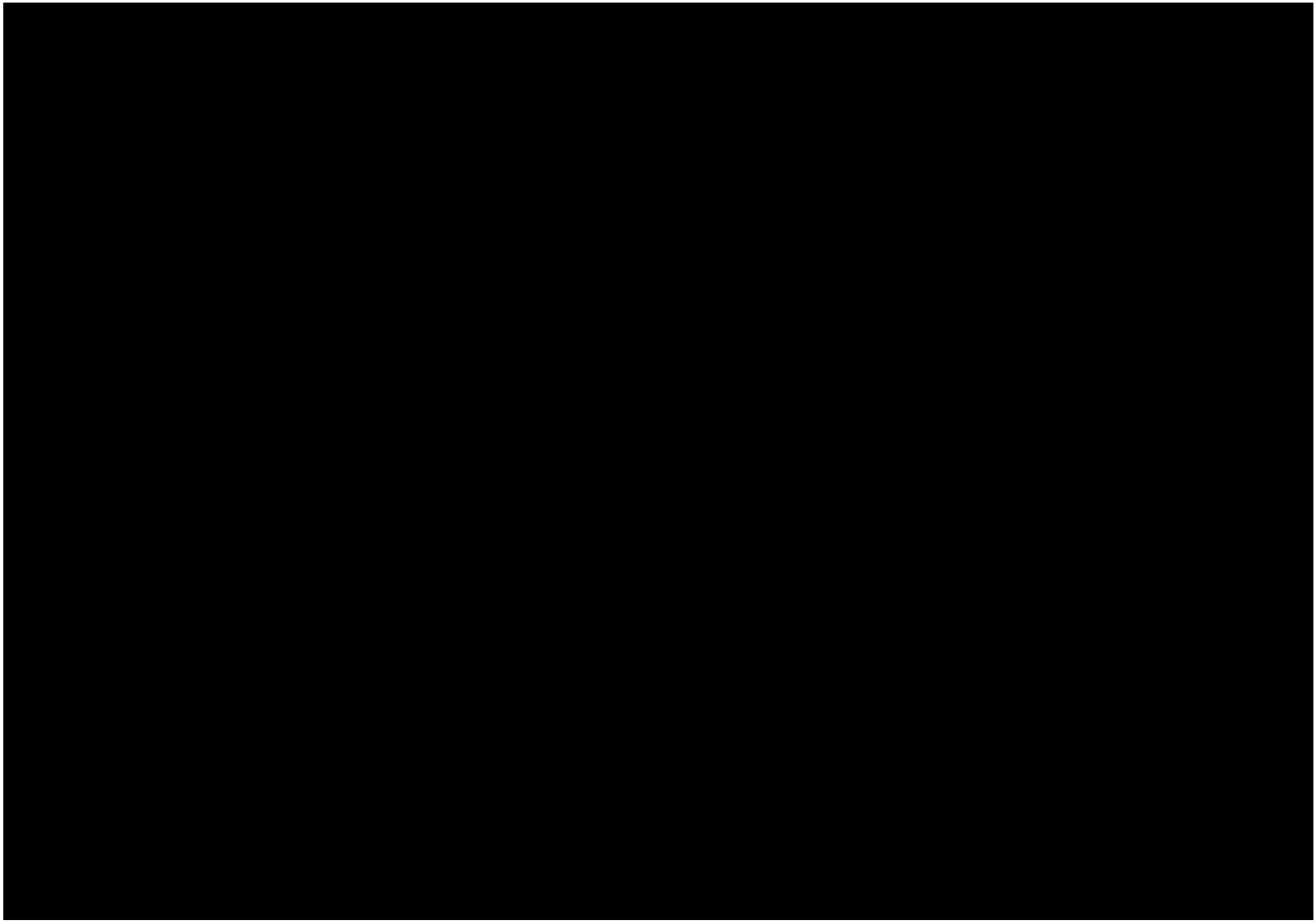
Hourly Average Day for December 2021
STATE OF WYOMING



Hourly Average Day for January 2021
Big Horn Rural Electric Company

[redacted]

Hourly Average Day for February 2021
Big Horn Rural Electric Company



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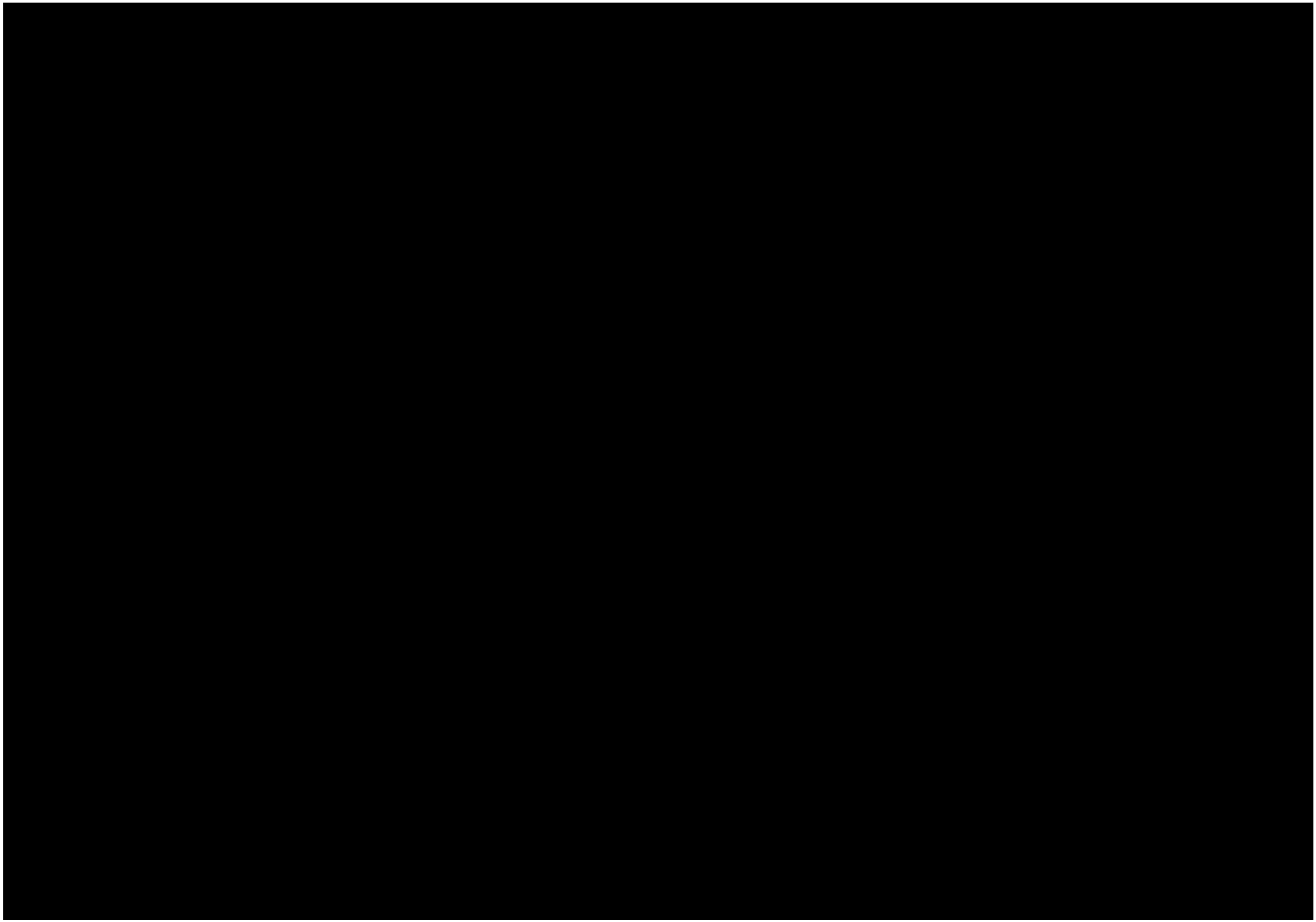
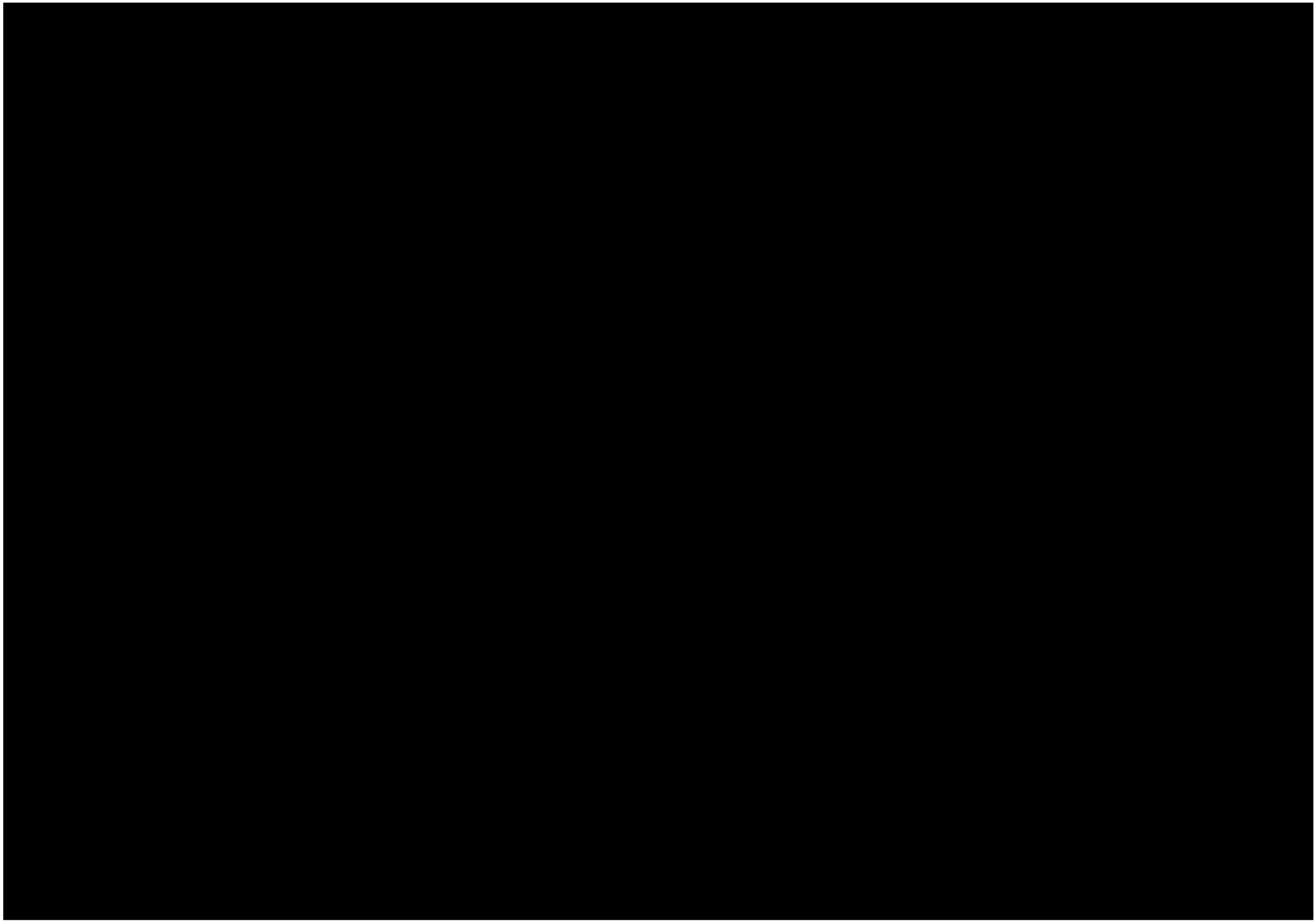
Hourly Average Day for March 2021

Big Horn Rural Electric Company



Hourly Average Day for April 2021

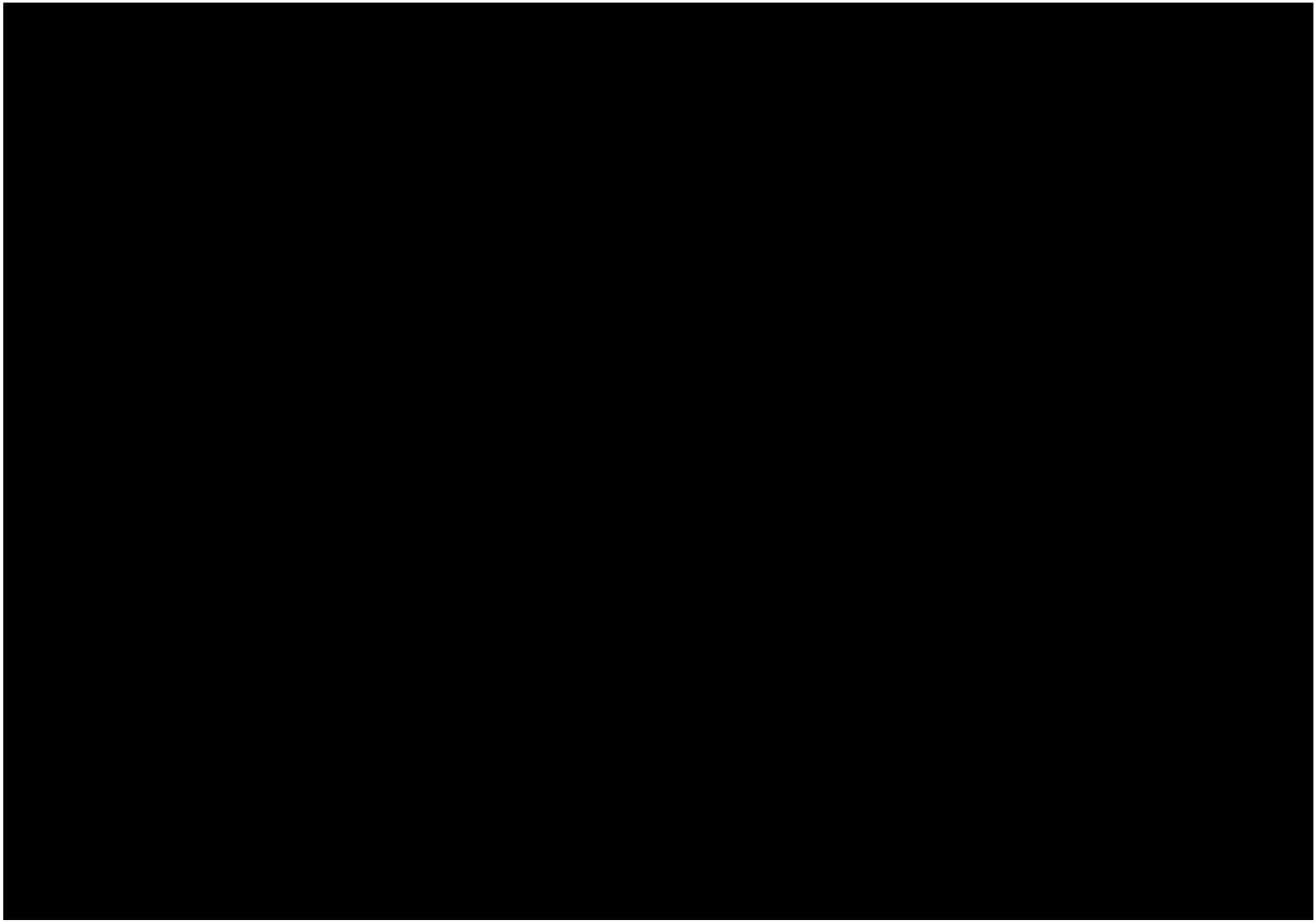
Big Horn Rural Electric Company



Hourly Average Day for May 2021
Big Horn Rural Electric Company

[redacted]

Hourly Average Day for June 2021
Big Horn Rural Electric Company



Hourly Average Day for July 2021

Big Horn Rural Electric Company

[redacted]

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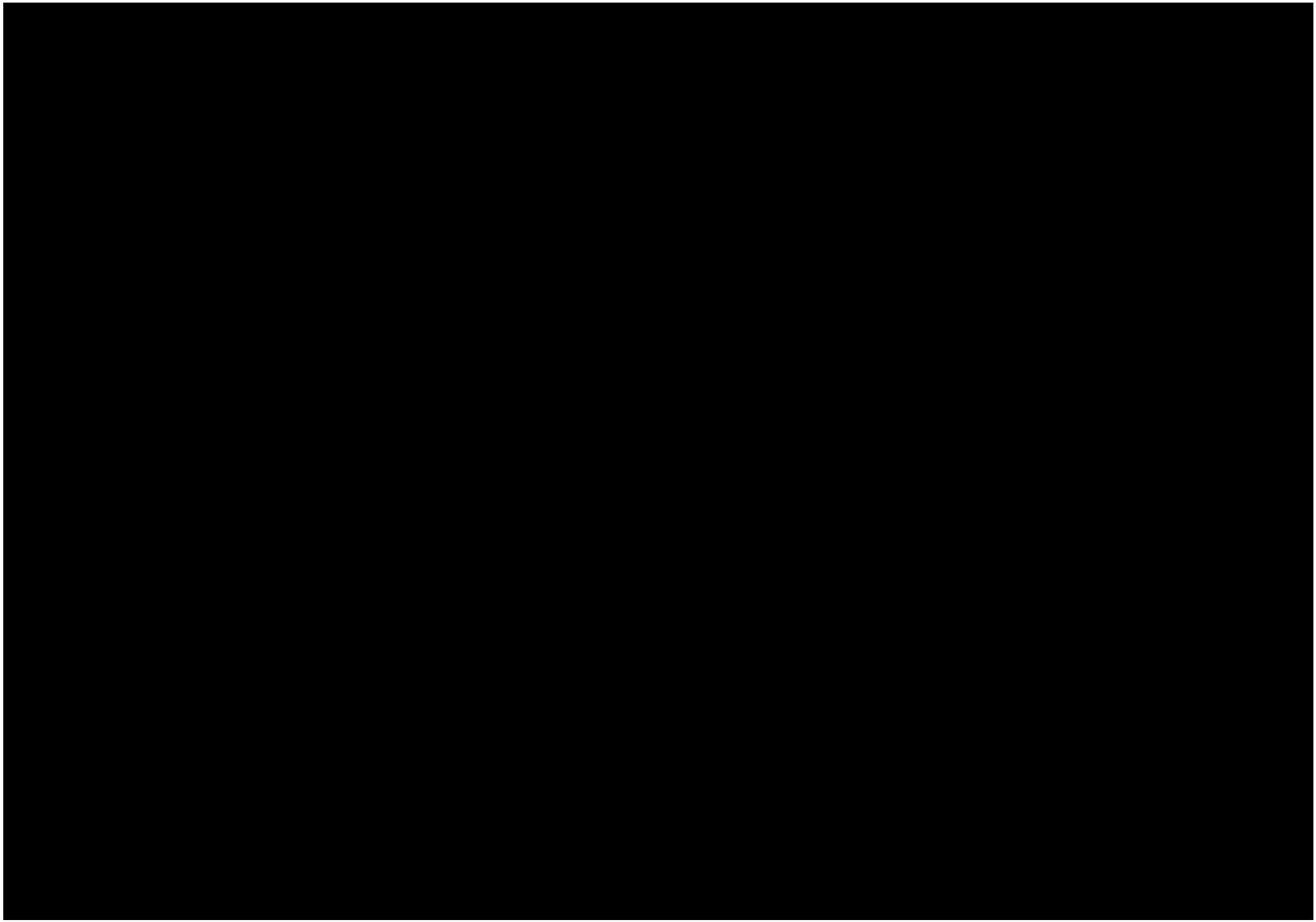
Hourly Average Day for August 2021

Big Horn Rural Electric Company



Hourly Average Day for September 2021

Big Horn Rural Electric Company

[redacted]

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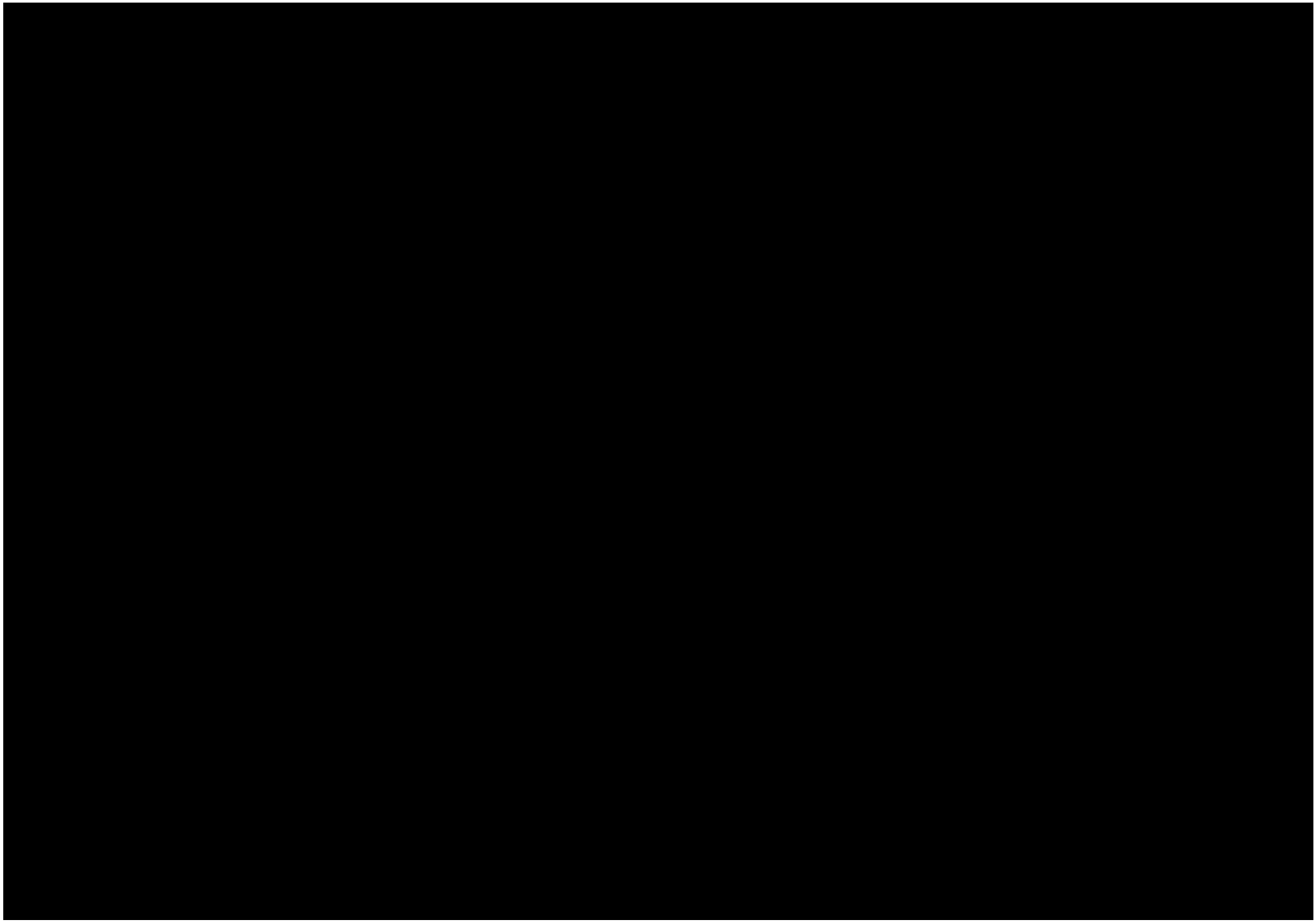
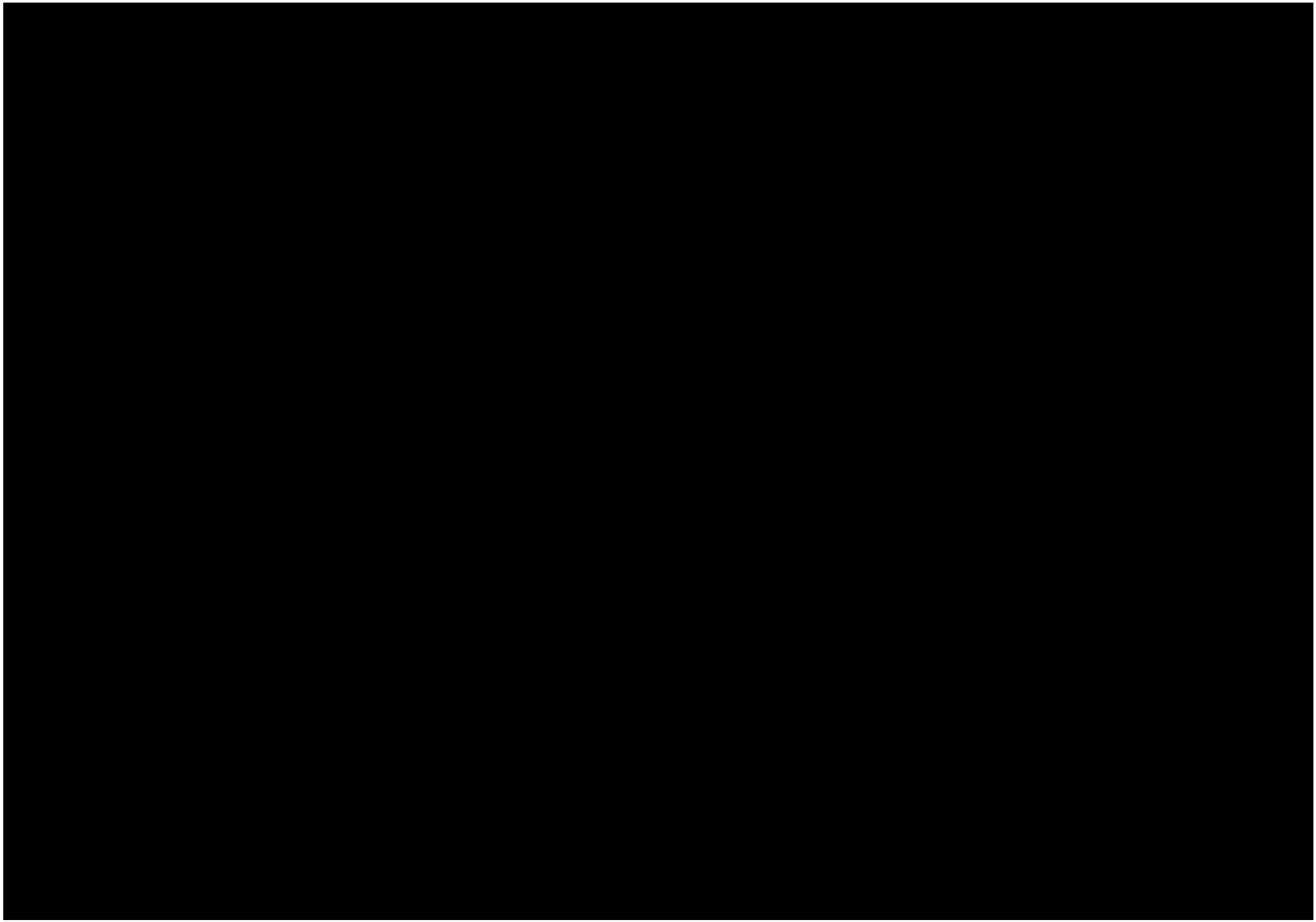
Hourly Average Day for October 2021

Big Horn Rural Electric Company



Hourly Average Day for November 2021
Big Horn Rural Electric Company



Hourly Average Day for December 2021
Big Horn Rural Electric Company

[redacted]

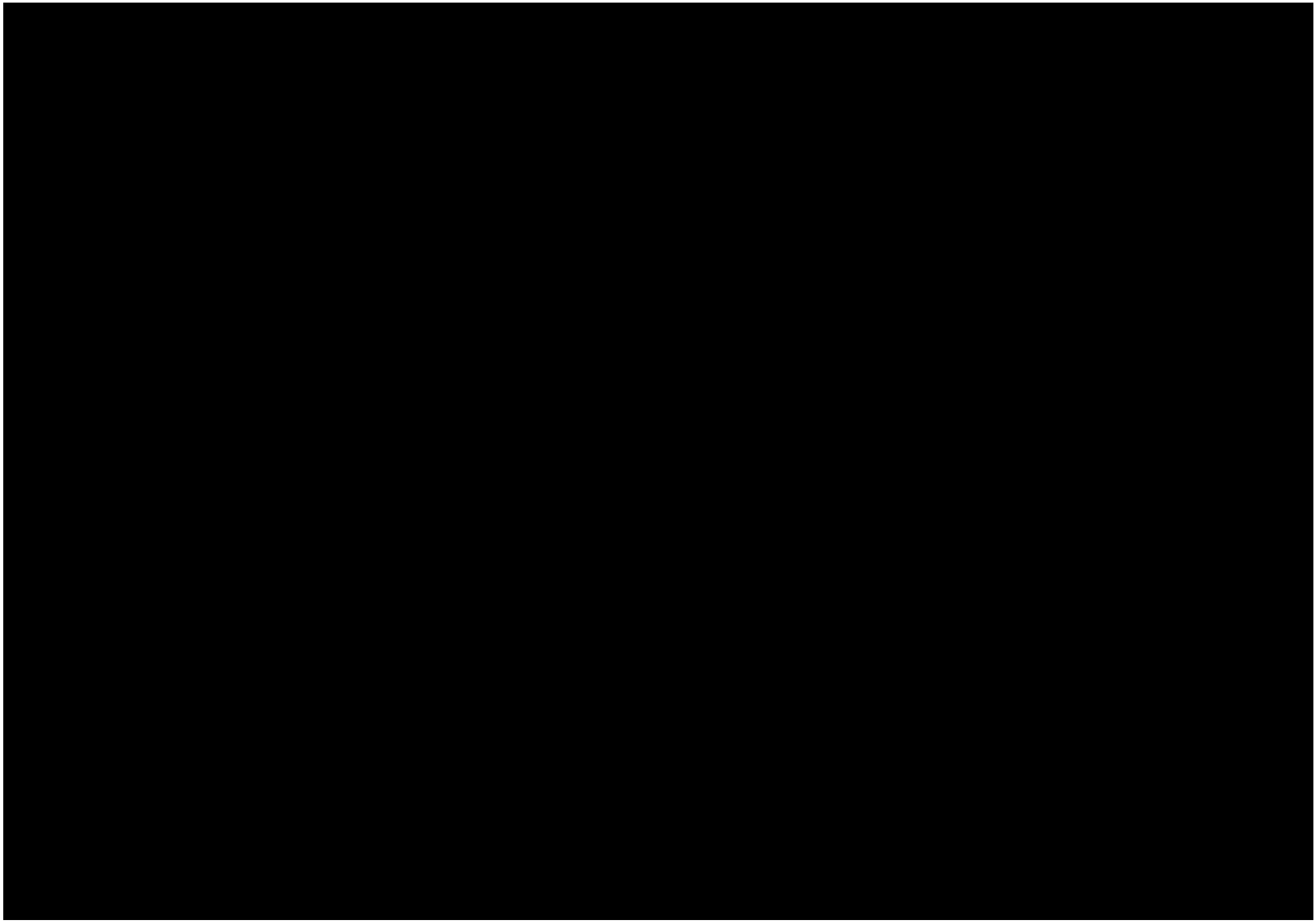
Hourly Average Day for January 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for February 2021

Carbon Power and Light, Inc.



Hourly Average Day for March 2021
Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for April 2021
Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for May 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for June 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for July 2021

Carbon Power and Light, Inc.

[redacted]

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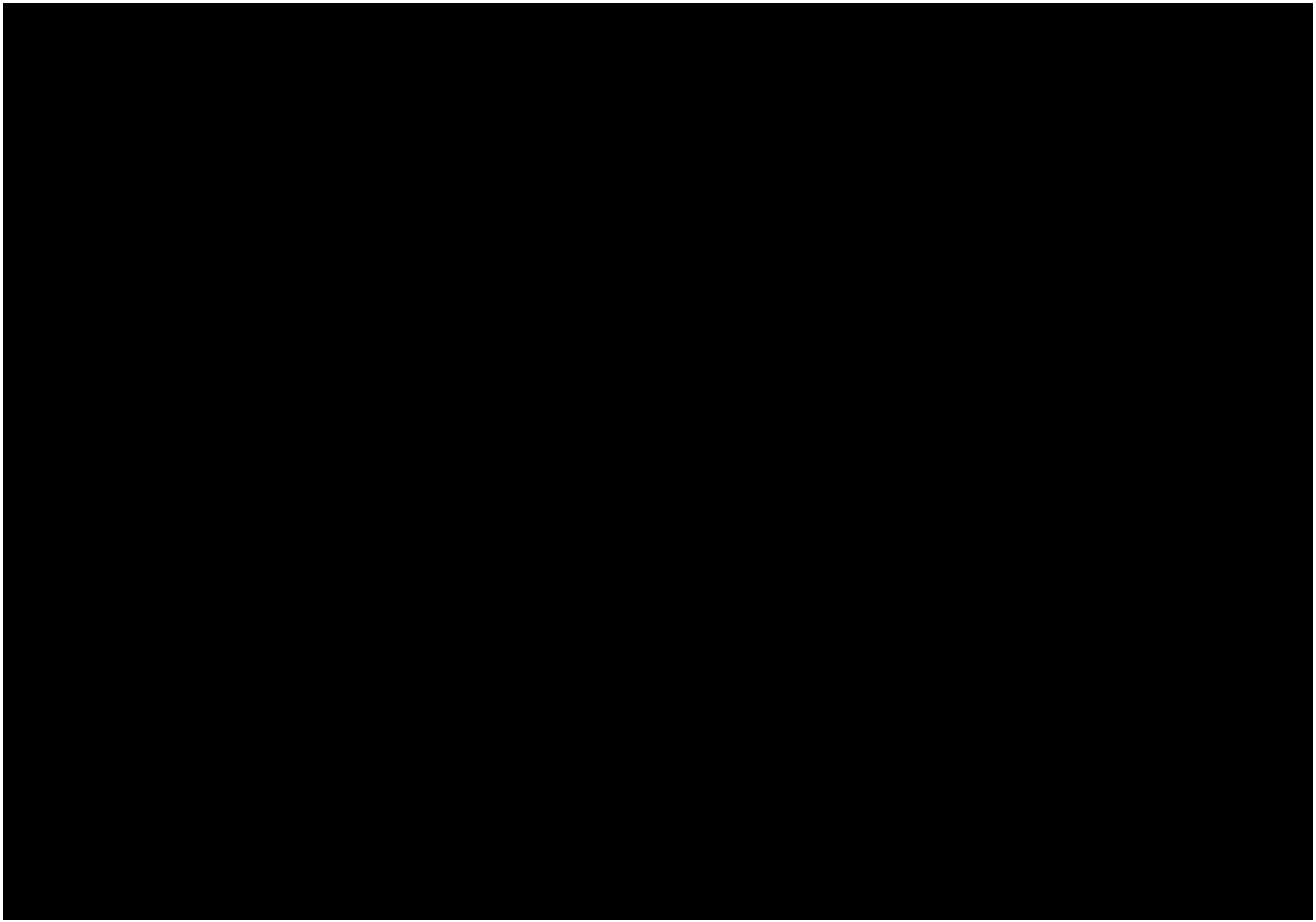
Hourly Average Day for August 2021

Carbon Power and Light, Inc.



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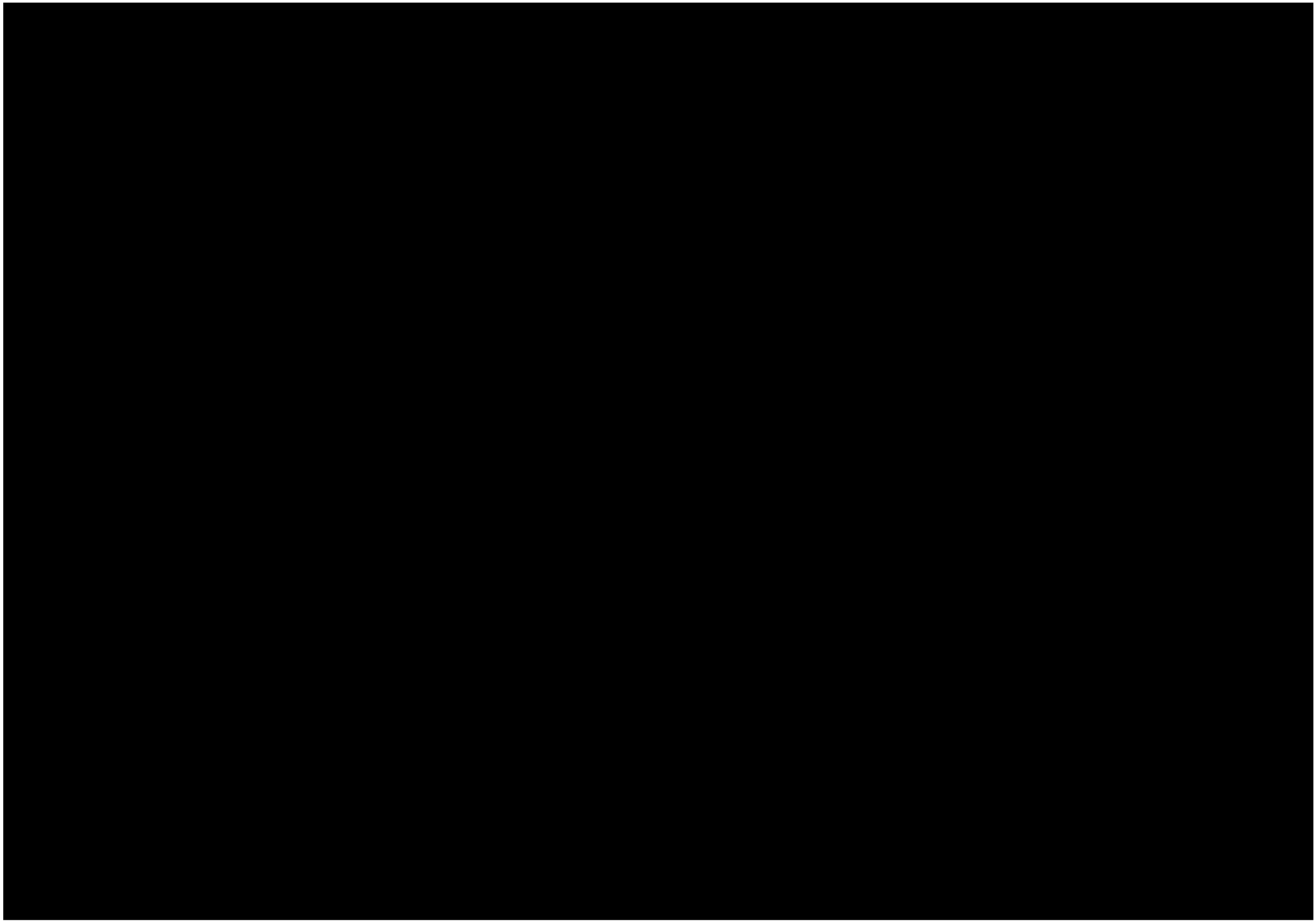
Hourly Average Day for September 2021

Carbon Power and Light, Inc.



Hourly Average Day for October 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for November 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for December 2021

Carbon Power and Light, Inc.

[redacted]

Hourly Average Day for January 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021
Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Continental Divide Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021
Columbus Electric Cooperative, Inc.

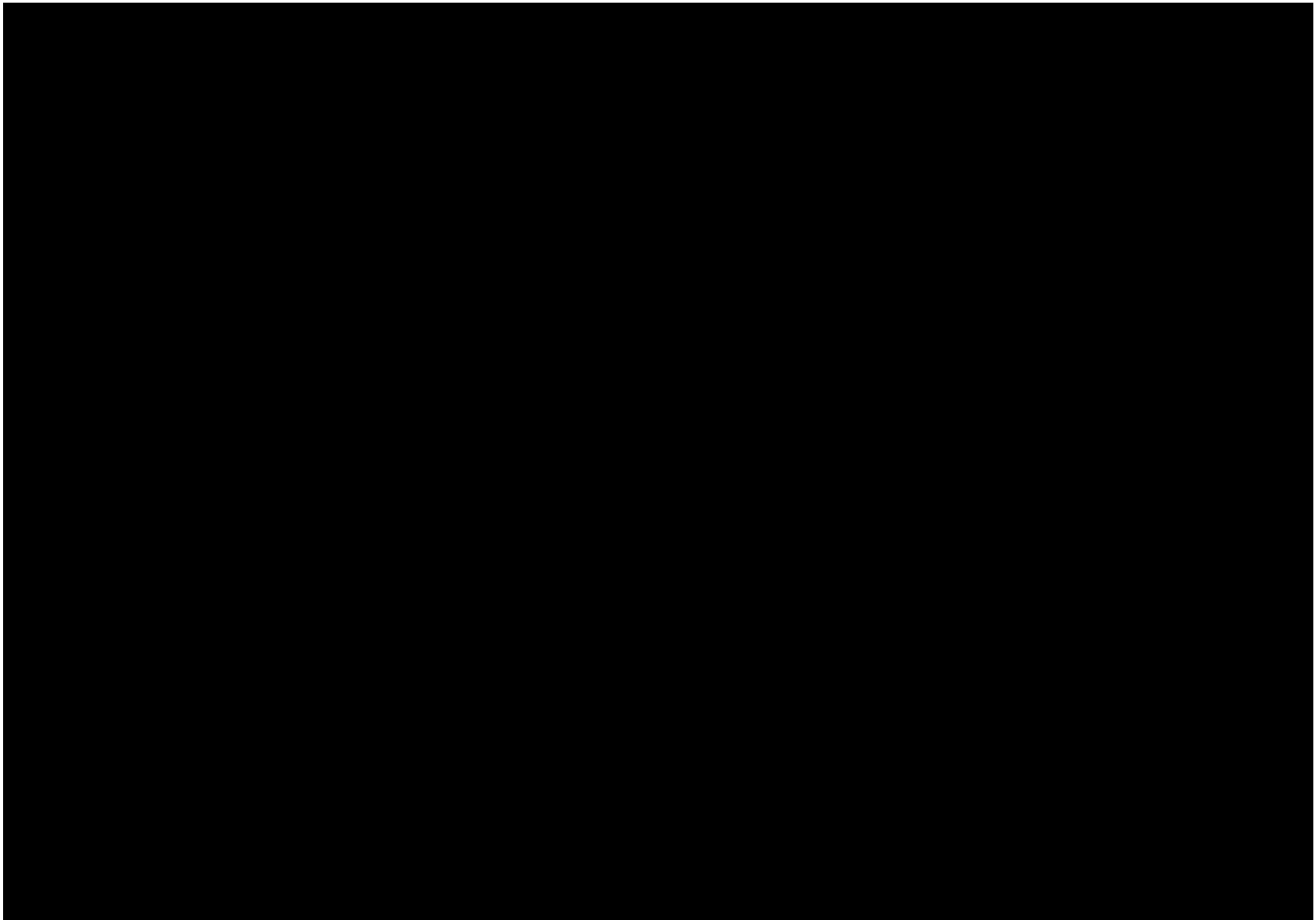
[redacted]

Hourly Average Day for March 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Columbus Electric Cooperative, Inc.



Hourly Average Day for May 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021
Columbus Electric Cooperative, Inc.

[redacted]

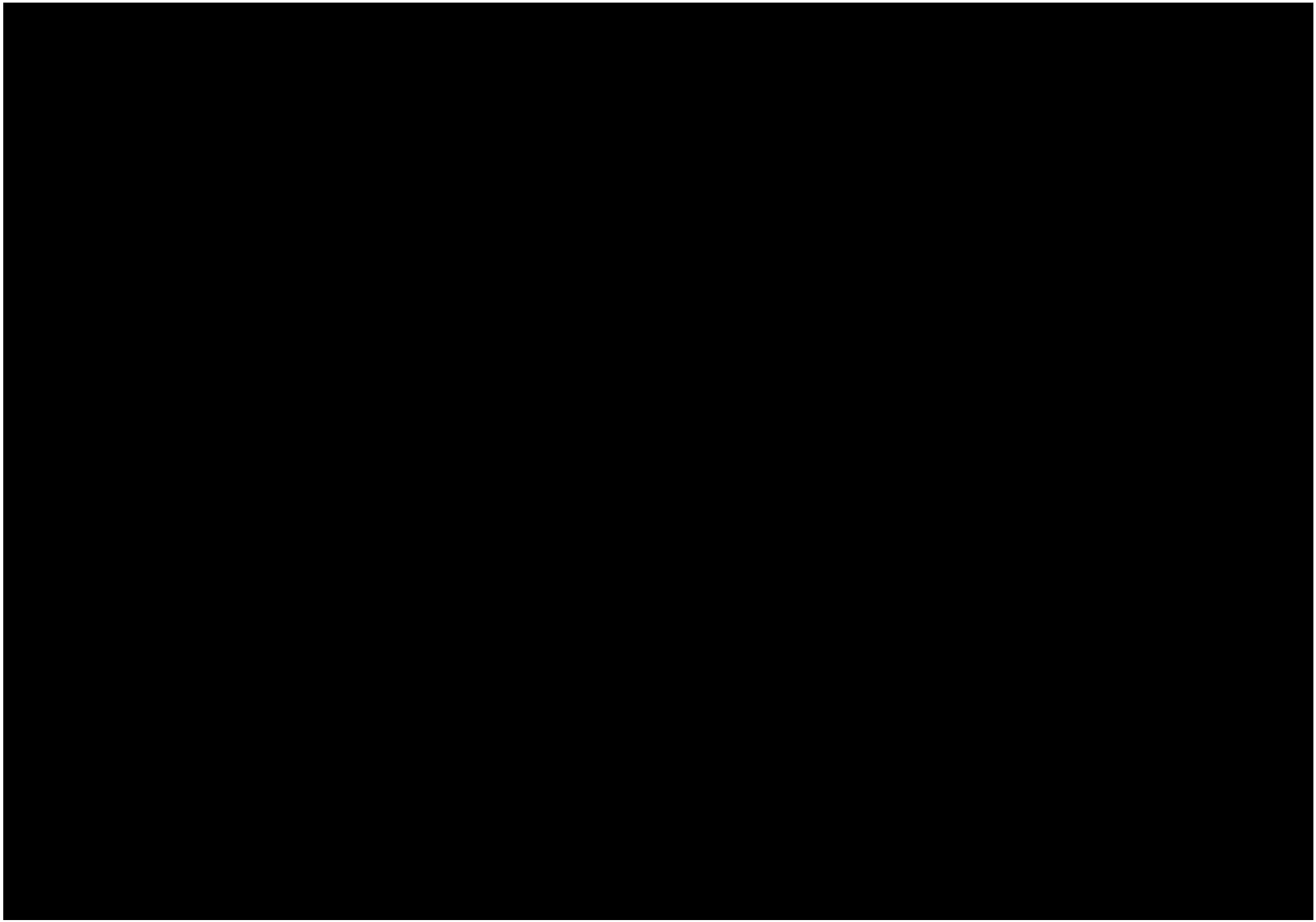
Hourly Average Day for July 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021
Columbus Electric Cooperative, Inc.



Hourly Average Day for October 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021
Columbus Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Central New Mexico Electric Cooperative, Inc.

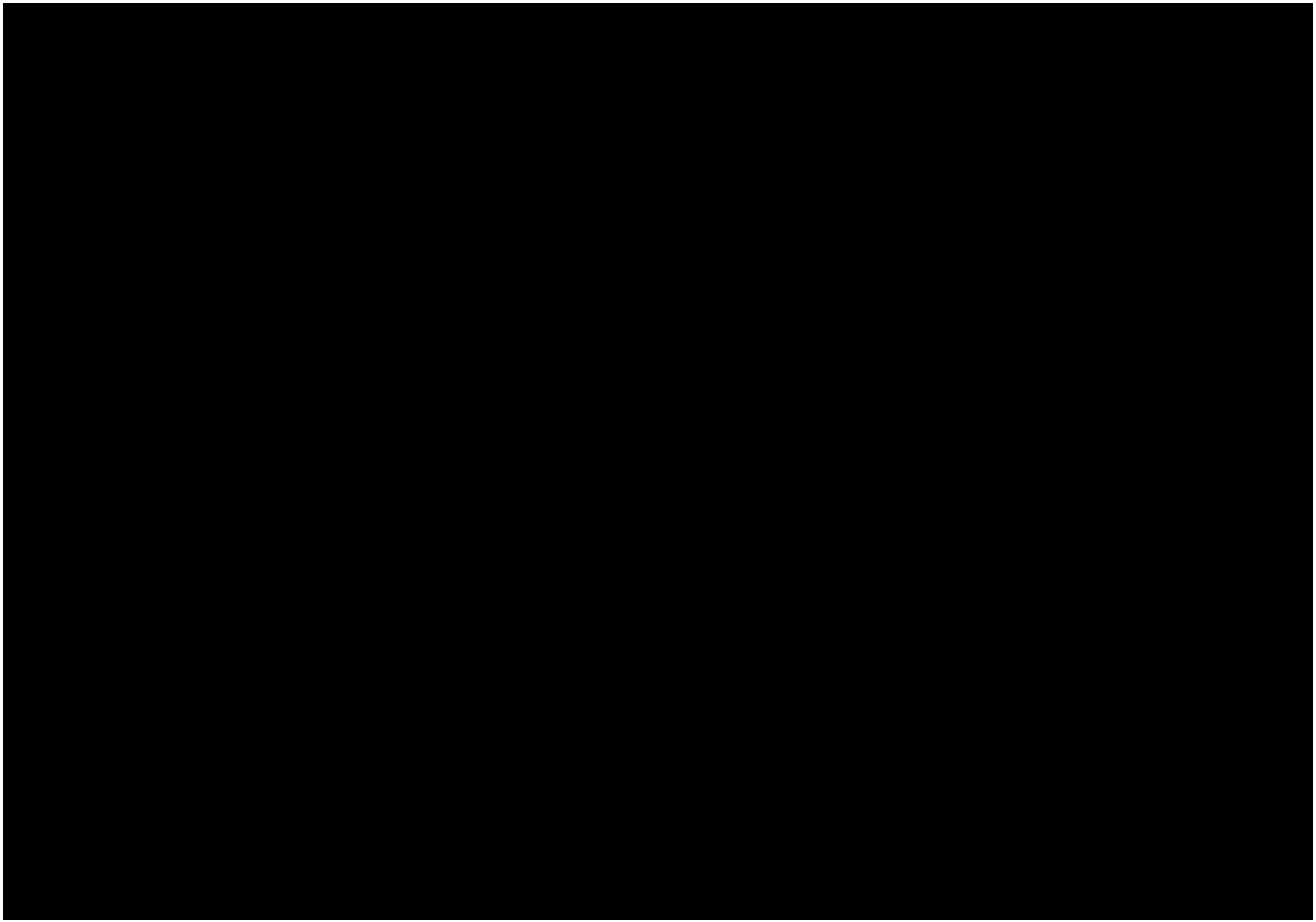
[redacted]

Hourly Average Day for March 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for May 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Central New Mexico Electric Cooperative, Inc.

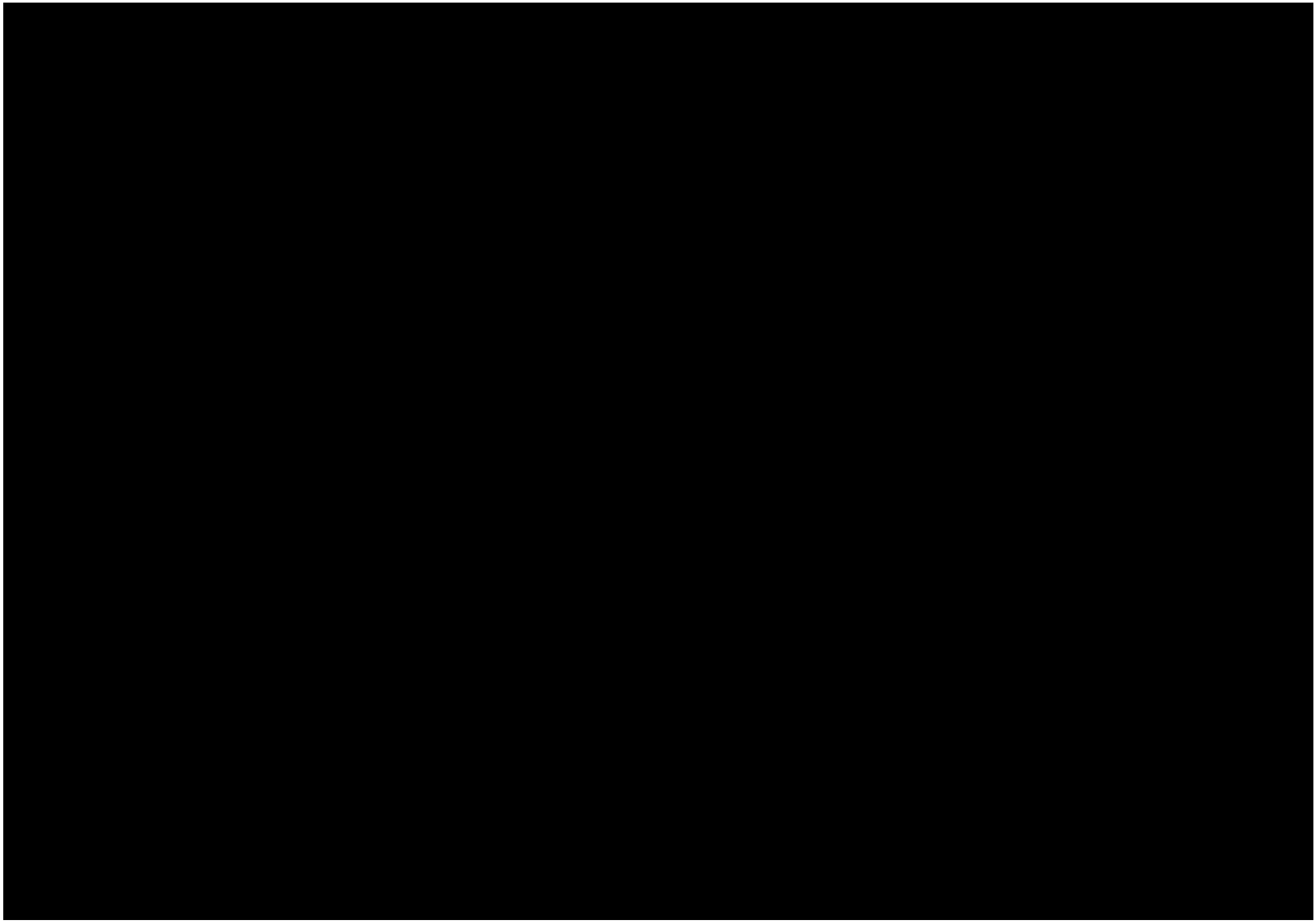
[redacted]

Hourly Average Day for August 2021
Central New Mexico Electric Cooperative, Inc.

[redacted]

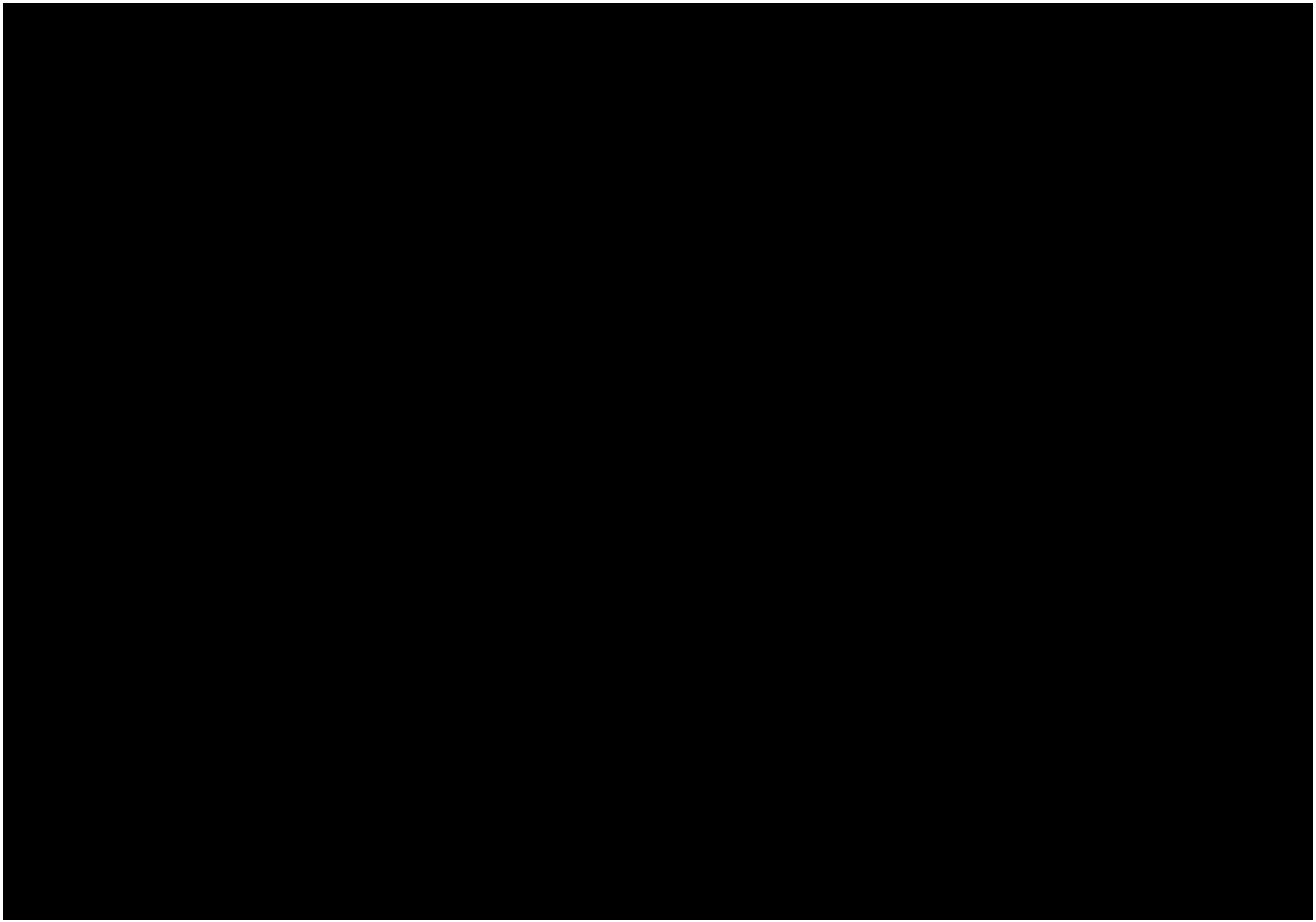
Hourly Average Day for September 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for October 2021

Central New Mexico Electric Cooperative, Inc.



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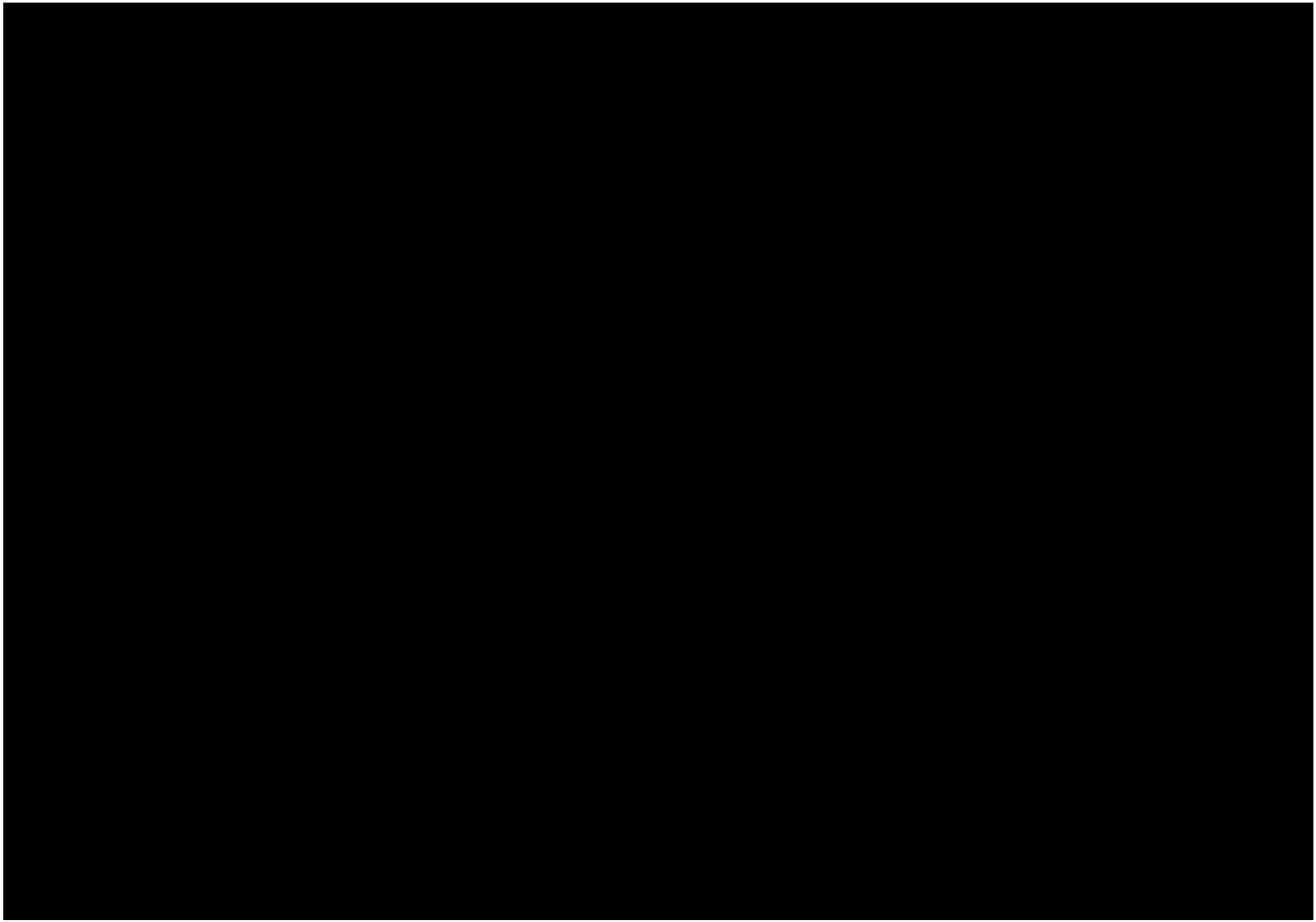
Hourly Average Day for November 2021

Central New Mexico Electric Cooperative, Inc.



Hourly Average Day for December 2021

Central New Mexico Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Chimney Rock Public Power District

[redacted]

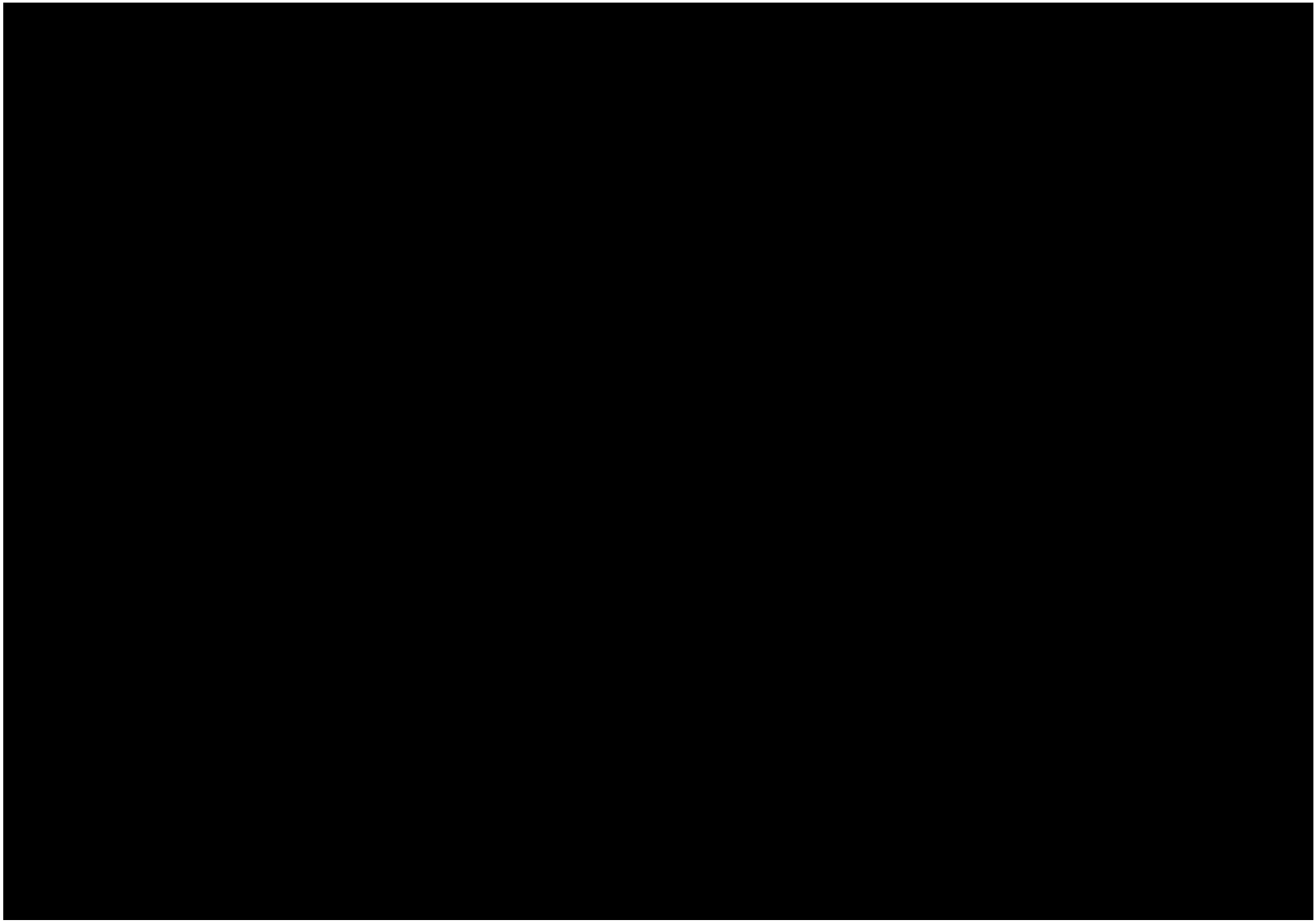
Hourly Average Day for February 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for March 2021

Chimney Rock Public Power District



Hourly Average Day for April 2021

Chimney Rock Public Power District

[redacted]

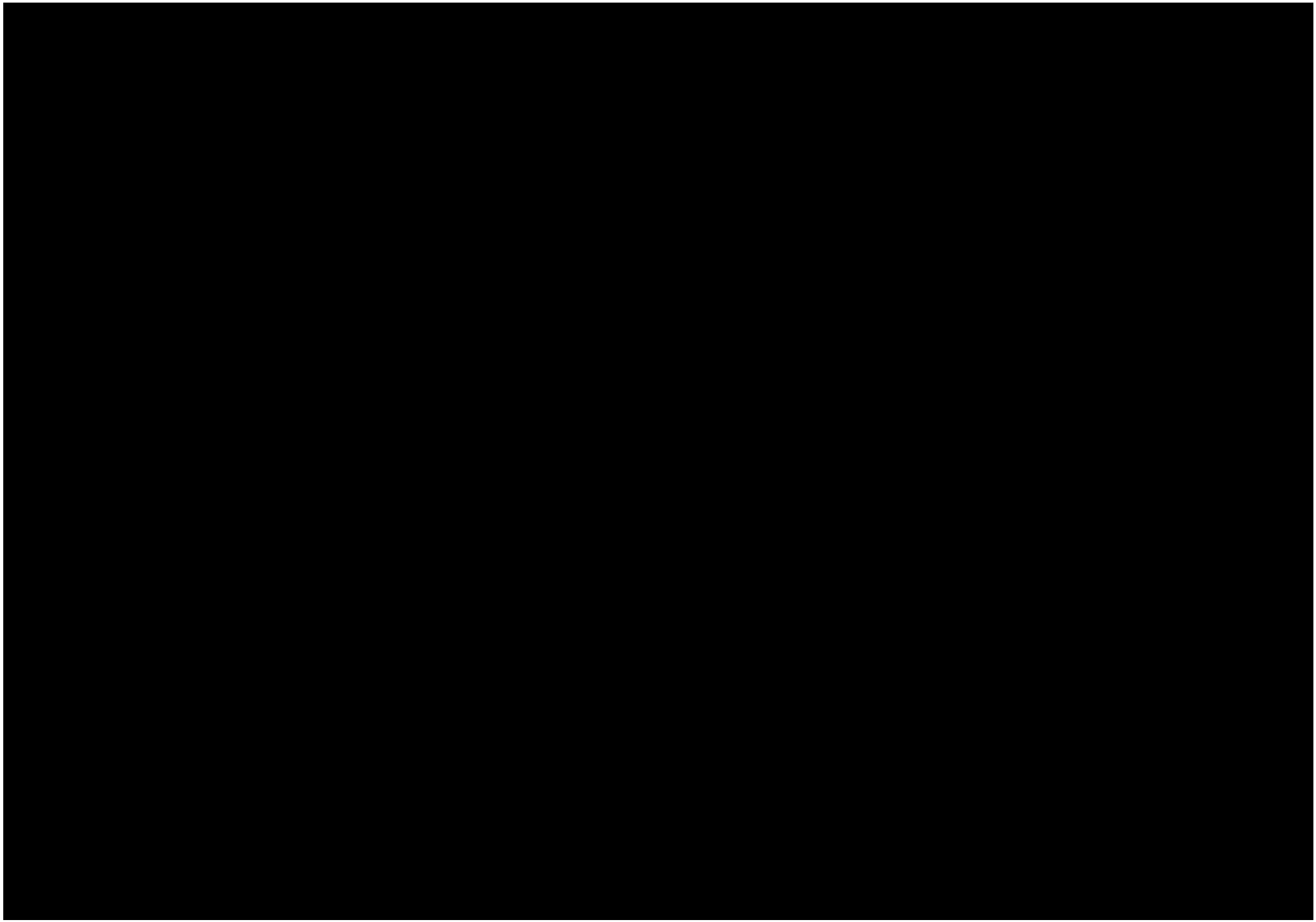
Hourly Average Day for May 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for June 2021

Chimney Rock Public Power District



Hourly Average Day for July 2021

Chimney Rock Public Power District

[redacted]

Hourly Average Day for August 2021

Chimney Rock Public Power District

[redacted]

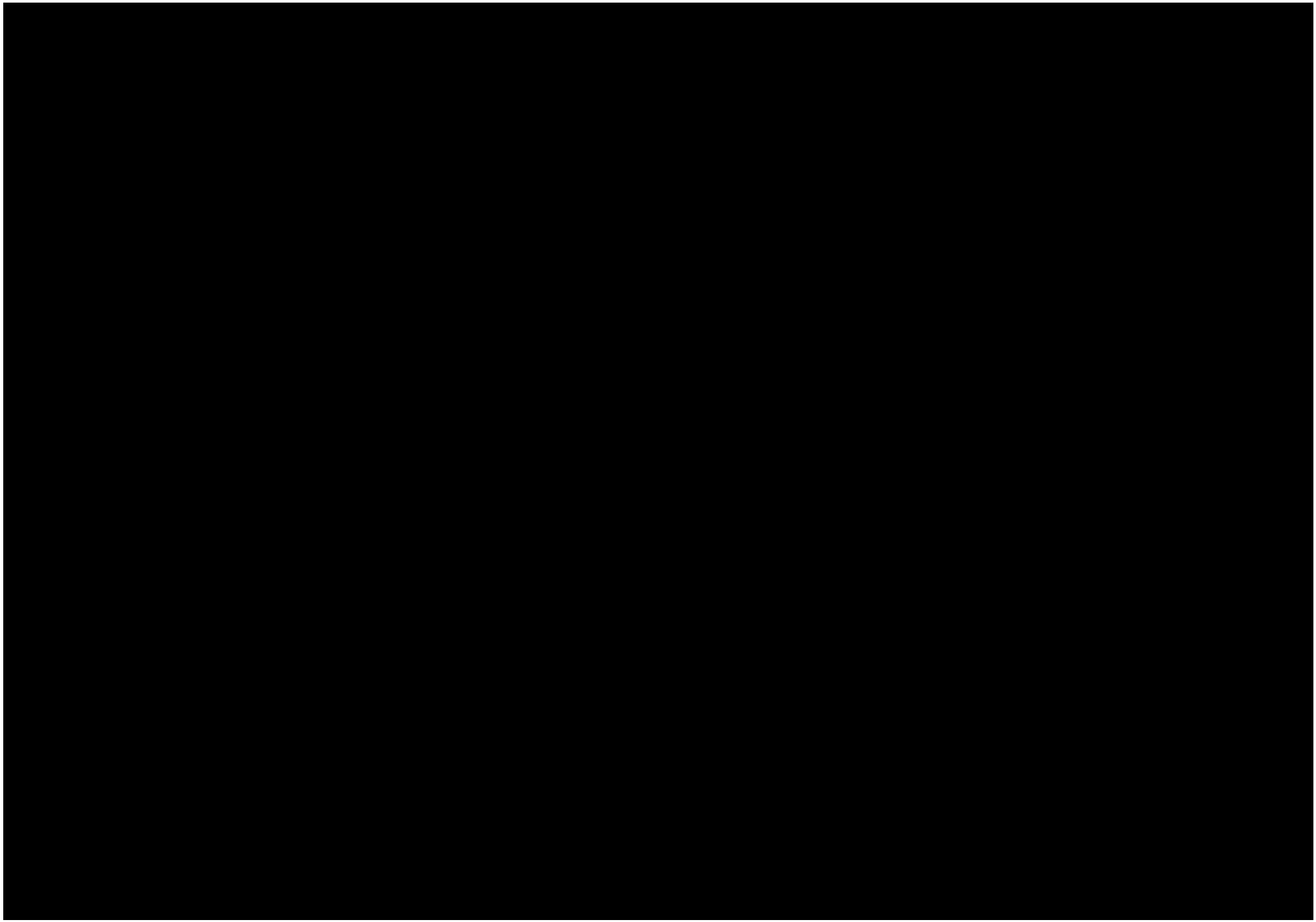
Hourly Average Day for September 2021

Chimney Rock Public Power District

[redacted]

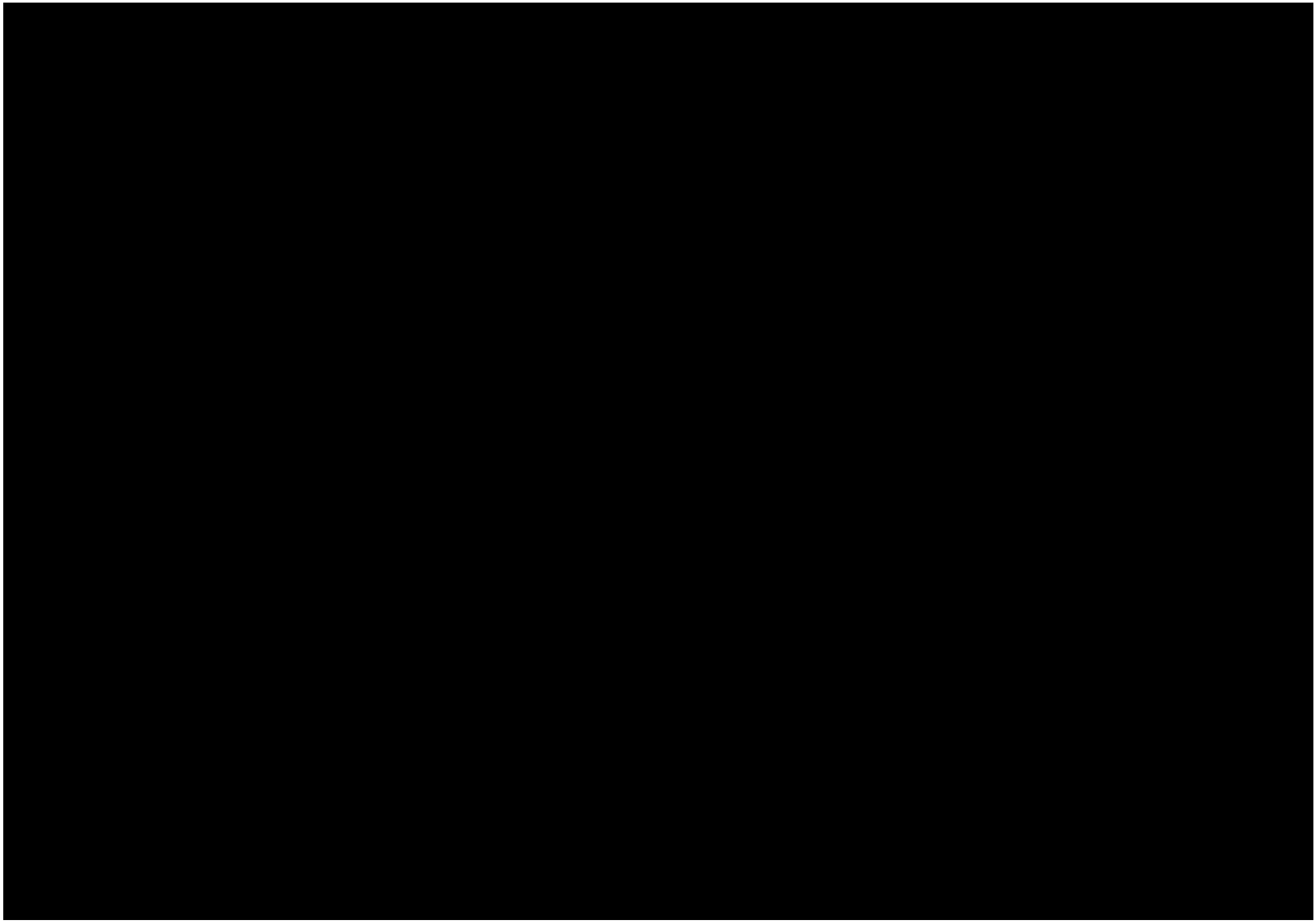
Hourly Average Day for October 2021

Chimney Rock Public Power District



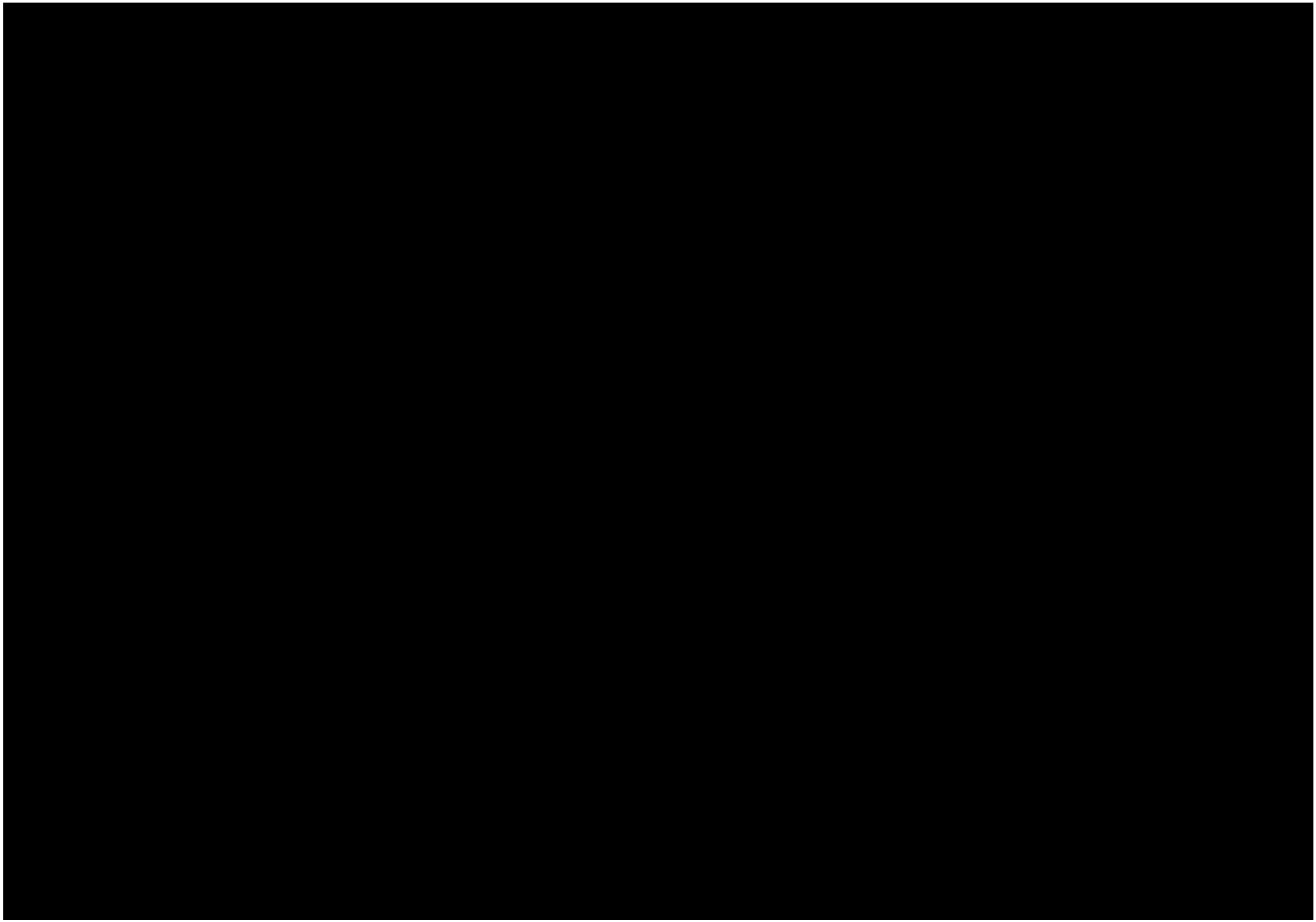
Hourly Average Day for November 2021

Chimney Rock Public Power District



Hourly Average Day for December 2021

Chimney Rock Public Power District



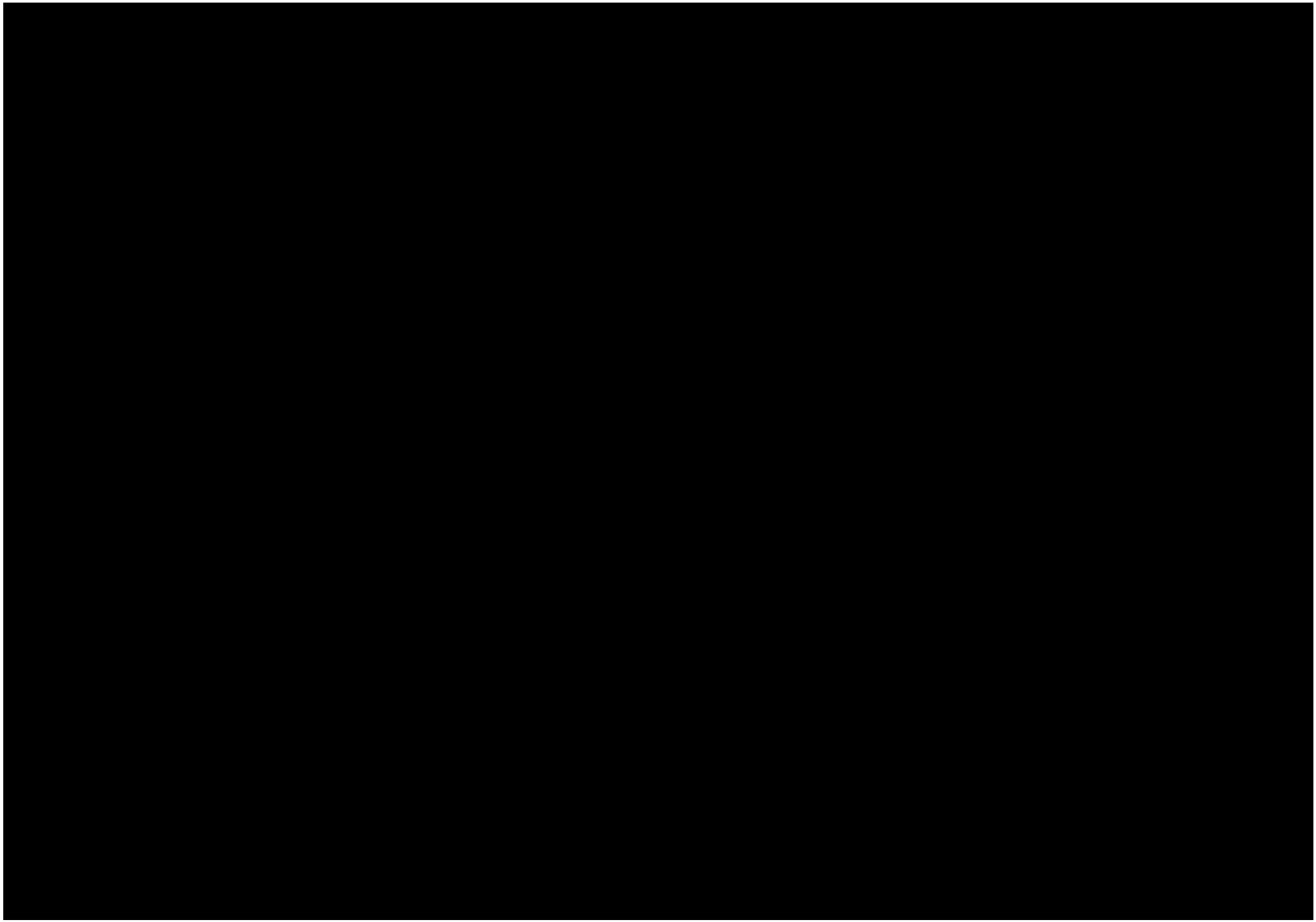
Hourly Average Day for January 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

Empire Electric Association, Inc.



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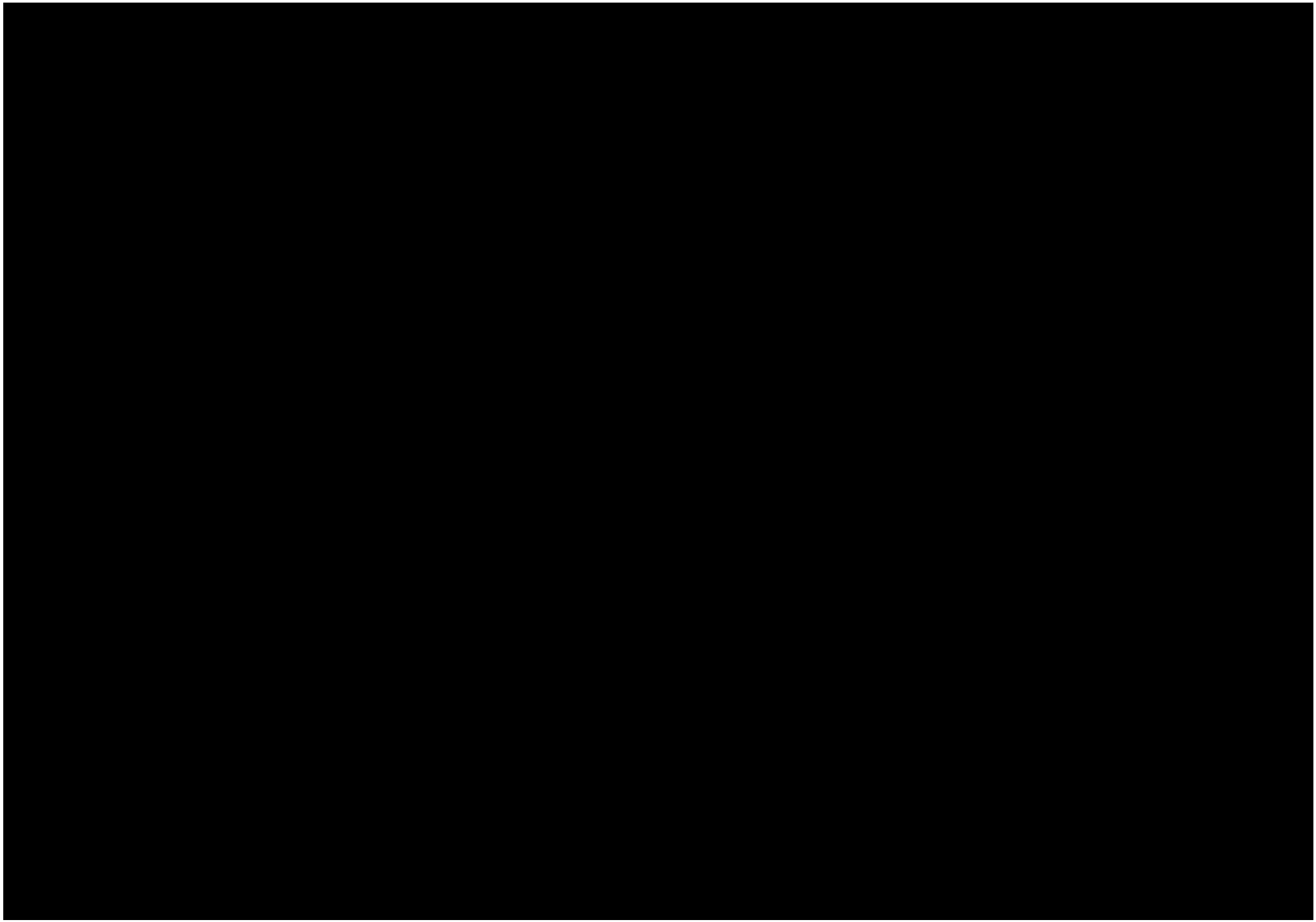
Hourly Average Day for March 2021

Empire Electric Association, Inc.



Hourly Average Day for April 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Empire Electric Association, Inc.

[redacted]

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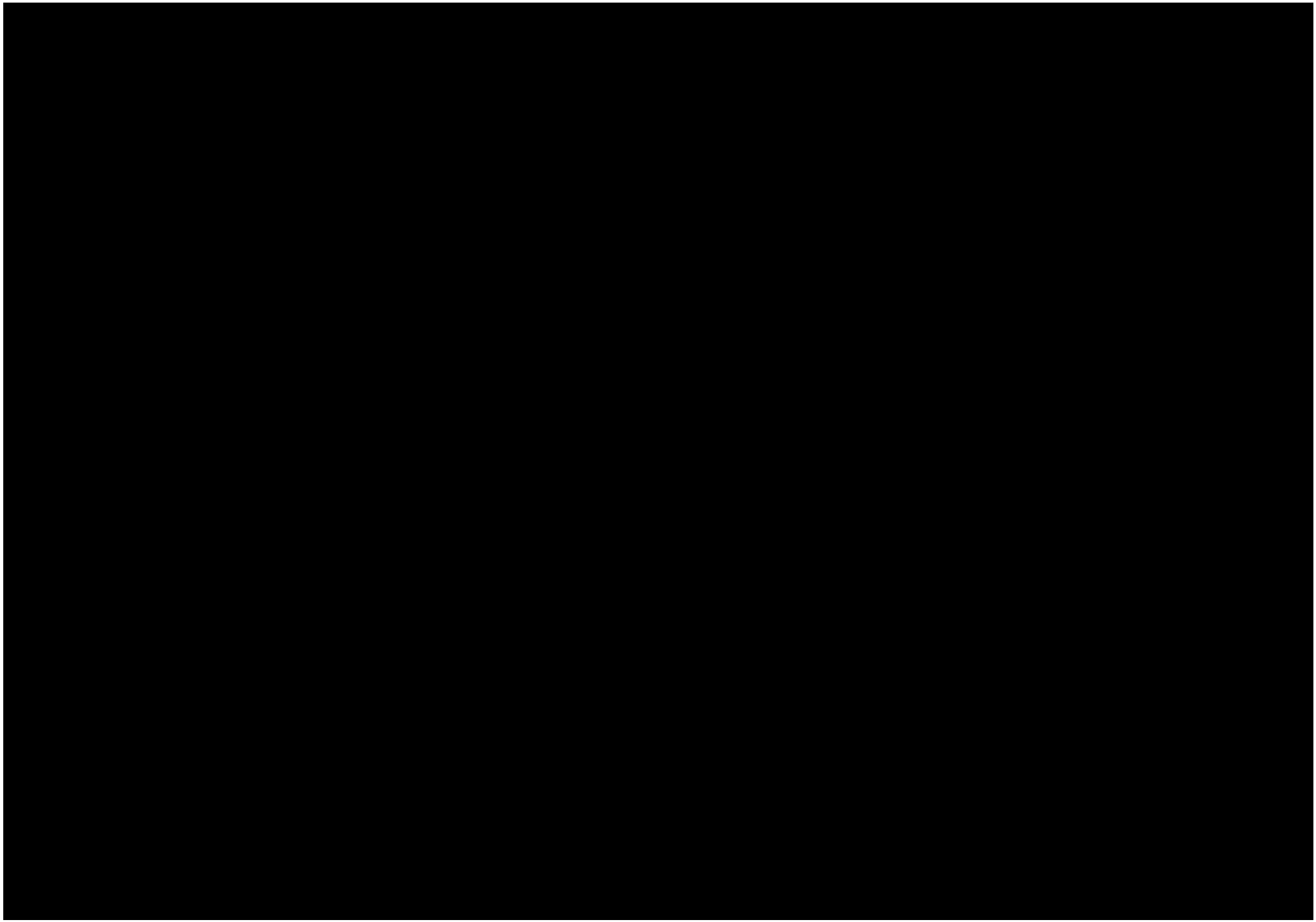
Hourly Average Day for August 2021

Empire Electric Association, Inc.



Hourly Average Day for September 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Empire Electric Association, Inc.

[redacted]

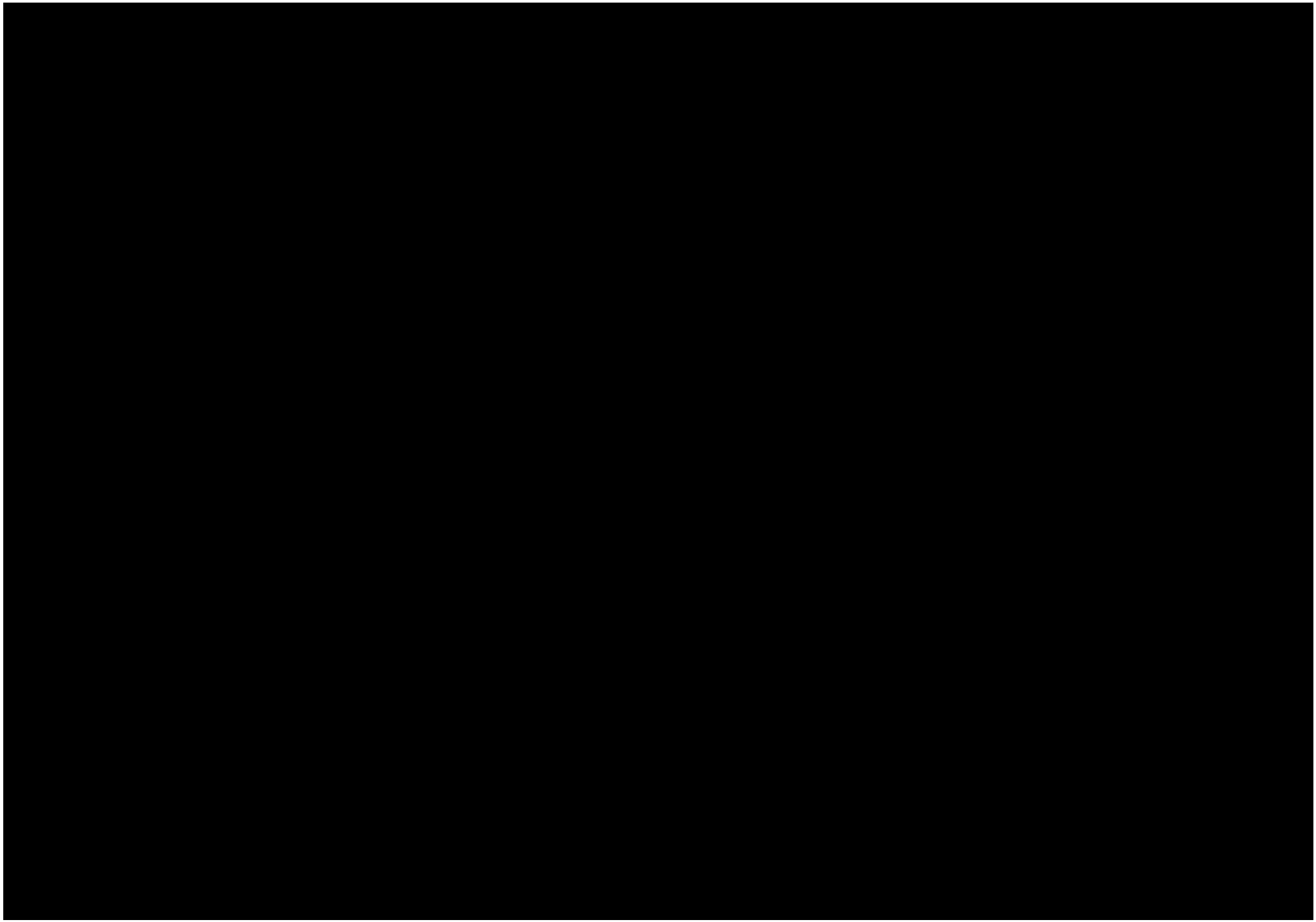
Hourly Average Day for November 2021

Empire Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Empire Electric Association, Inc.



Hourly Average Day for January 2021
Gunnison County Electric Association, Inc.

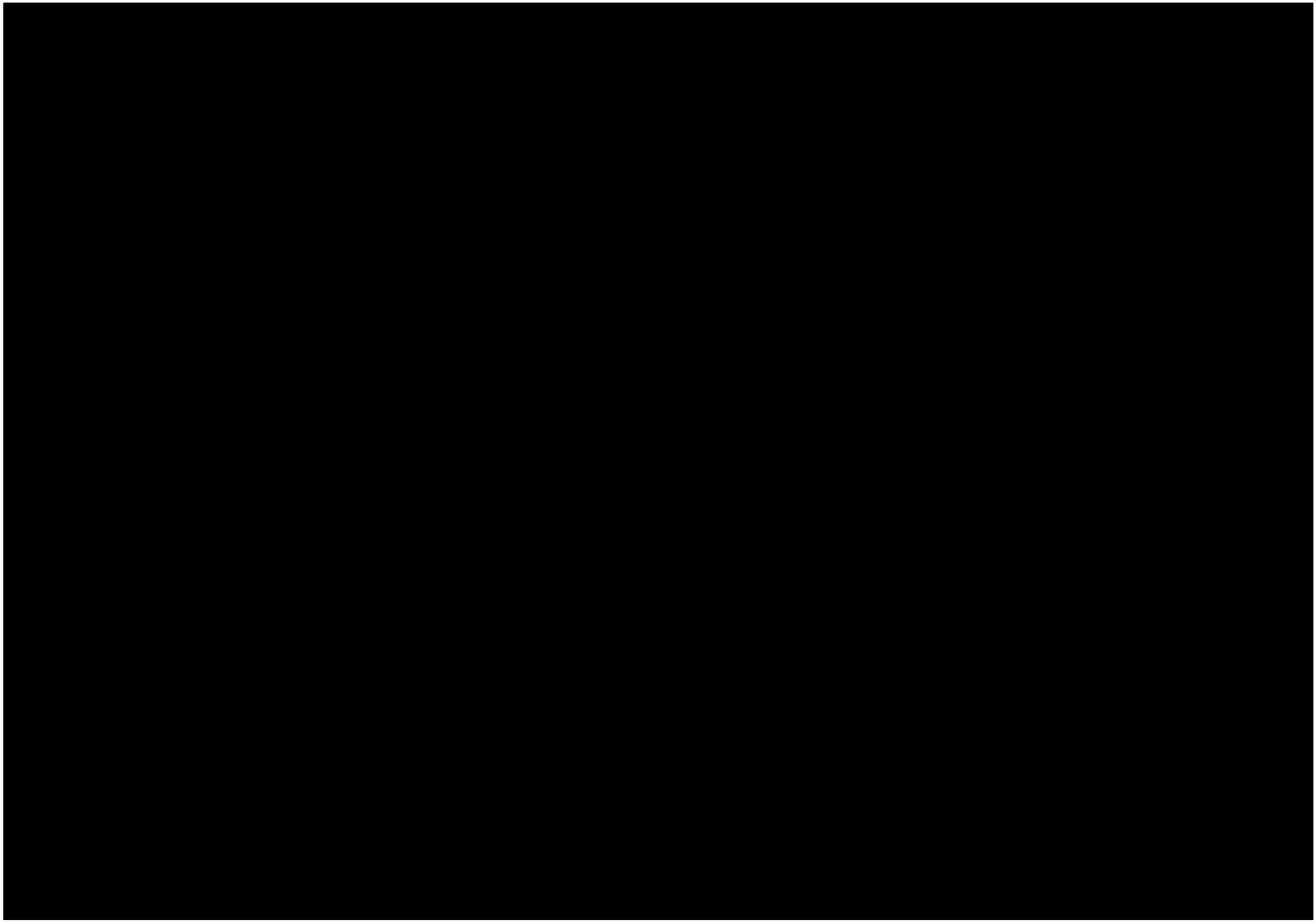
[redacted]

Hourly Average Day for February 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Gunnison County Electric Association, Inc.



Hourly Average Day for April 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021
Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Gunnison County Electric Association, Inc.

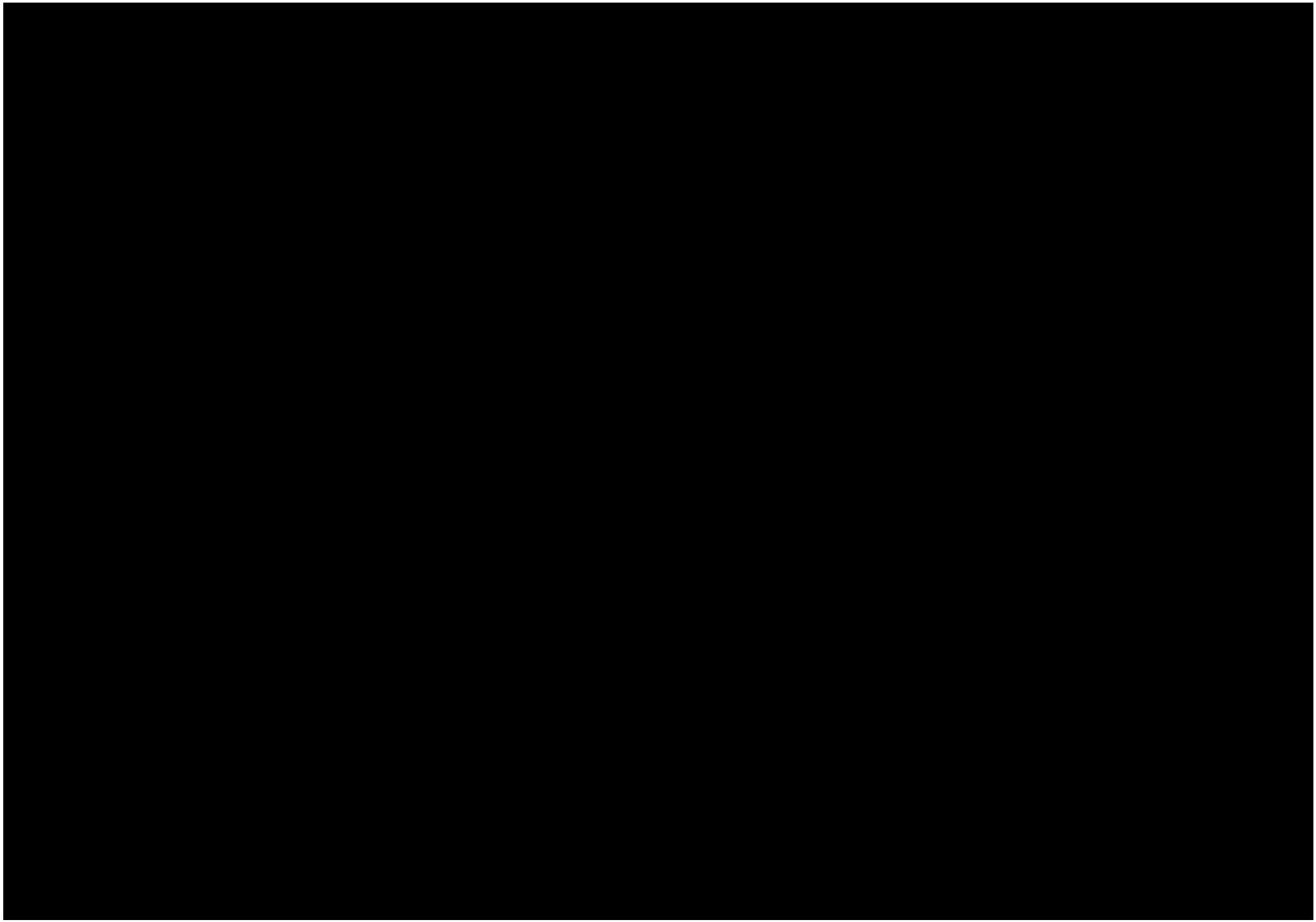
[redacted]

Hourly Average Day for November 2021

Gunnison County Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021
Gunnison County Electric Association, Inc.



Hourly Average Day for January 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for February 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for March 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for April 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for May 2021
Garland Light and Power Company

[redacted]

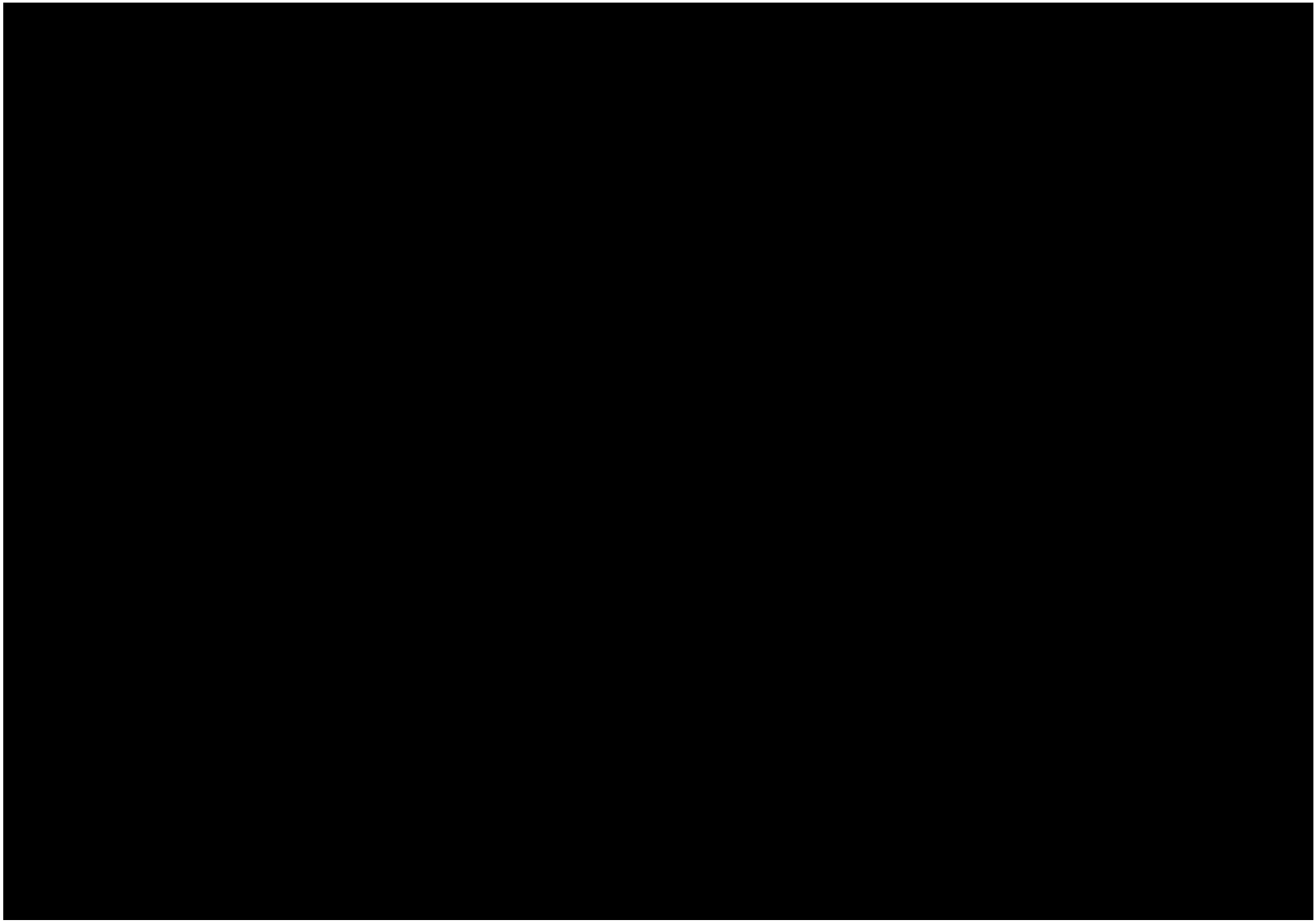
Hourly Average Day for June 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for July 2021

Garland Light and Power Company



Hourly Average Day for August 2021

Garland Light and Power Company

[redacted]

Hourly Average Day for September 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for October 2021
Garland Light and Power Company

[redacted]

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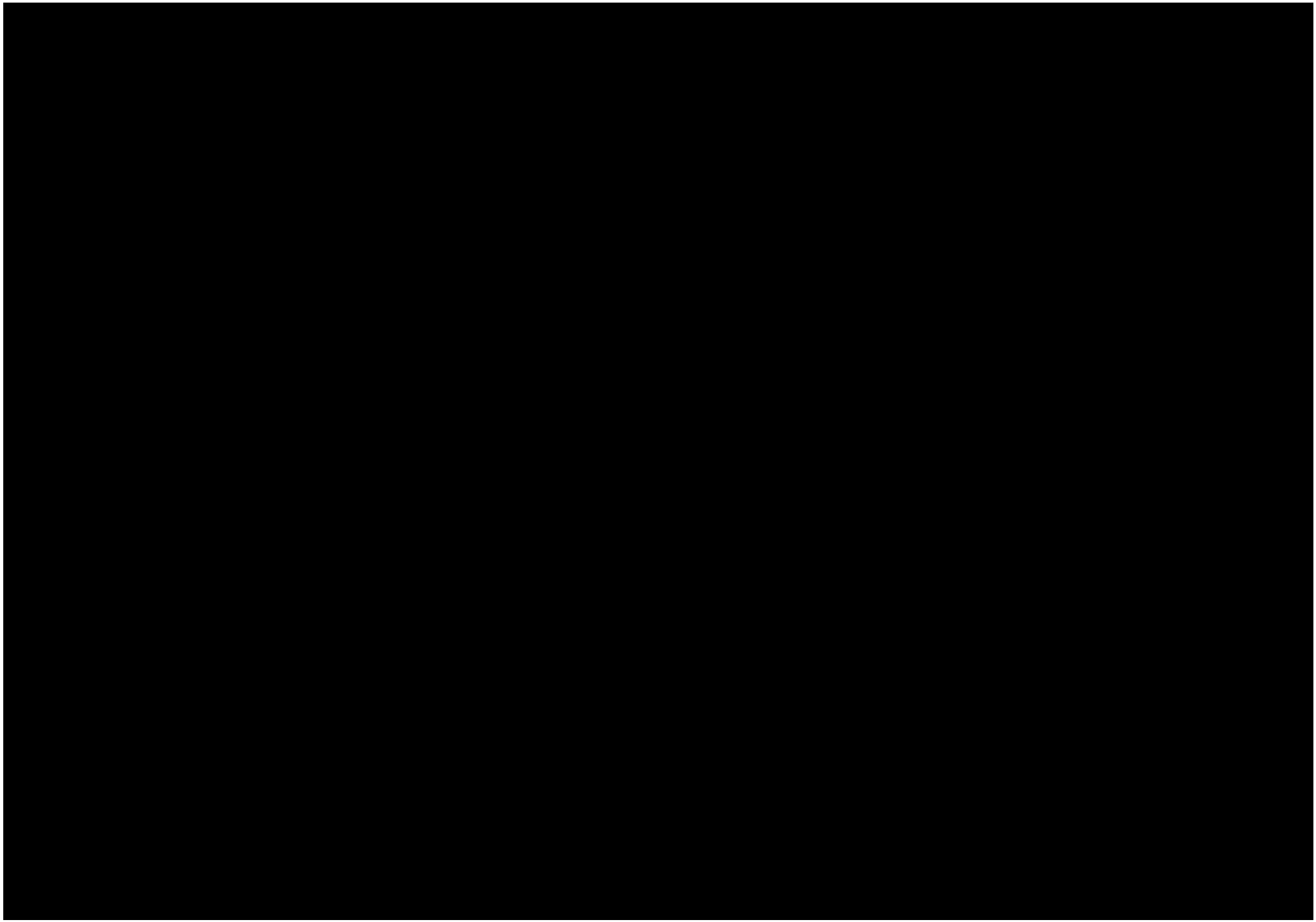
Hourly Average Day for November 2021

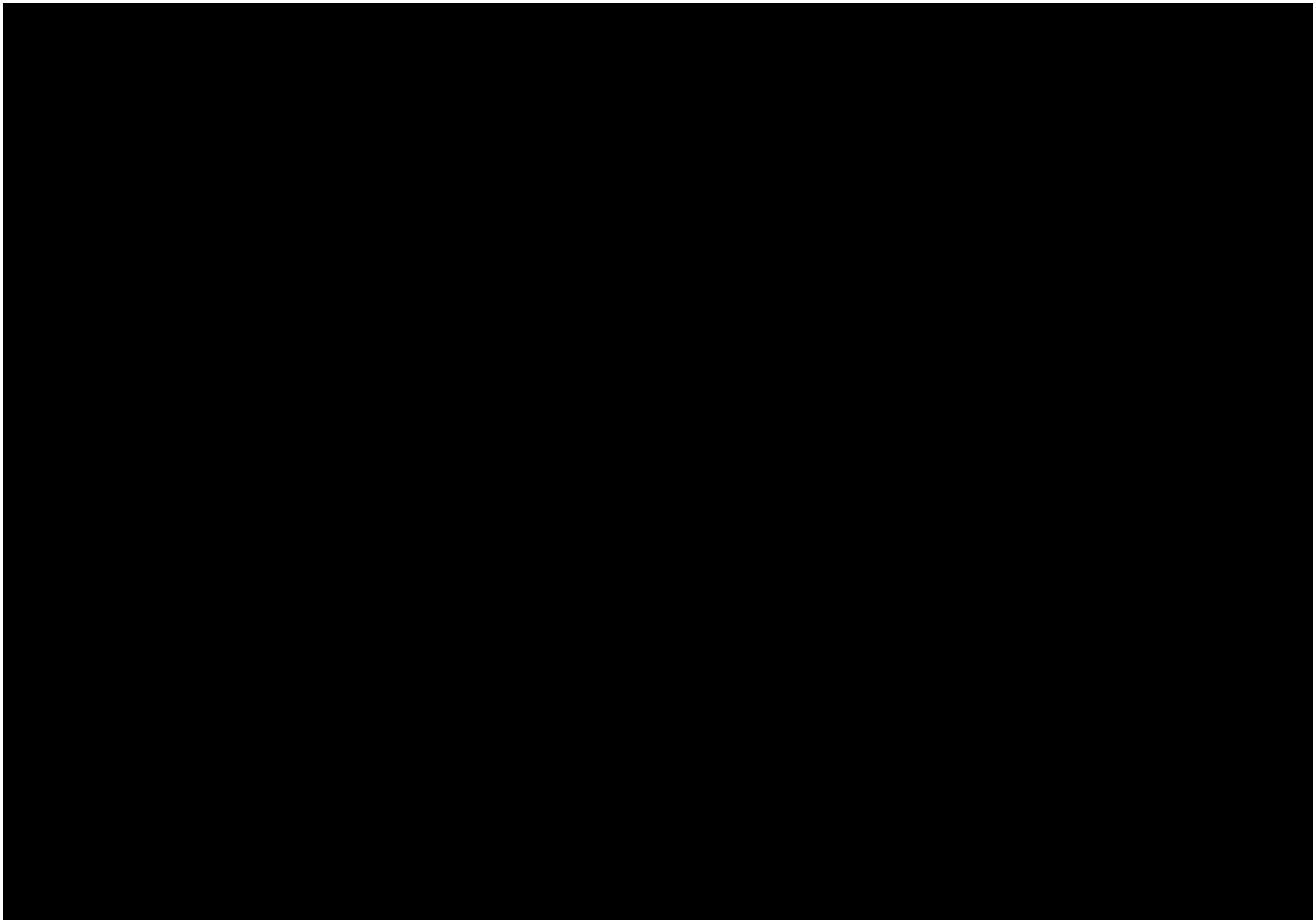
Garland Light and Power Company



Hourly Average Day for December 2021
Garland Light and Power Company

[redacted]

Hourly Average Day for January 2021
Highline Electric Association



Hourly Average Day for February 2021
Highline Electric Association

[redacted]

Hourly Average Day for March 2021
Highline Electric Association

[redacted]

Hourly Average Day for April 2021
Highline Electric Association

[redacted]

Hourly Average Day for May 2021
Highline Electric Association

[redacted]

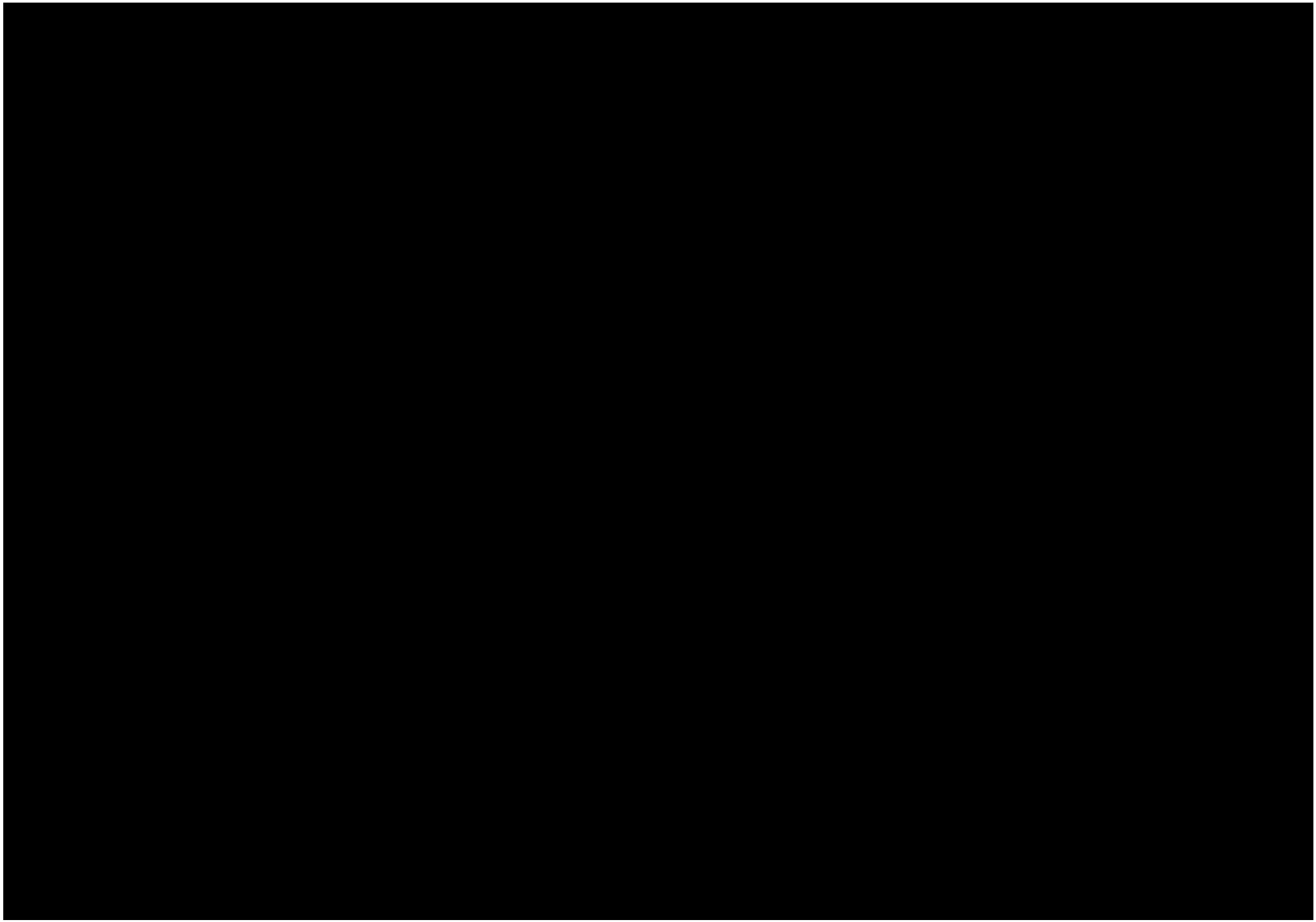
Hourly Average Day for June 2021
Highline Electric Association

[redacted]

Hourly Average Day for July 2021
Highline Electric Association

[redacted]

Hourly Average Day for August 2021
Highline Electric Association



Hourly Average Day for September 2021

Highline Electric Association

[redacted]

Hourly Average Day for October 2021
Highline Electric Association

[redacted]

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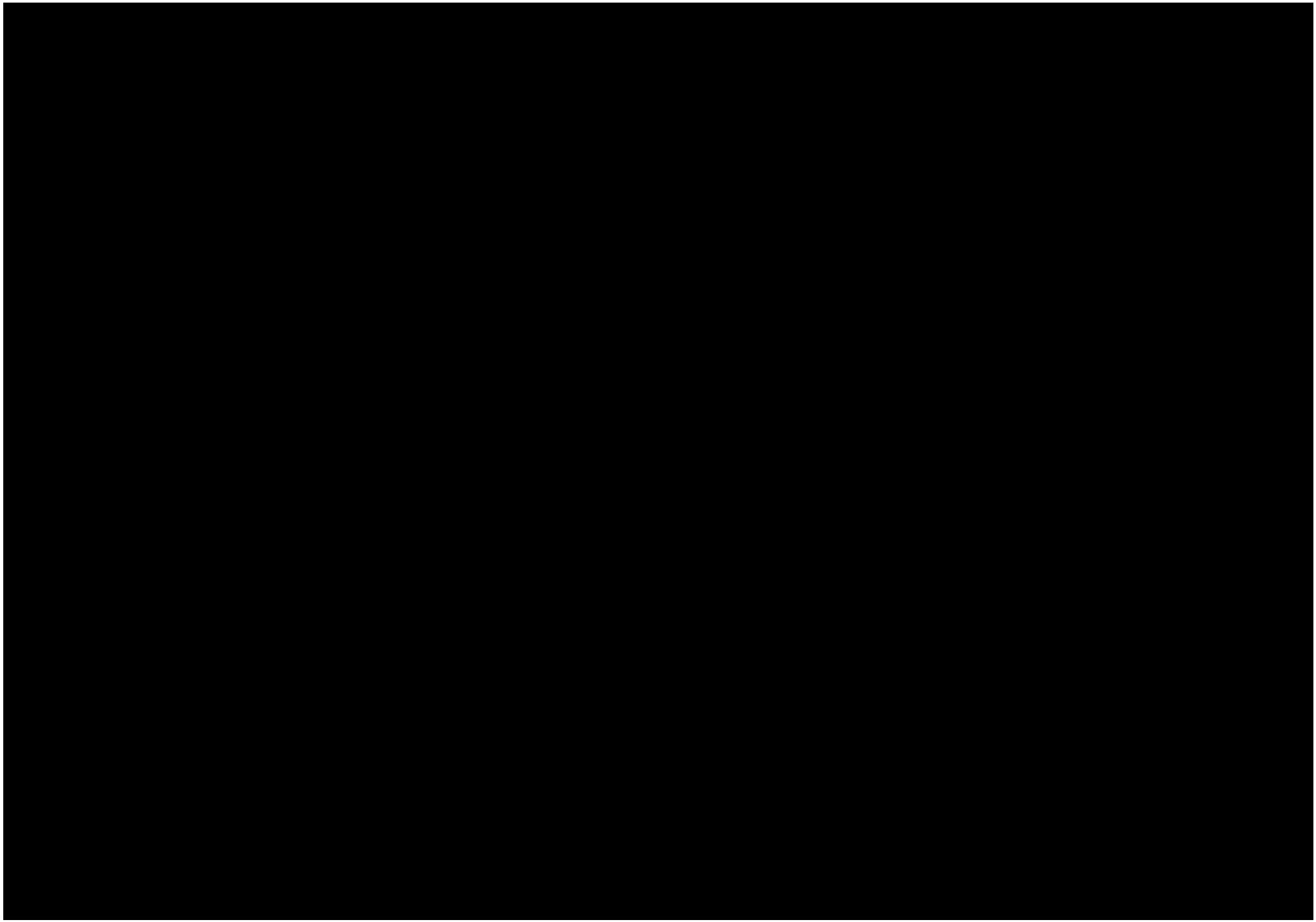
Hourly Average Day for November 2021

Highline Electric Association



Hourly Average Day for December 2021

Highline Electric Association

[redacted]

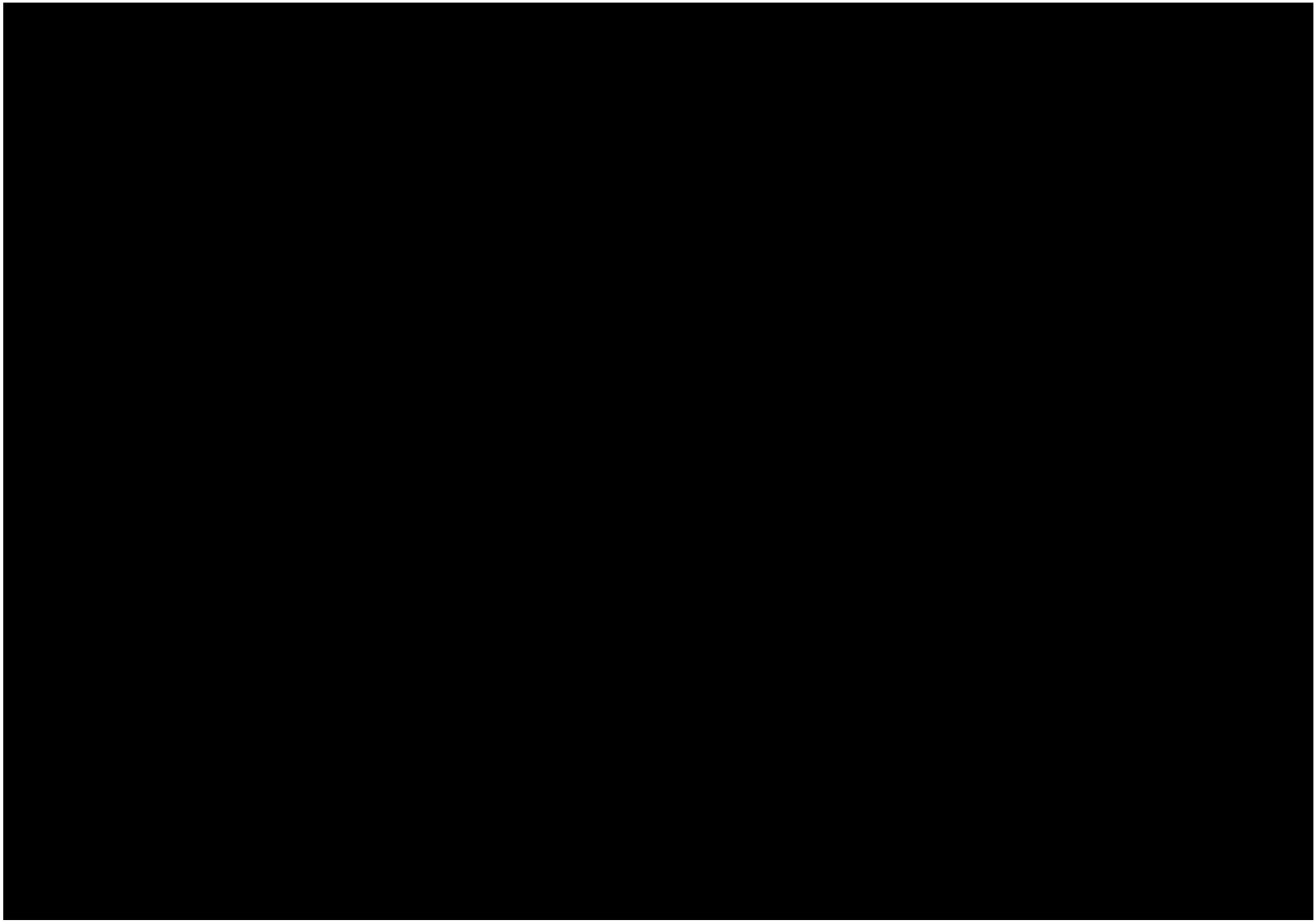
Hourly Average Day for January 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for February 2021

High Plains Power, Inc.



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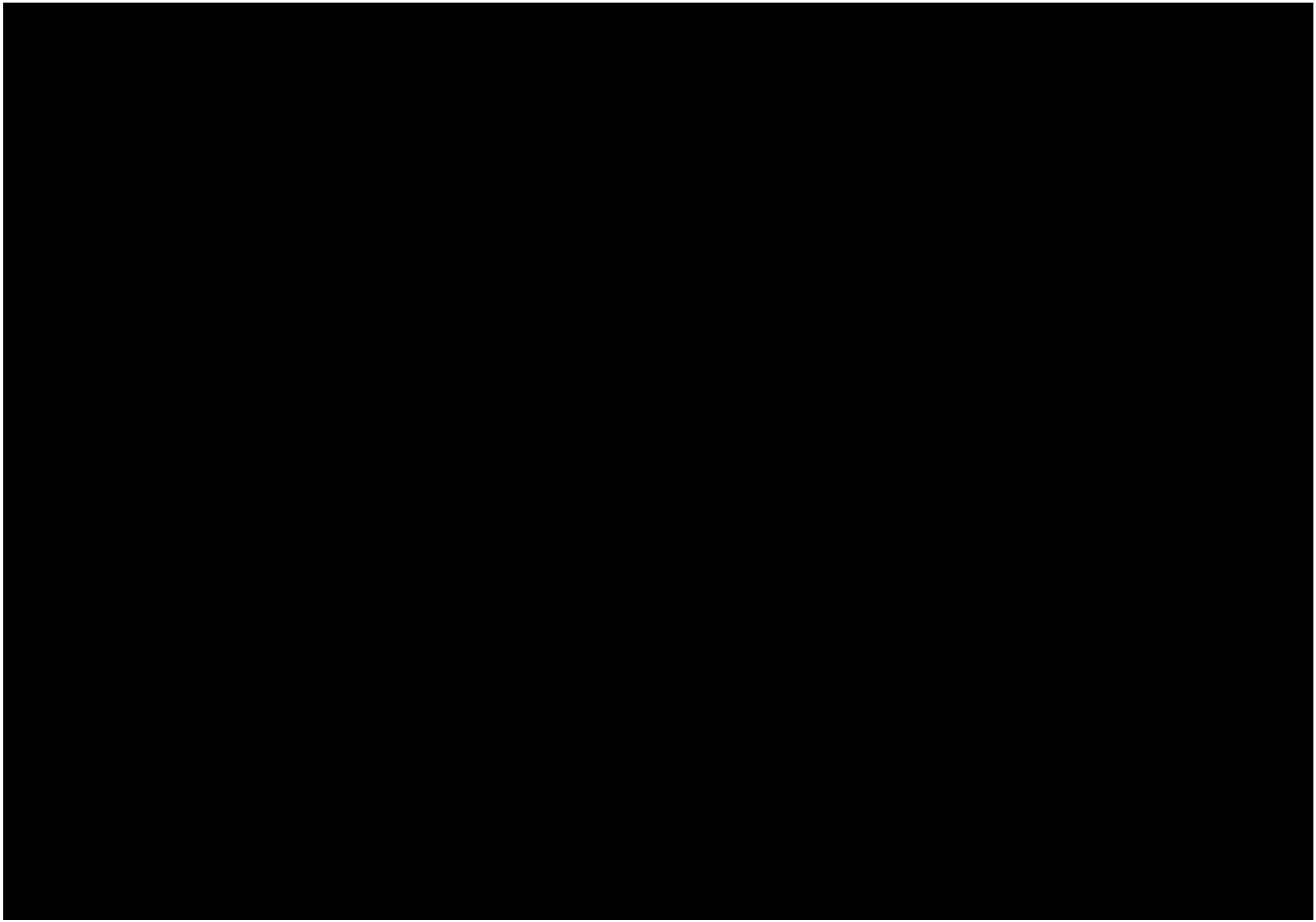
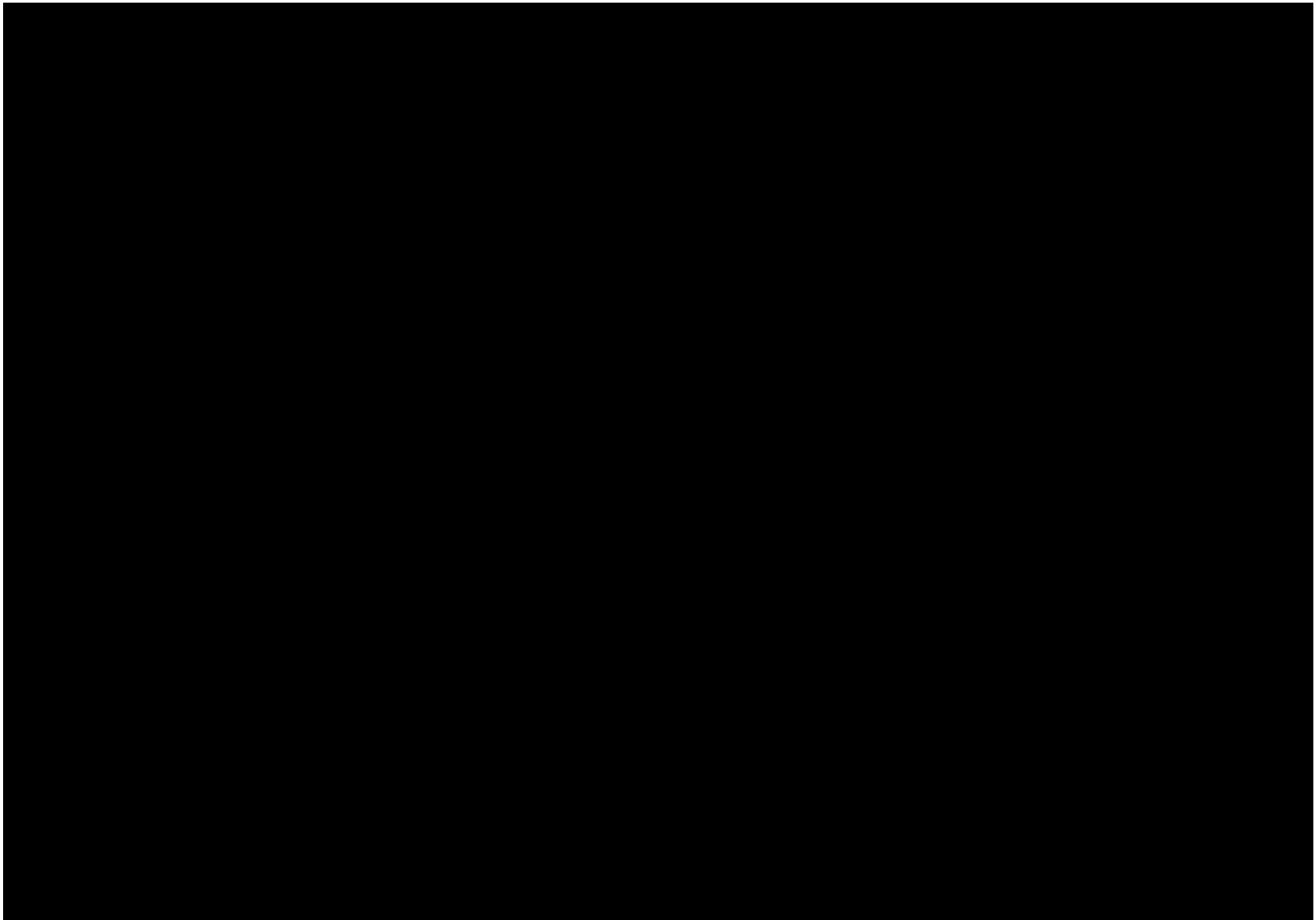
Hourly Average Day for March 2021

High Plains Power, Inc.



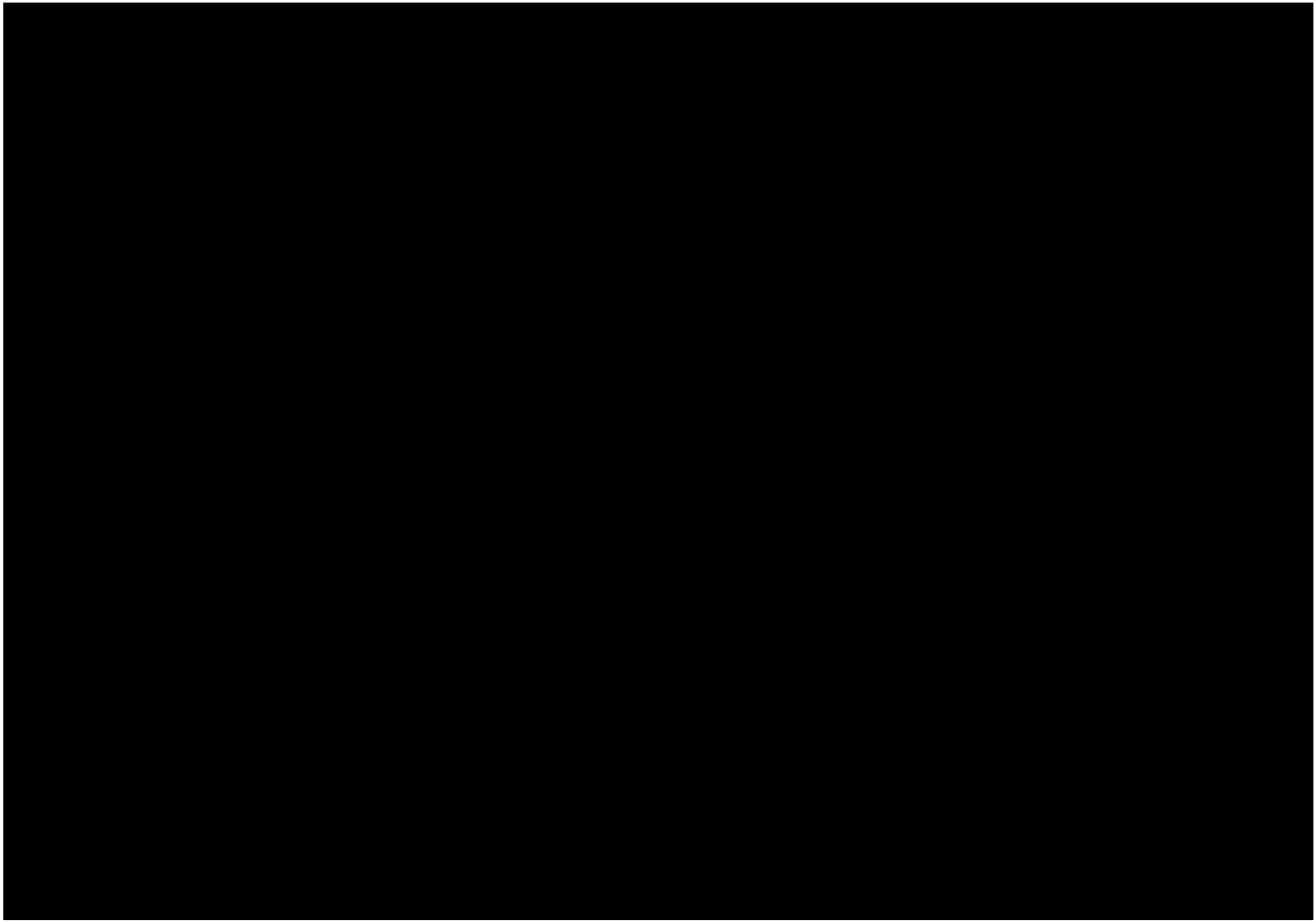
Hourly Average Day for April 2021

High Plains Power, Inc.



Hourly Average Day for May 2021

High Plains Power, Inc.



Hourly Average Day for June 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for July 2021

High Plains Power, Inc.

[redacted]

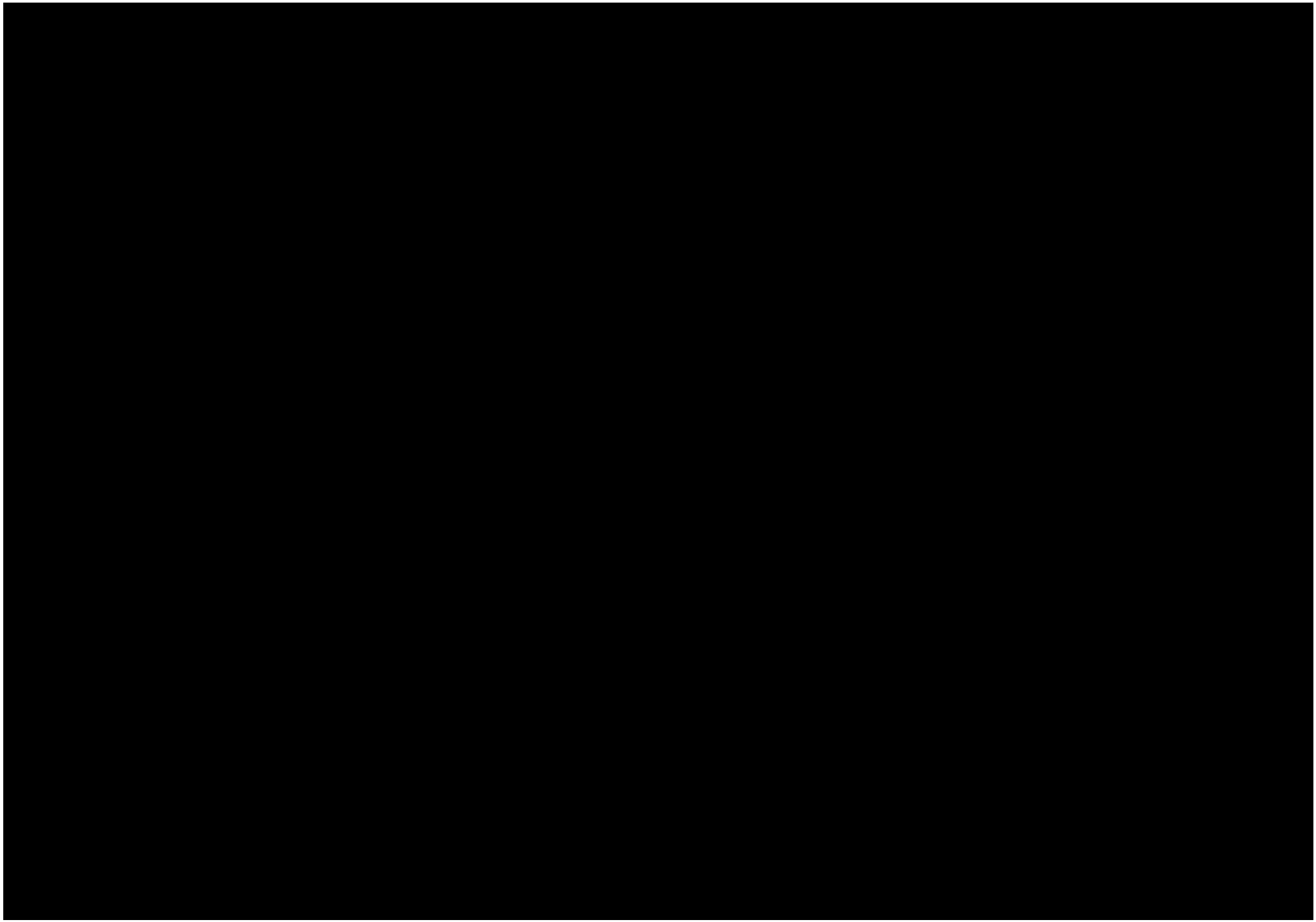
Hourly Average Day for August 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for September 2021

High Plains Power, Inc.



Hourly Average Day for October 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for November 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for December 2021

High Plains Power, Inc.

[redacted]

Hourly Average Day for January 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for February 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for March 2021

High West Energy, Inc.

[redacted]

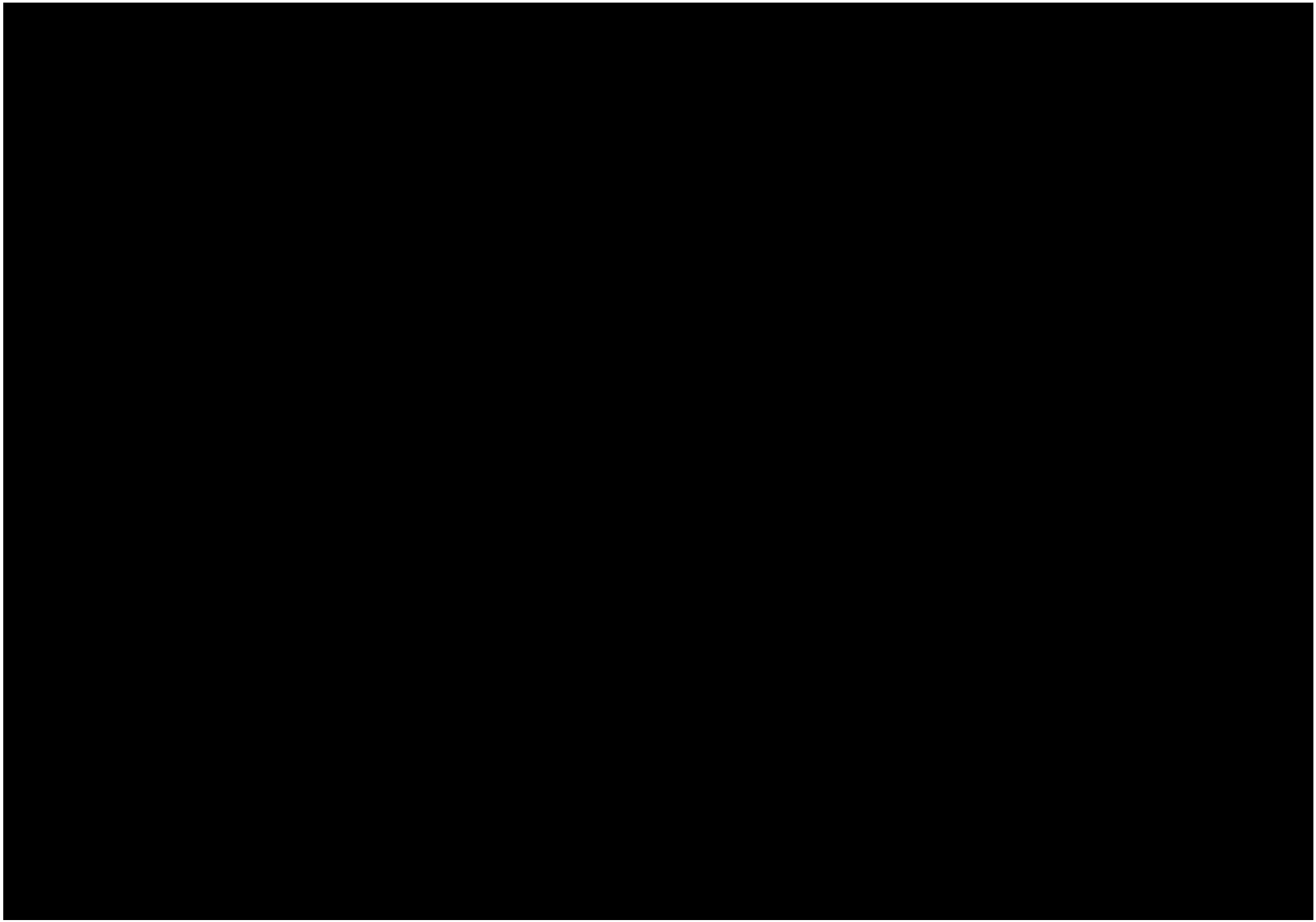
Hourly Average Day for April 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for May 2021

High West Energy, Inc.



Hourly Average Day for June 2021

High West Energy, Inc.

[redacted]

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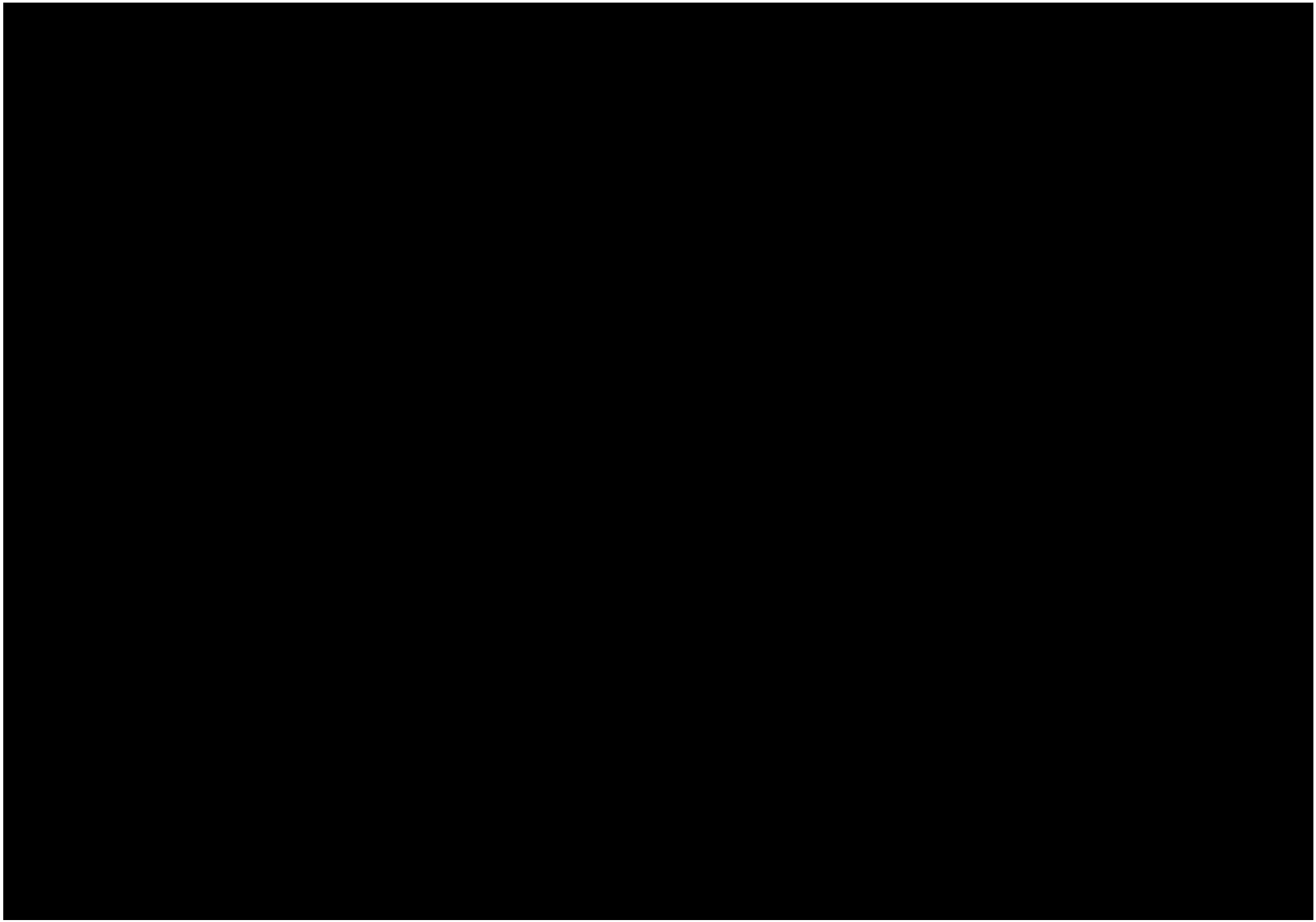
Hourly Average Day for July 2021

High West Energy, Inc.



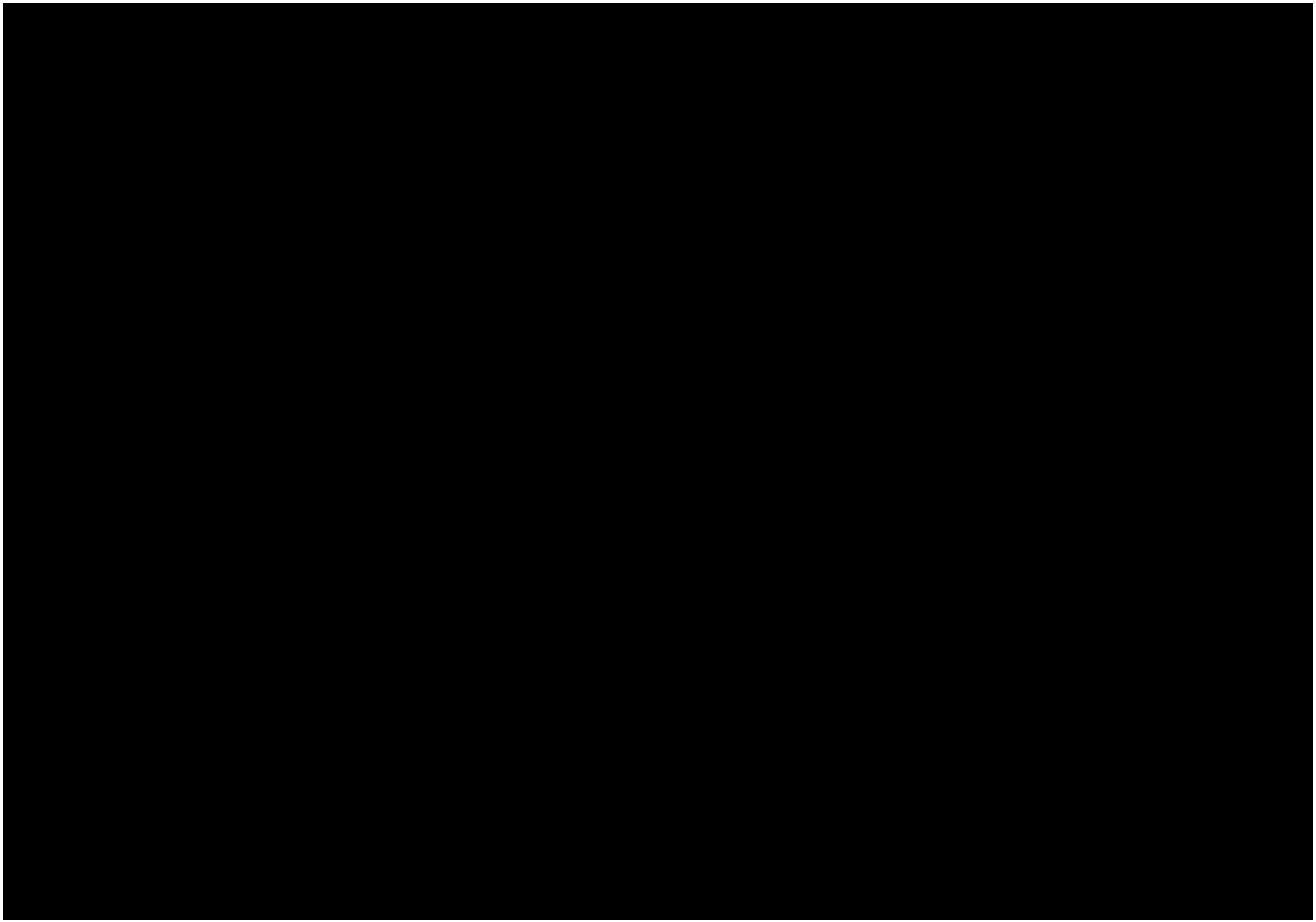
Hourly Average Day for August 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for September 2021

High West Energy, Inc.



Hourly Average Day for October 2021

High West Energy, Inc.

[redacted]

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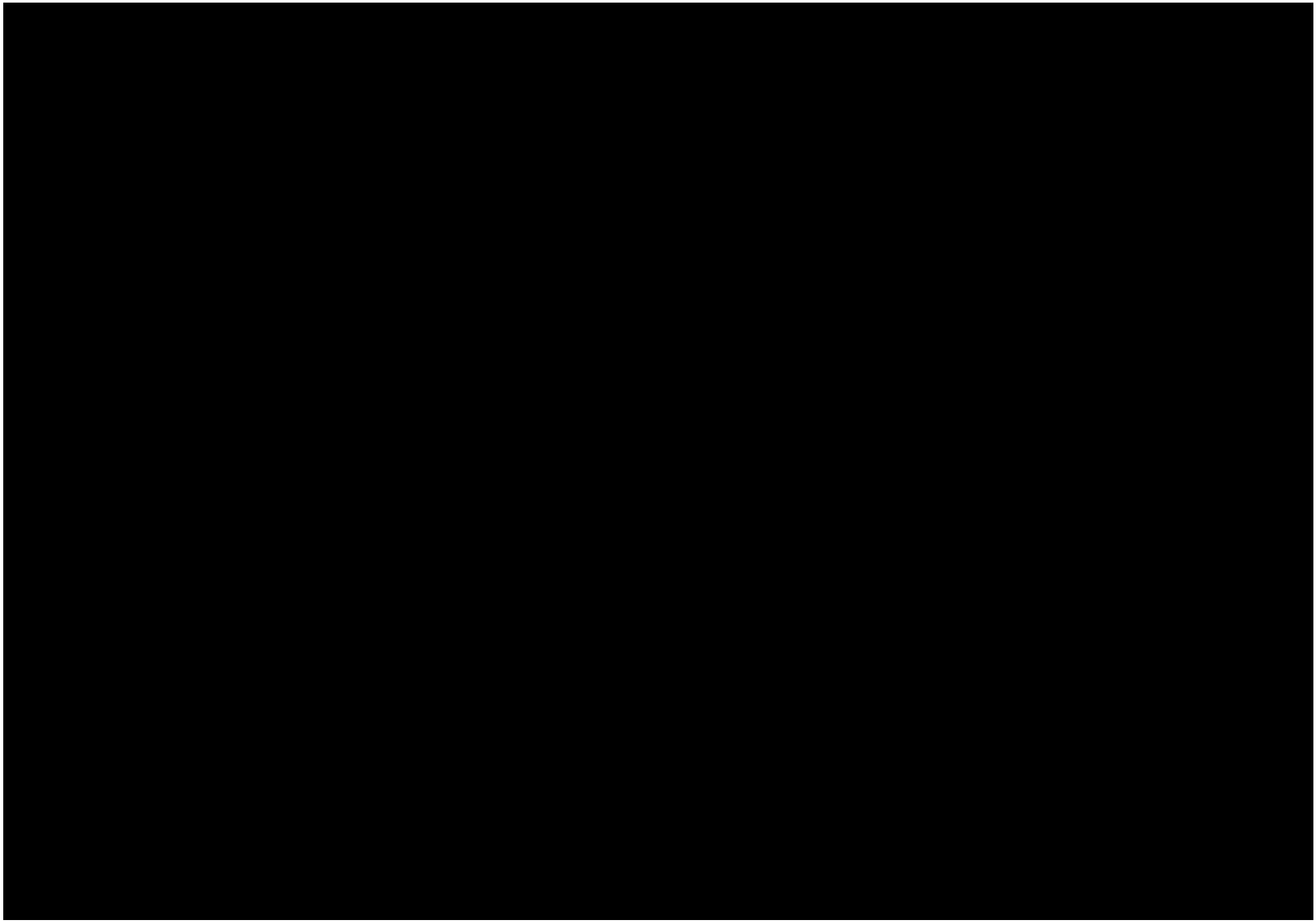
Hourly Average Day for November 2021

High West Energy, Inc.



Hourly Average Day for December 2021

High West Energy, Inc.

[redacted]

Hourly Average Day for January 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

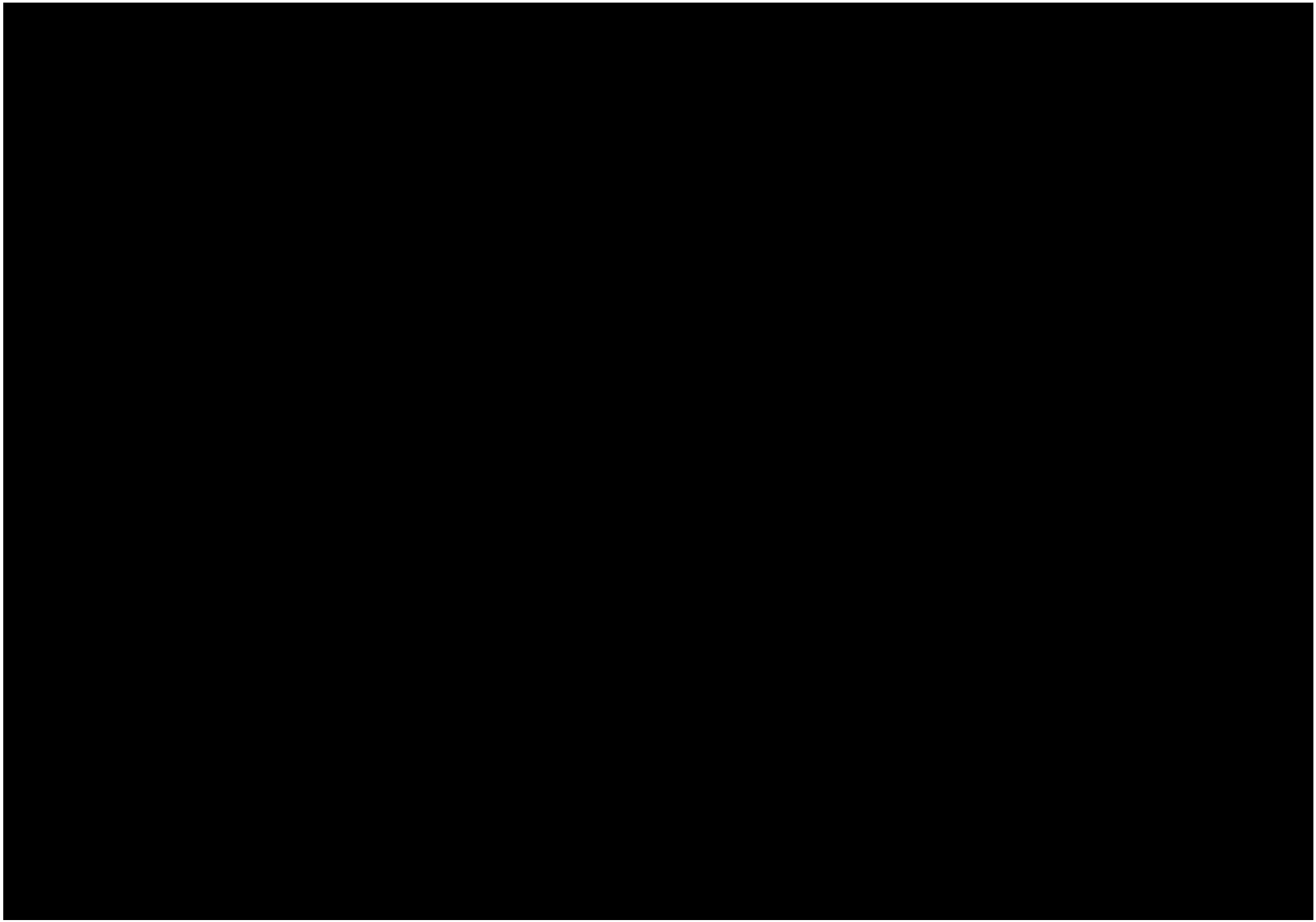
Hourly Average Day for February 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for April 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

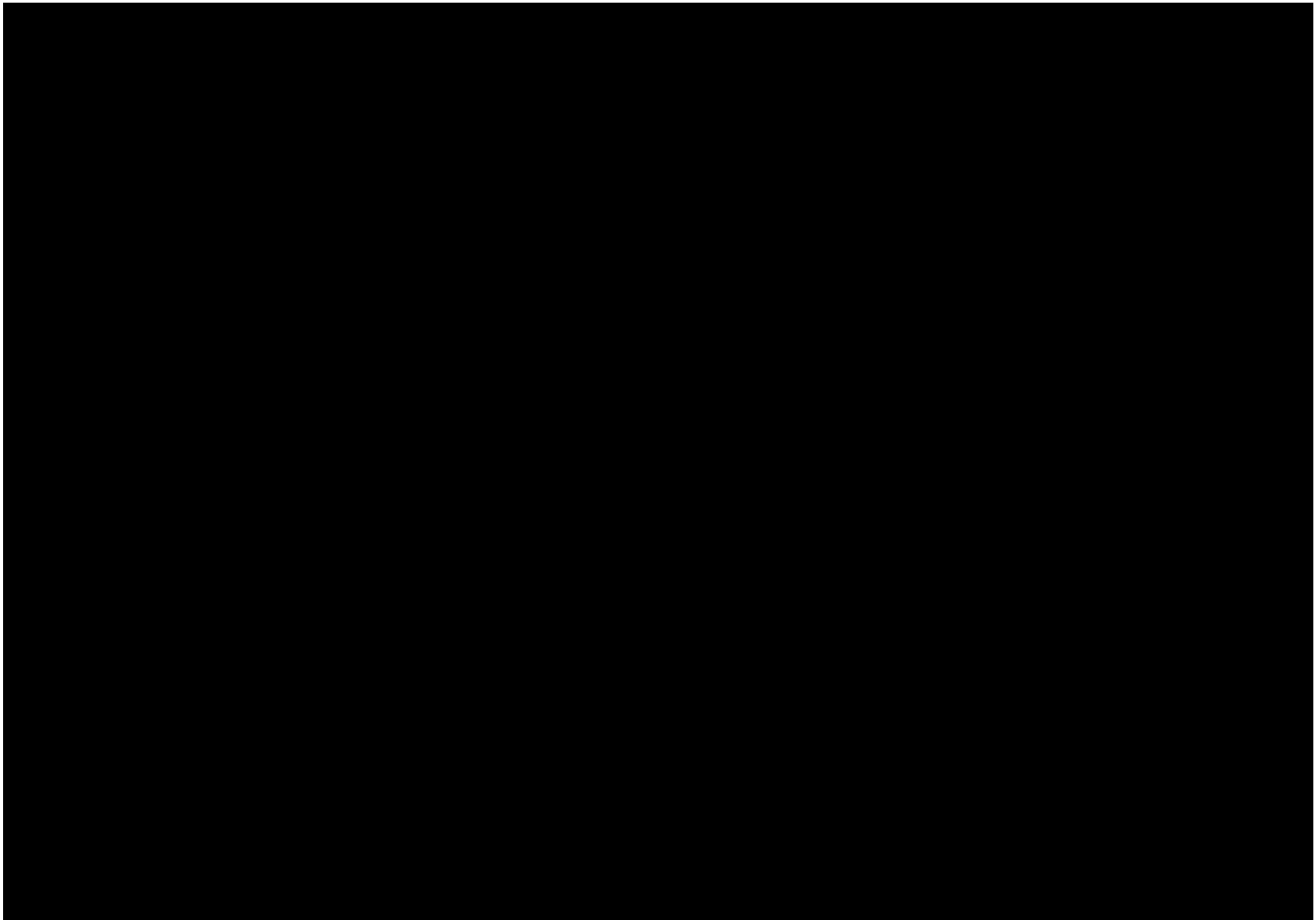
Hourly Average Day for July 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for September 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

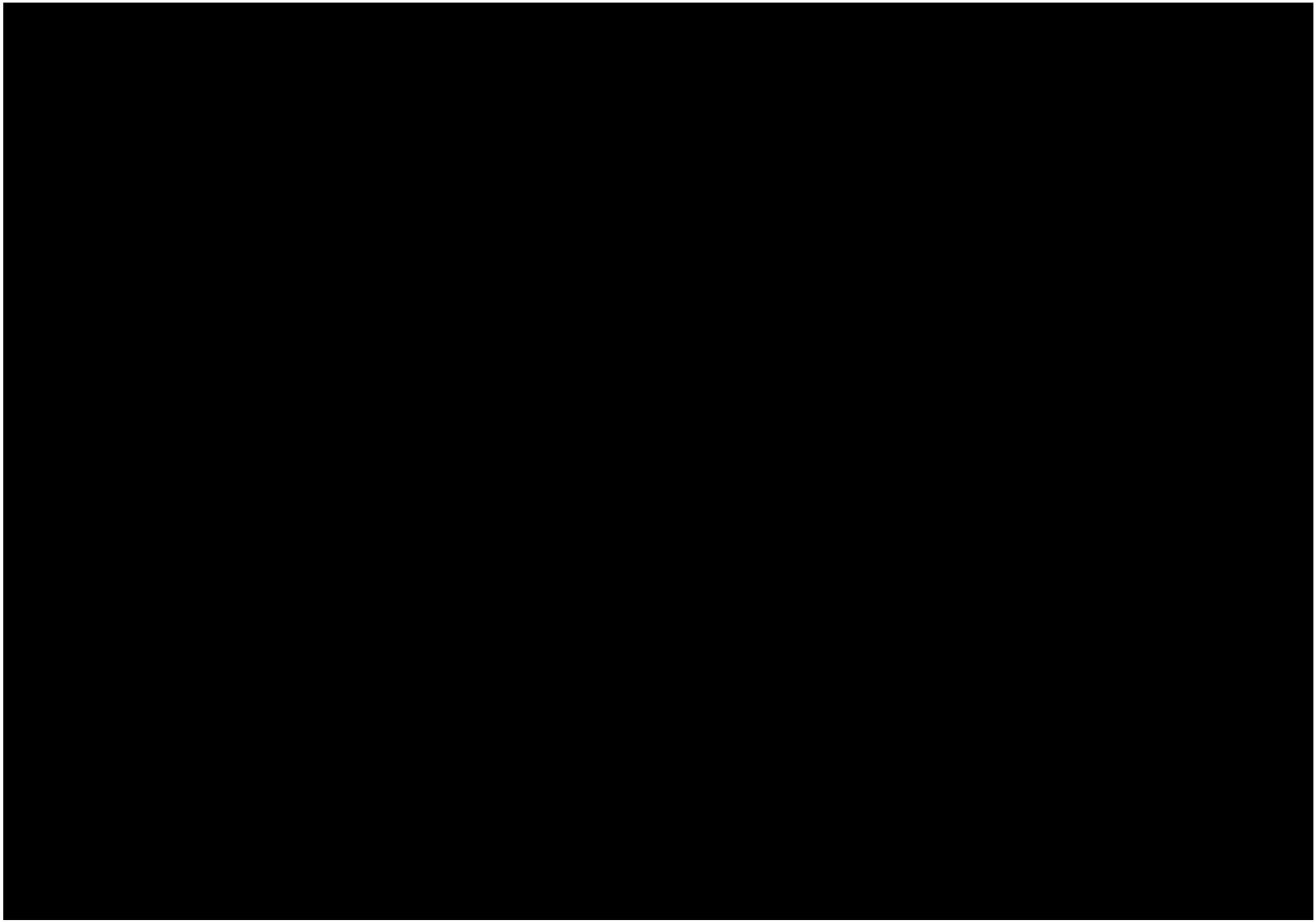
Hourly Average Day for November 2021

Jemez Mountains Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Jemez Mountains Electric Cooperative, Inc.



Hourly Average Day for January 2021

K.C. Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
K.C. Electric Association, Inc.

[redacted]

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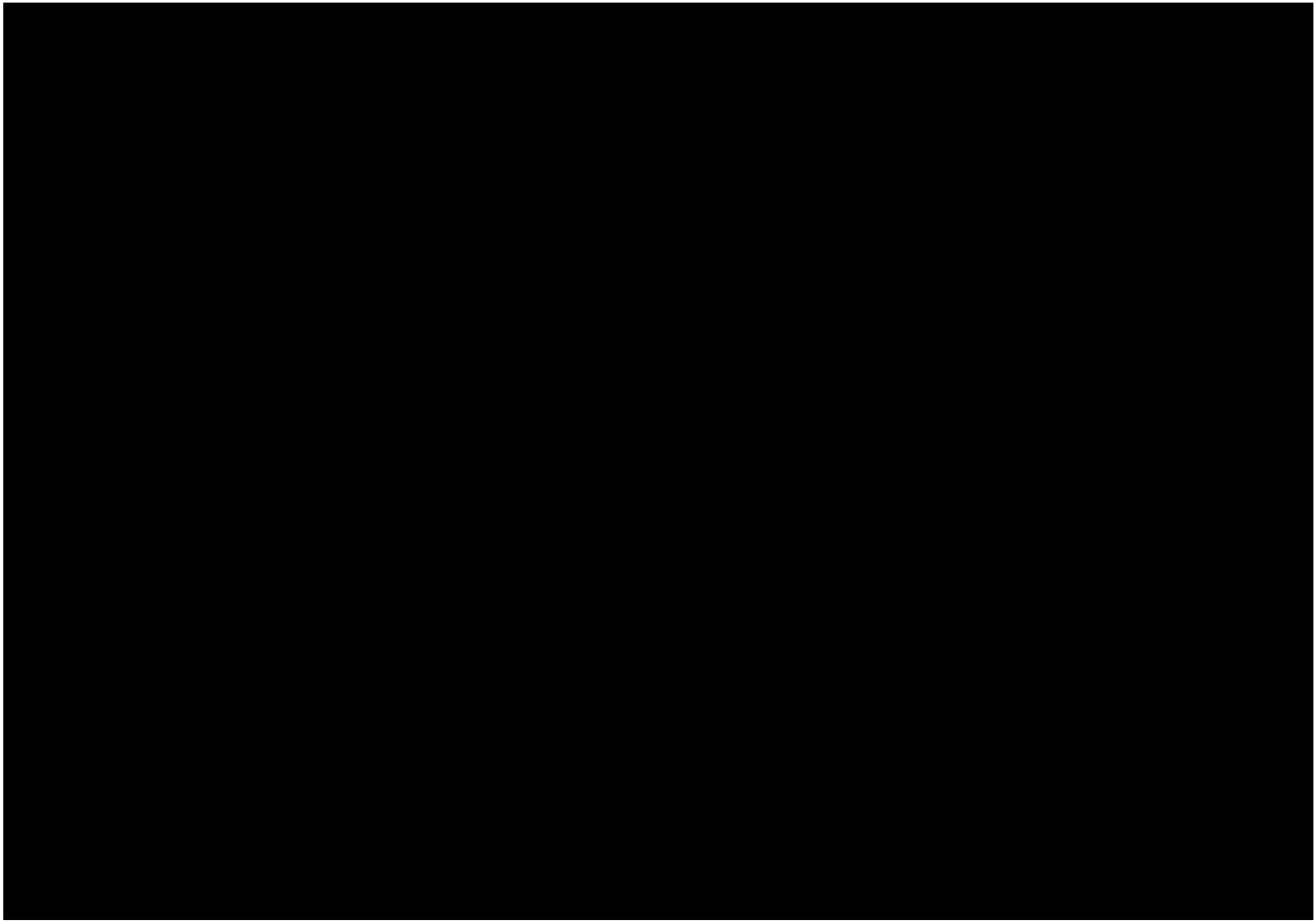
Hourly Average Day for March 2021

K.C. Electric Association, Inc.



Hourly Average Day for April 2021

K.C. Electric Association, Inc.

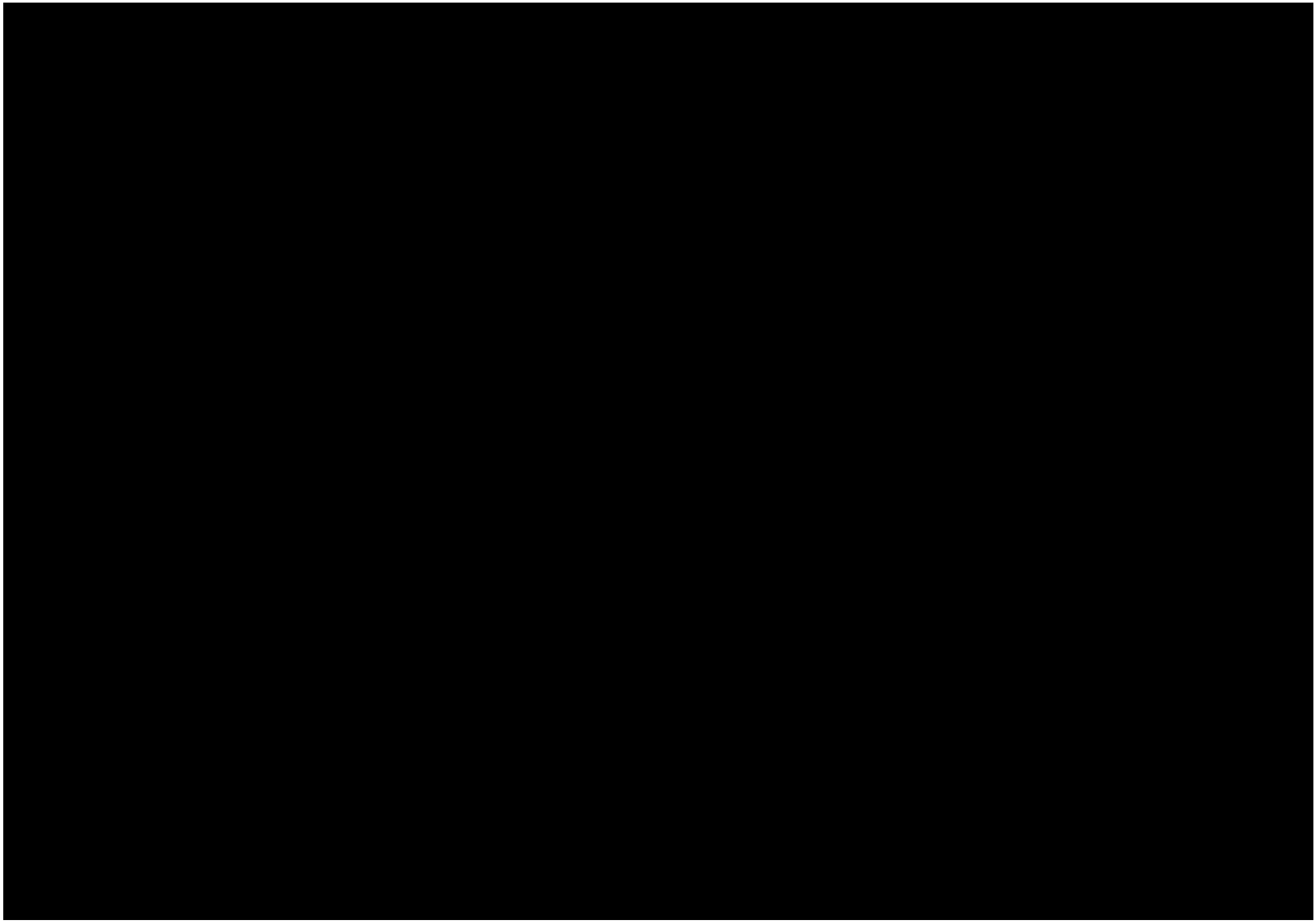
[redacted]

Hourly Average Day for May 2021
K.C. Electric Association, Inc.

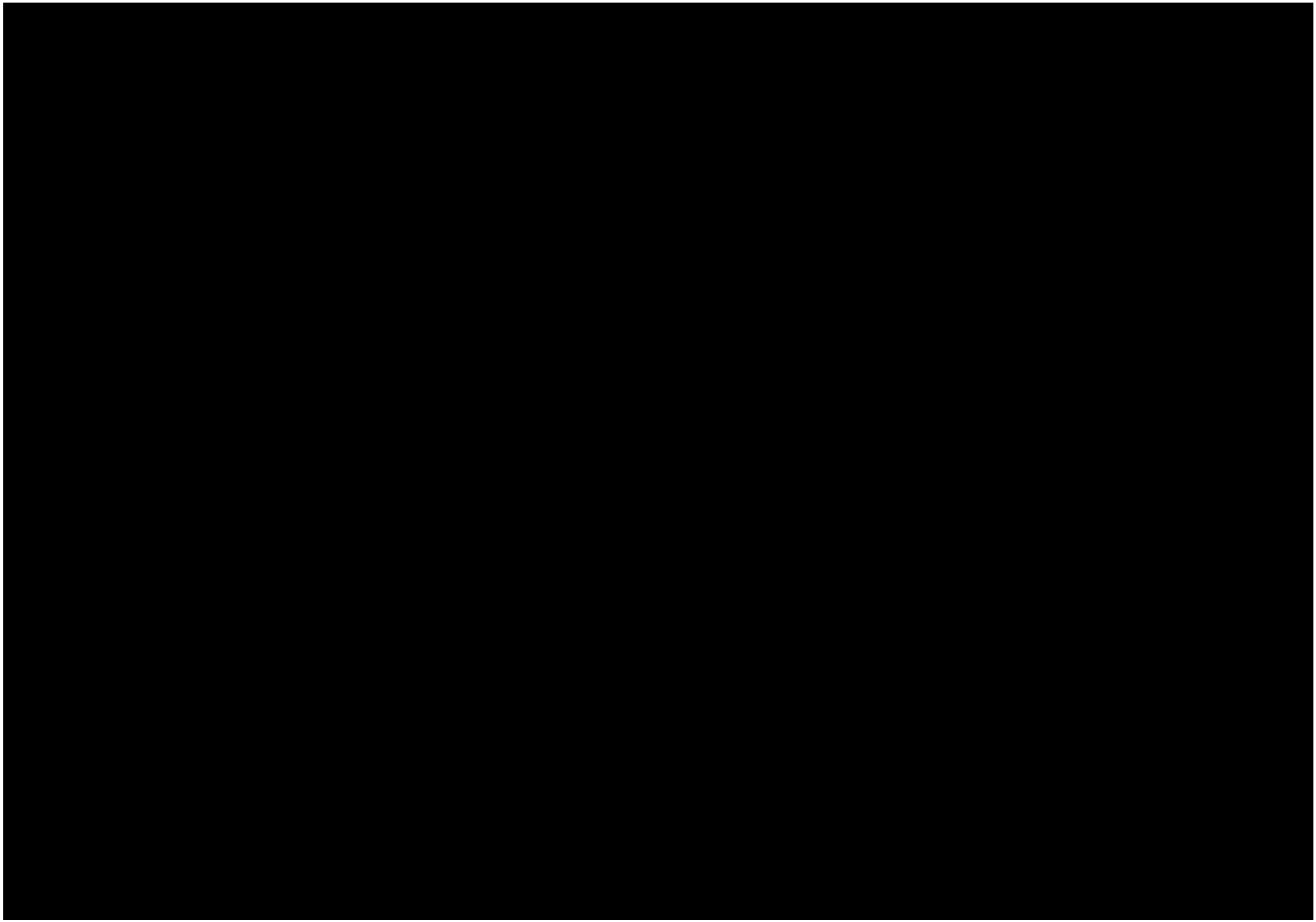
[redacted]

Hourly Average Day for June 2021

K.C. Electric Association, Inc.



Hourly Average Day for July 2021
K.C. Electric Association, Inc.



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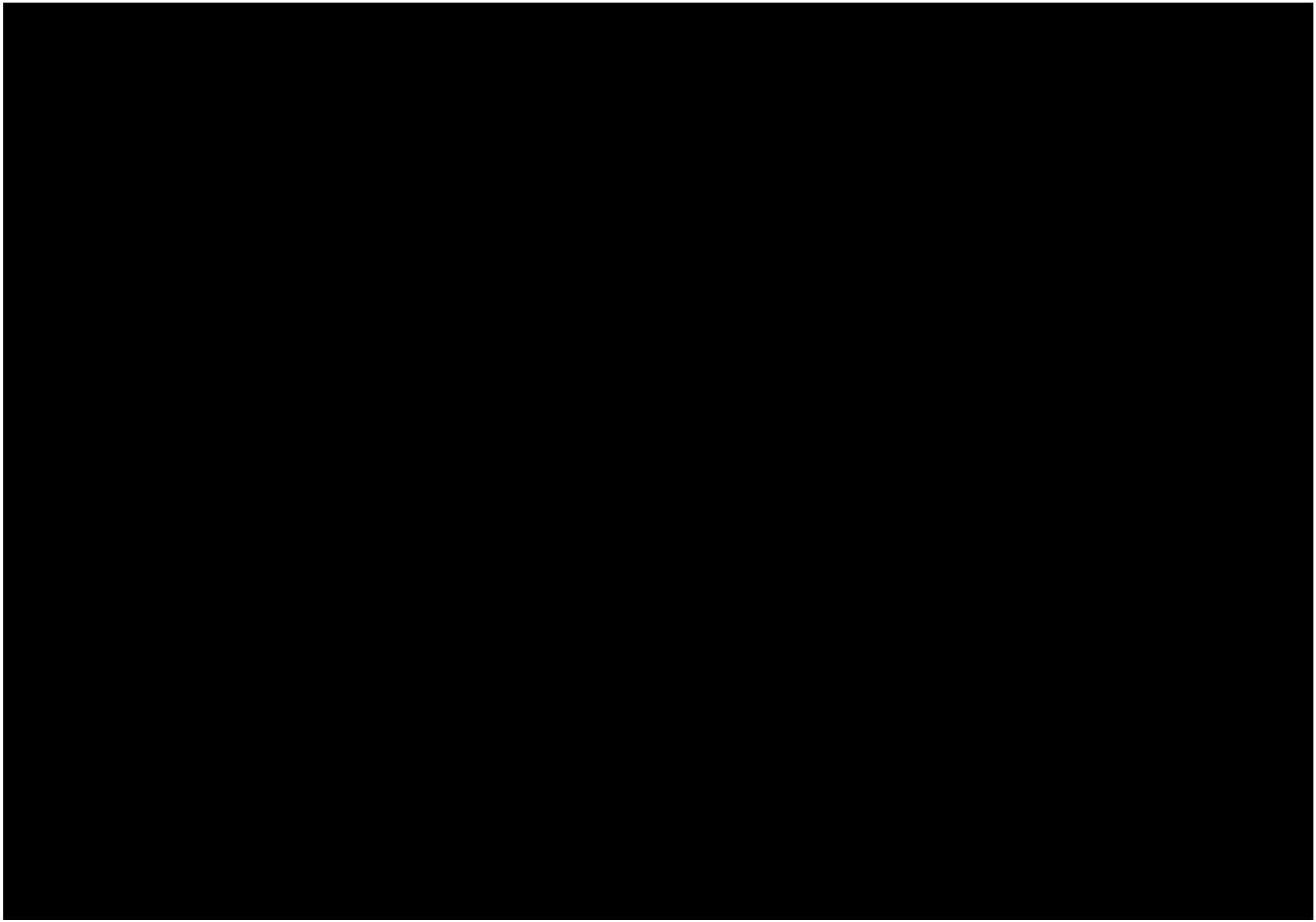
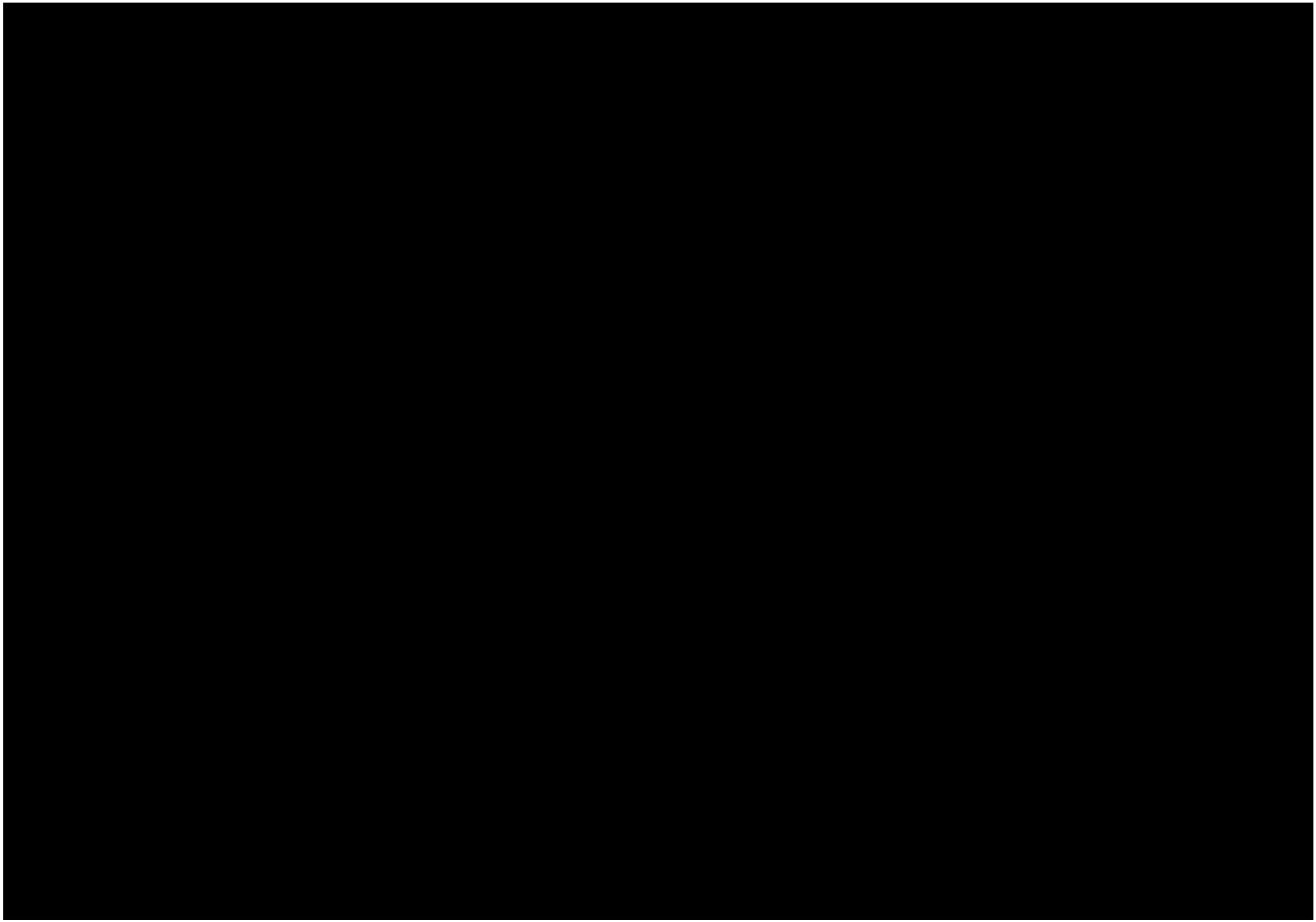
Hourly Average Day for August 2021

K.C. Electric Association, Inc.



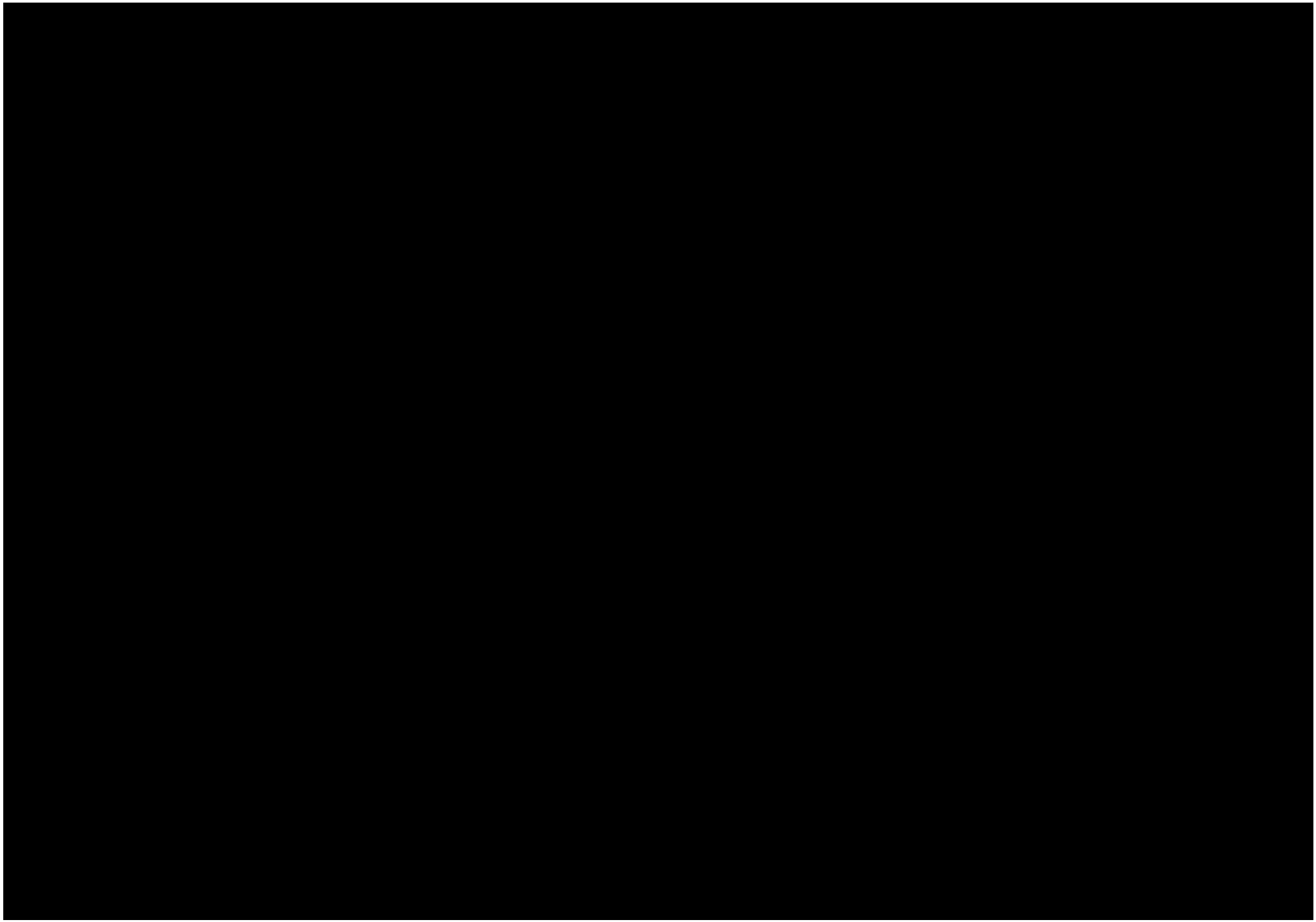
Hourly Average Day for September 2021

K.C. Electric Association, Inc.



Hourly Average Day for October 2021

K.C. Electric Association, Inc.



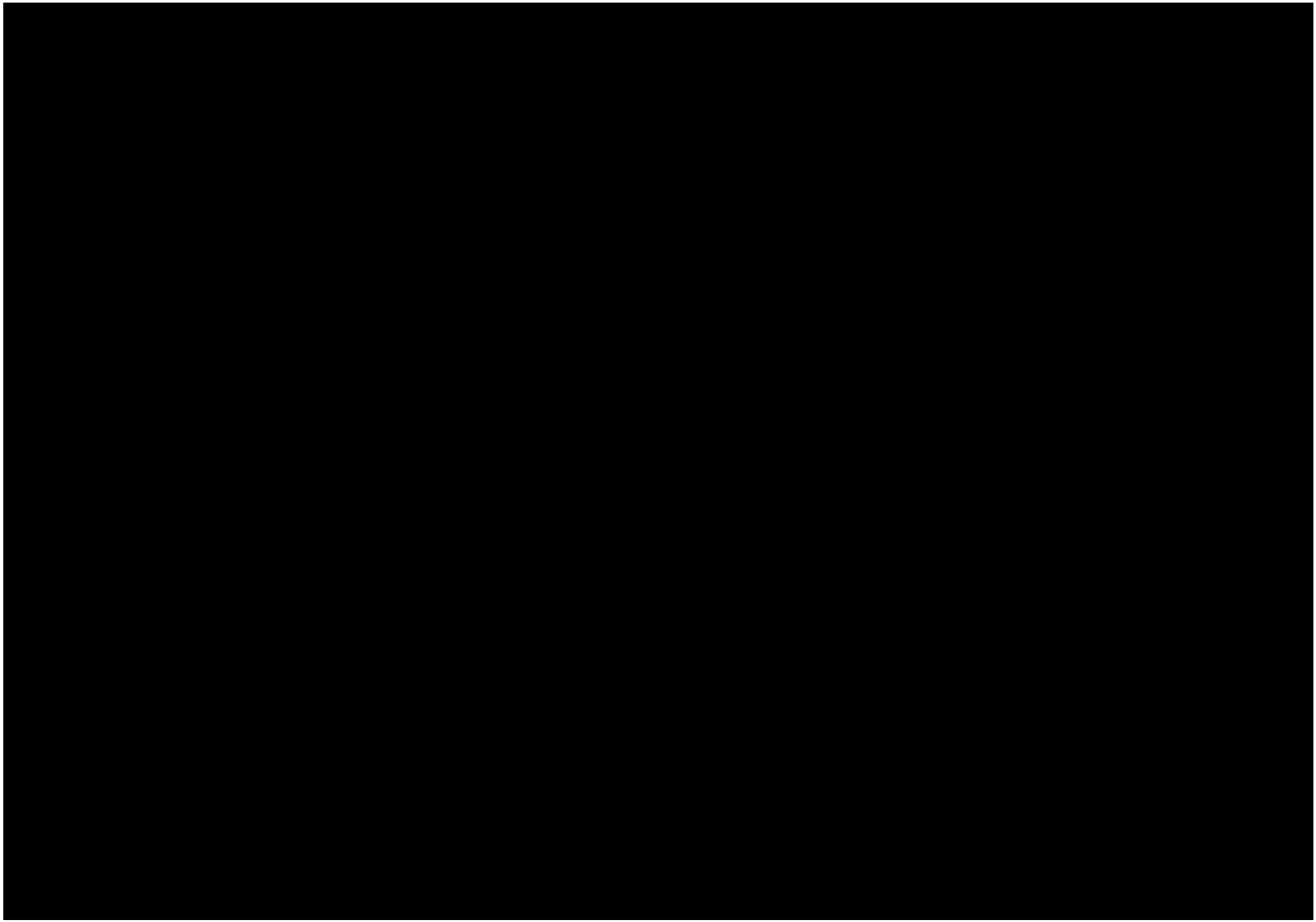
Hourly Average Day for November 2021

K.C. Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

K.C. Electric Association, Inc.



Hourly Average Day for January 2021
La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

La Plata Electric Association, Inc.

[redacted]

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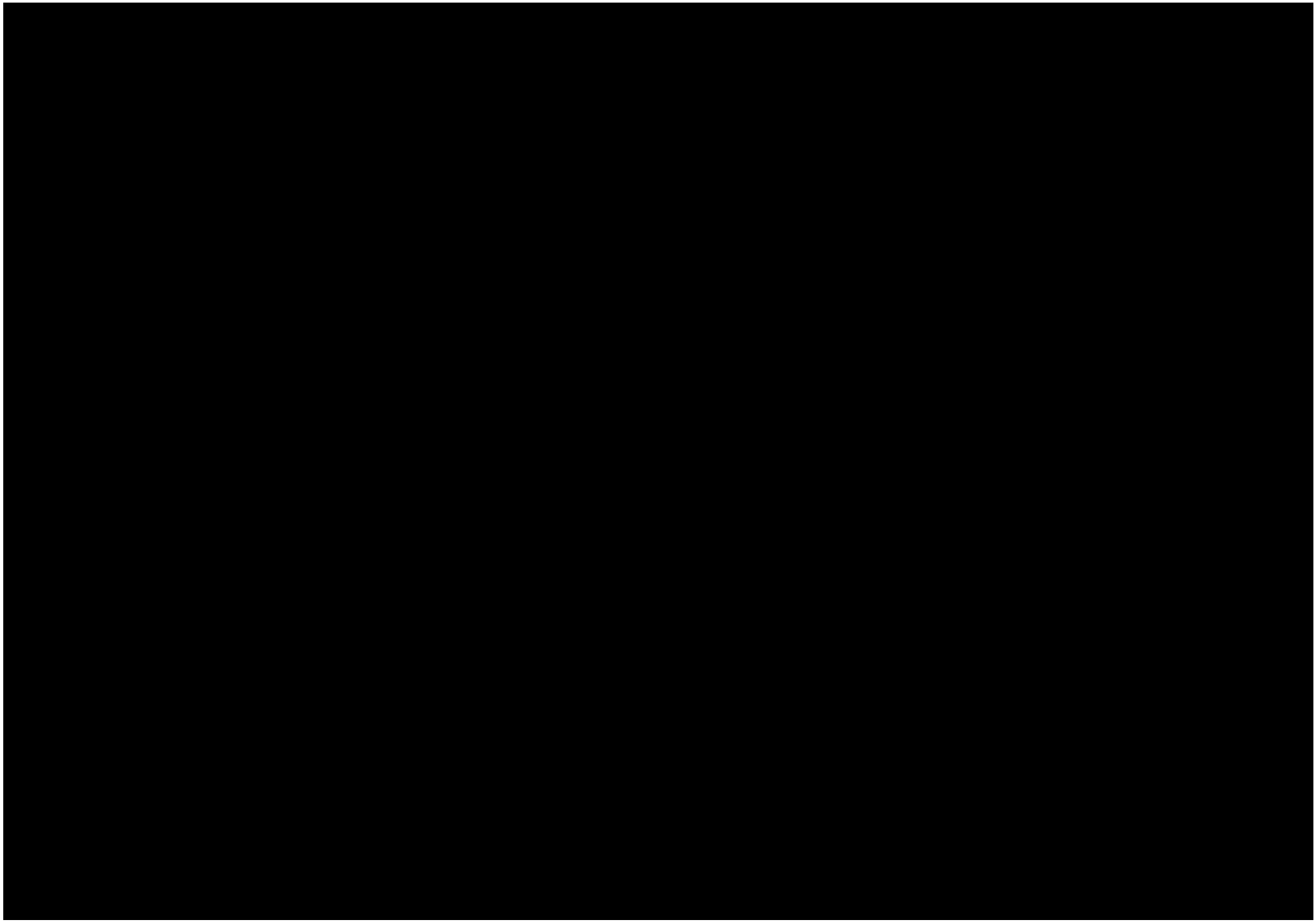
Hourly Average Day for July 2021

La Plata Electric Association, Inc.



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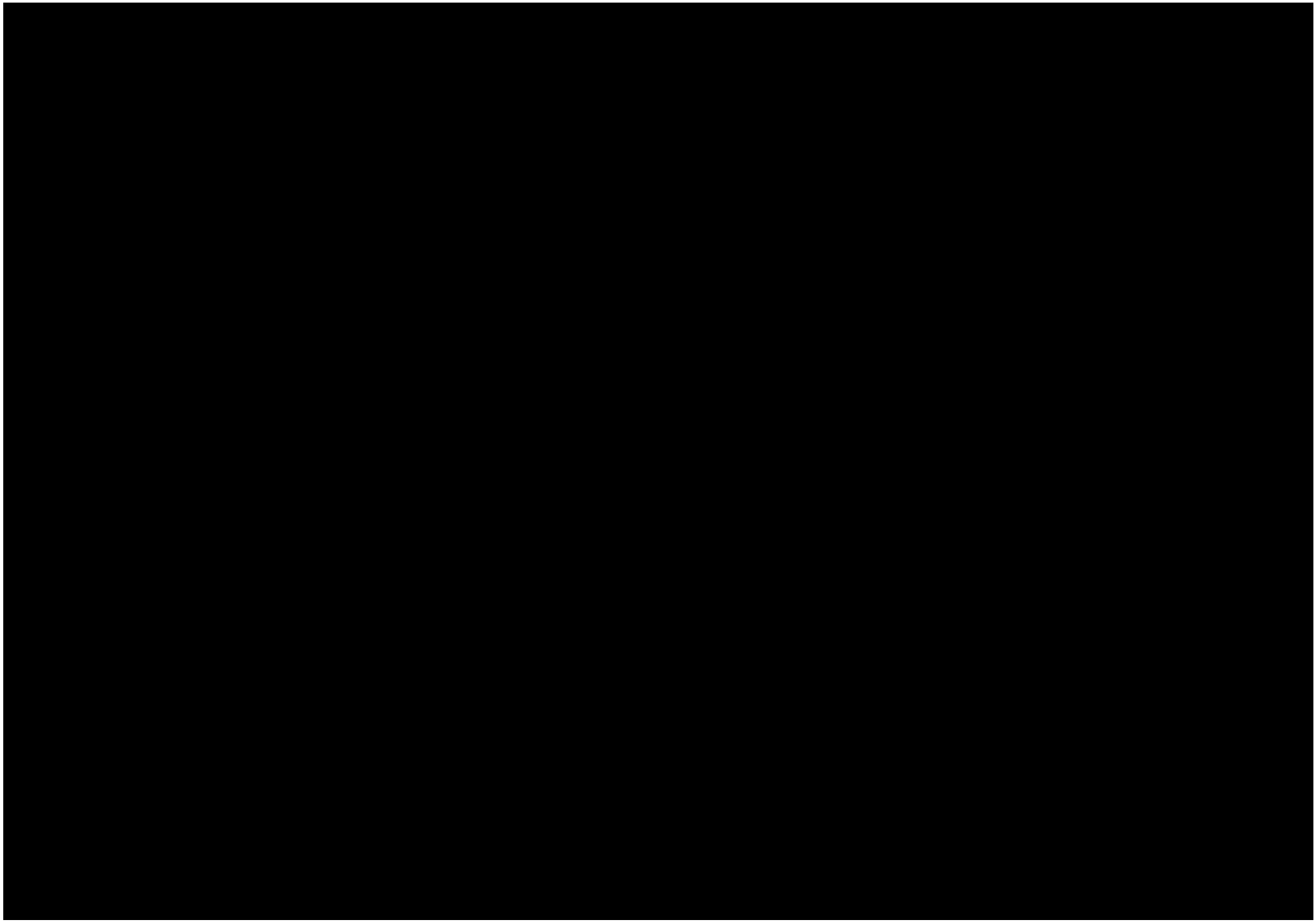
Hourly Average Day for August 2021

La Plata Electric Association, Inc.



Hourly Average Day for September 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

La Plata Electric Association, Inc.

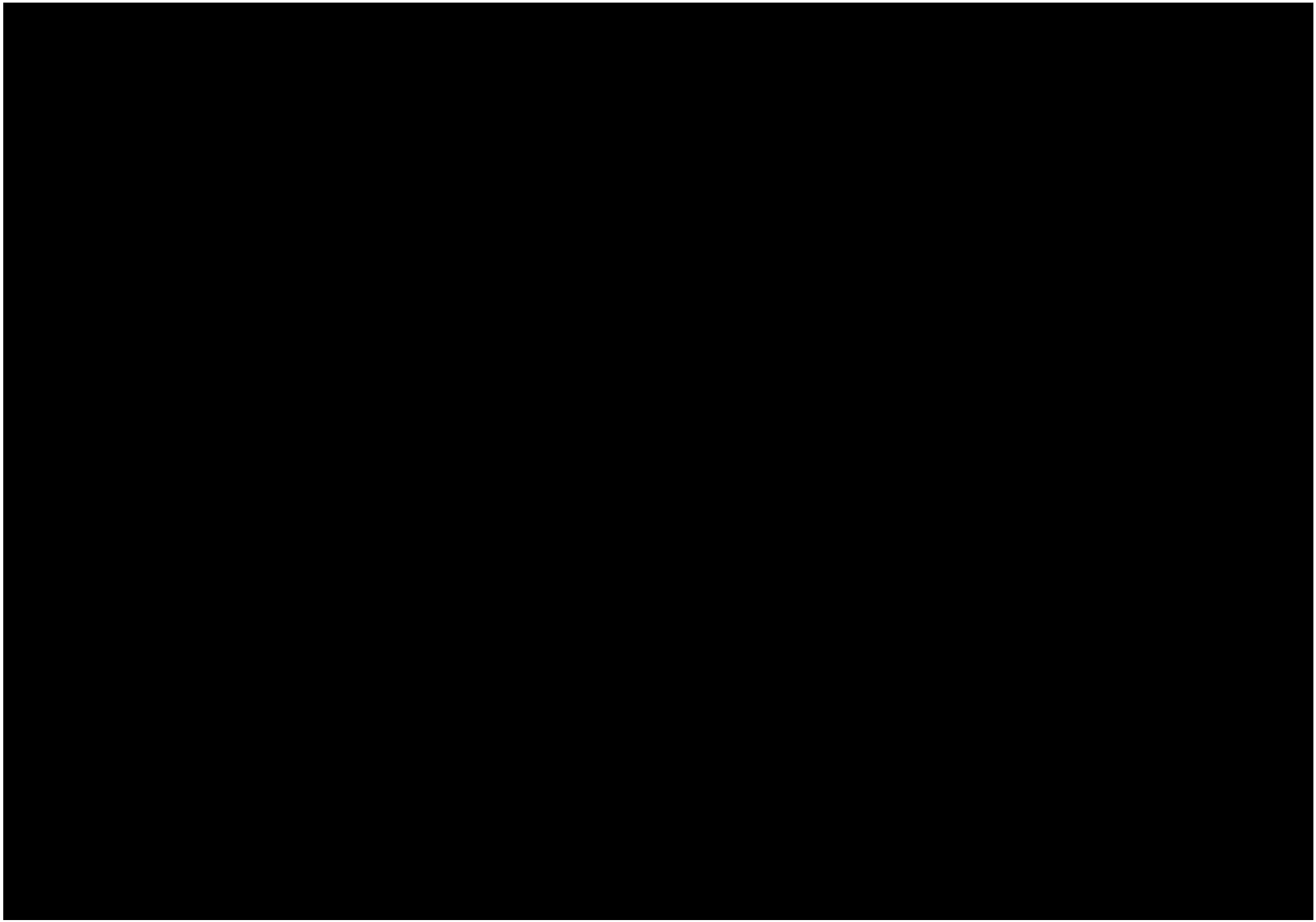
[redacted]

Hourly Average Day for November 2021

La Plata Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021
La Plata Electric Association, Inc.

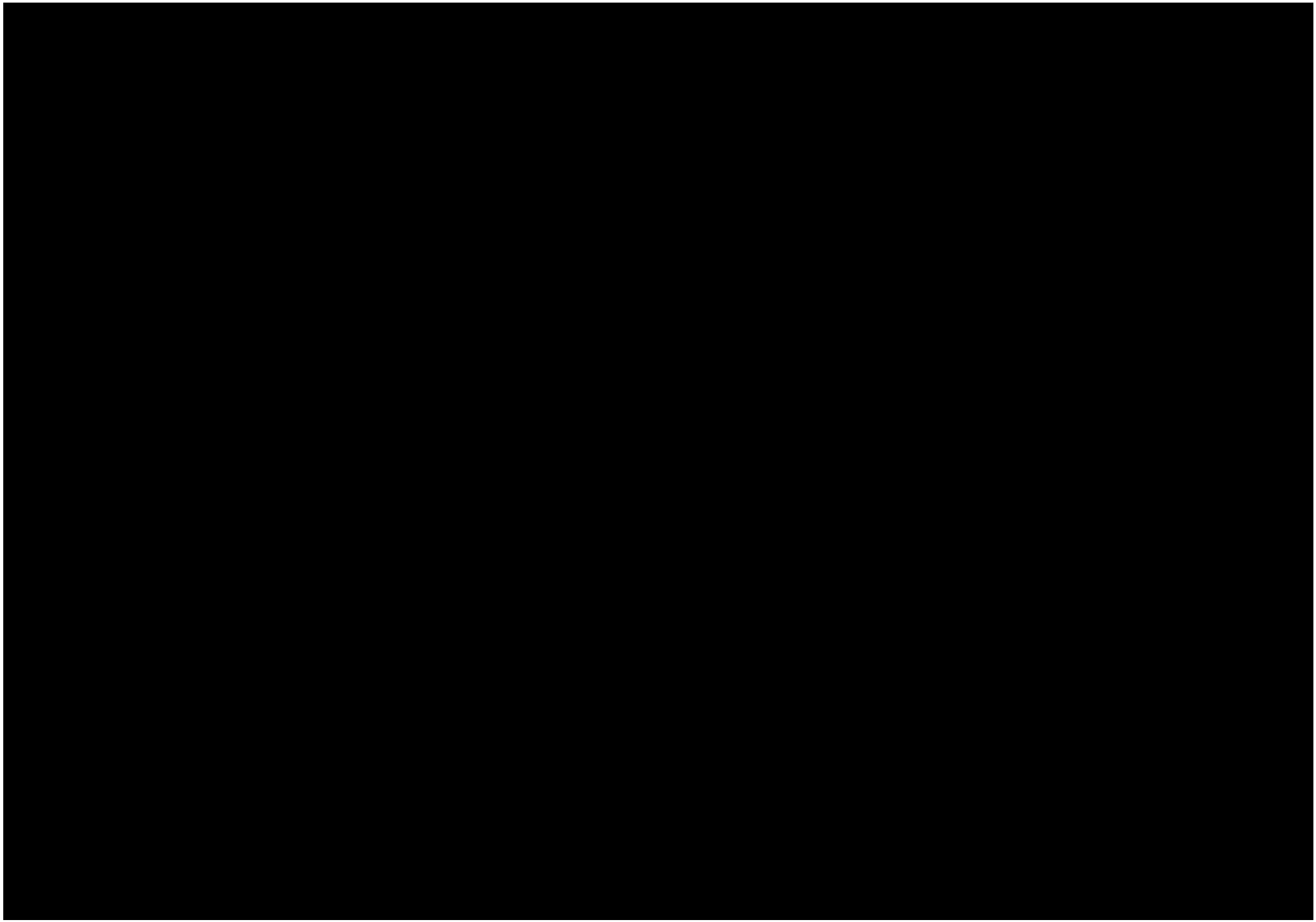


Hourly Average Day for January 2021

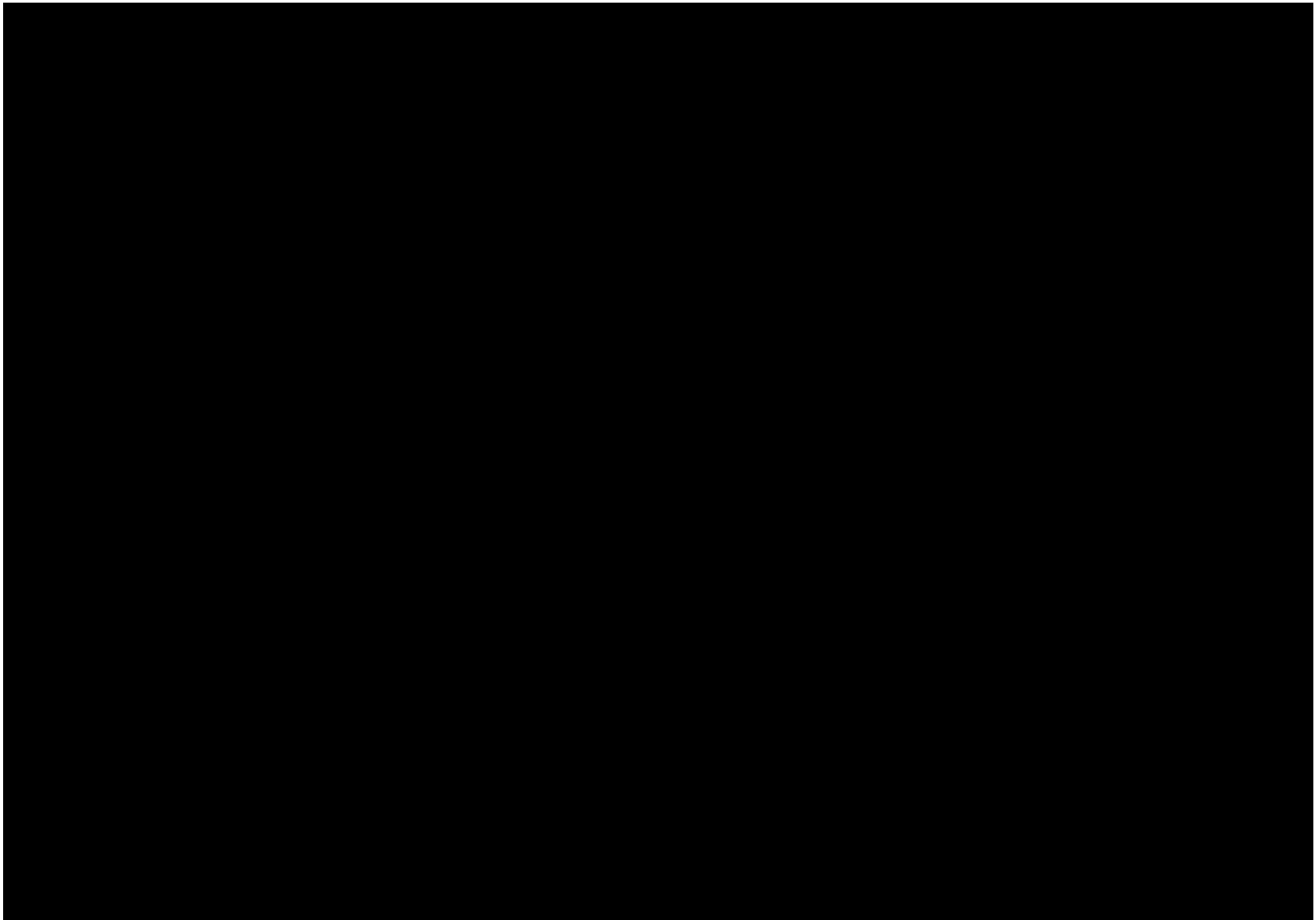
Morgan County Rural Electric Association

[redacted]

Hourly Average Day for February 2021
Morgan County Rural Electric Association

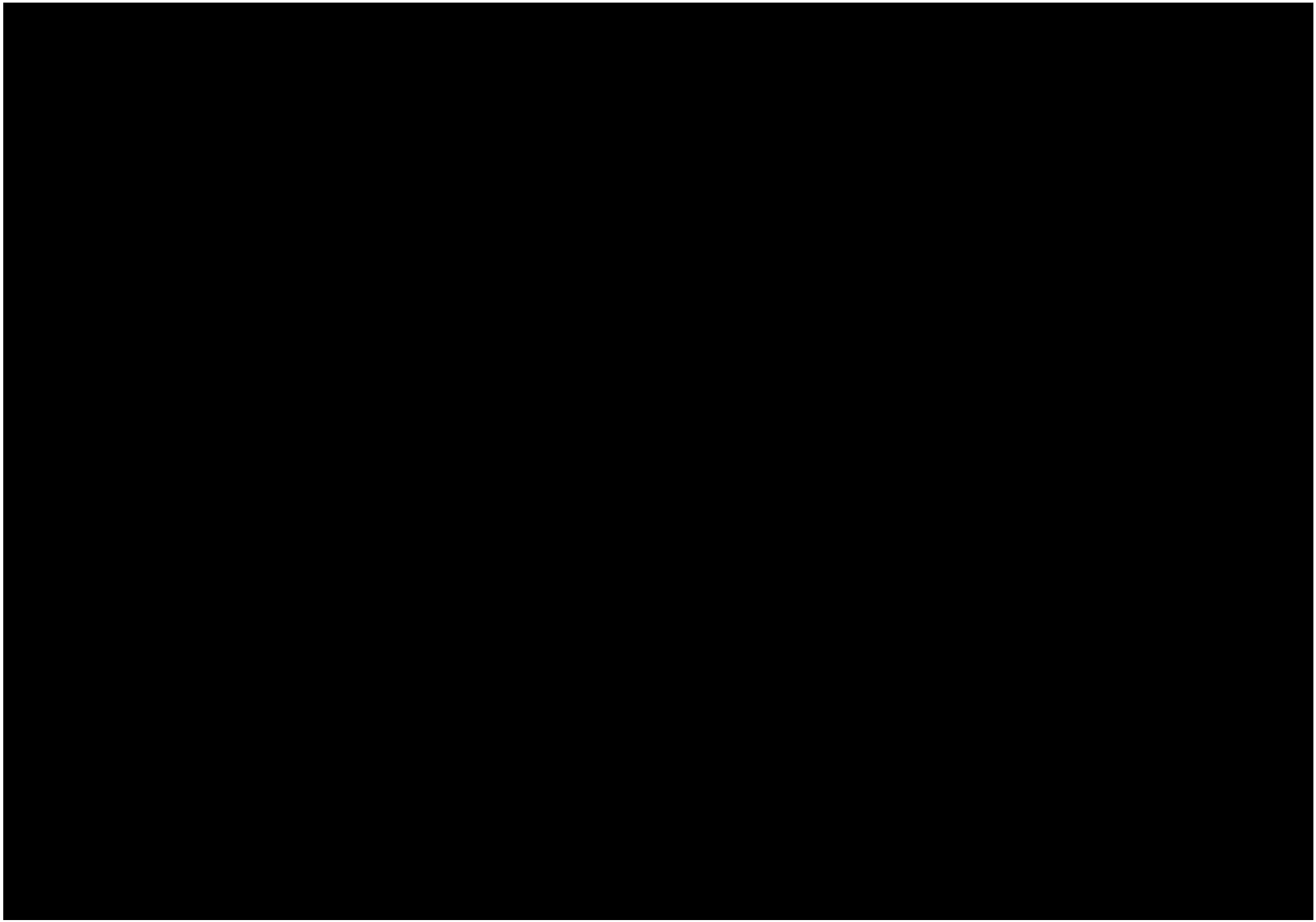


Hourly Average Day for March 2021
Morgan County Rural Electric Association

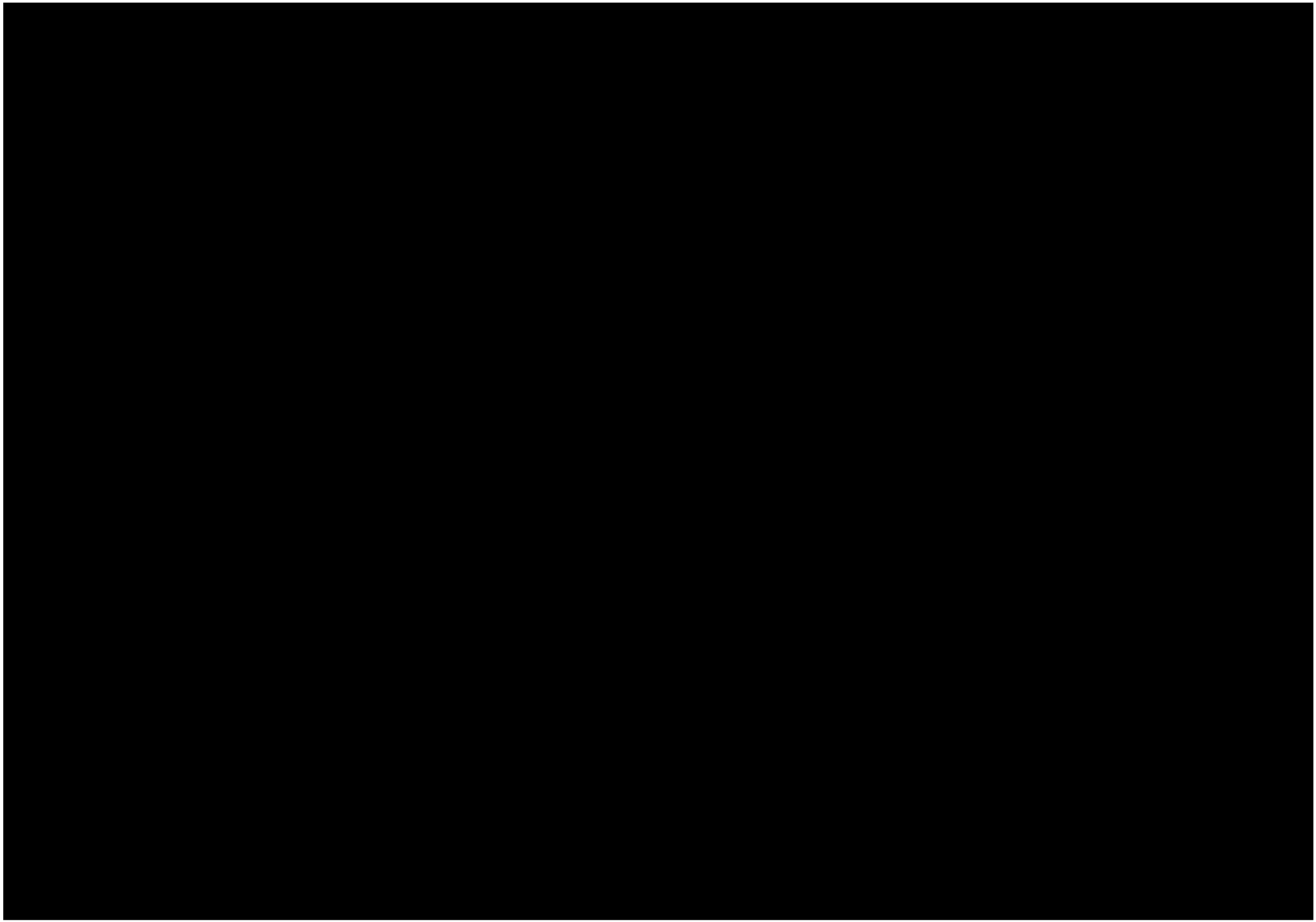


Hourly Average Day for April 2021

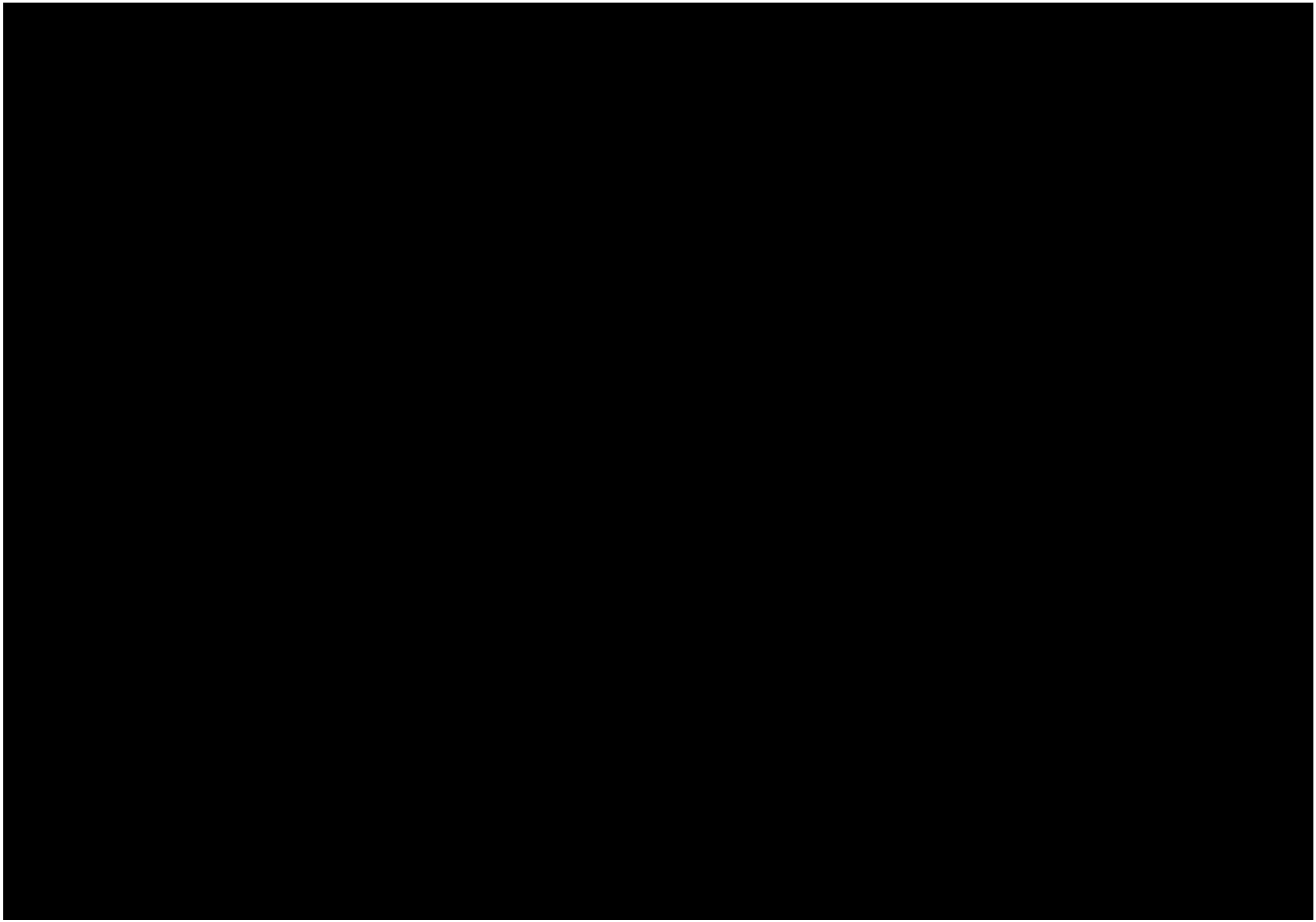
Morgan County Rural Electric Association



Hourly Average Day for May 2021
Morgan County Rural Electric Association



Hourly Average Day for June 2021
Morgan County Rural Electric Association



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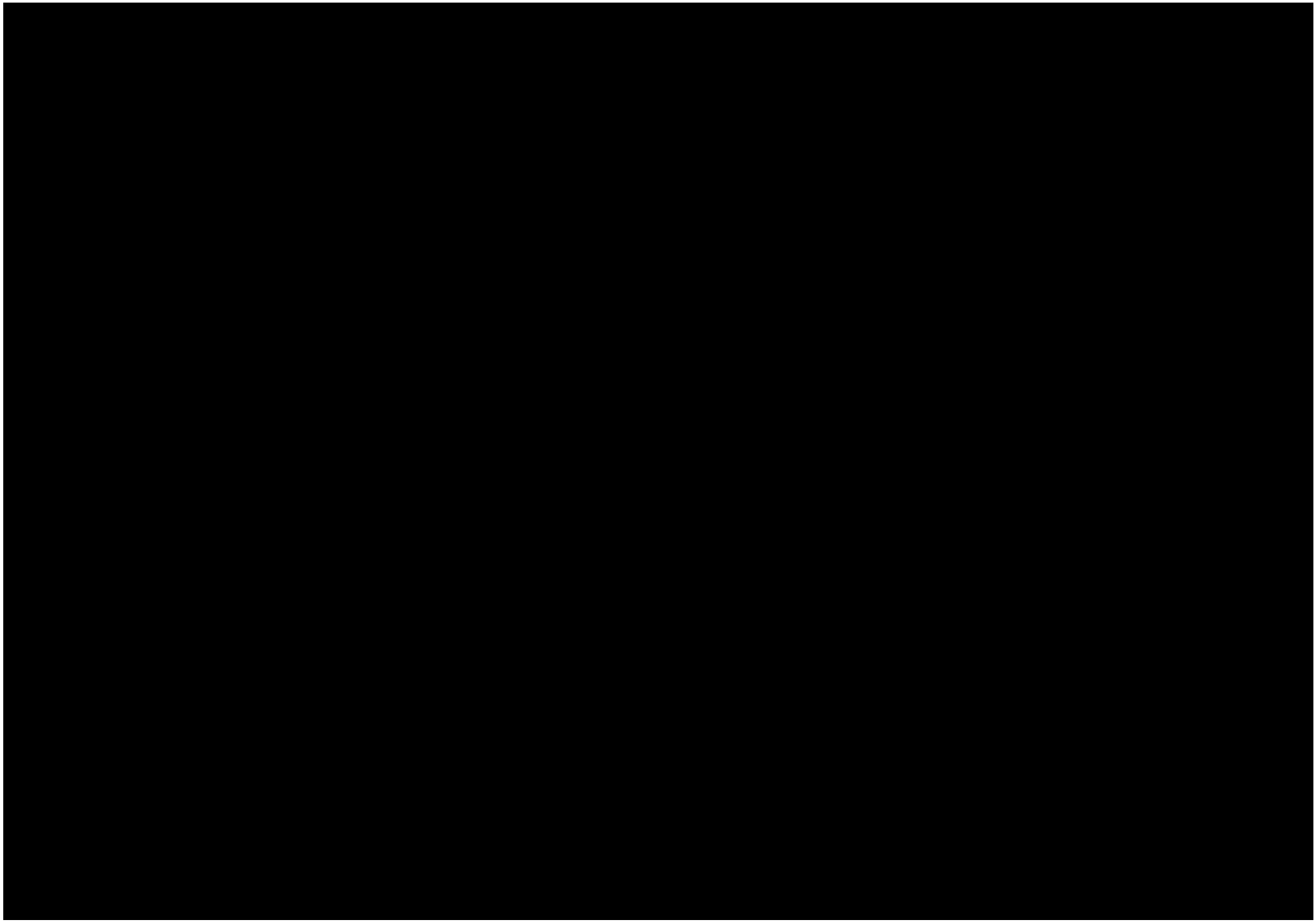
Hourly Average Day for July 2021

Morgan County Rural Electric Association



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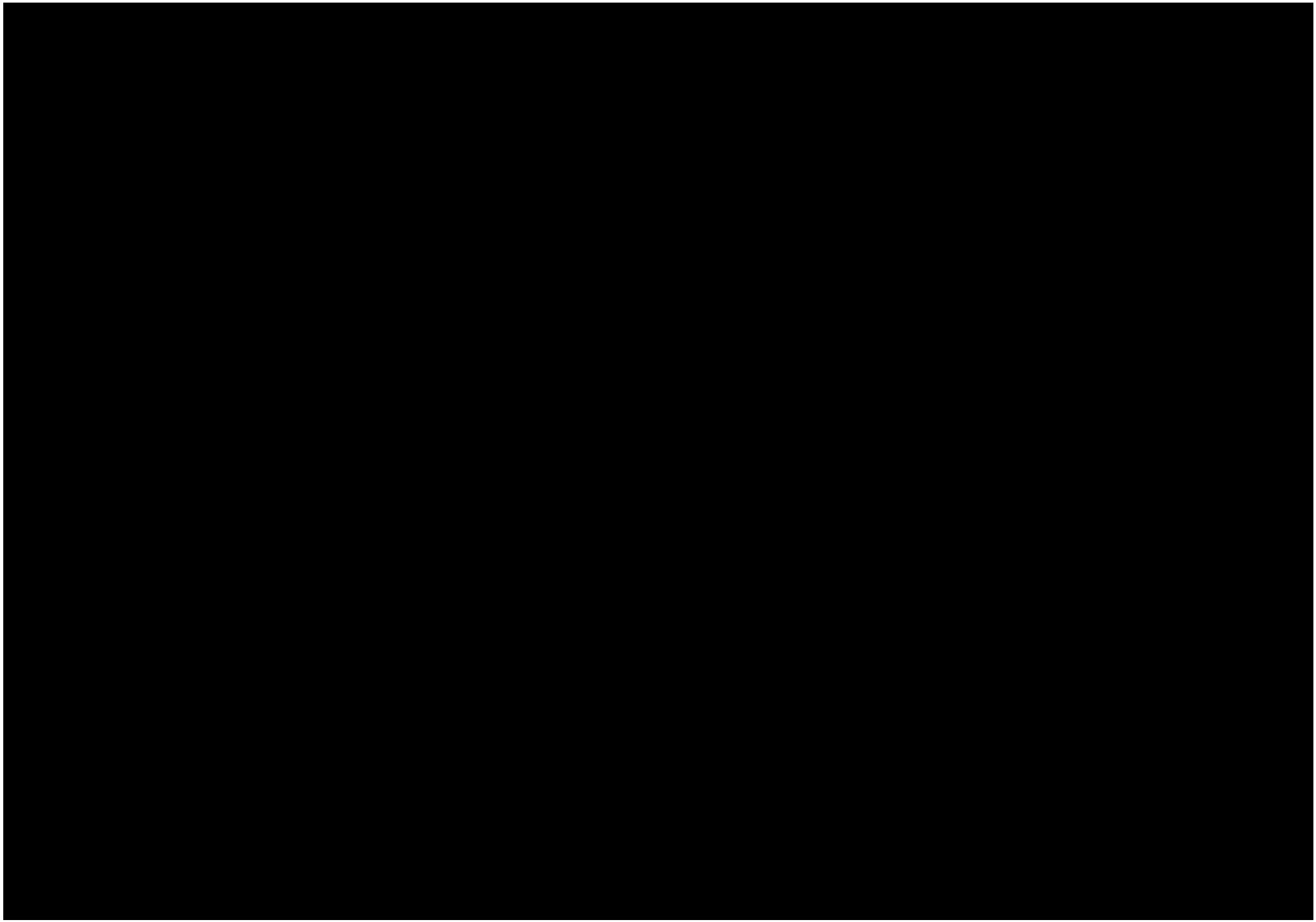
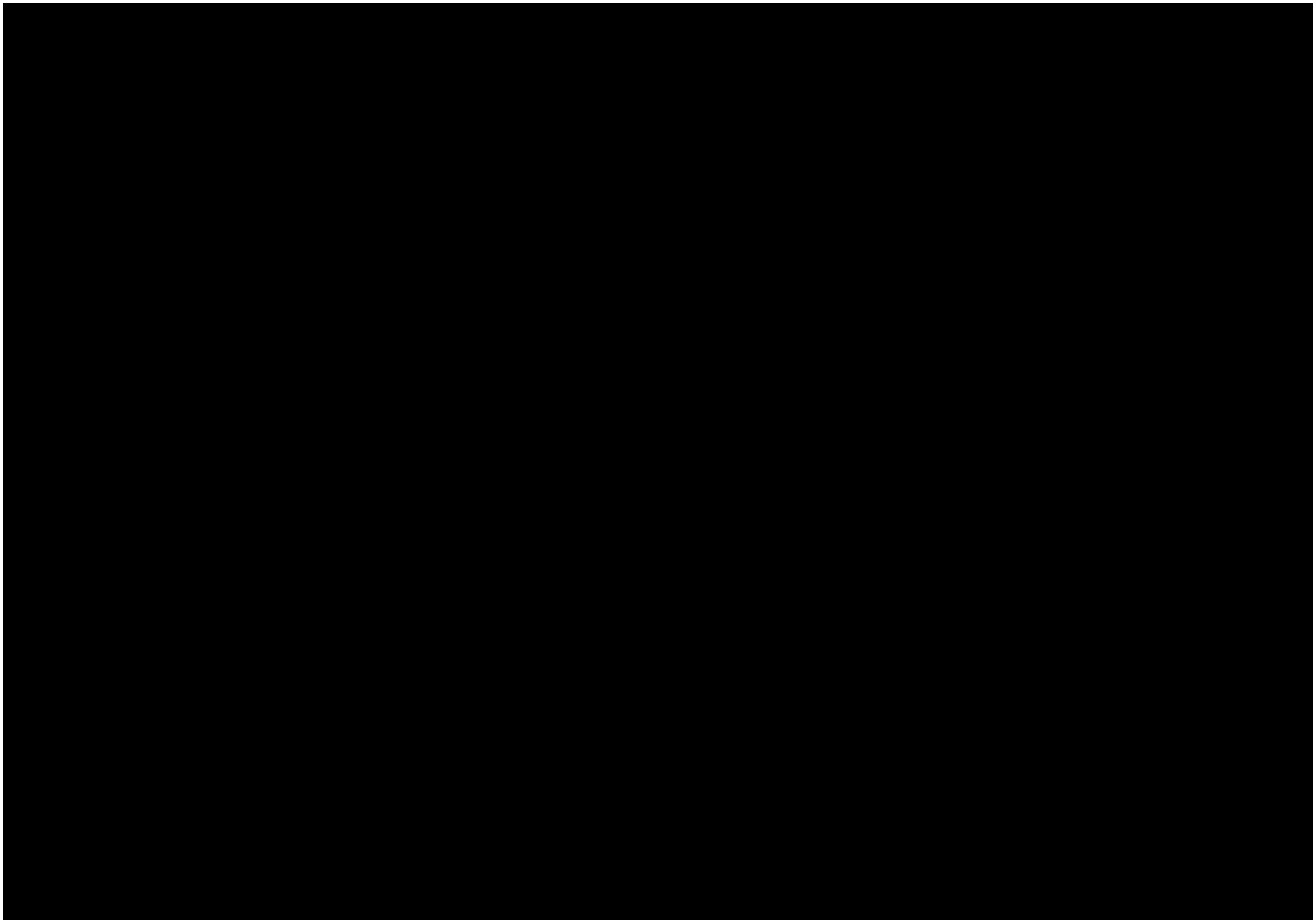
Hourly Average Day for August 2021

Morgan County Rural Electric Association



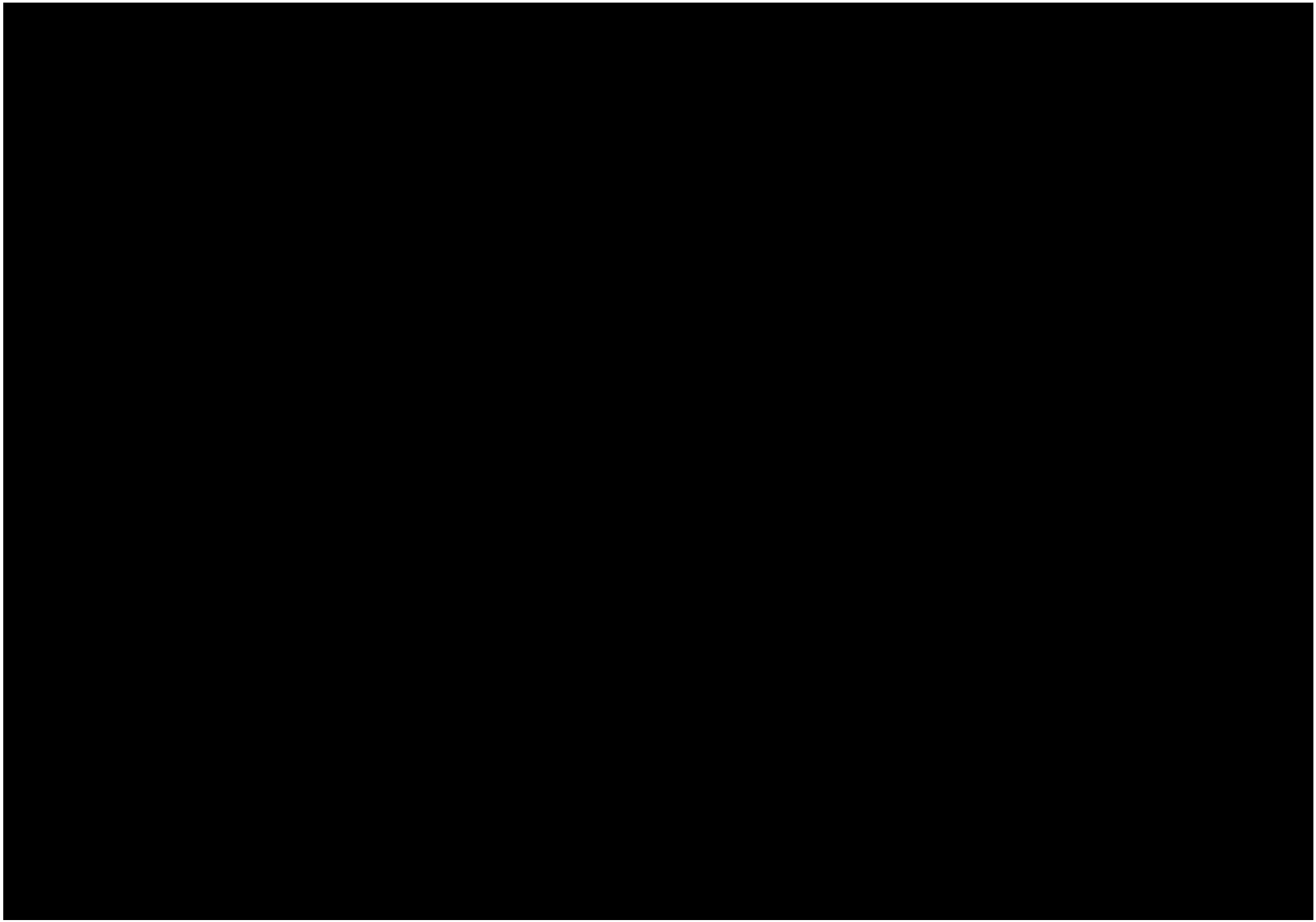
Hourly Average Day for September 2021

Morgan County Rural Electric Association



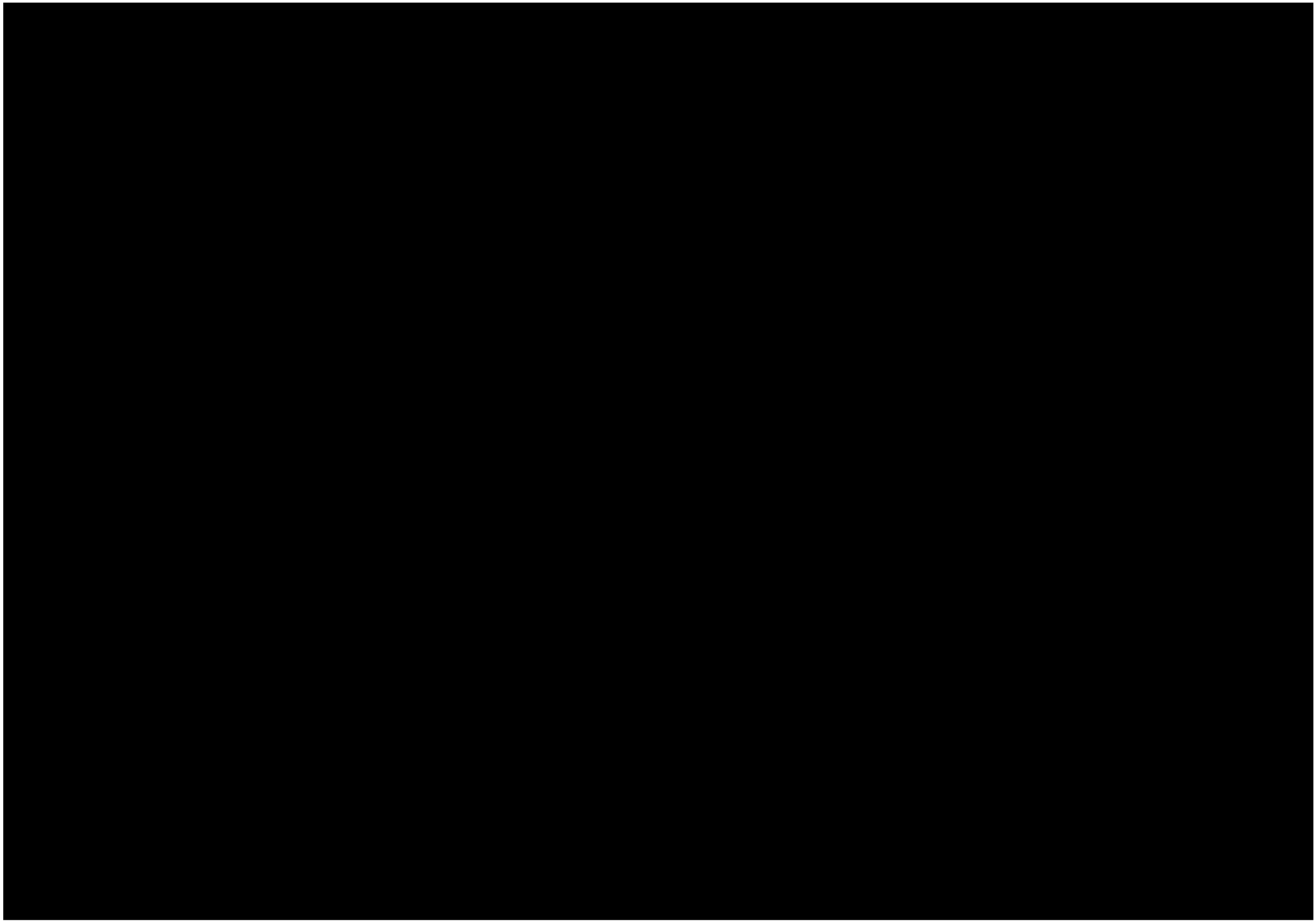
Hourly Average Day for October 2021

Morgan County Rural Electric Association



Hourly Average Day for November 2021

Morgan County Rural Electric Association



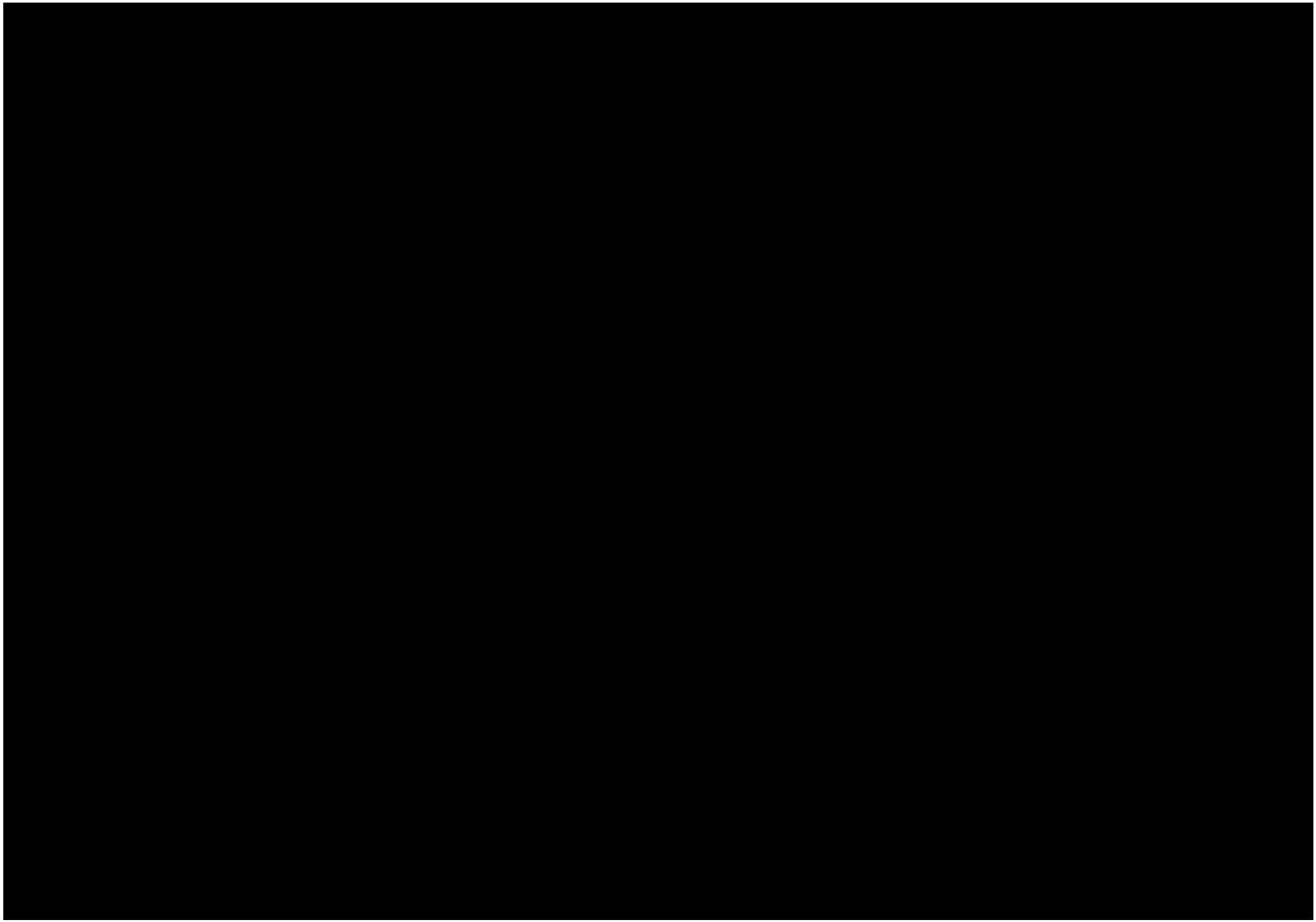
Hourly Average Day for December 2021

Morgan County Rural Electric Association

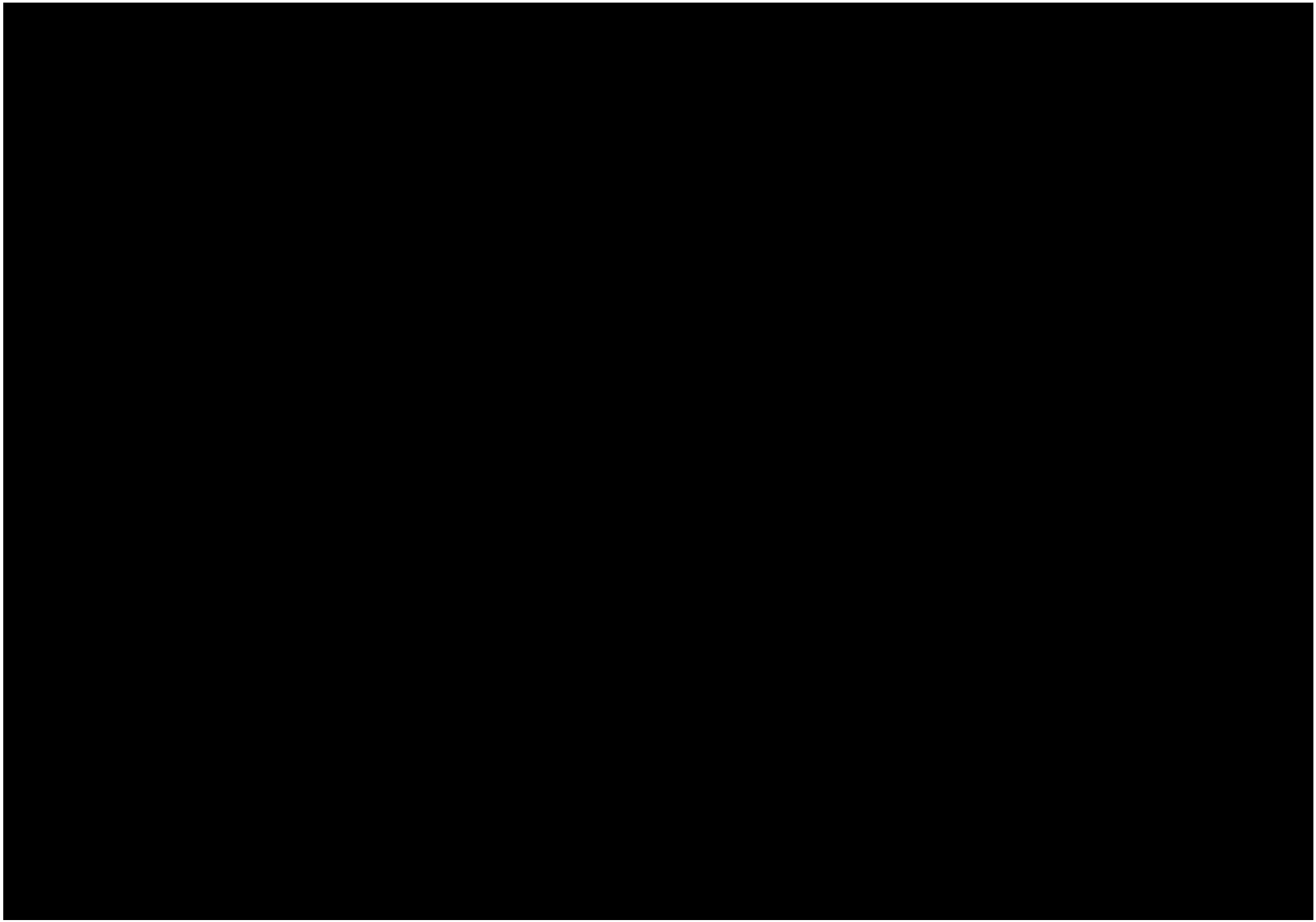
[redacted]

Hourly Average Day for January 2021

Mountain Parks Electric, Inc.



Hourly Average Day for February 2021
Mountain Parks Electric, Inc.



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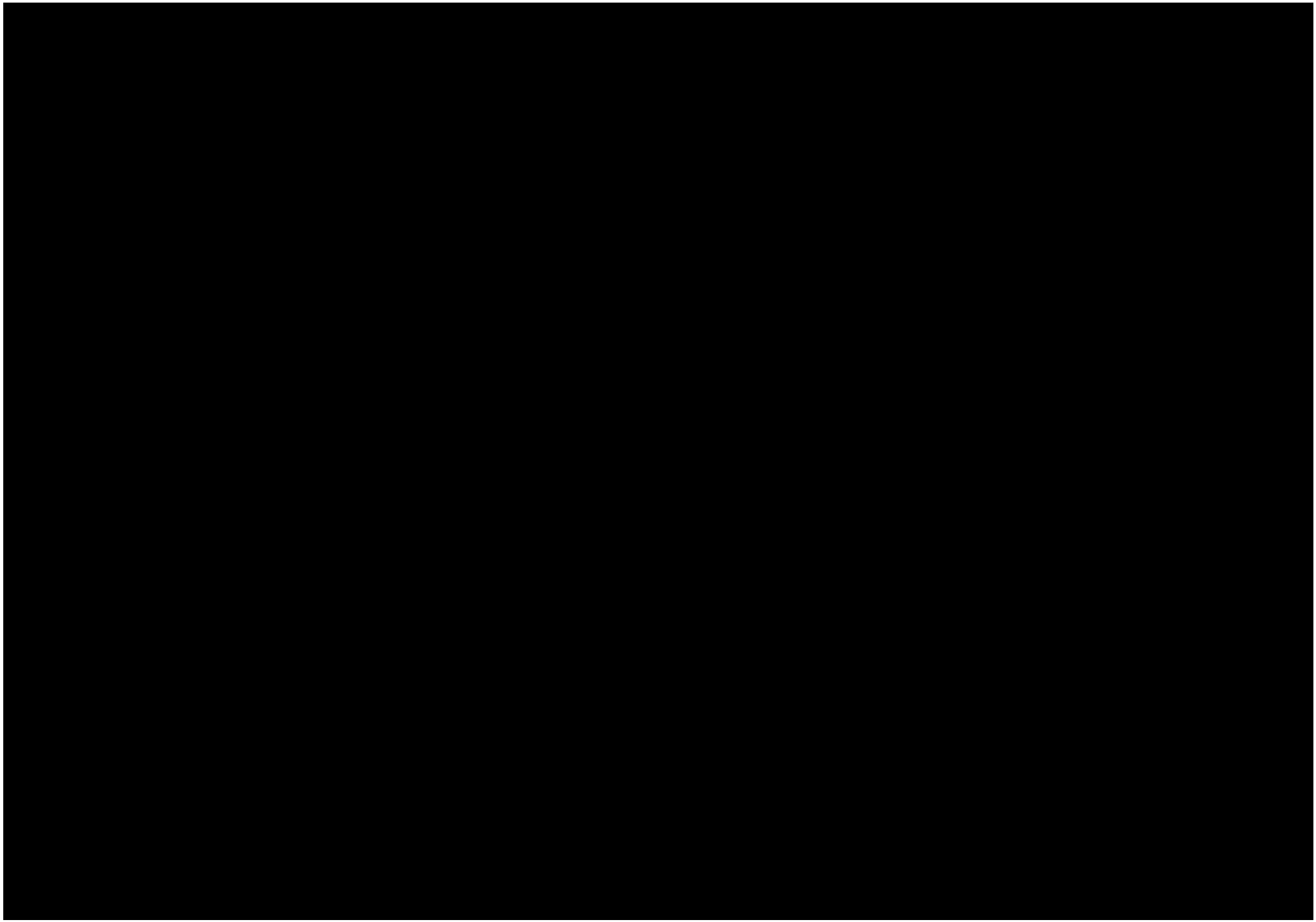
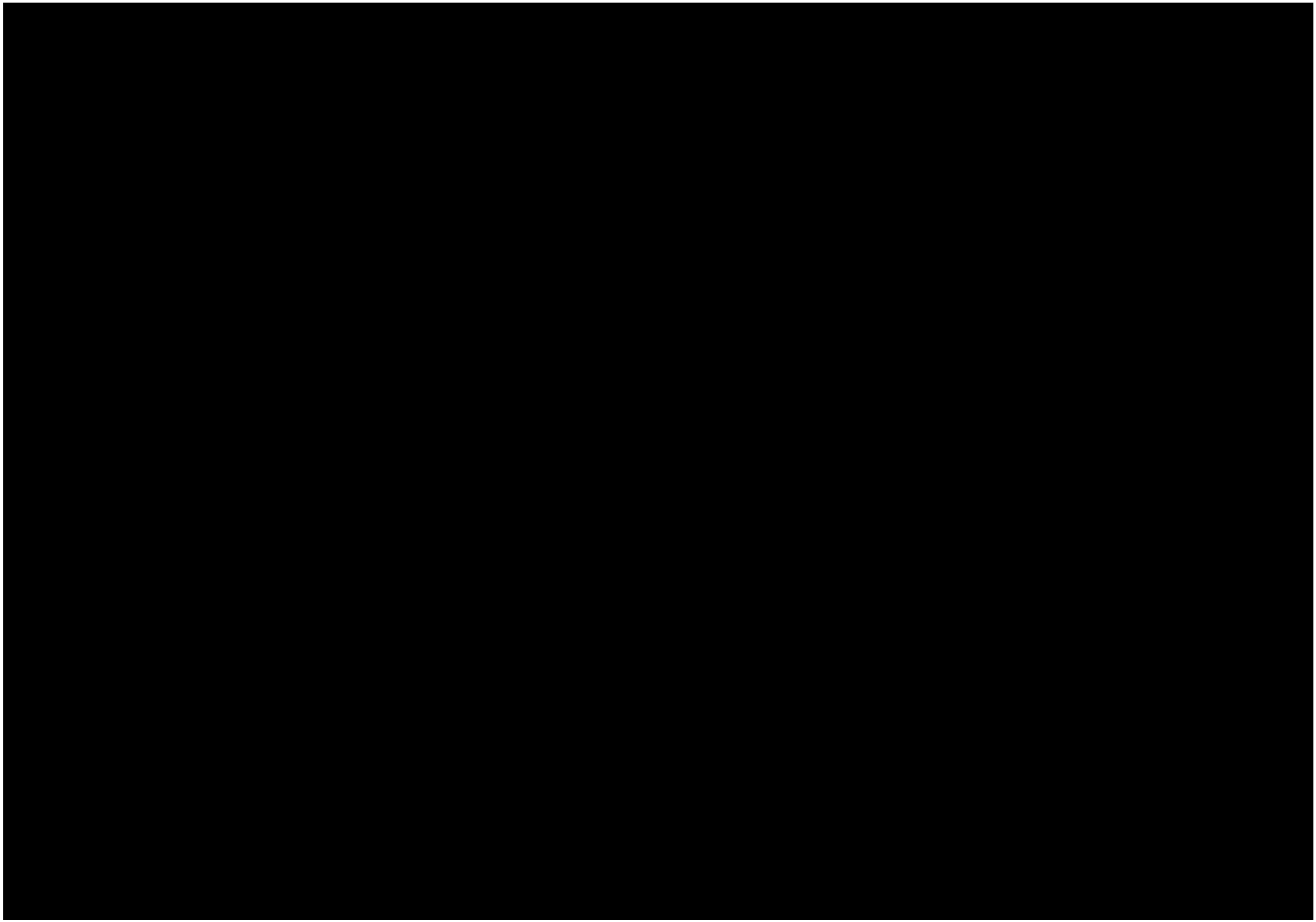
Hourly Average Day for March 2021

Mountain Parks Electric, Inc.



Hourly Average Day for April 2021

Mountain Parks Electric, Inc.



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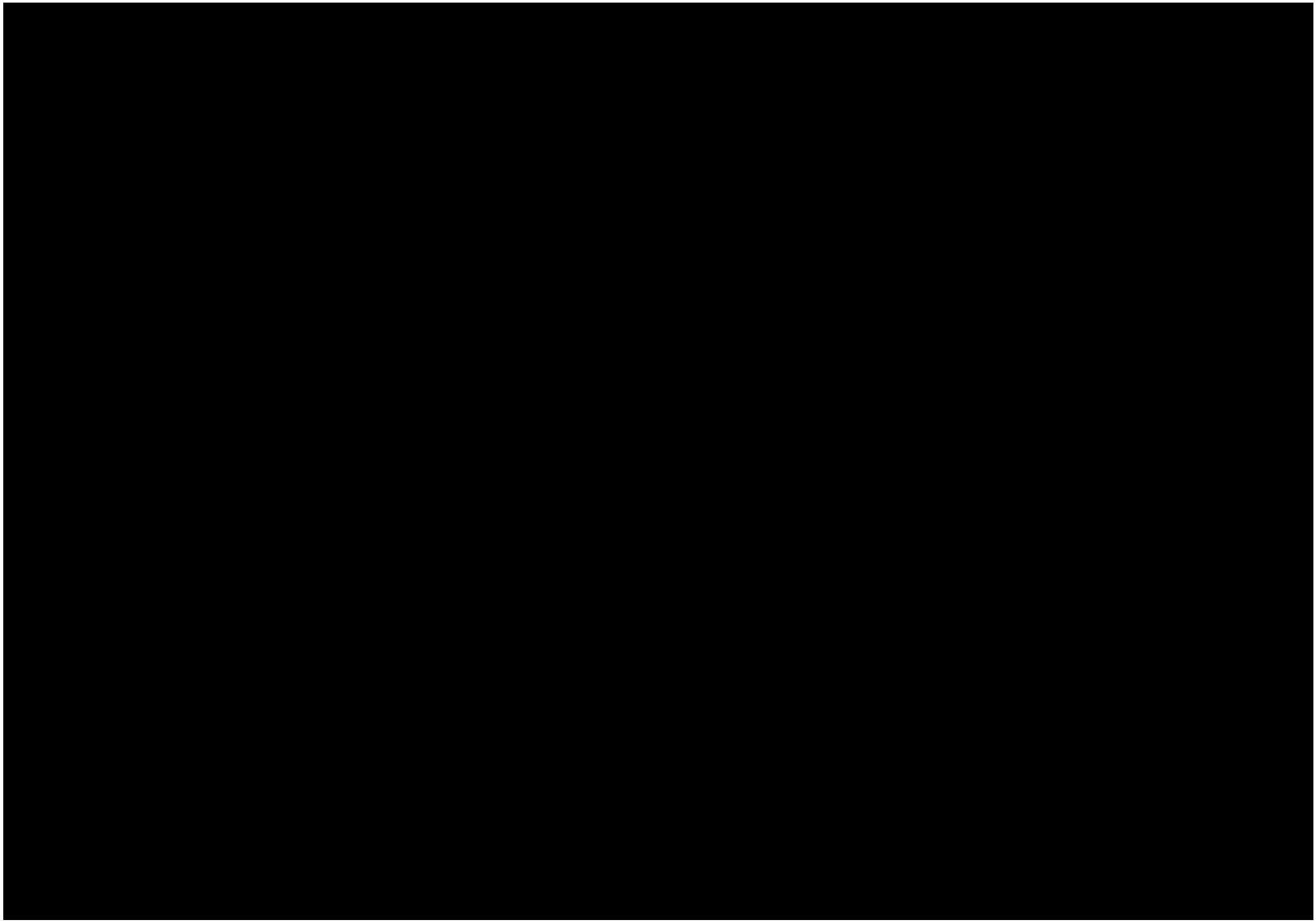
Hourly Average Day for May 2021

Mountain Parks Electric, Inc.



Hourly Average Day for June 2021

Mountain Parks Electric, Inc.

[redacted]

Hourly Average Day for July 2021

Mountain Parks Electric, Inc.

[redacted]

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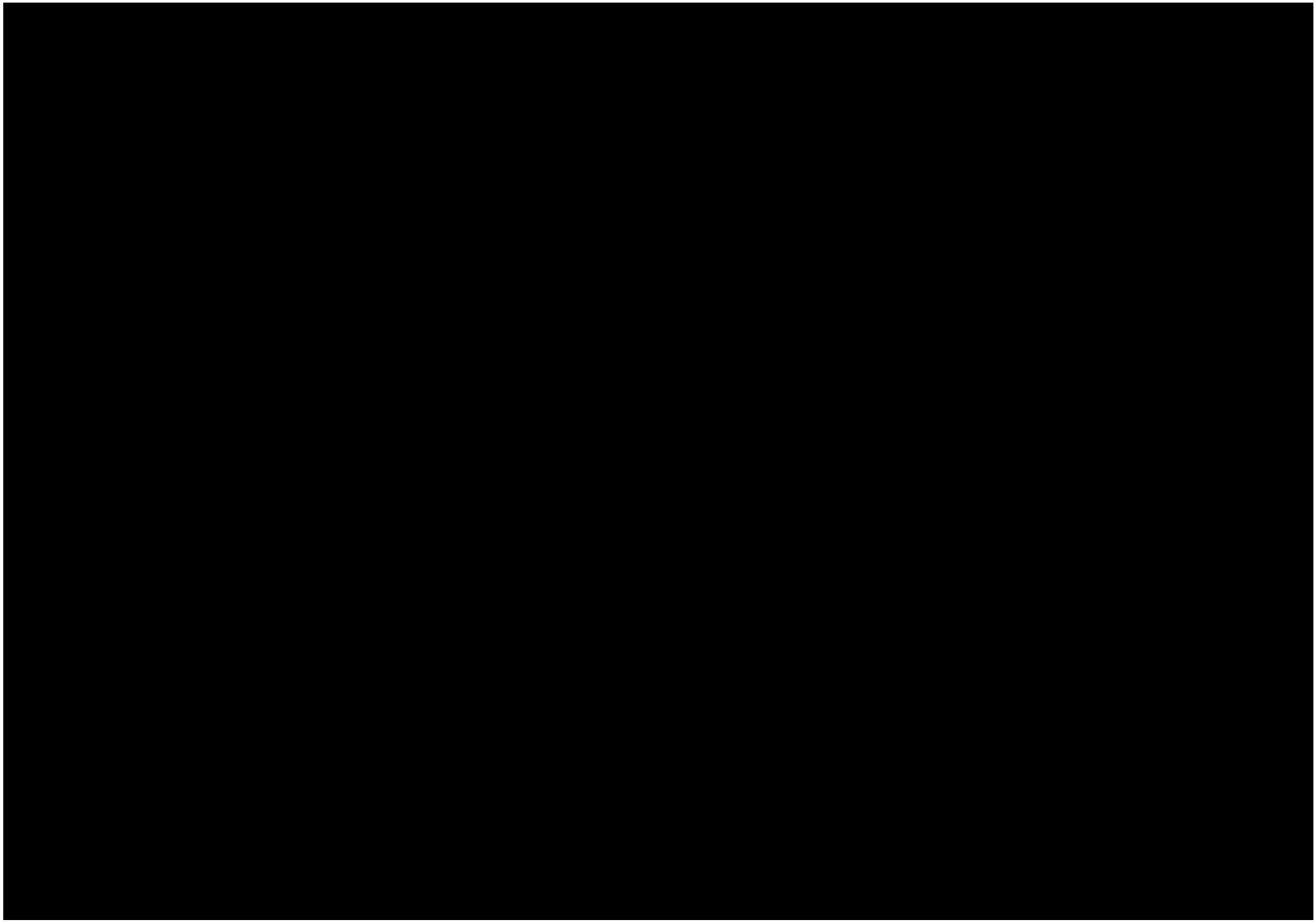
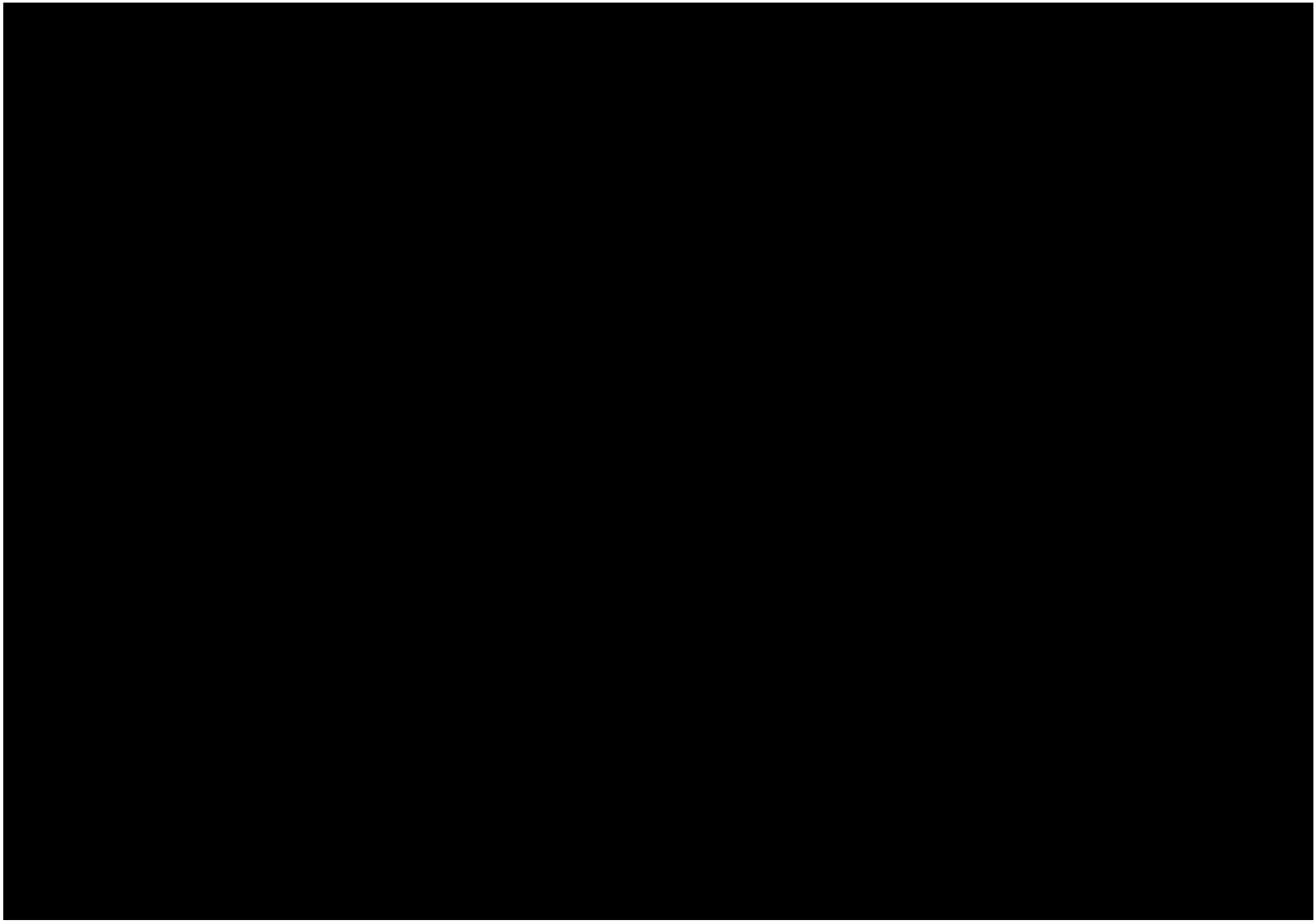
Hourly Average Day for August 2021

Mountain Parks Electric, Inc.



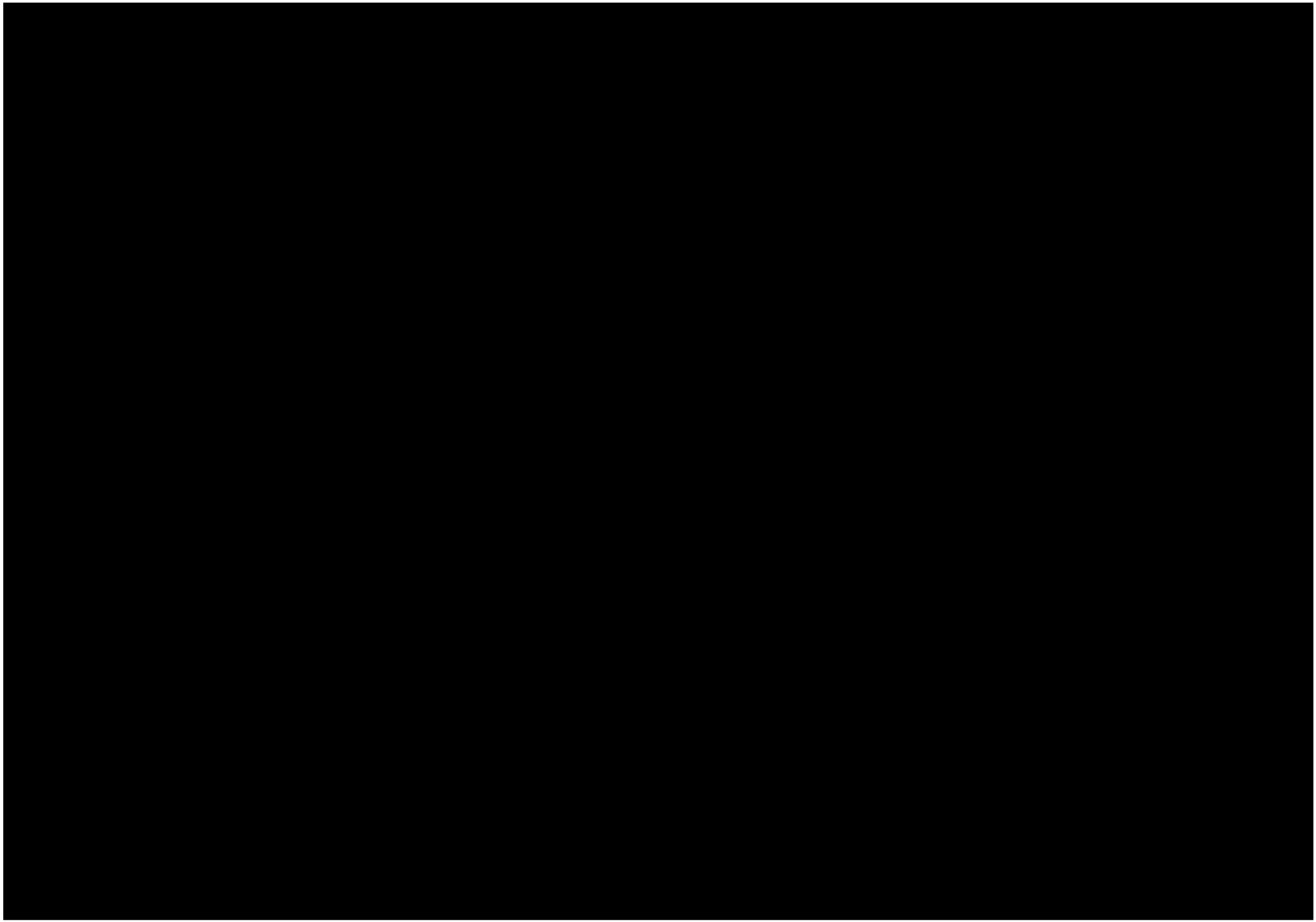
Hourly Average Day for September 2021

Mountain Parks Electric, Inc.



Hourly Average Day for October 2021

Mountain Parks Electric, Inc.



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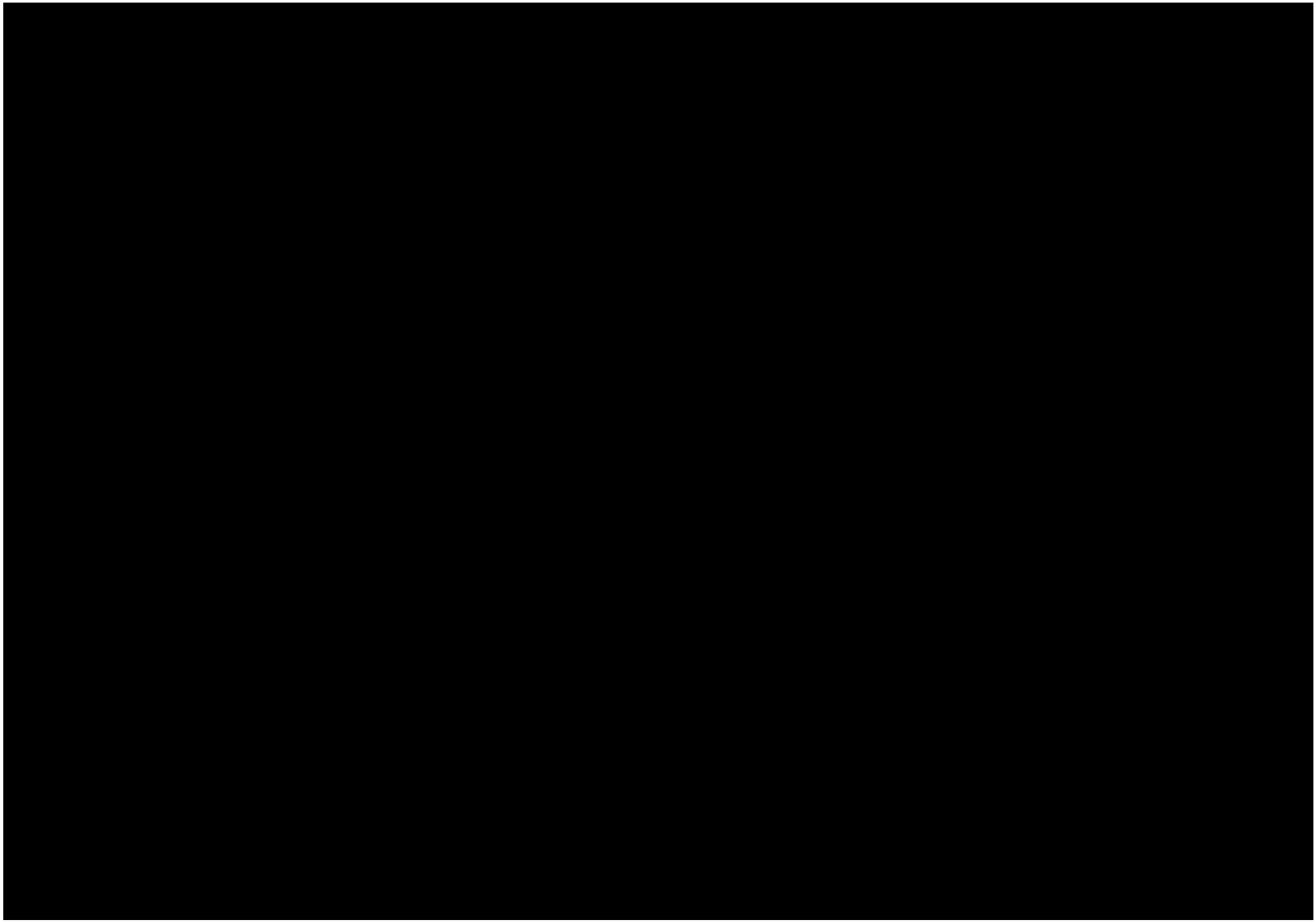
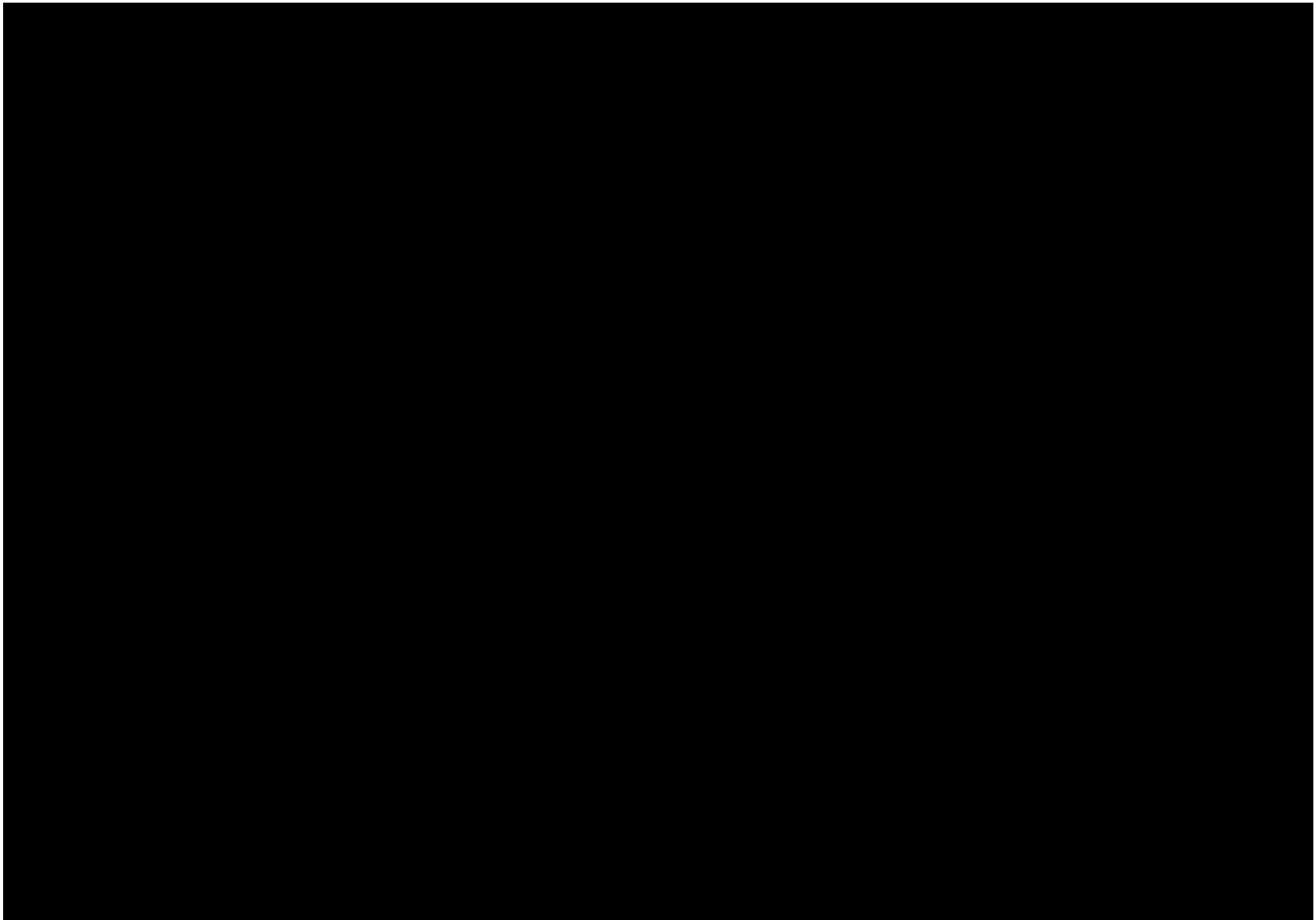
Hourly Average Day for November 2021

Mountain Parks Electric, Inc.



Hourly Average Day for December 2021

Mountain Parks Electric, Inc.



Hourly Average Day for January 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

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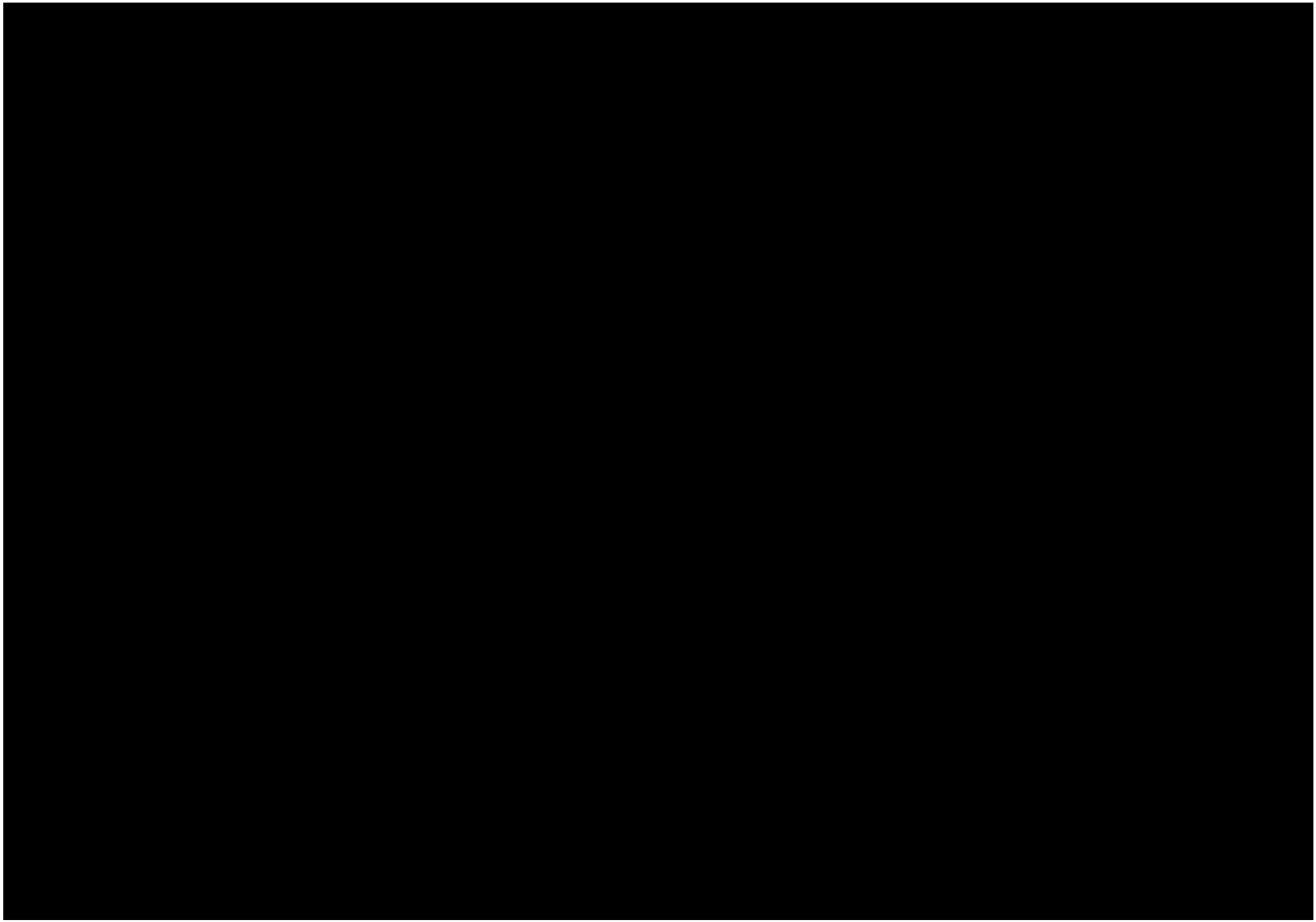
Hourly Average Day for March 2021

Mora-San Miguel Electric Cooperative, Inc.



Hourly Average Day for April 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

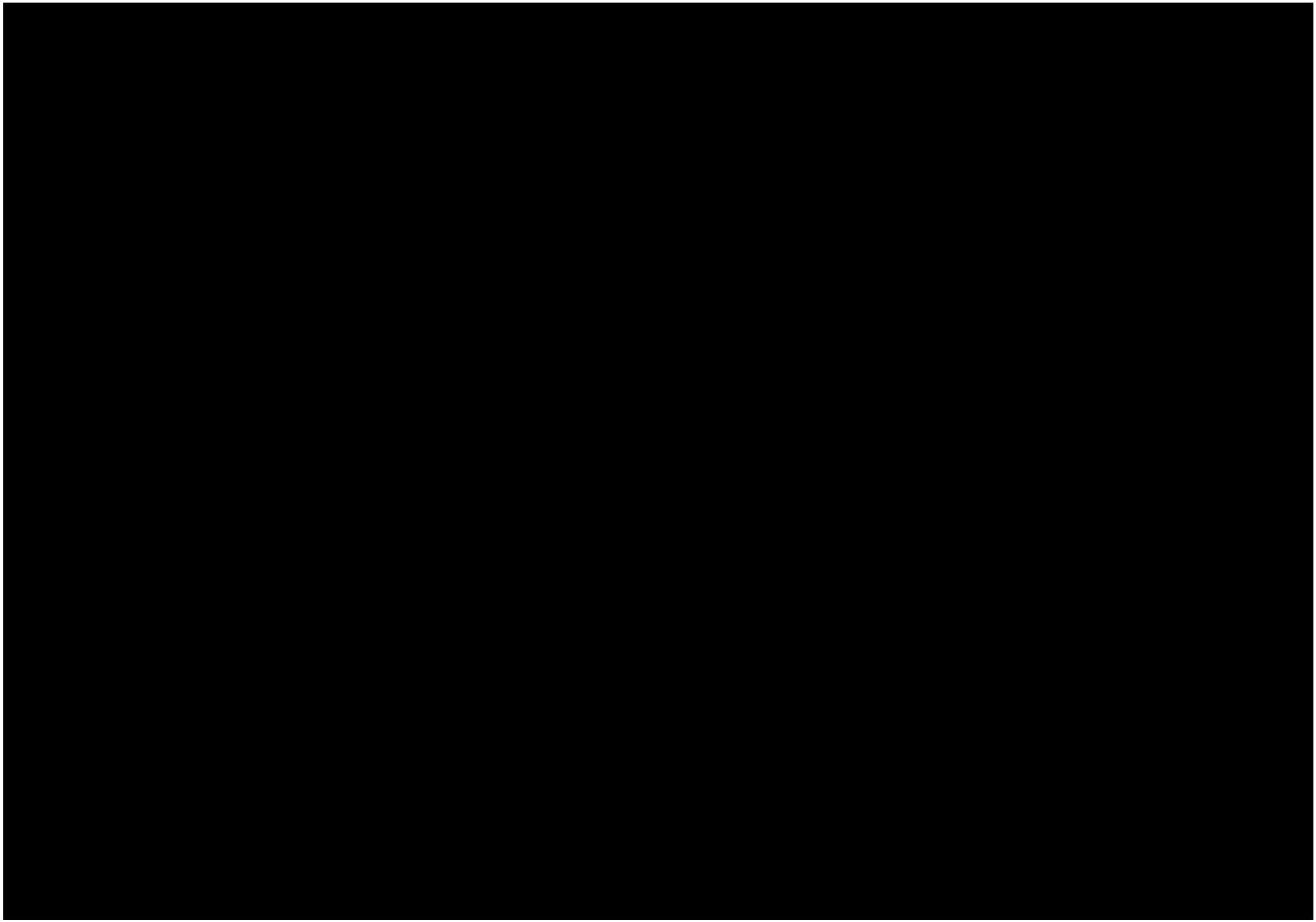
Hourly Average Day for August 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Mora-San Miguel Electric Cooperative, Inc.



Hourly Average Day for October 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Mora-San Miguel Electric Cooperative, Inc.

[redacted]

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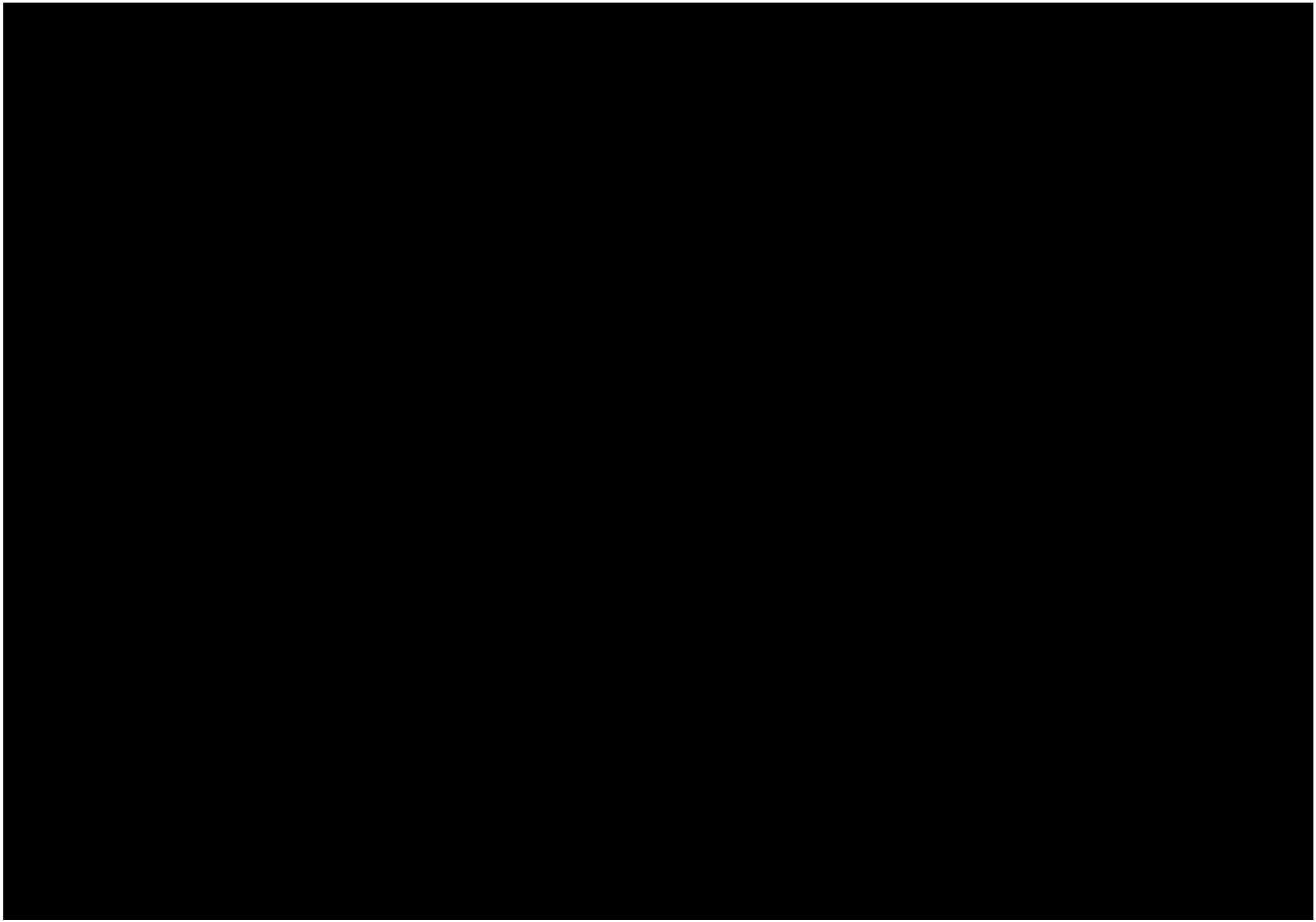
Hourly Average Day for January 2021

Mountain View Electric Association, Inc.



Hourly Average Day for February 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021
Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Mountain View Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

Midwest Electric Cooperative Corporation

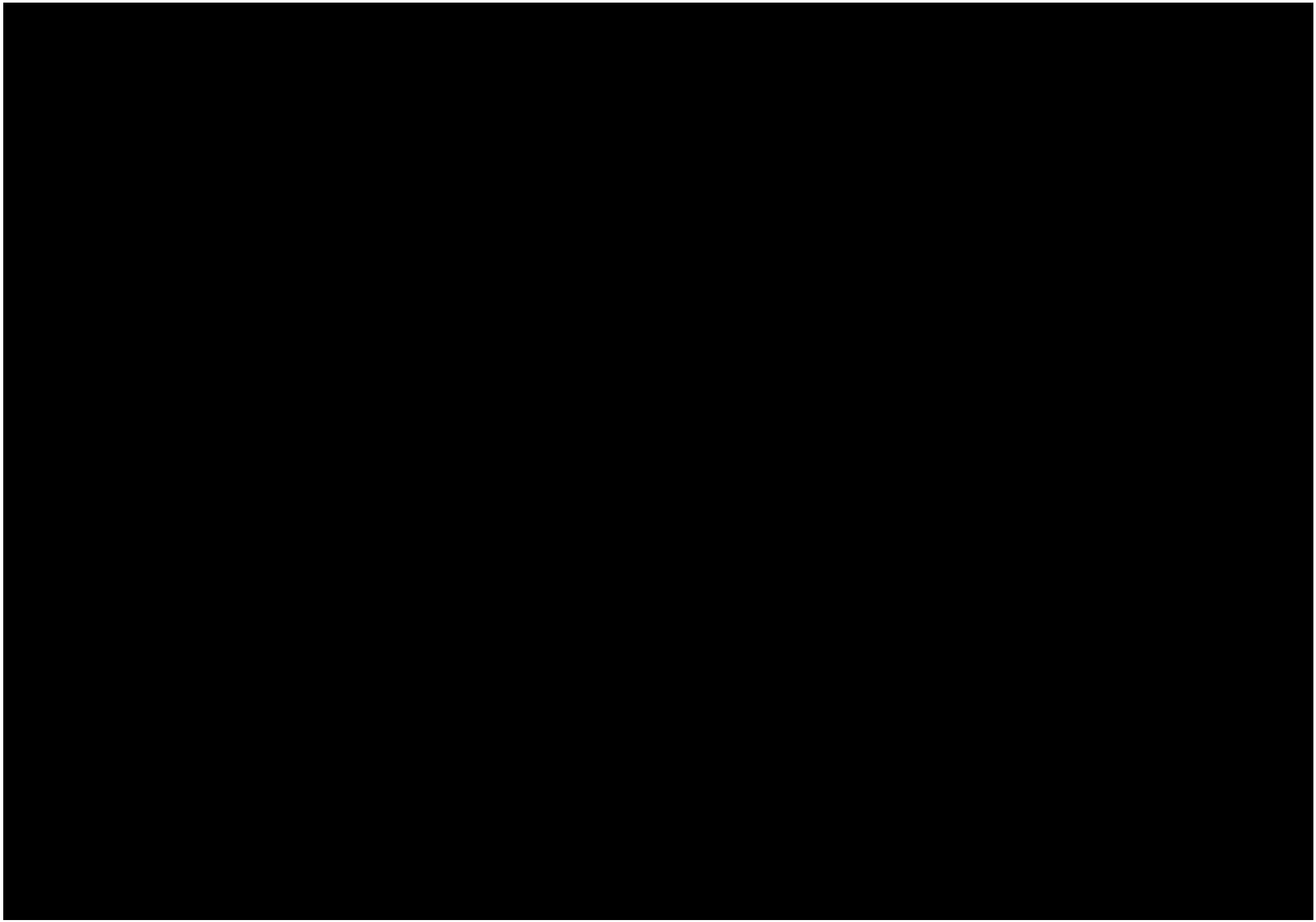
[redacted]

Hourly Average Day for February 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for March 2021
Midwest Electric Cooperative Corporation

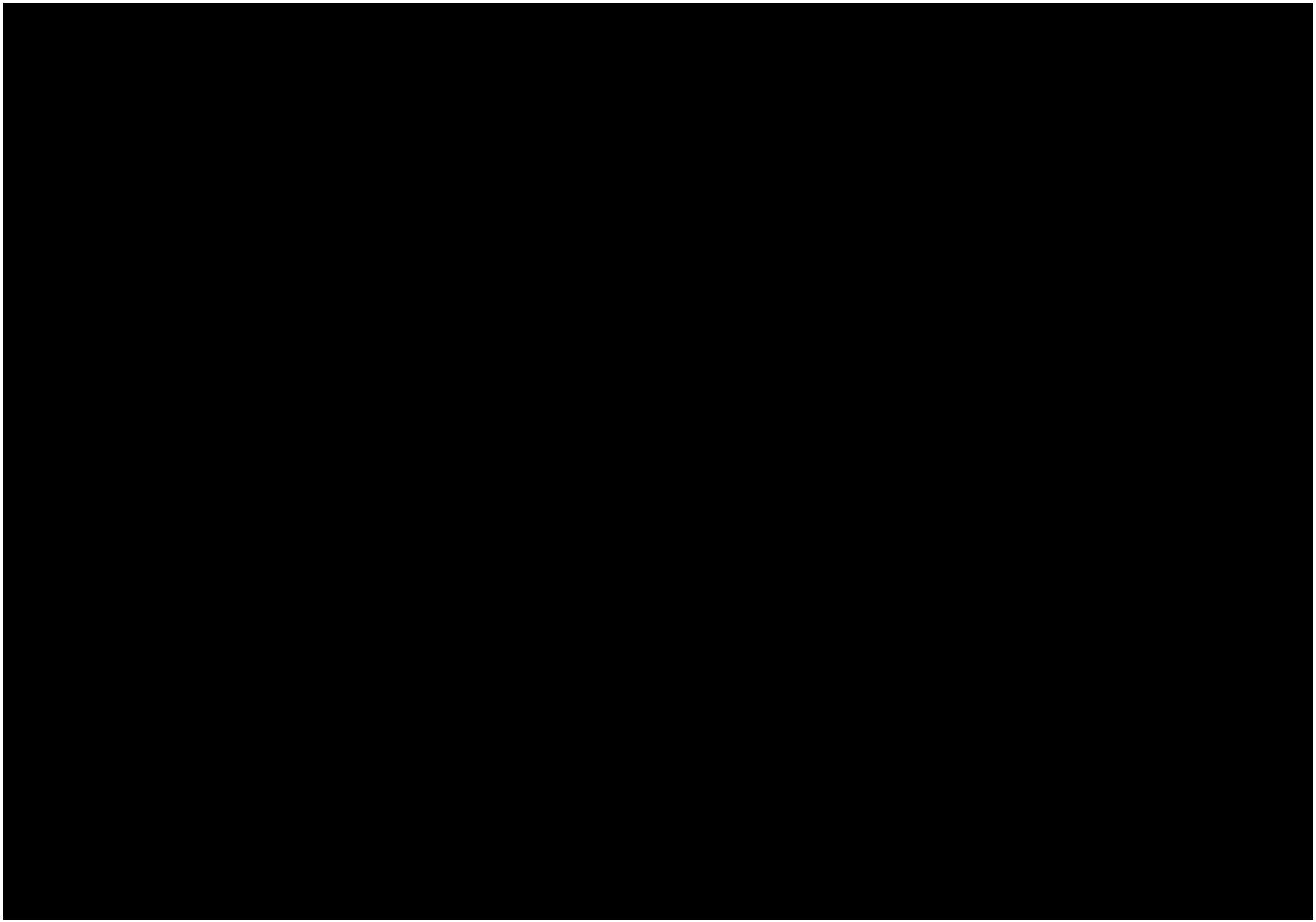


Hourly Average Day for April 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for May 2021
Midwest Electric Cooperative Corporation

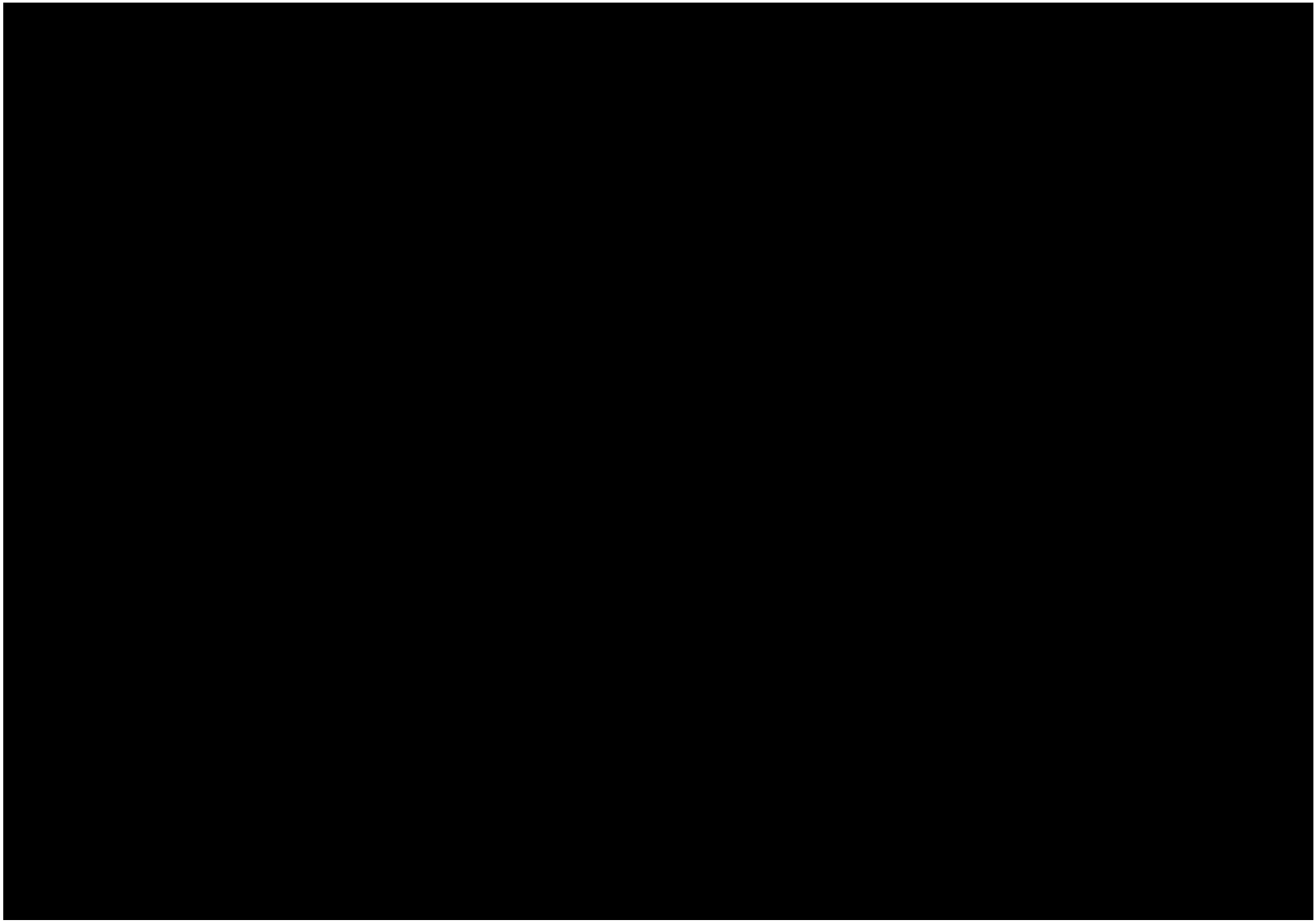


Hourly Average Day for June 2021
Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for July 2021

Midwest Electric Cooperative Corporation



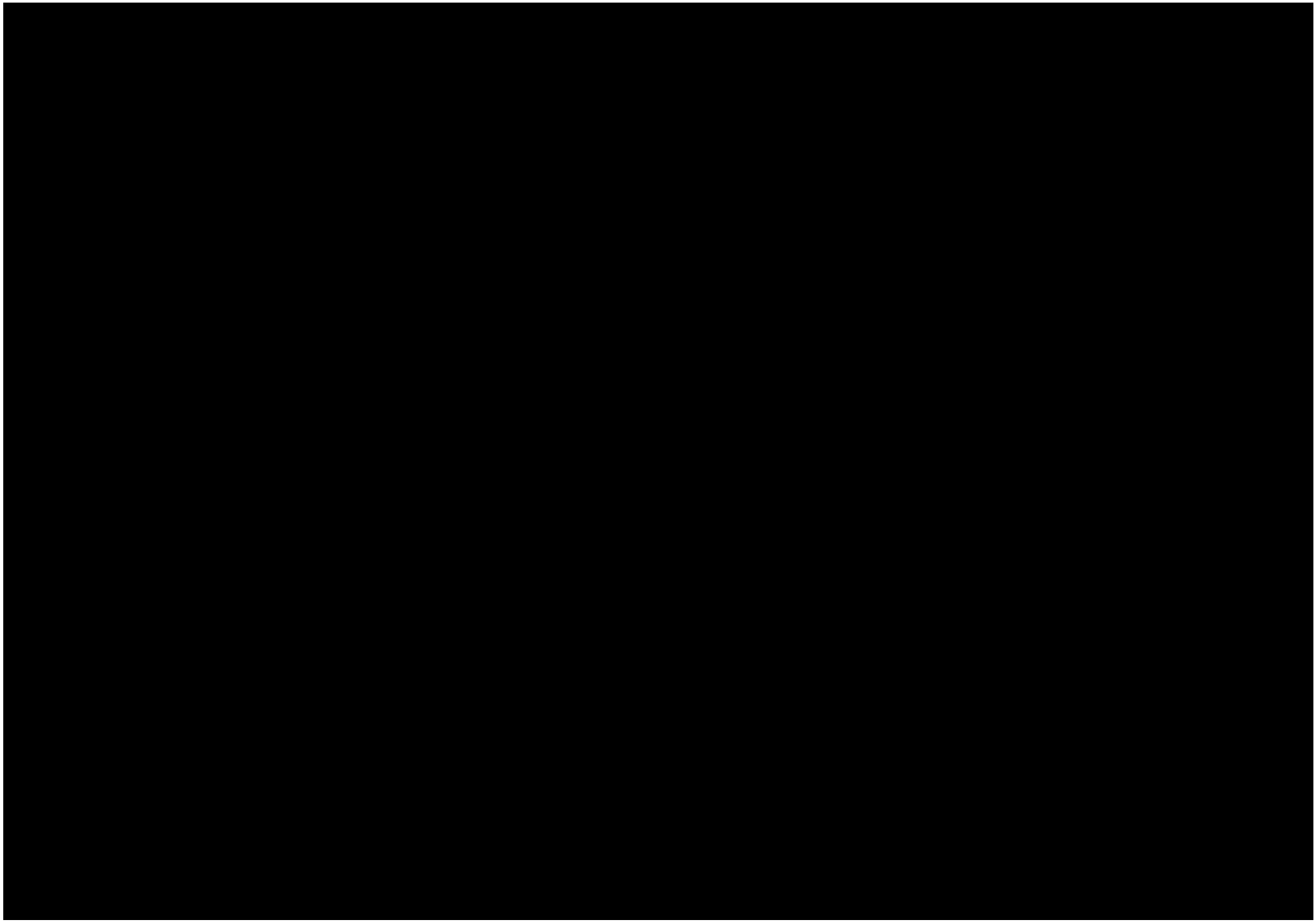
Hourly Average Day for August 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for September 2021

Midwest Electric Cooperative Corporation



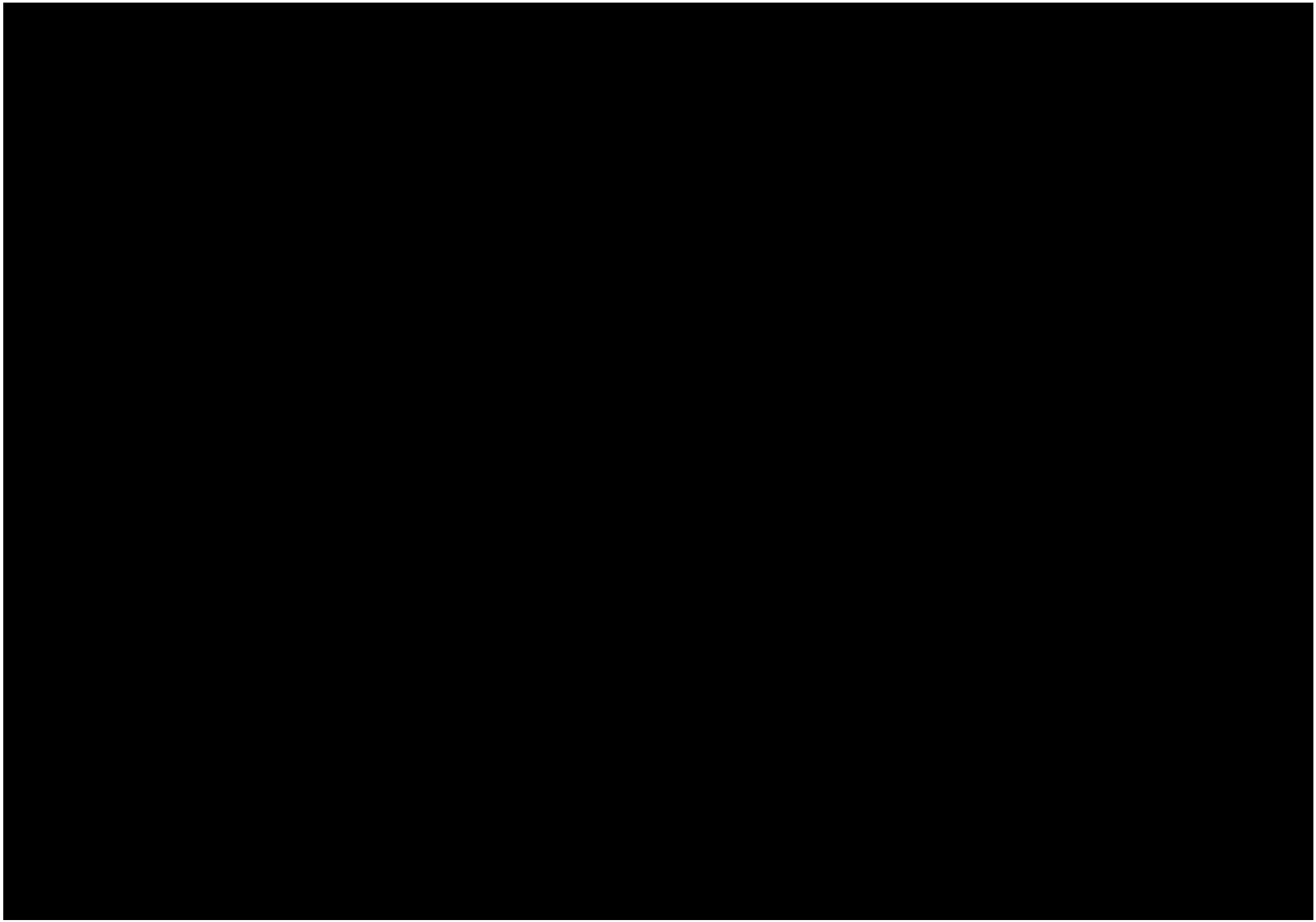
Hourly Average Day for October 2021

Midwest Electric Cooperative Corporation

[redacted]

Hourly Average Day for November 2021

Midwest Electric Cooperative Corporation



Hourly Average Day for December 2021

Midwest Electric Cooperative Corporation

[redacted]

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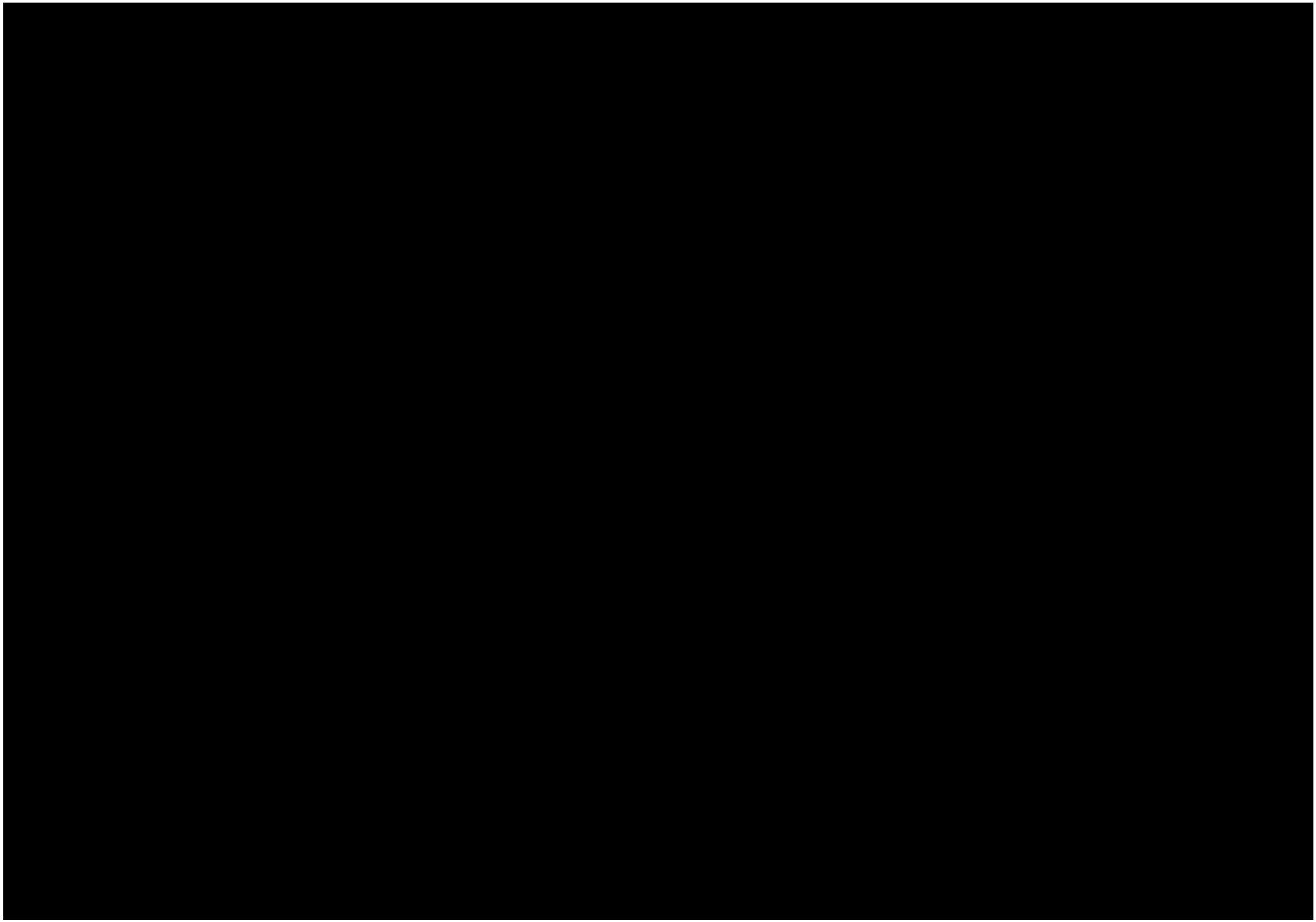
Hourly Average Day for January 2021

Niobrara Electric Association, Inc.



Hourly Average Day for February 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Niobrara Electric Association, Inc.

[redacted]

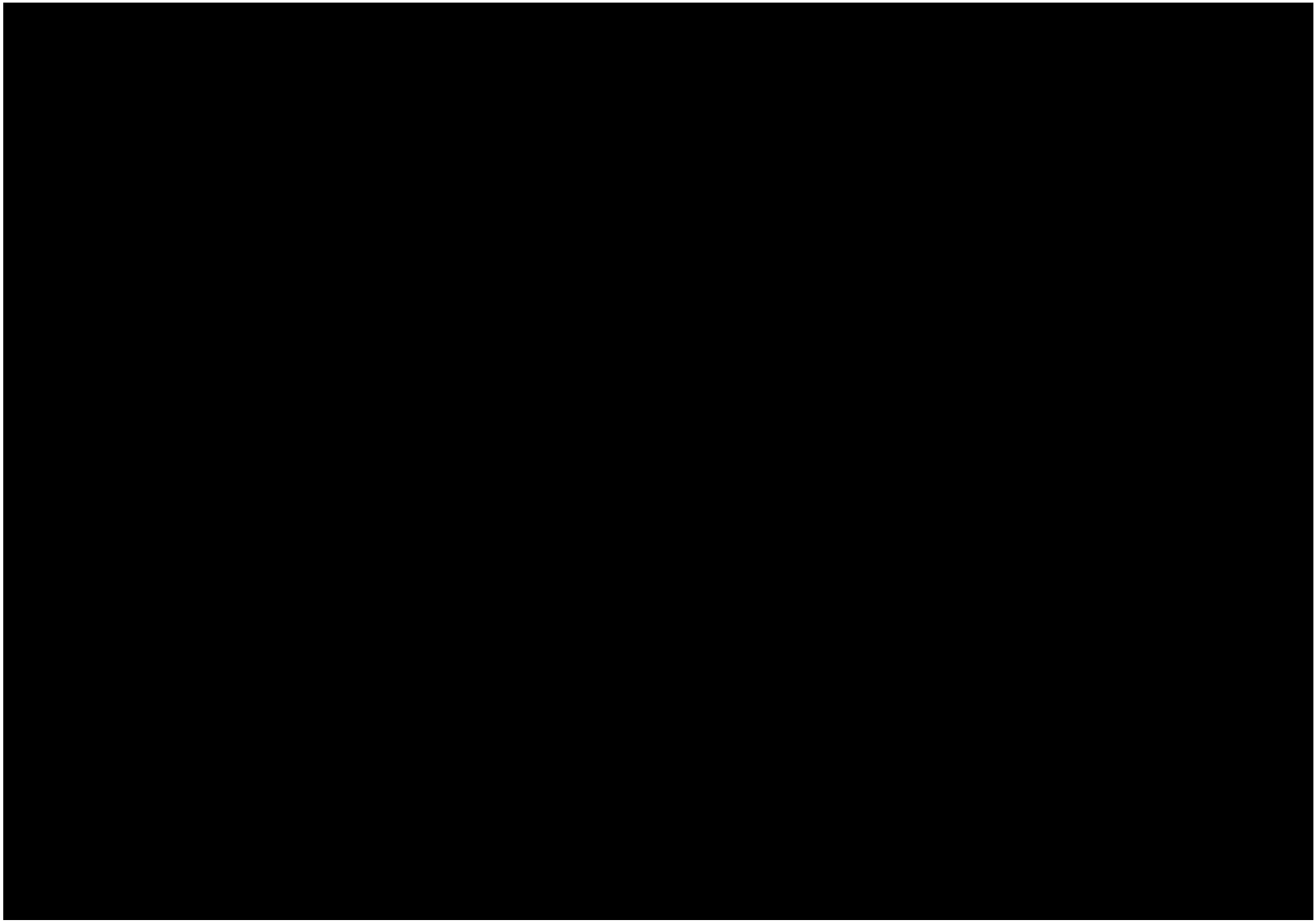
Hourly Average Day for June 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Niobrara Electric Association, Inc.



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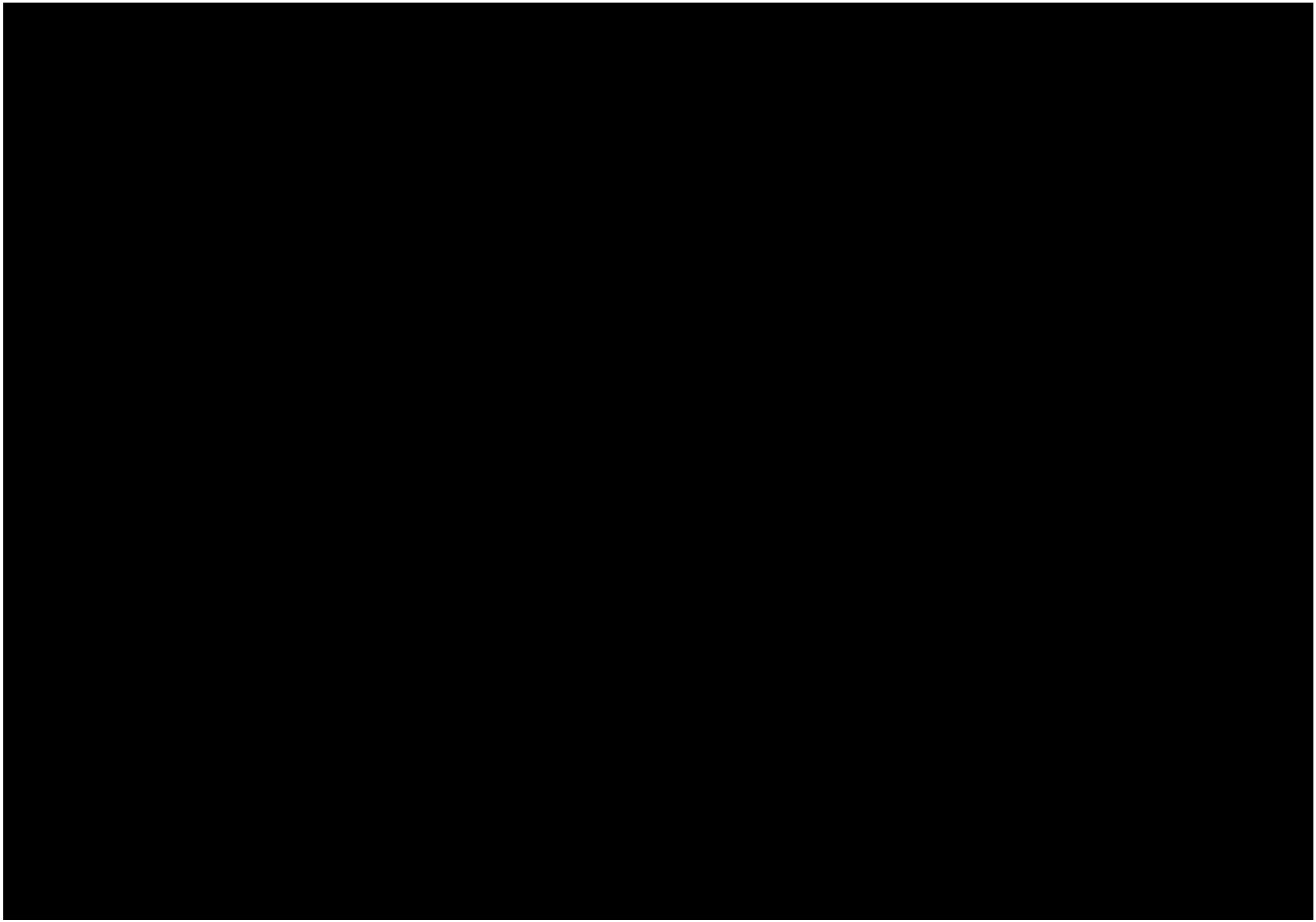
Hourly Average Day for August 2021

Niobrara Electric Association, Inc.



Hourly Average Day for September 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Niobrara Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for February 2021

Northwest Rural Public Power District

[redacted]

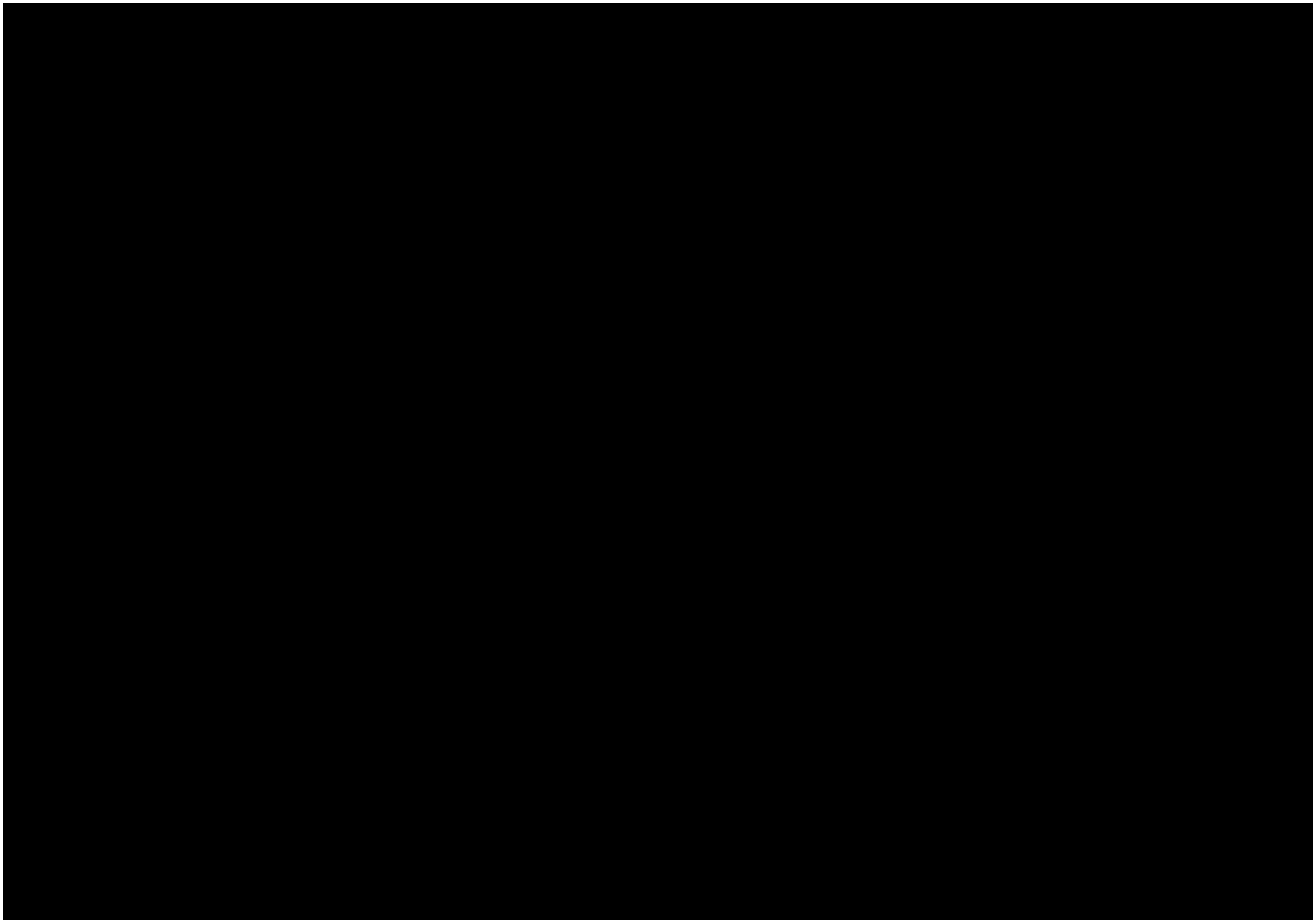
Hourly Average Day for March 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for April 2021

Northwest Rural Public Power District



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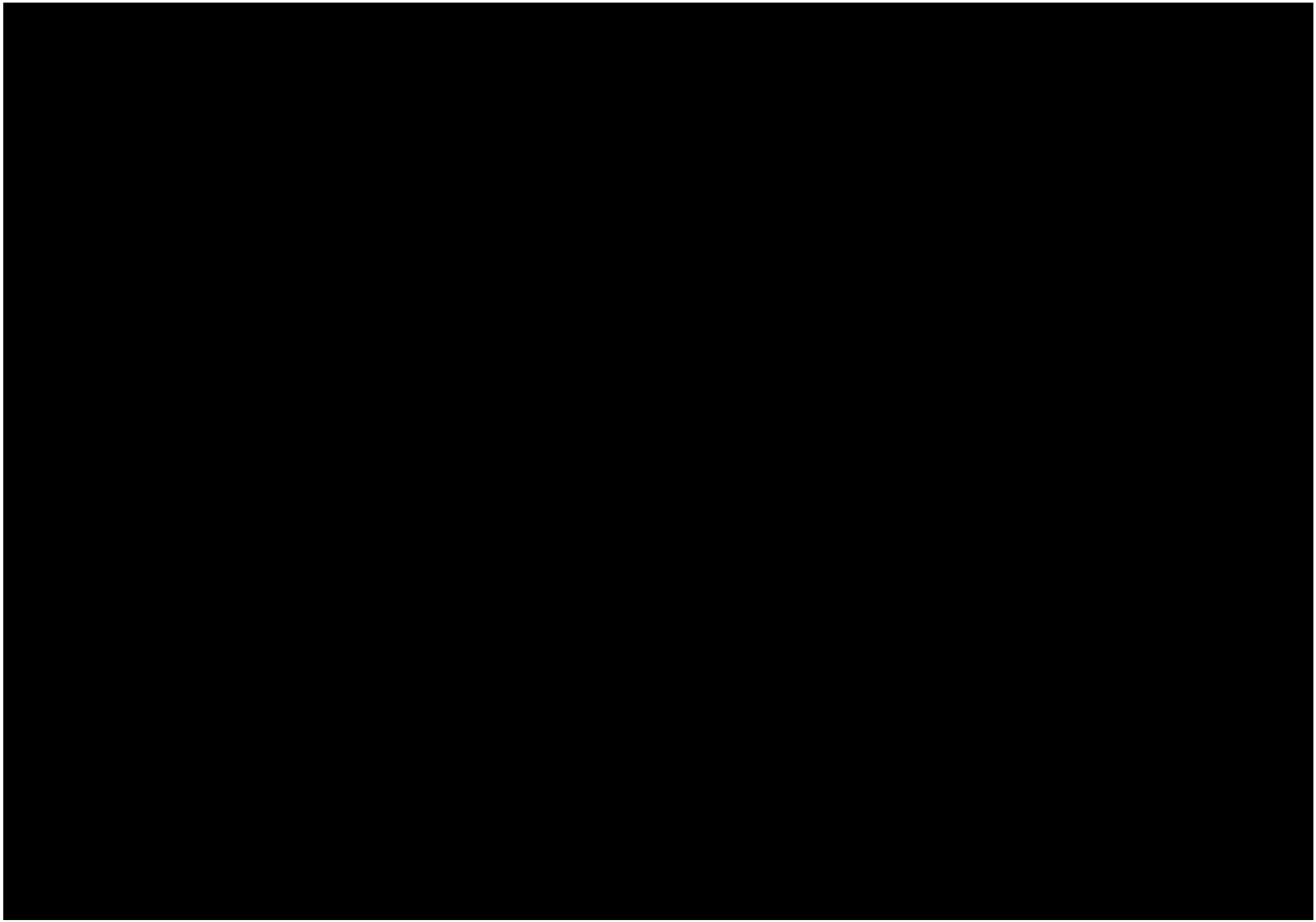
Hourly Average Day for May 2021

Northwest Rural Public Power District



Hourly Average Day for June 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for July 2021

Northwest Rural Public Power District

[redacted]

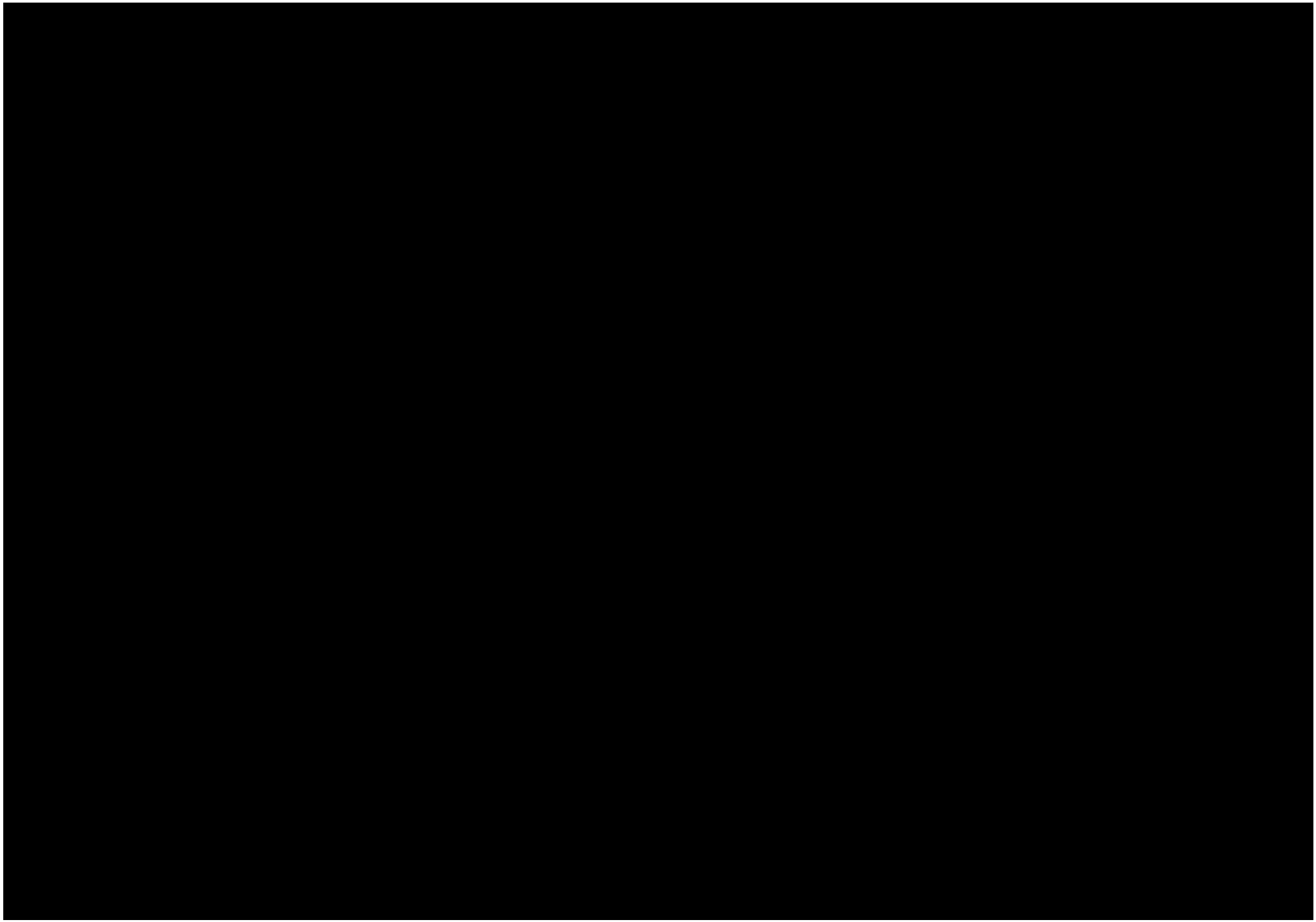
Hourly Average Day for August 2021

Northwest Rural Public Power District

[redacted]

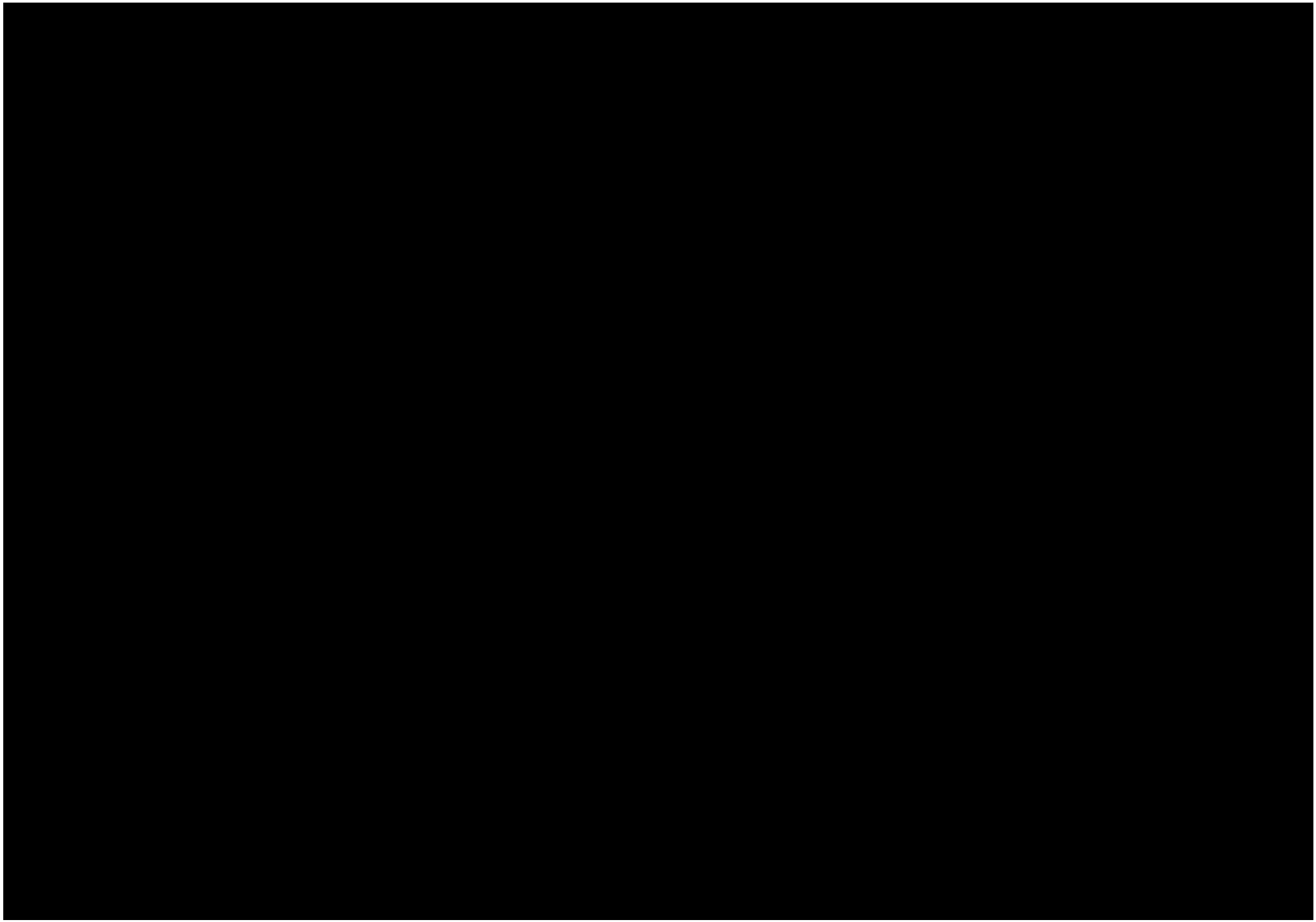
Hourly Average Day for September 2021

Northwest Rural Public Power District



Hourly Average Day for October 2021

Northwest Rural Public Power District



Hourly Average Day for November 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for December 2021

Northwest Rural Public Power District

[redacted]

Hourly Average Day for January 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Otero County Electric Cooperative, Inc.

[redacted]

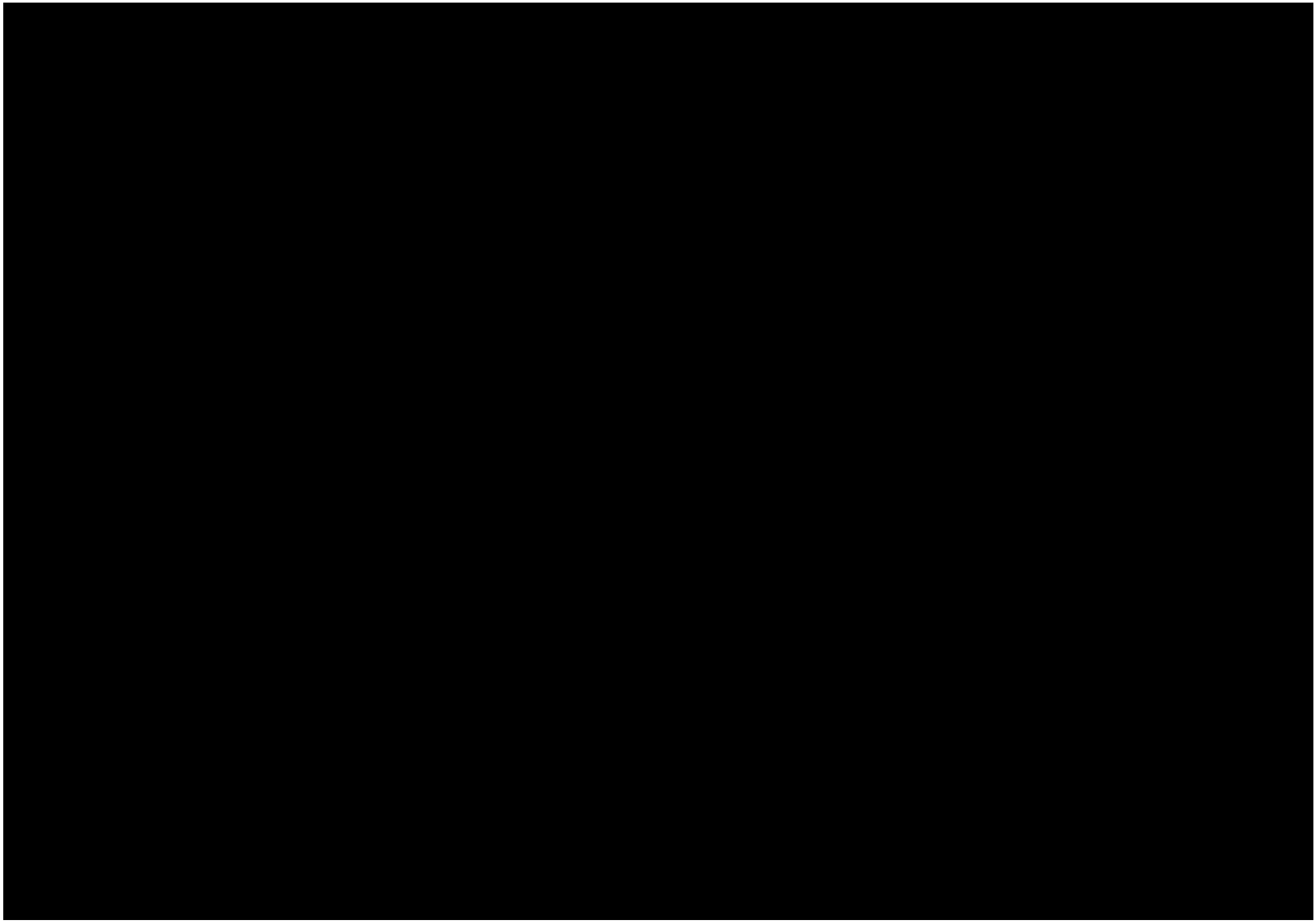
Hourly Average Day for May 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Otero County Electric Cooperative, Inc.



Hourly Average Day for July 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Otero County Electric Cooperative, Inc.

[redacted]

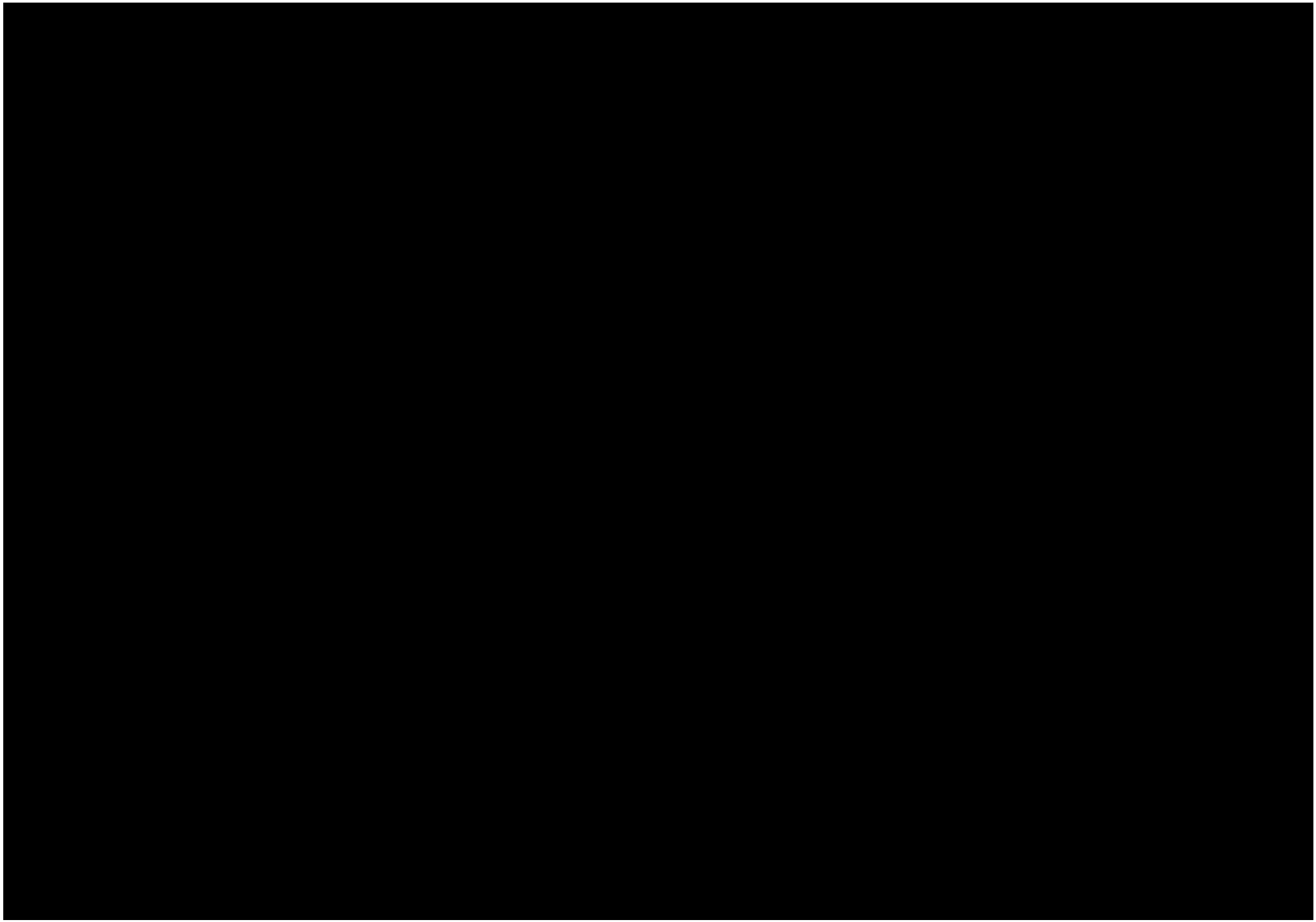
Hourly Average Day for September 2021

Otero County Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Otero County Electric Cooperative, Inc.



Hourly Average Day for November 2021

Otero County Electric Cooperative, Inc.

[redacted]

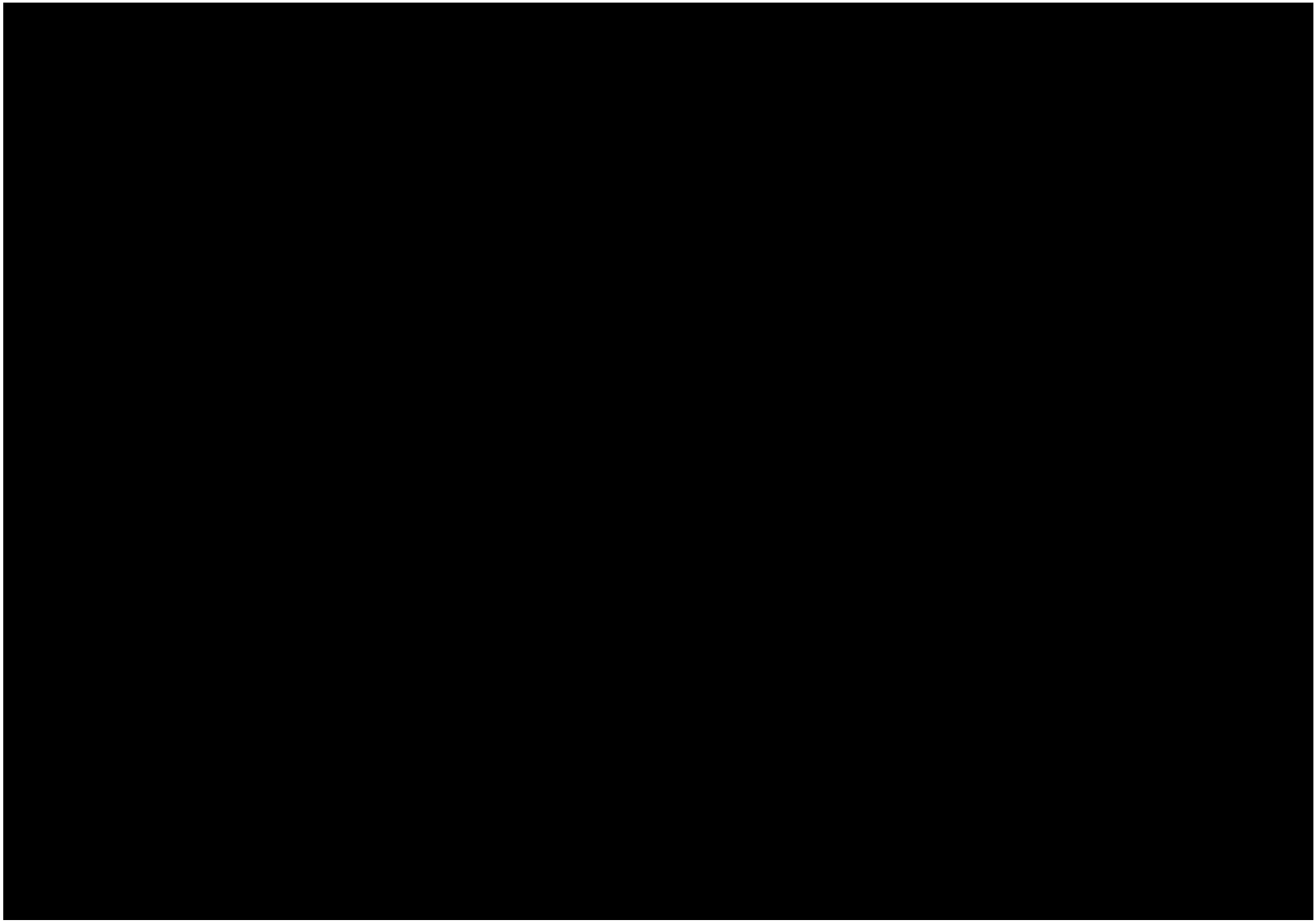
Hourly Average Day for December 2021

Otero County Electric Cooperative, Inc.

[redacted]

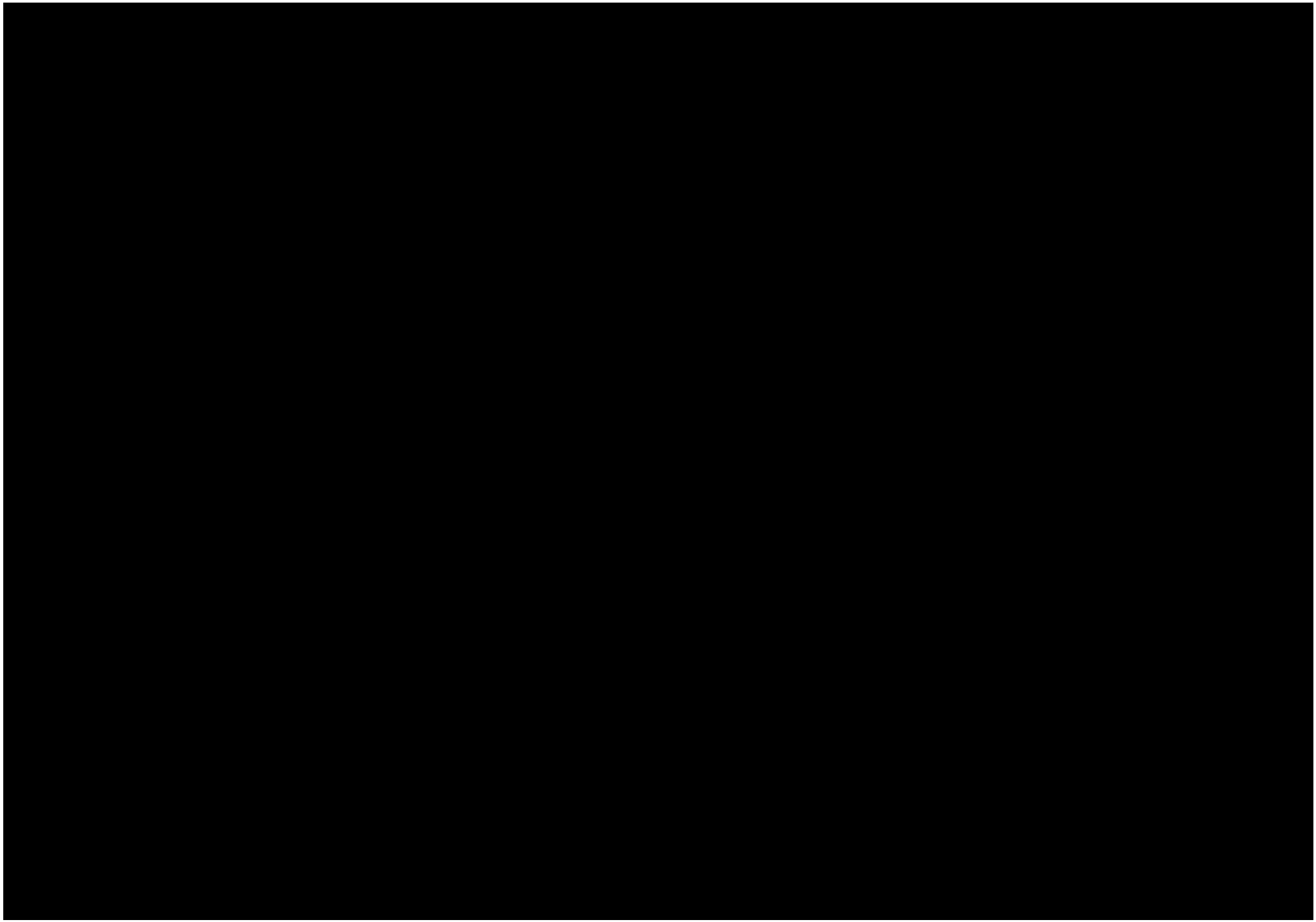
Hourly Average Day for January 2021

Panhandle Rural Electric Membership Association



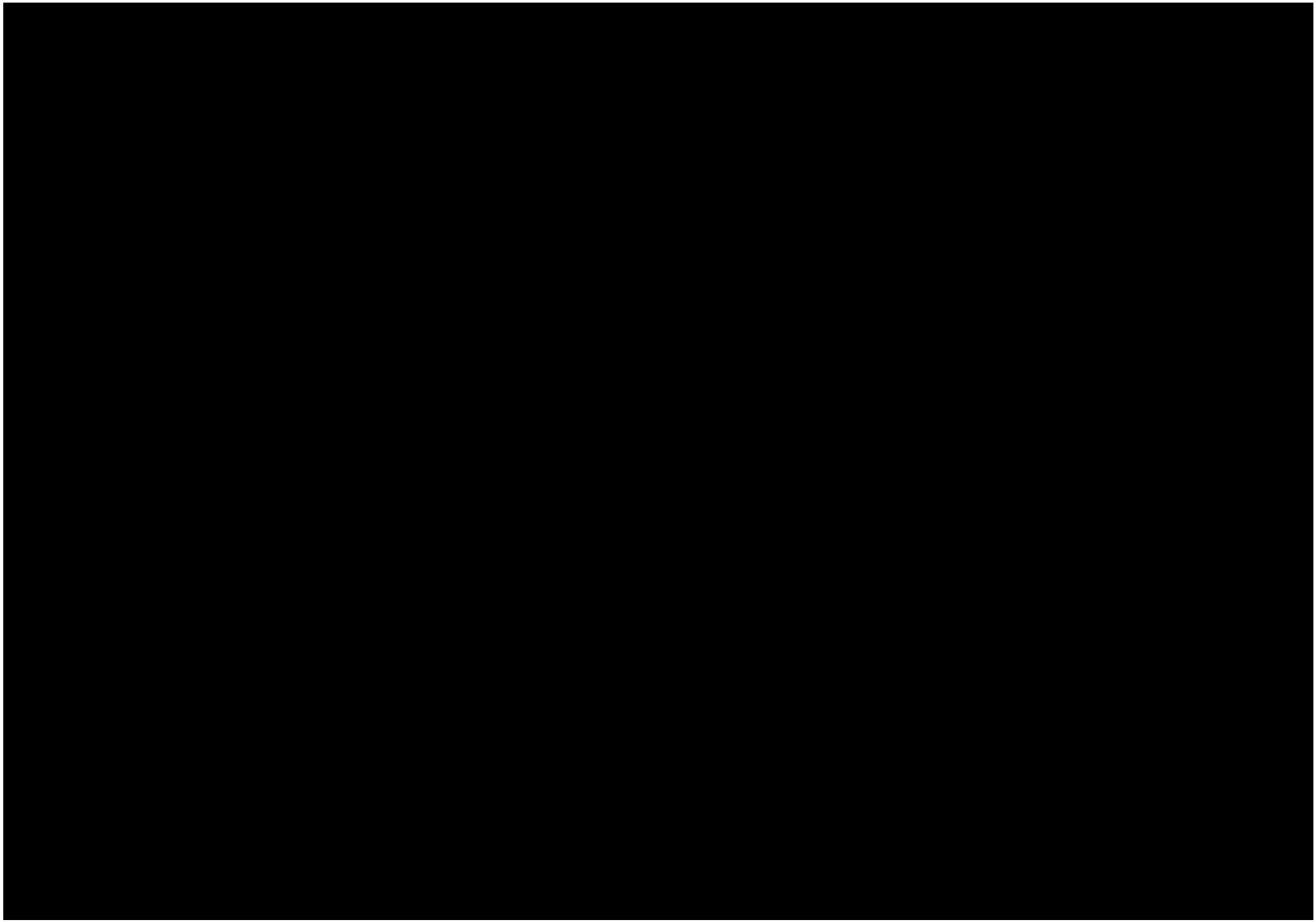
Hourly Average Day for February 2021

Panhandle Rural Electric Membership Association



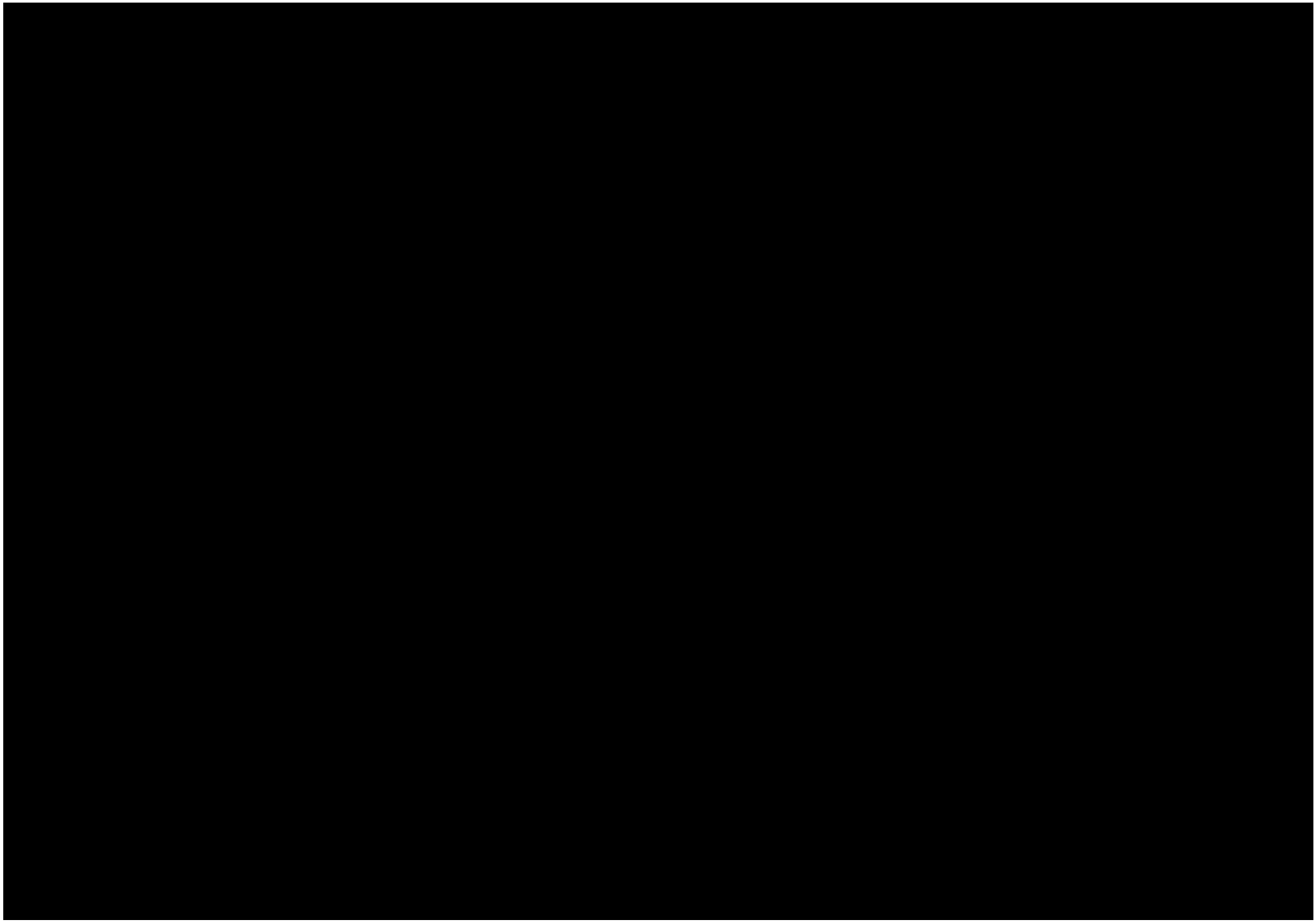
Hourly Average Day for March 2021

Panhandle Rural Electric Membership Association



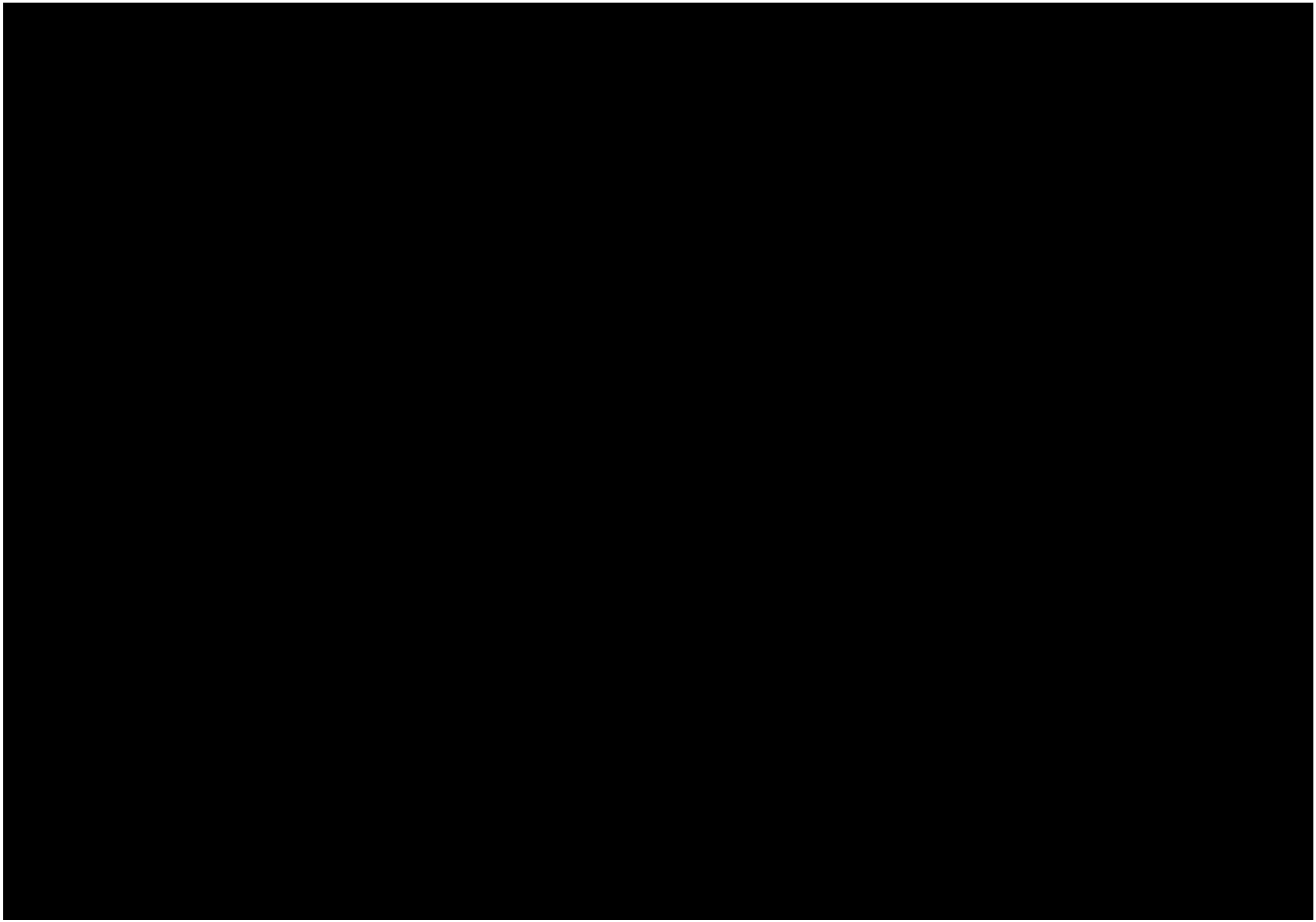
Hourly Average Day for April 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for May 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for June 2021

Panhandle Rural Electric Membership Association

[redacted]

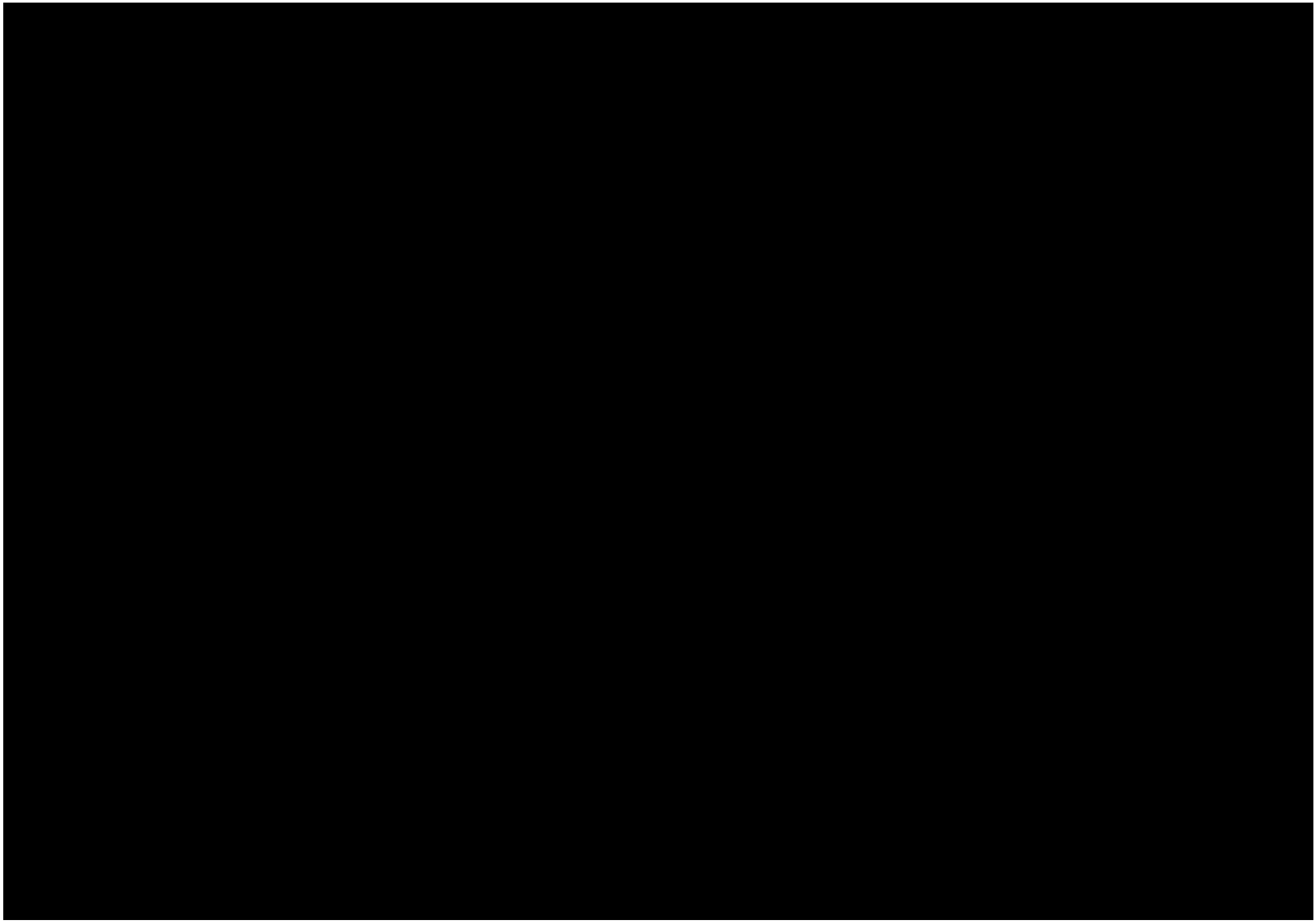
Hourly Average Day for July 2021

Panhandle Rural Electric Membership Association

[redacted]

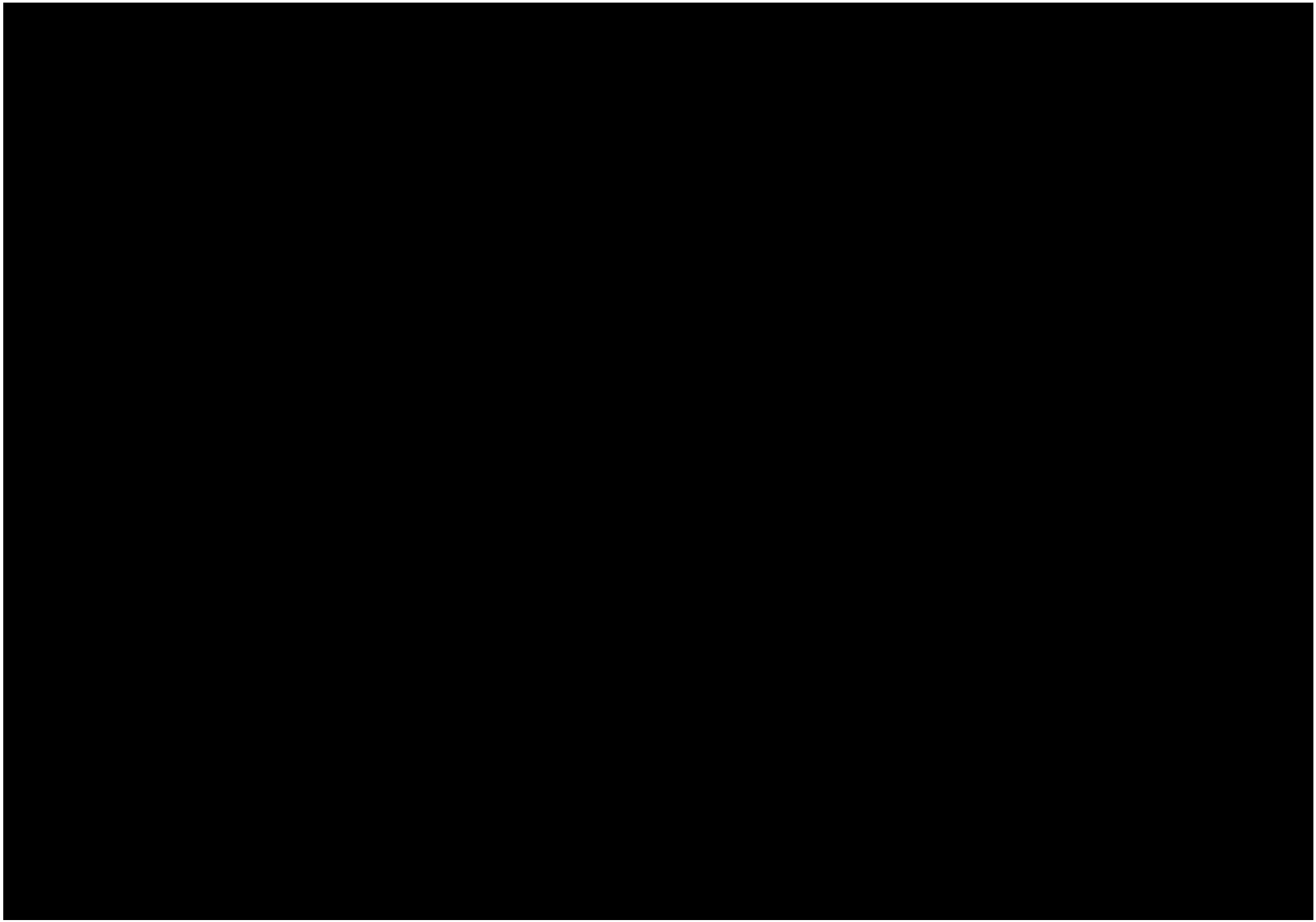
Hourly Average Day for August 2021

Panhandle Rural Electric Membership Association



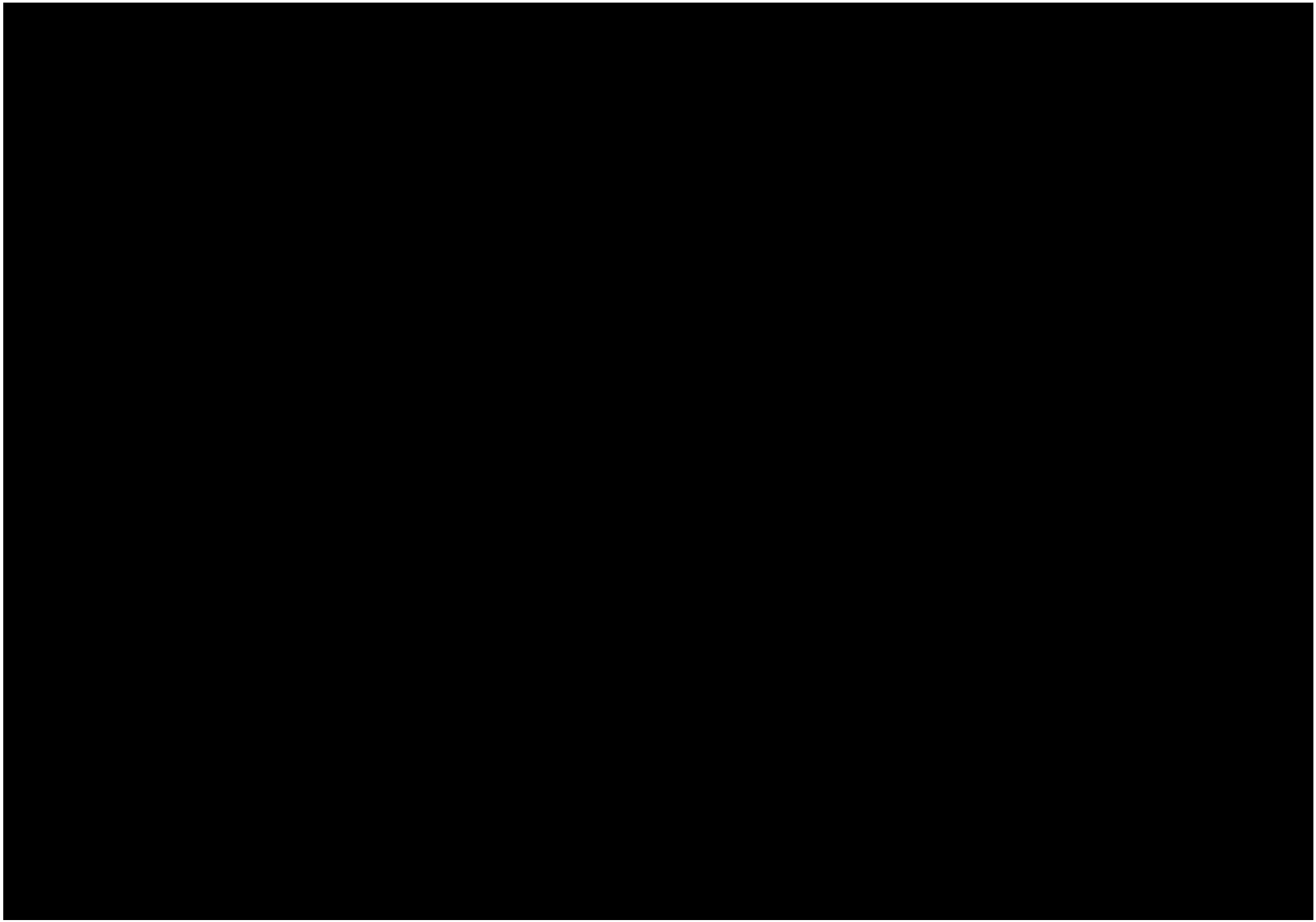
Hourly Average Day for September 2021

Panhandle Rural Electric Membership Association



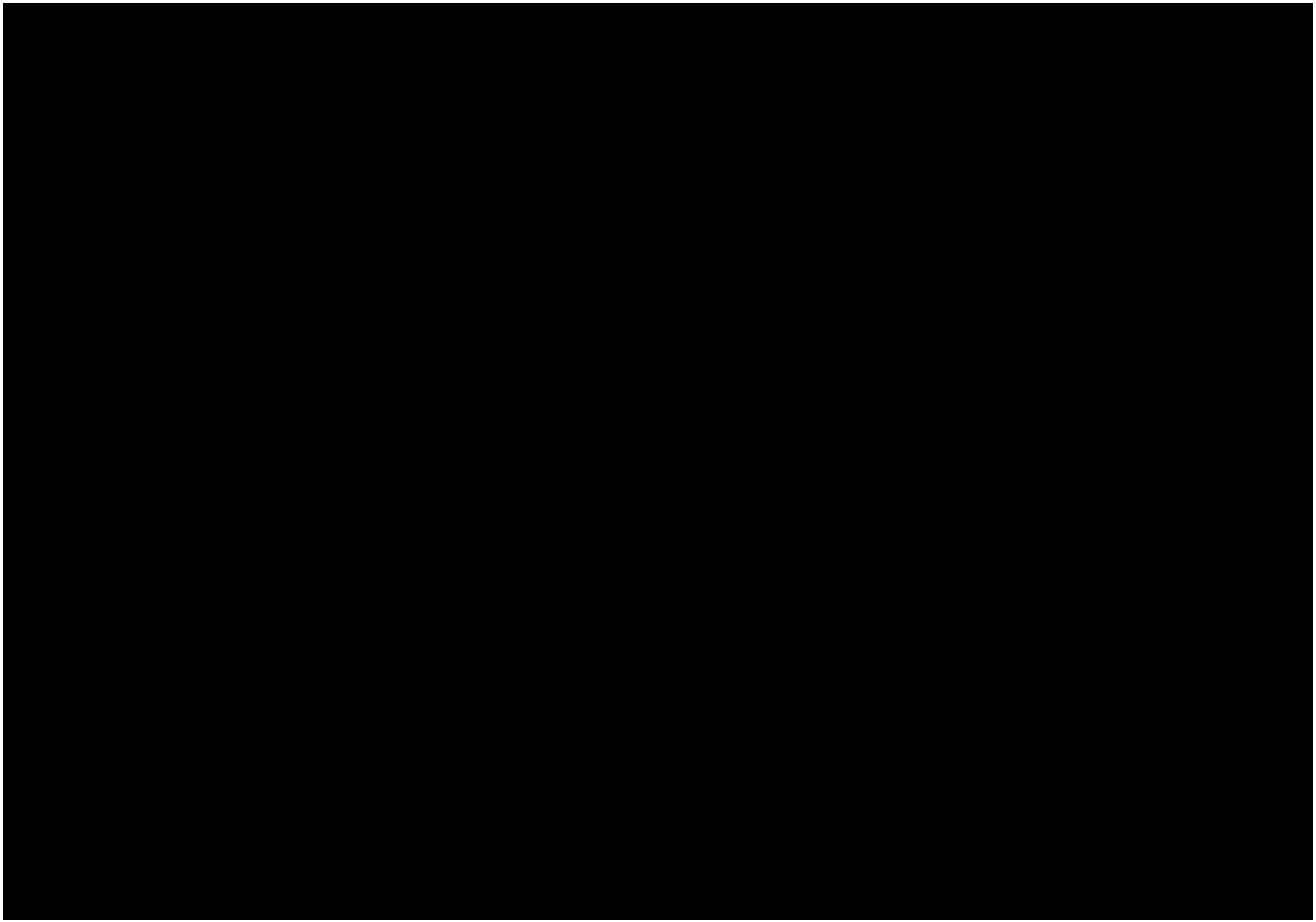
Hourly Average Day for October 2021

Panhandle Rural Electric Membership Association



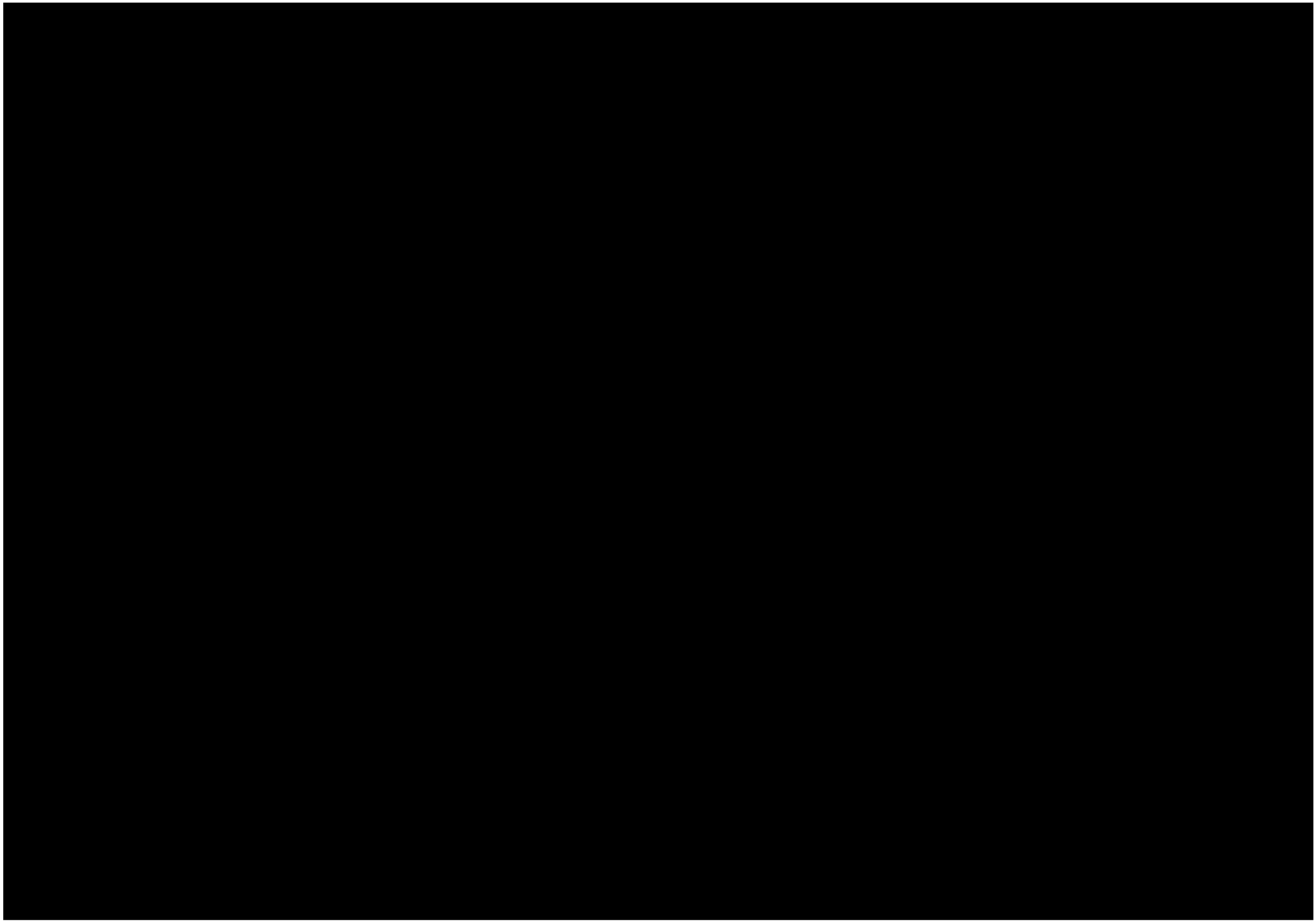
Hourly Average Day for November 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for December 2021

Panhandle Rural Electric Membership Association



Hourly Average Day for January 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Poudre Valley Electric Association, Inc.

[redacted]

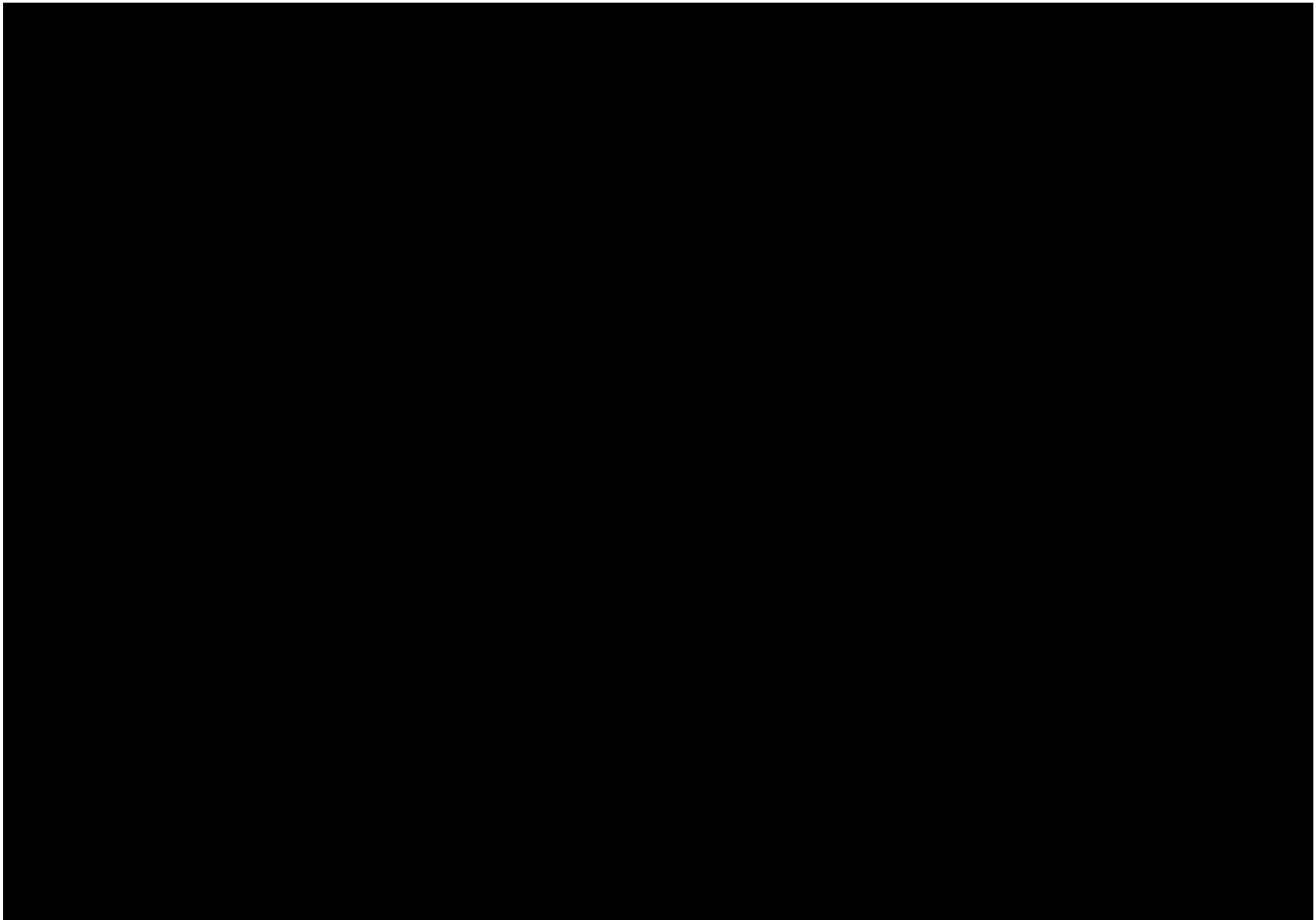
Hourly Average Day for August 2021

Poudre Valley Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Poudre Valley Electric Association, Inc.



Hourly Average Day for October 2021

Poudre Valley Electric Association, Inc.

[redacted]

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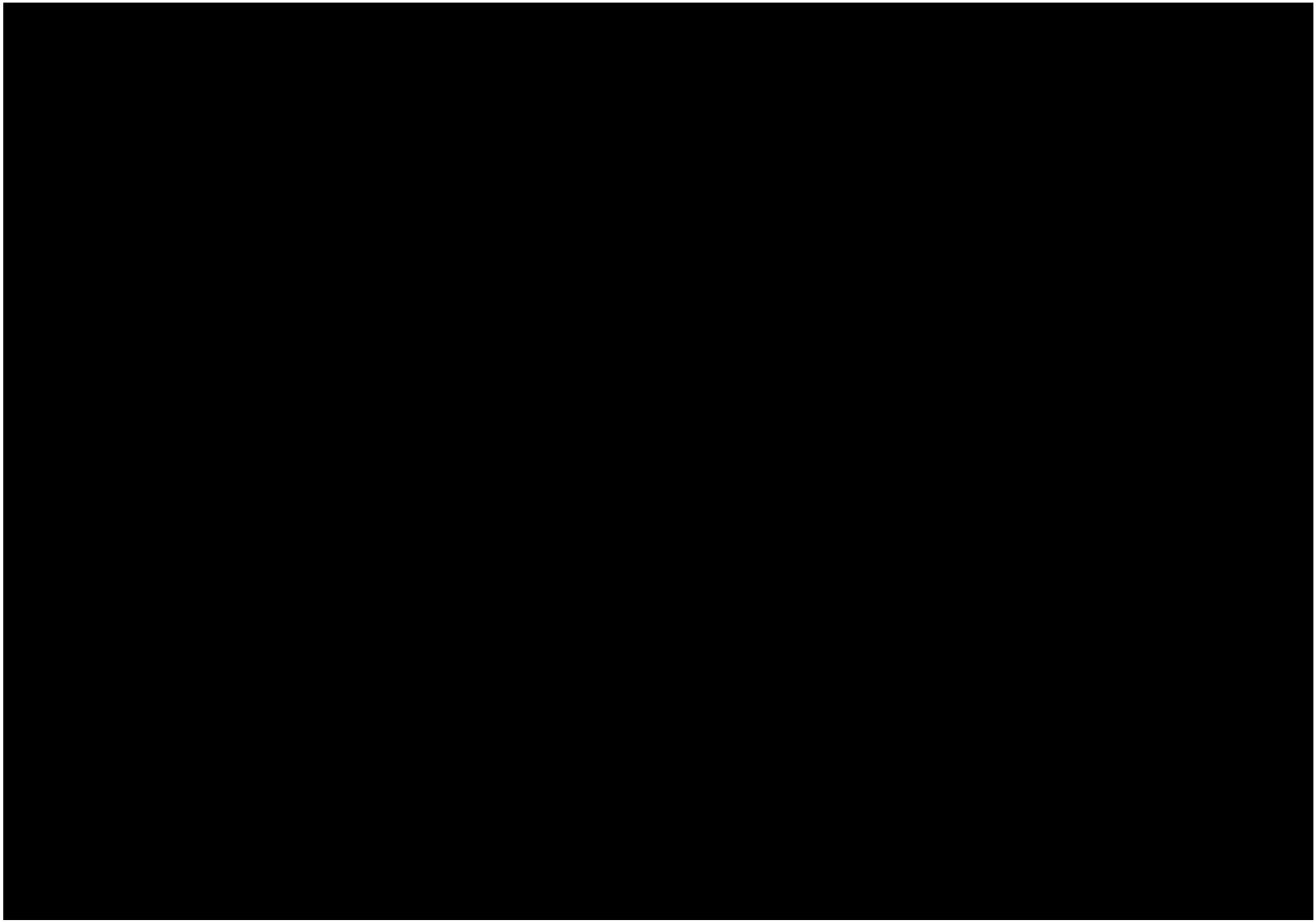
Hourly Average Day for November 2021

Poudre Valley Electric Association, Inc.



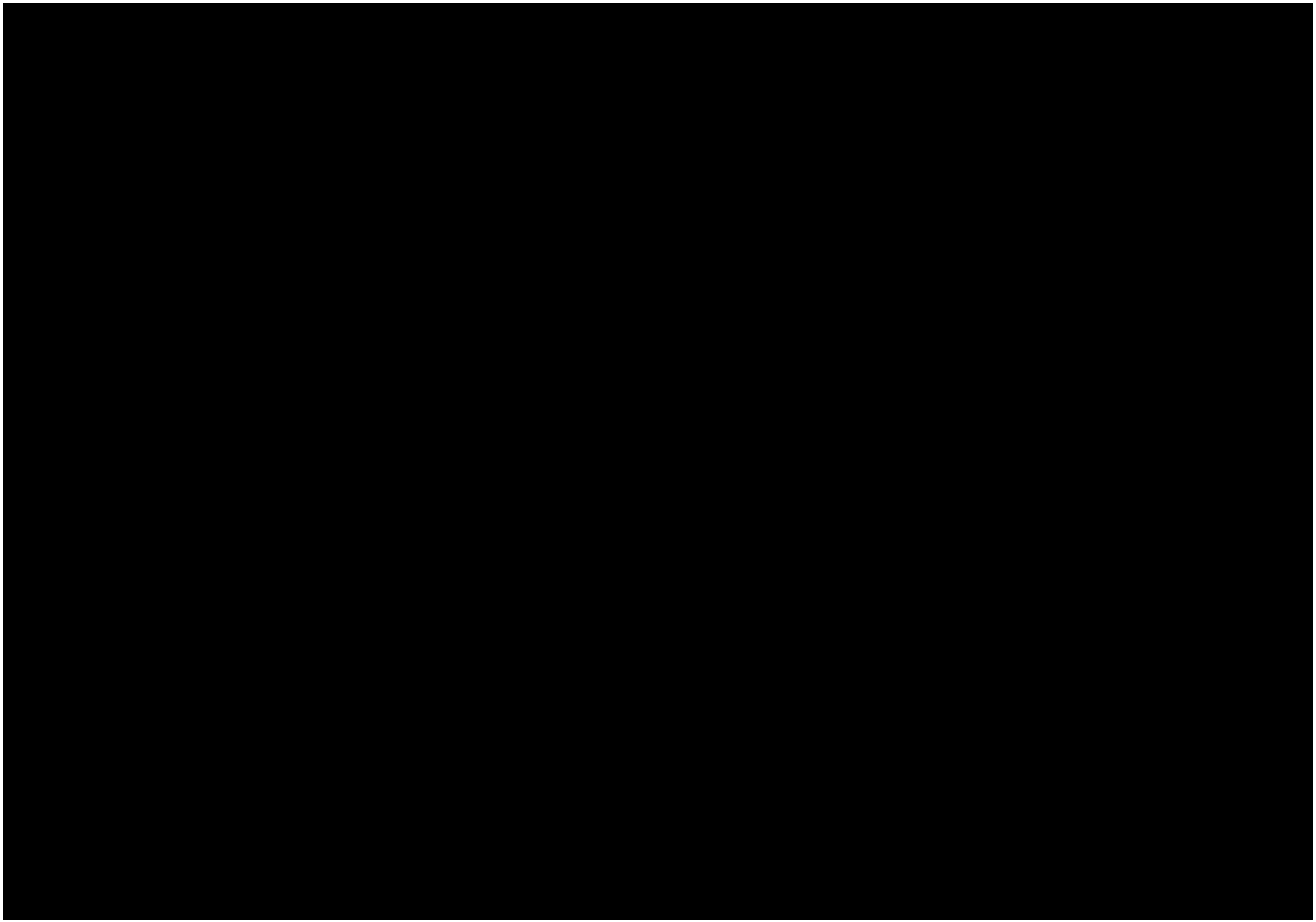
Hourly Average Day for December 2021

Poudre Valley Electric Association, Inc.

[redacted]

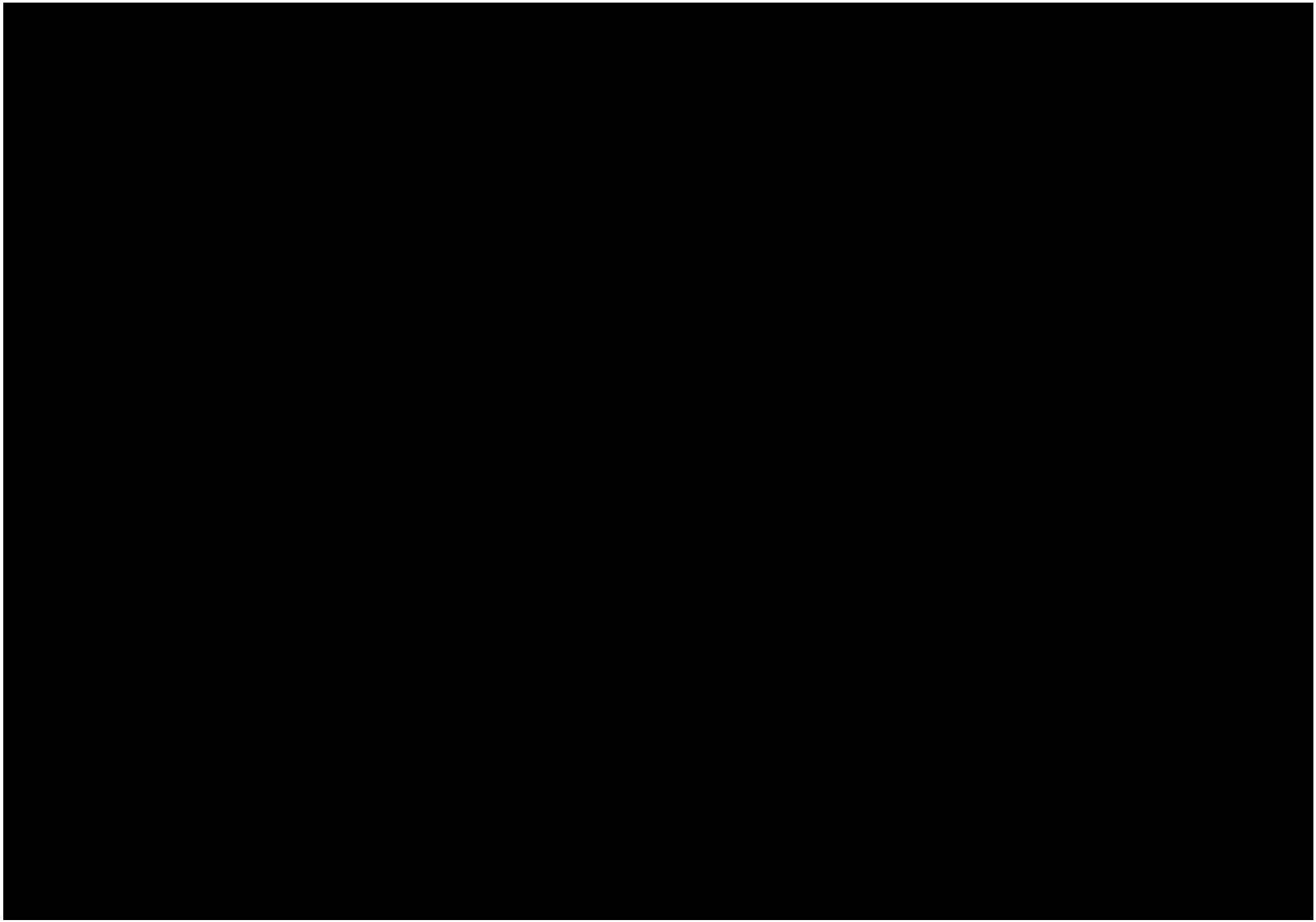
Hourly Average Day for January 2021

Northern Rio Arriba Electric Cooperative, Inc.



Hourly Average Day for February 2021

Northern Rio Arriba Electric Cooperative, Inc.



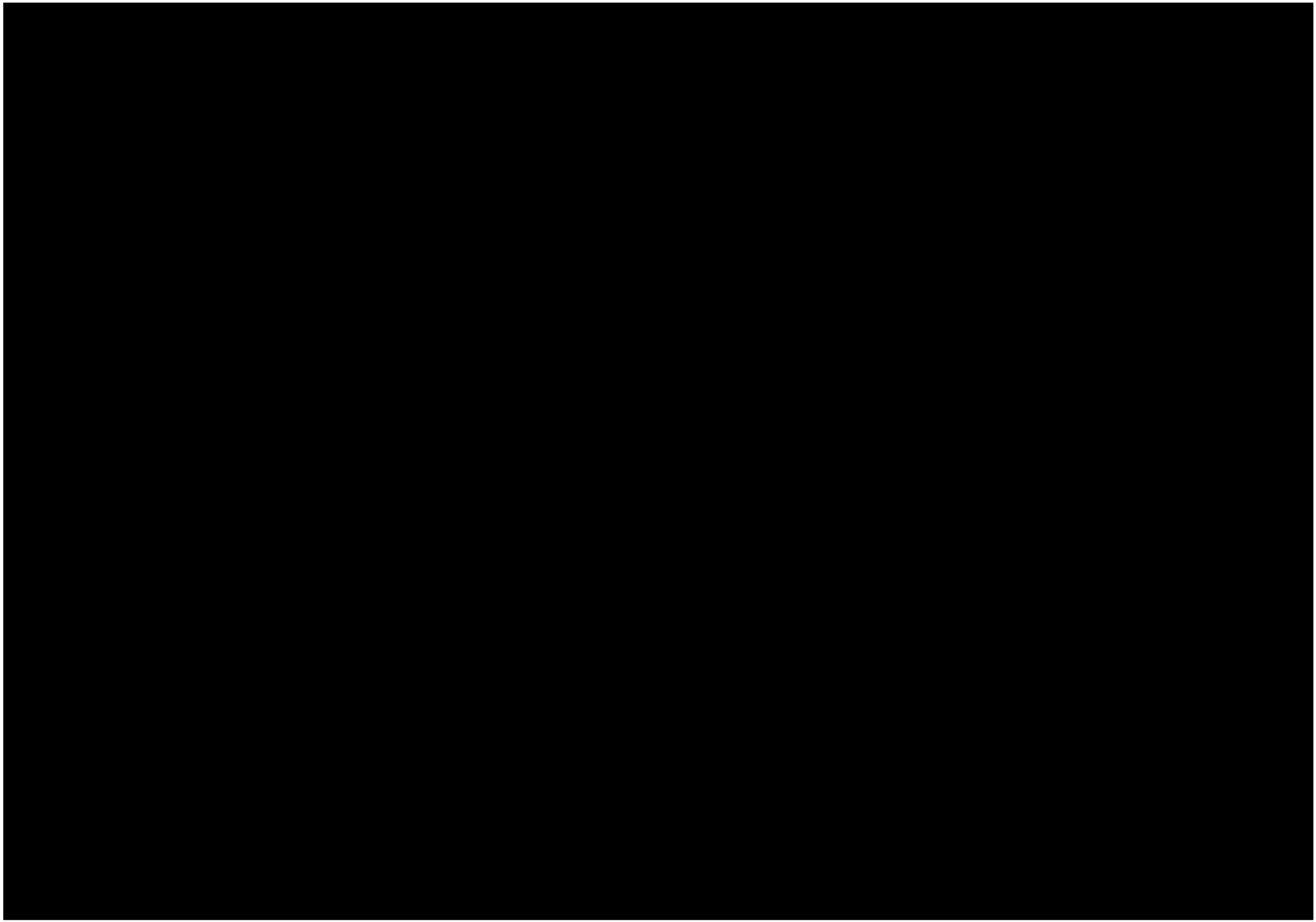
Hourly Average Day for March 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Northern Rio Arriba Electric Cooperative, Inc.



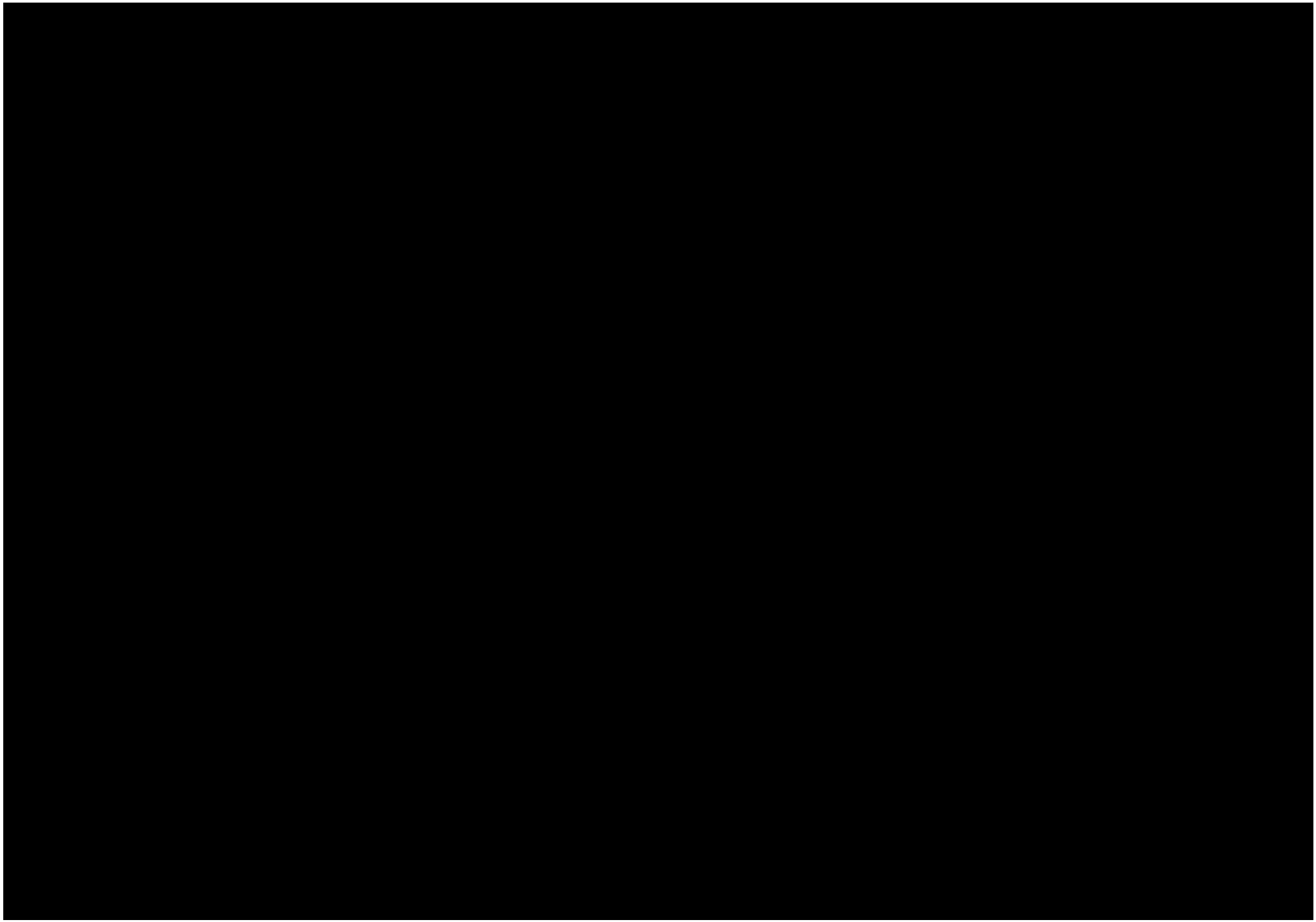
Hourly Average Day for May 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Northern Rio Arriba Electric Cooperative, Inc.



Hourly Average Day for July 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for September 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for November 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

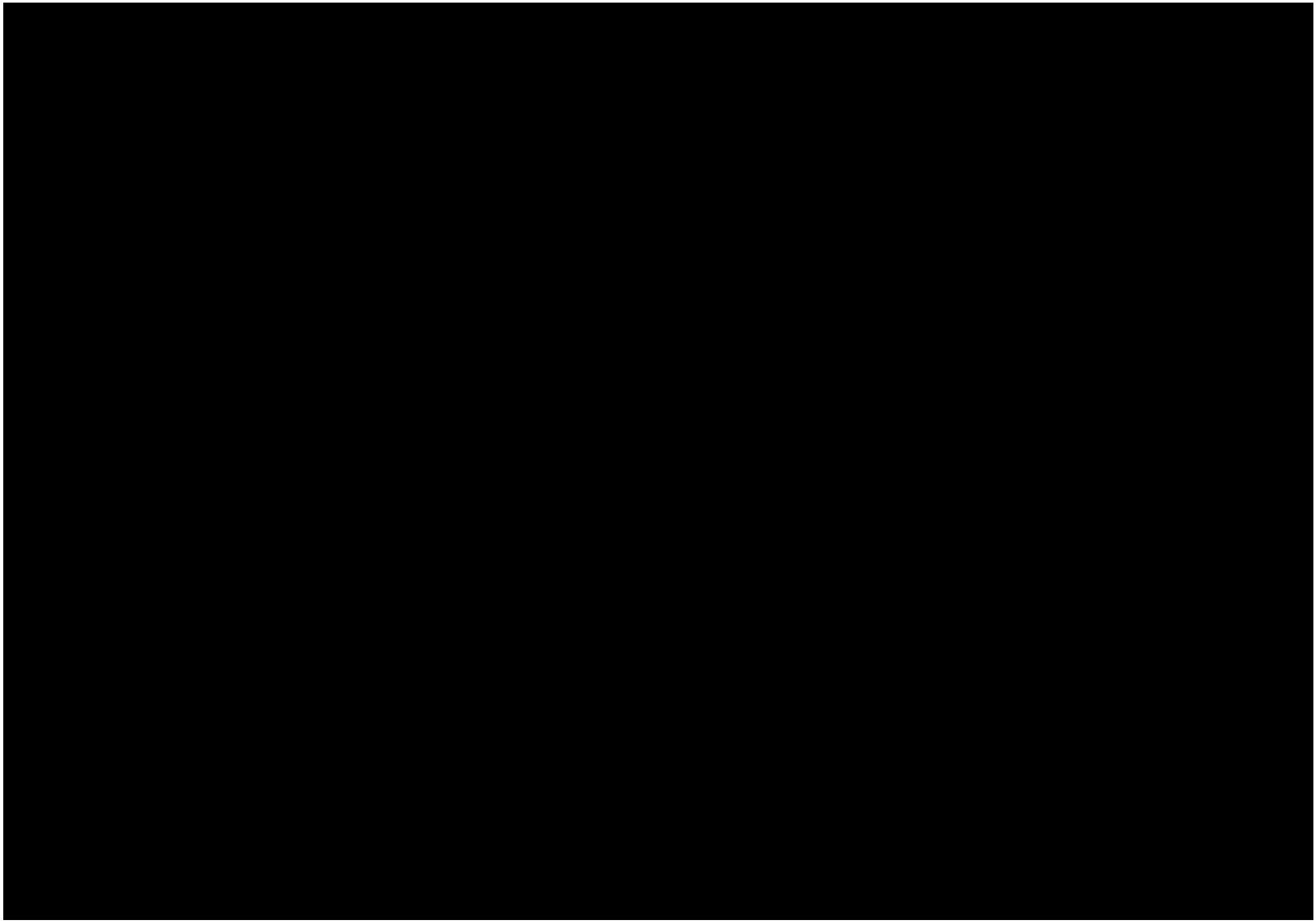
Hourly Average Day for December 2021

Northern Rio Arriba Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Roosevelt Public Power District

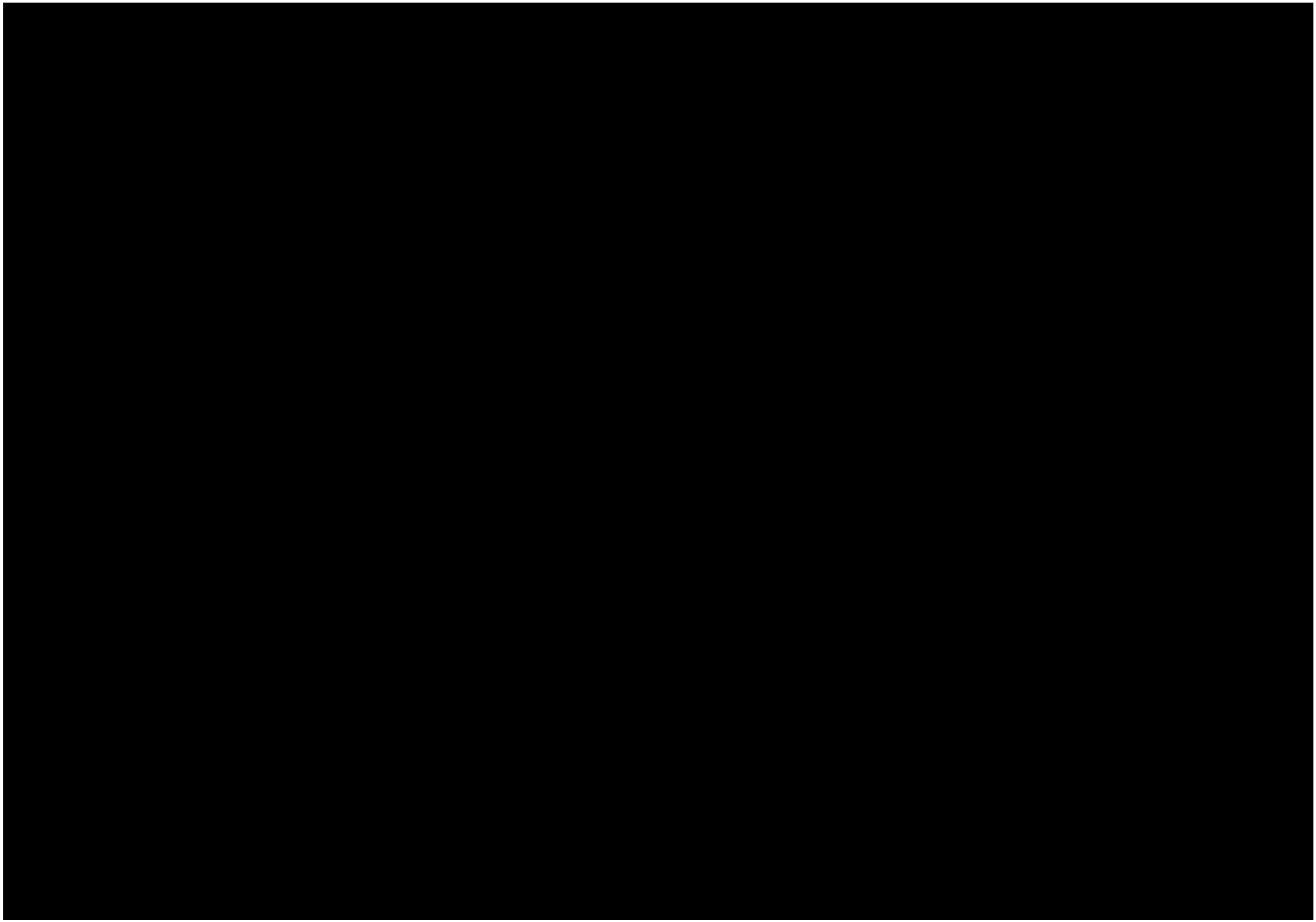


Hourly Average Day for February 2021
Roosevelt Public Power District

[redacted]

Hourly Average Day for March 2021

Roosevelt Public Power District



Hourly Average Day for April 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for May 2021

Roosevelt Public Power District

[redacted]

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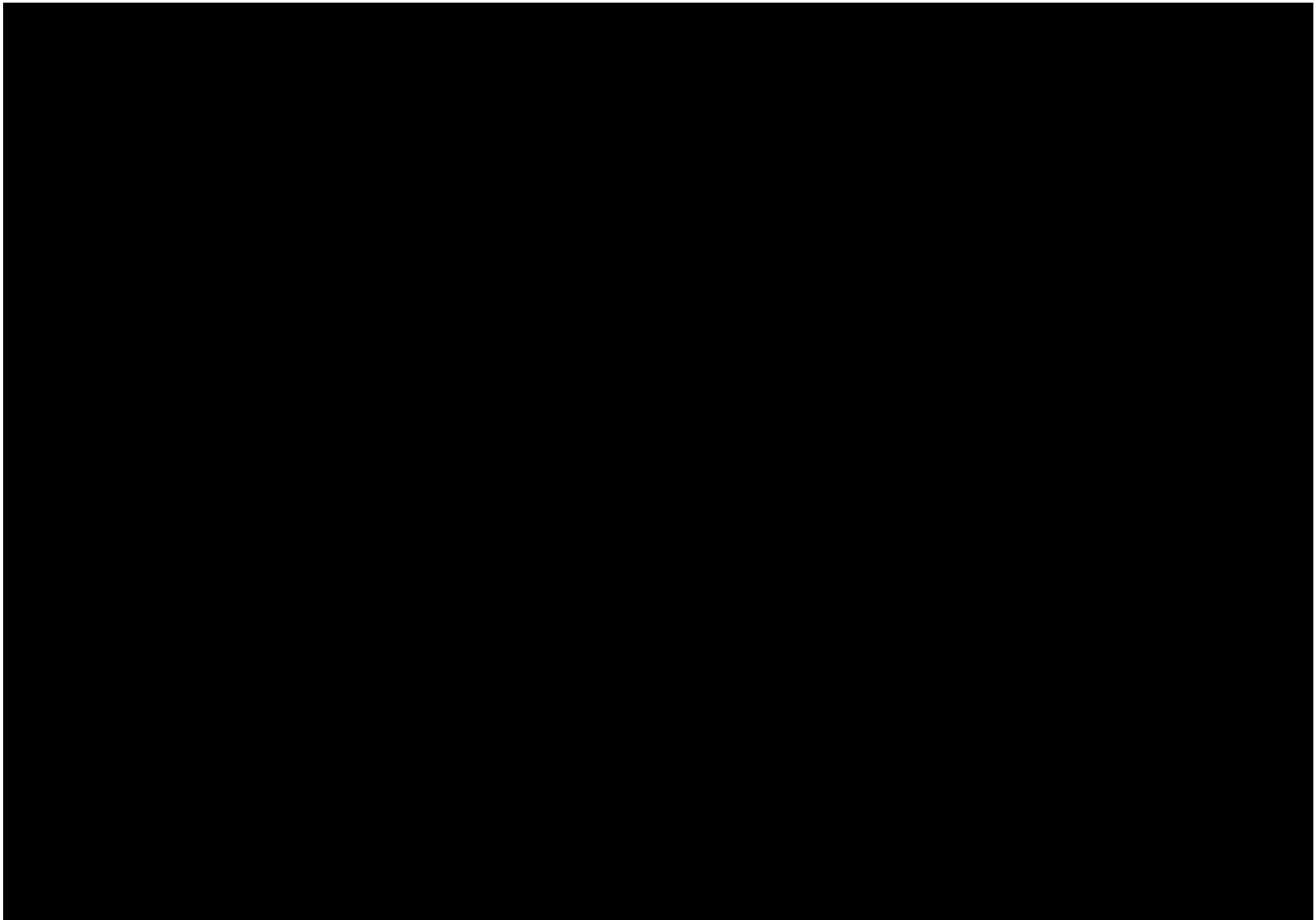
Hourly Average Day for June 2021

Roosevelt Public Power District



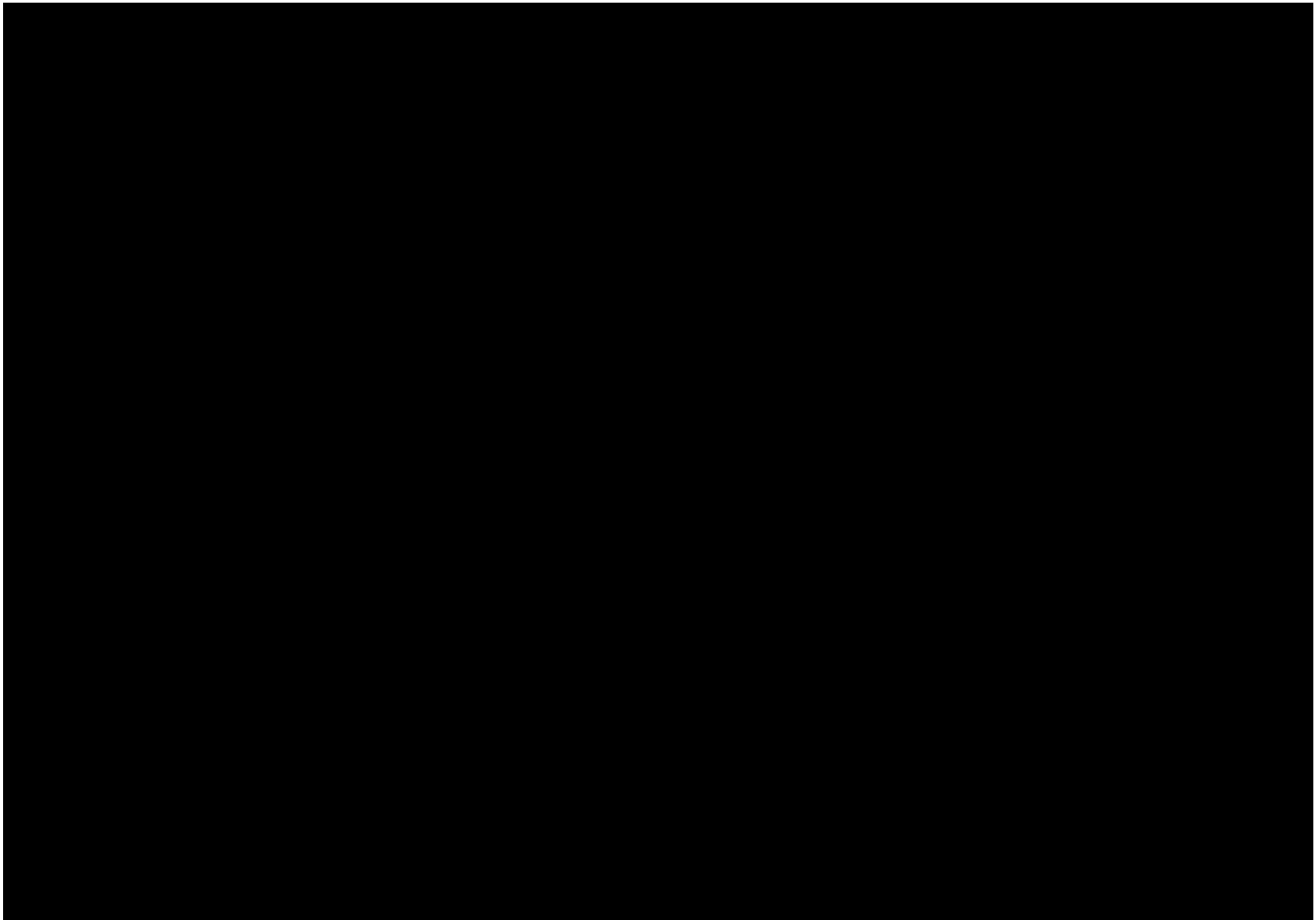
Hourly Average Day for July 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for August 2021

Roosevelt Public Power District



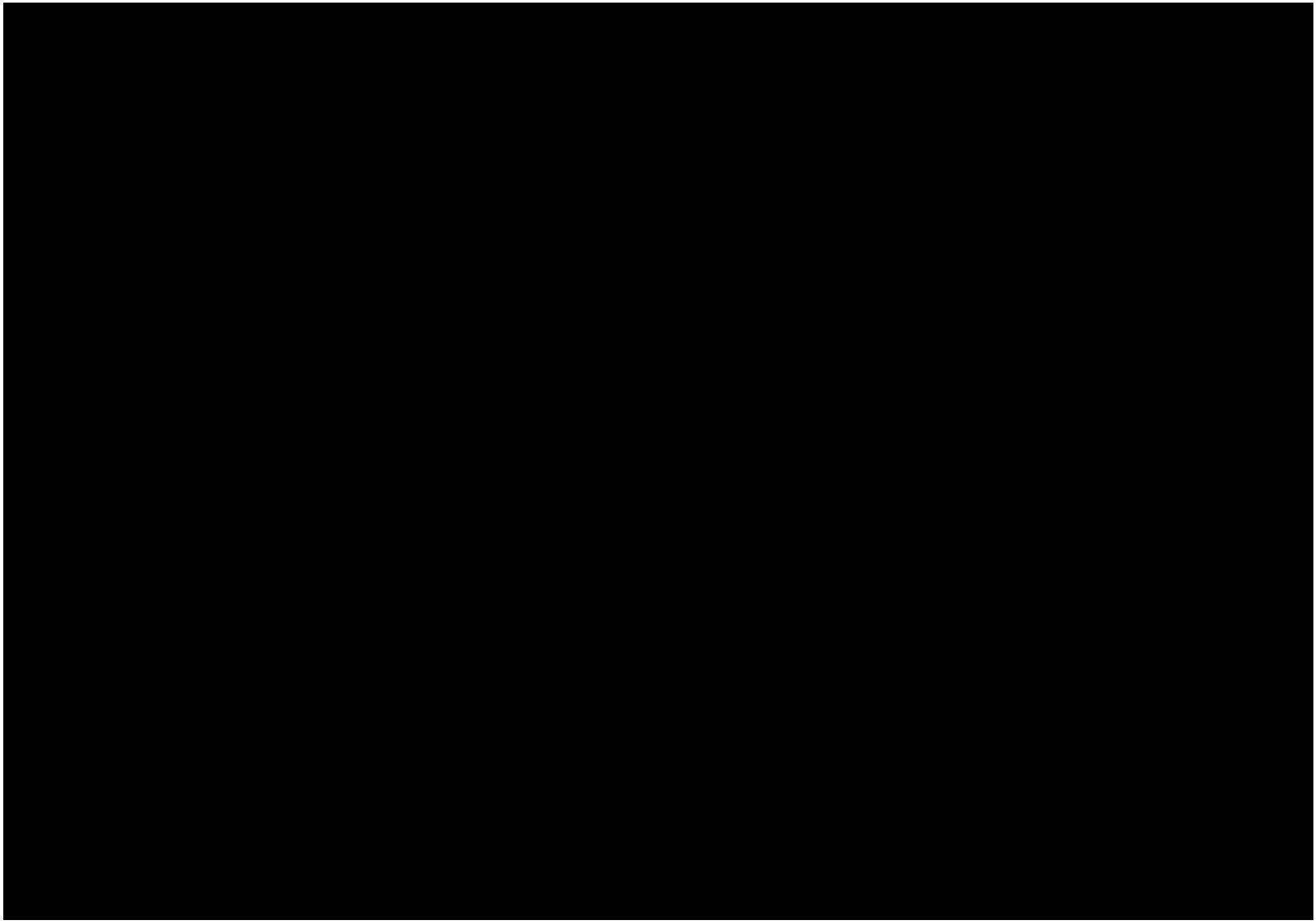
Hourly Average Day for September 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for October 2021

Roosevelt Public Power District



Hourly Average Day for November 2021

Roosevelt Public Power District

[redacted]

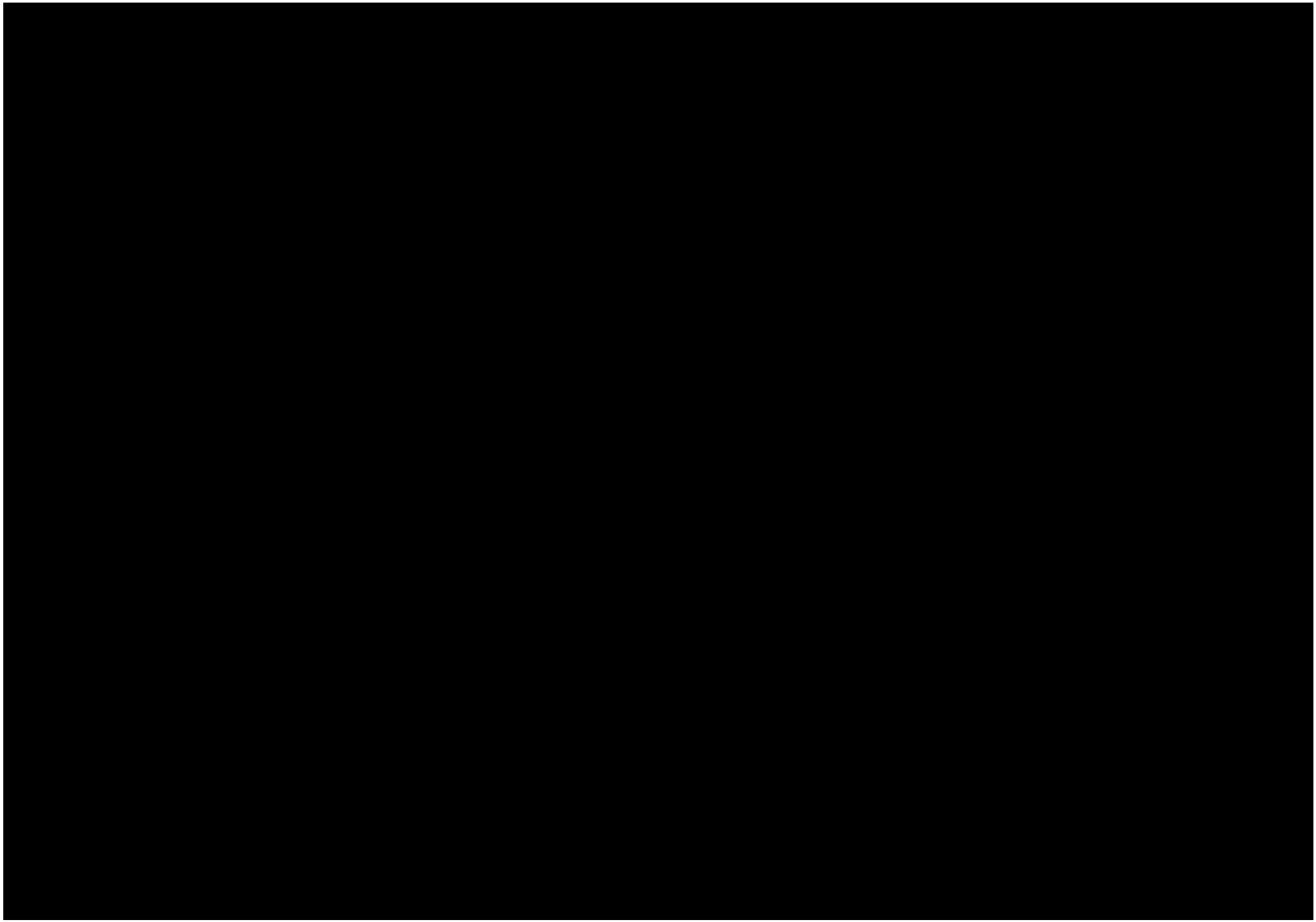
Hourly Average Day for December 2021

Roosevelt Public Power District

[redacted]

Hourly Average Day for January 2021

Sierra Electric Cooperative, Inc.



Hourly Average Day for February 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Sierra Electric Cooperative, Inc.

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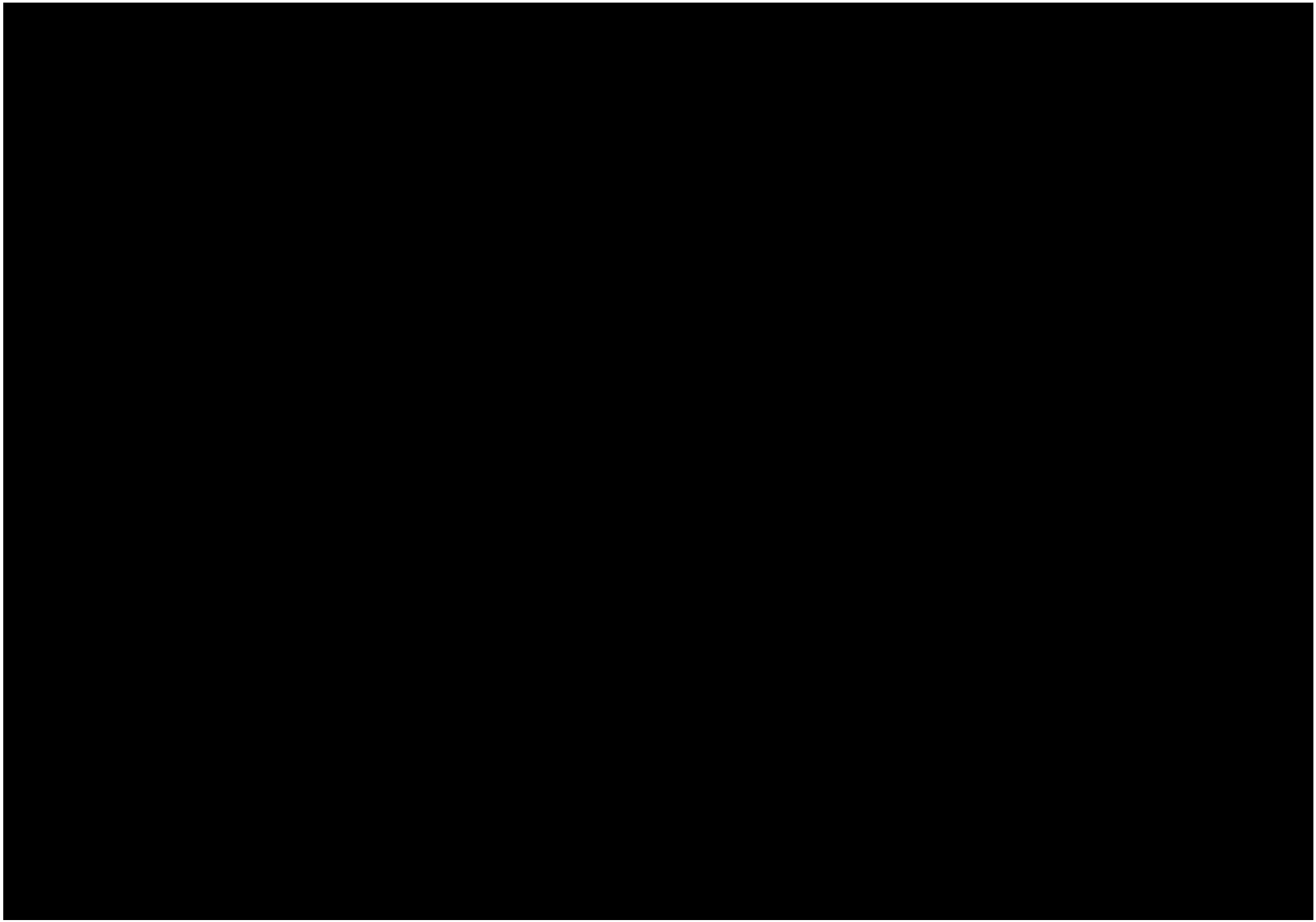
Hourly Average Day for September 2021

Sierra Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Sierra Electric Cooperative, Inc.



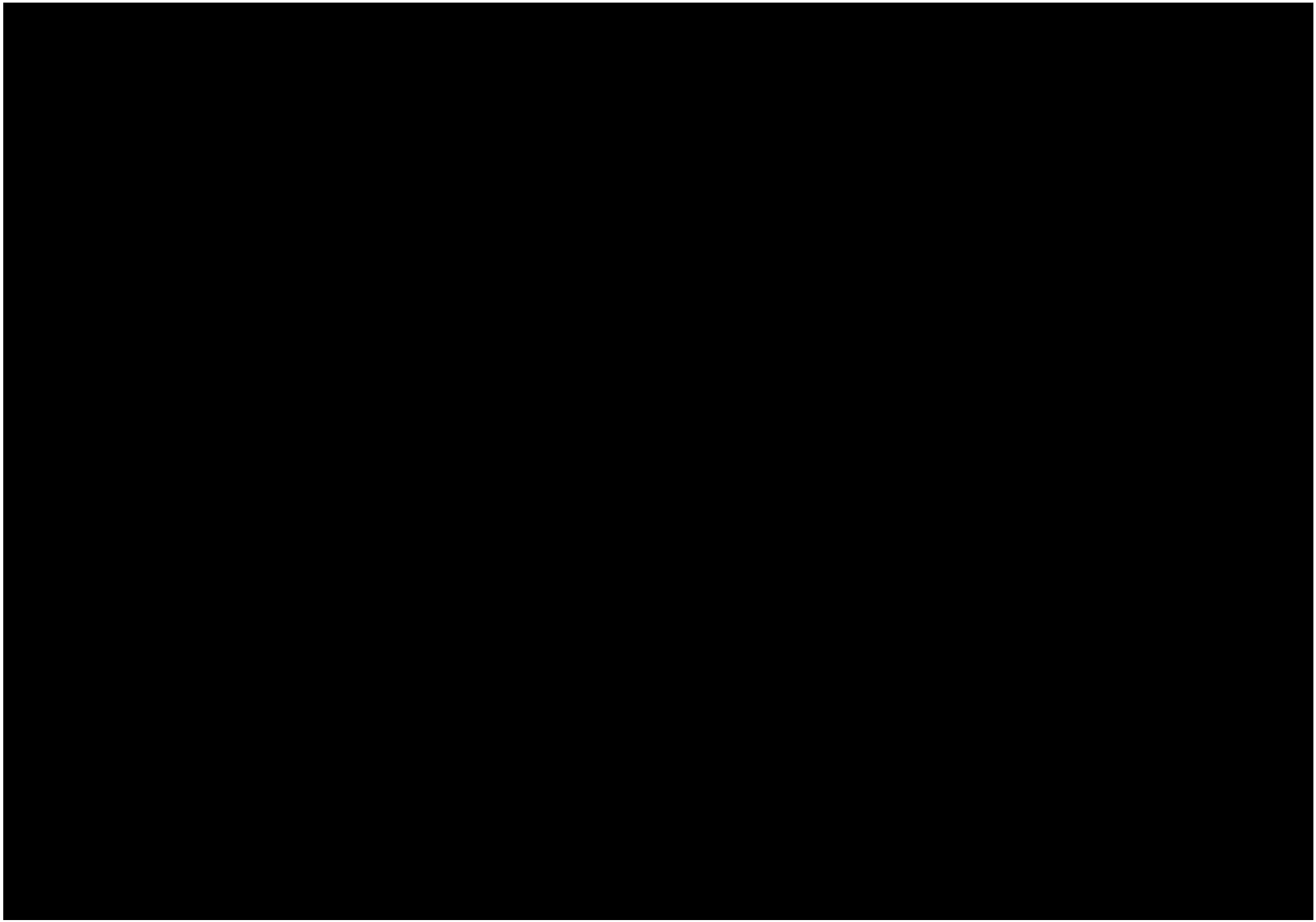
Hourly Average Day for November 2021

Sierra Electric Cooperative, Inc.

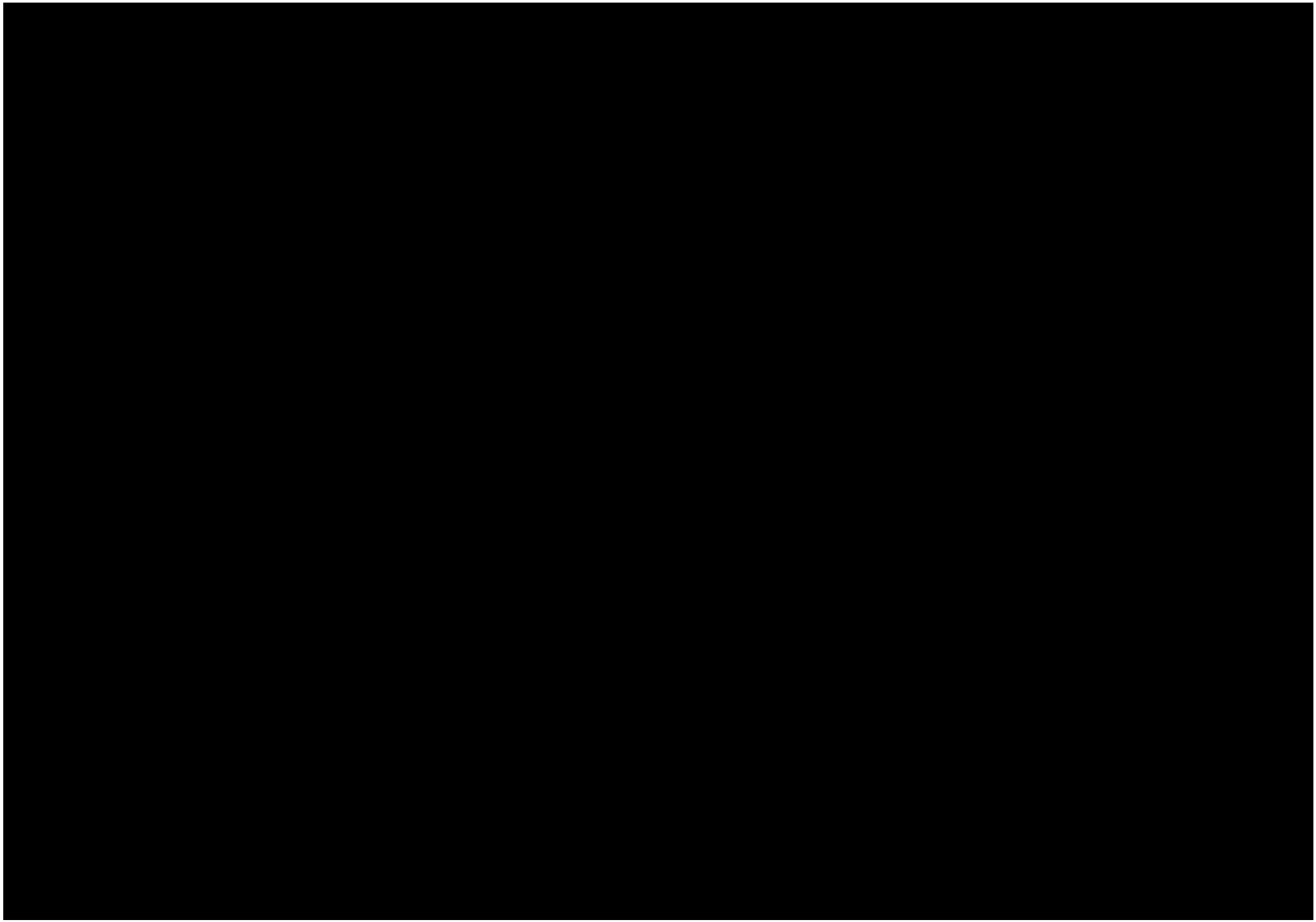
[redacted]

Hourly Average Day for December 2021

Sierra Electric Cooperative, Inc.



Hourly Average Day for January 2021
Sangre de Cristo Electric Association, Inc.



Hourly Average Day for February 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021
Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

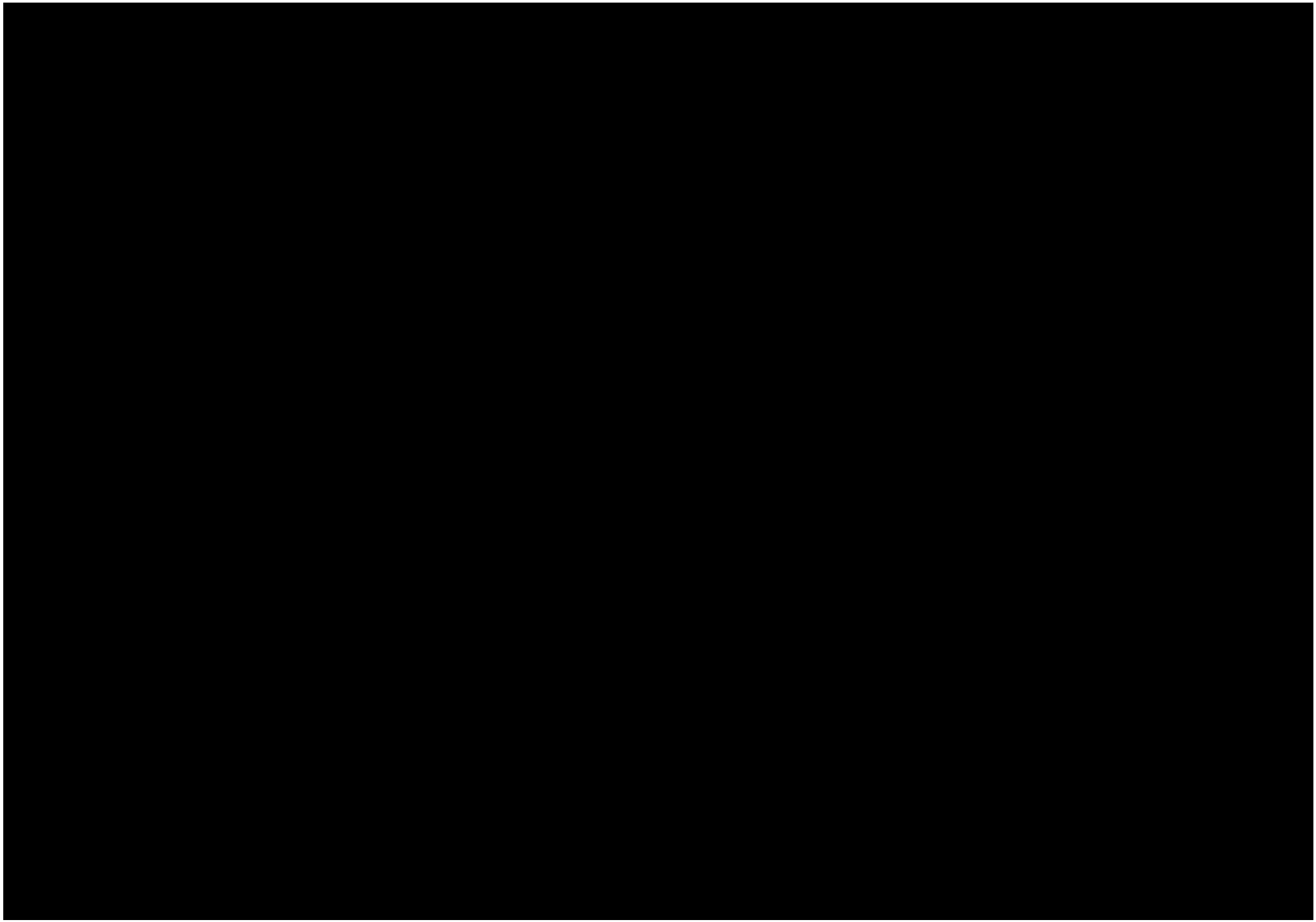
Hourly Average Day for December 2021

Sangre de Cristo Electric Association, Inc.

[redacted]

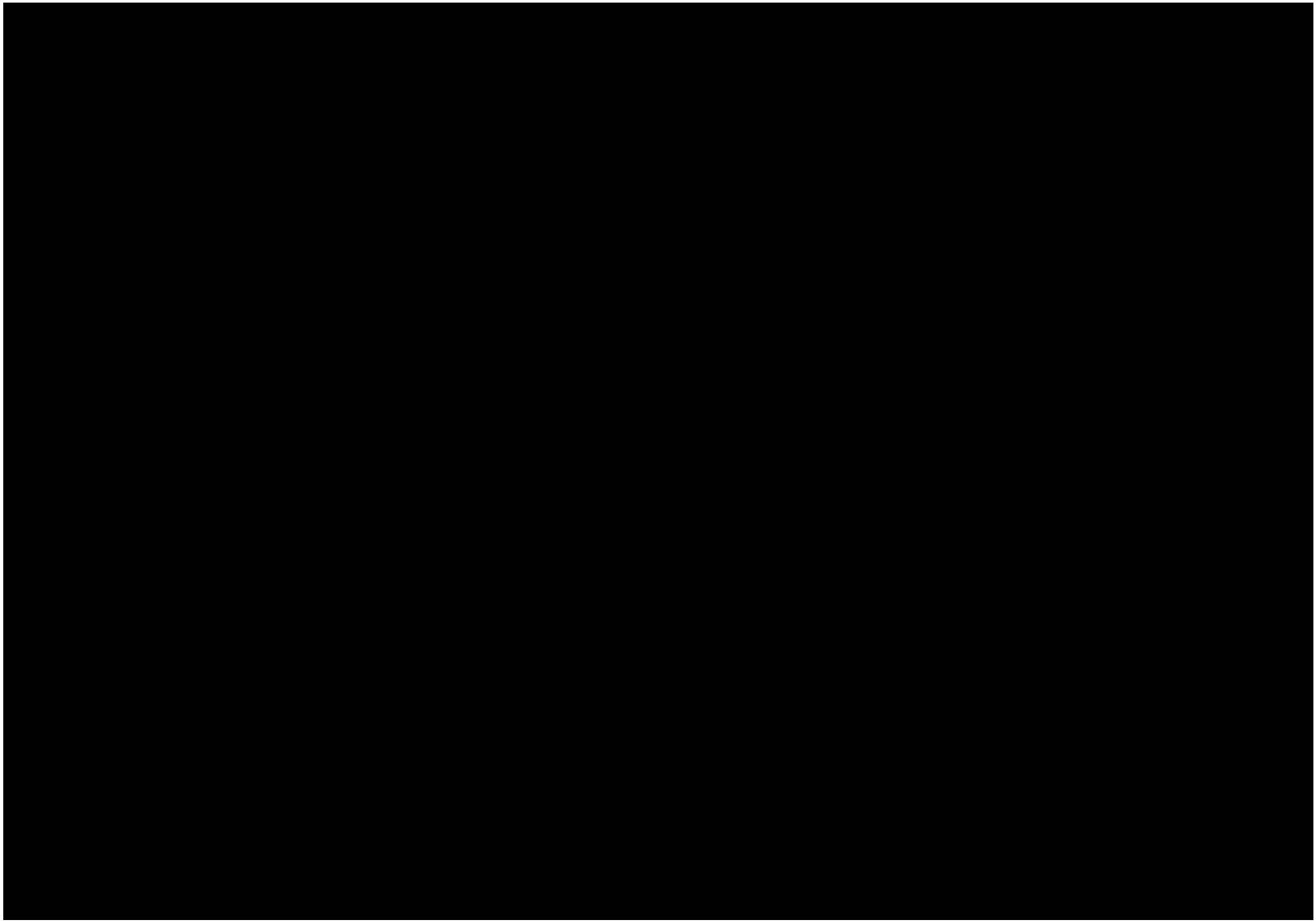
Hourly Average Day for January 2021

Southeast Colorado Power Association

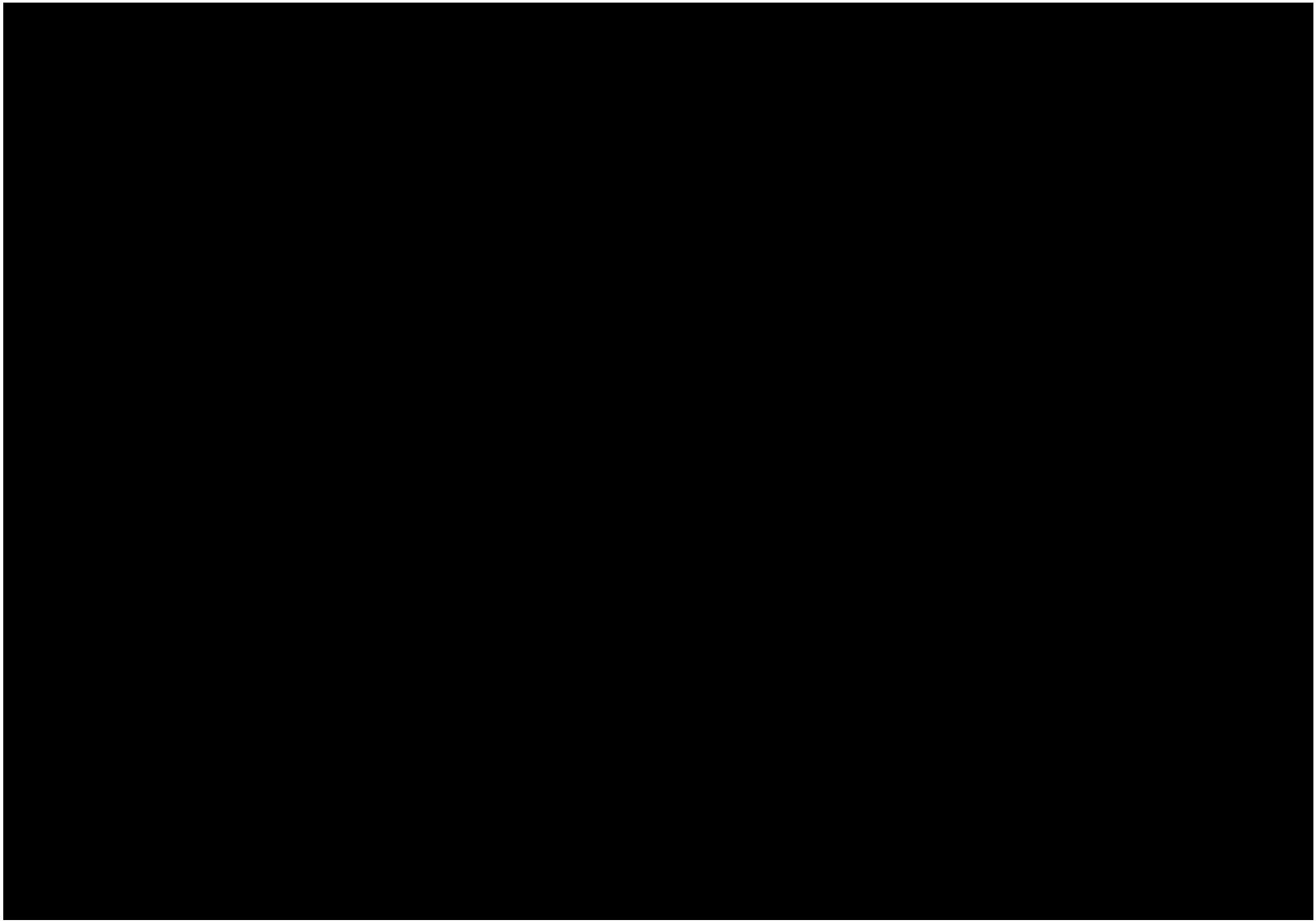


Hourly Average Day for February 2021

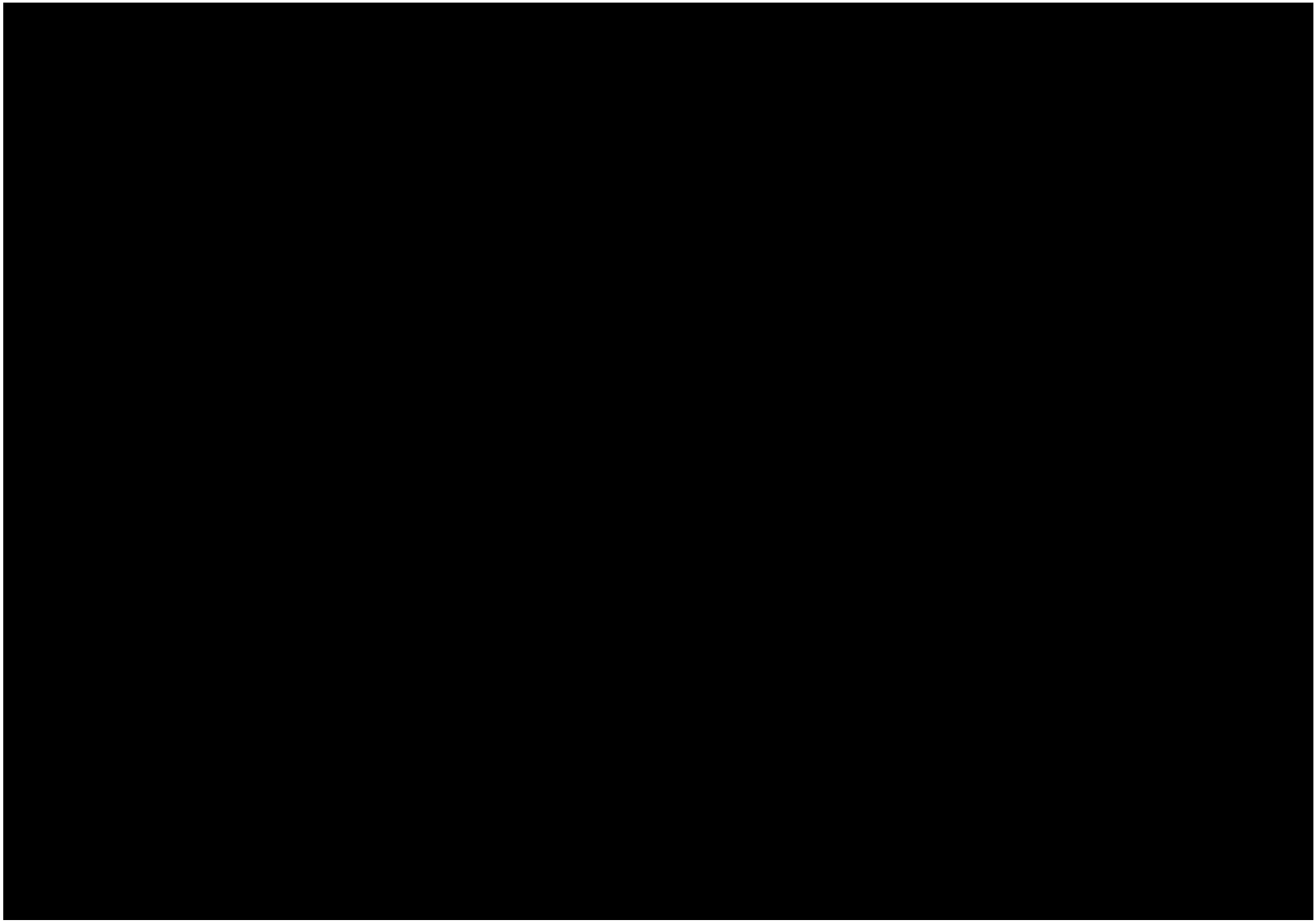
Southeast Colorado Power Association



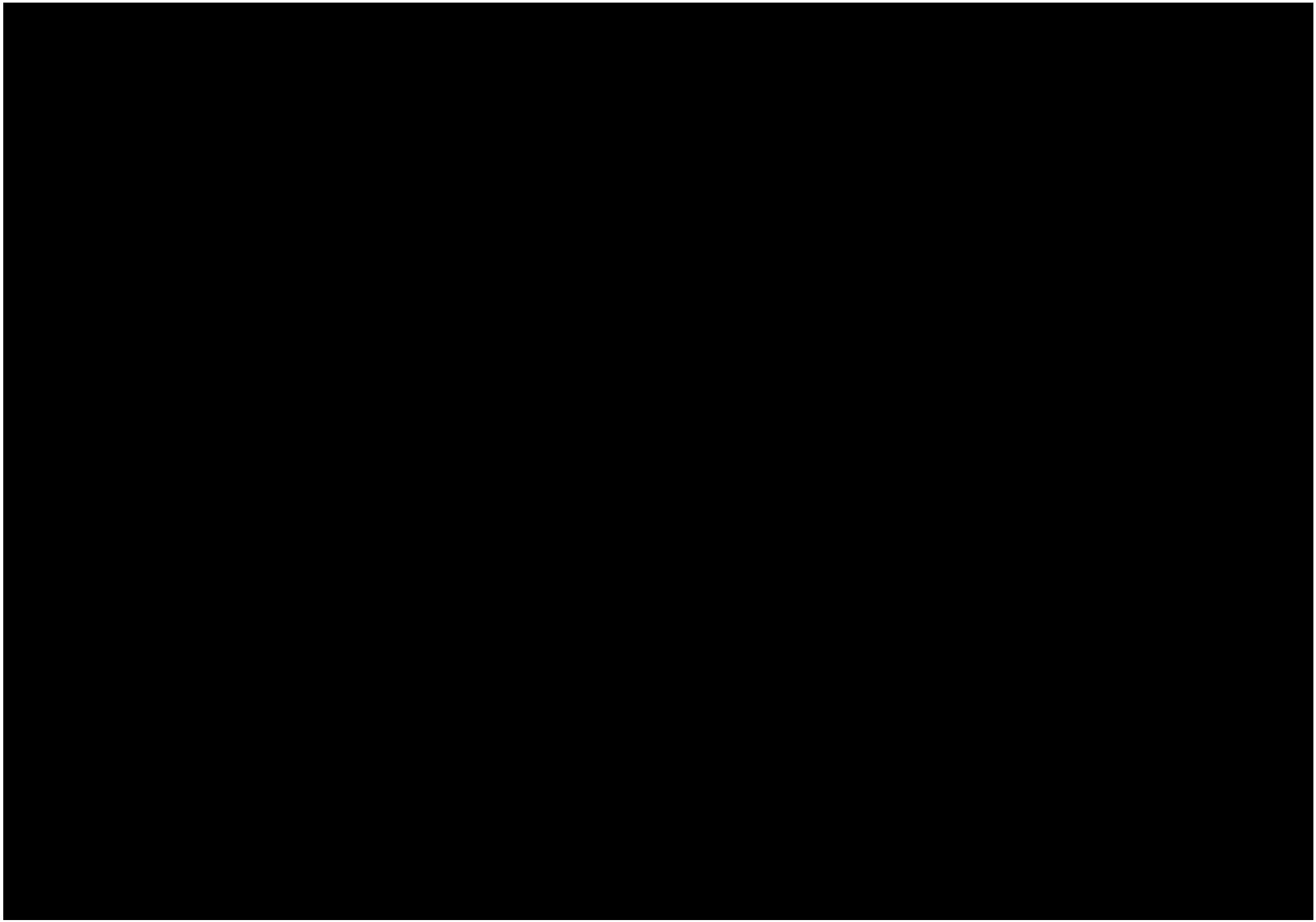
Hourly Average Day for March 2021
Southeast Colorado Power Association



Hourly Average Day for April 2021
Southeast Colorado Power Association



Hourly Average Day for May 2021
Southeast Colorado Power Association



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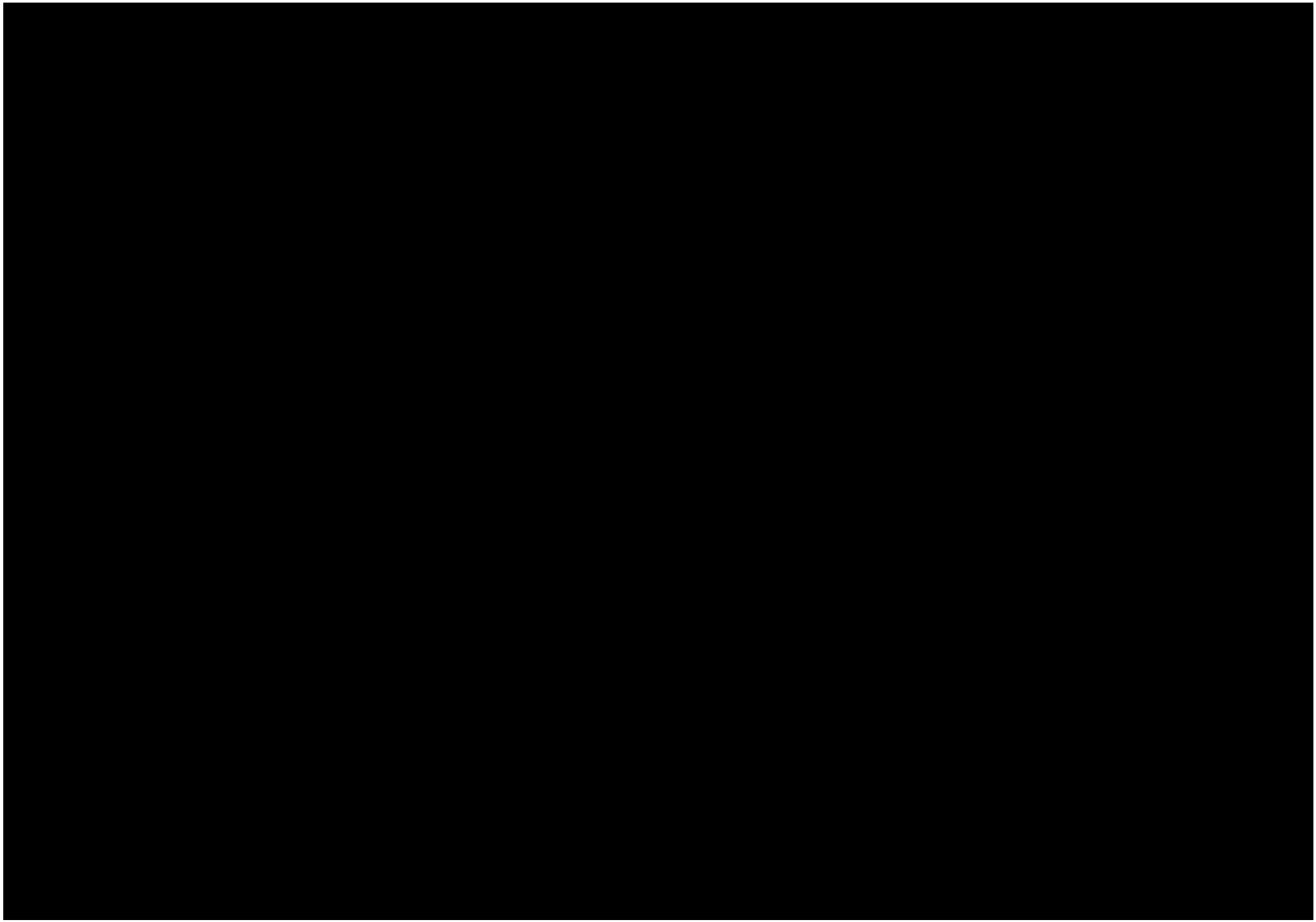
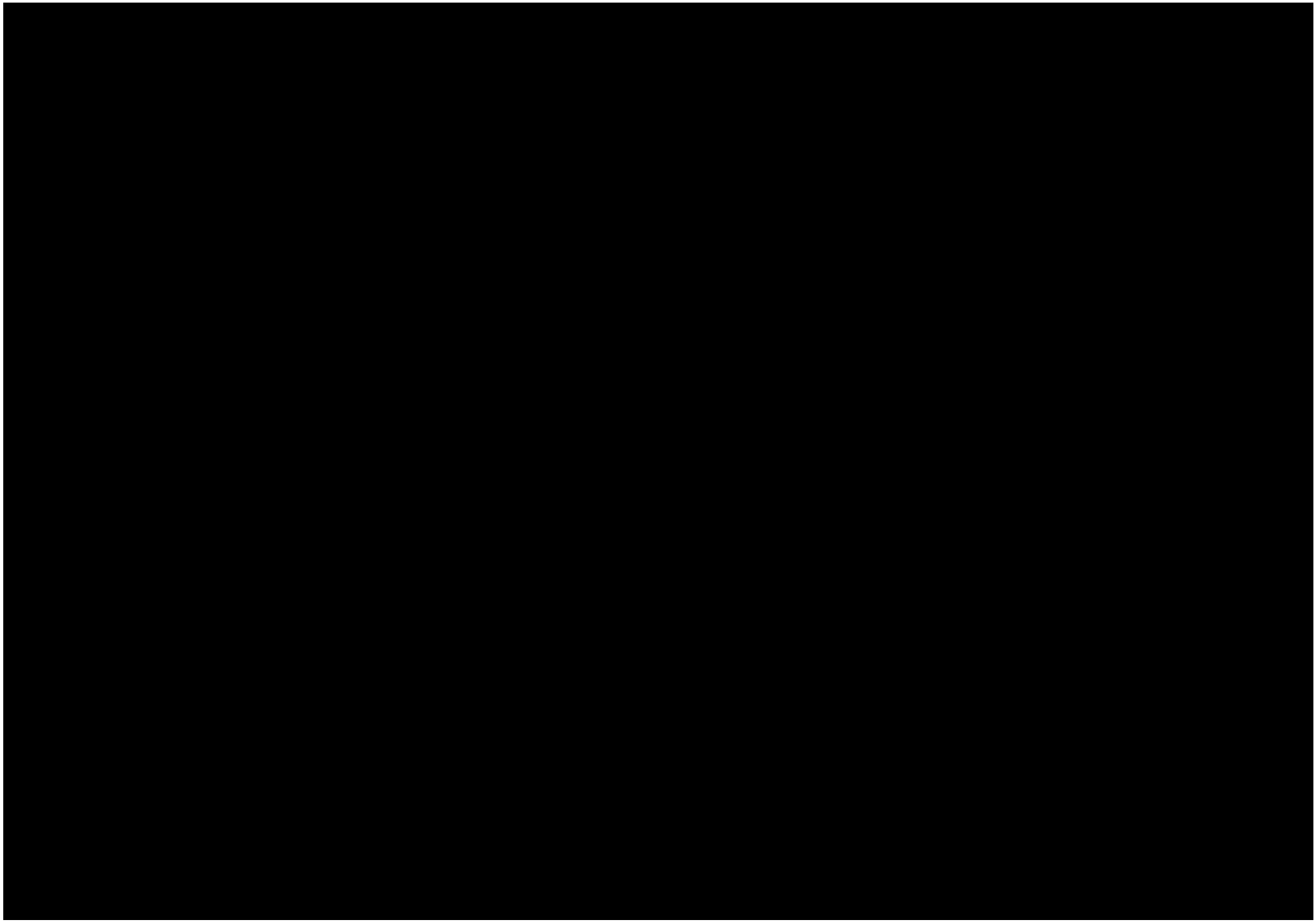
Hourly Average Day for June 2021

Southeast Colorado Power Association

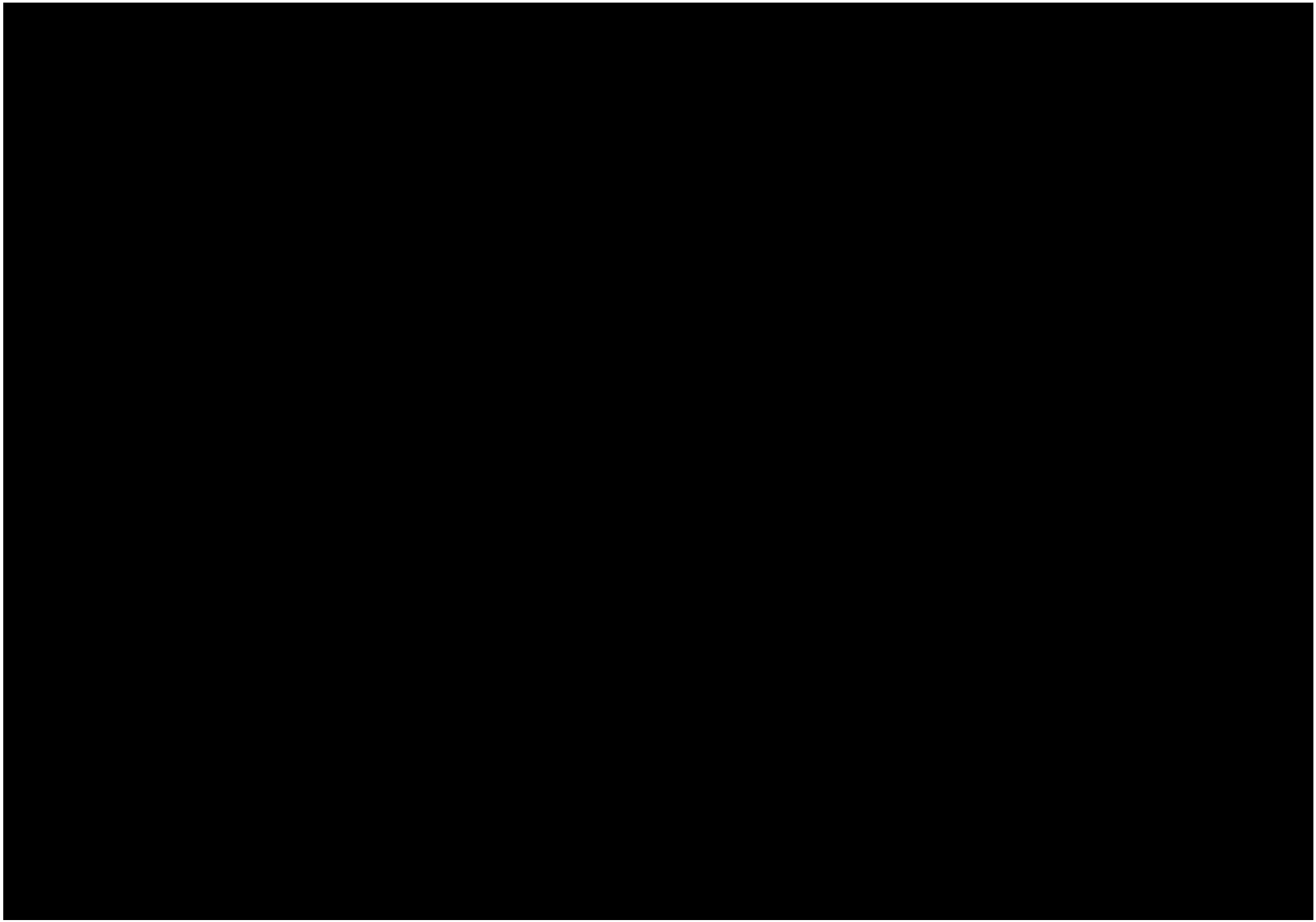


Hourly Average Day for July 2021
Southeast Colorado Power Association



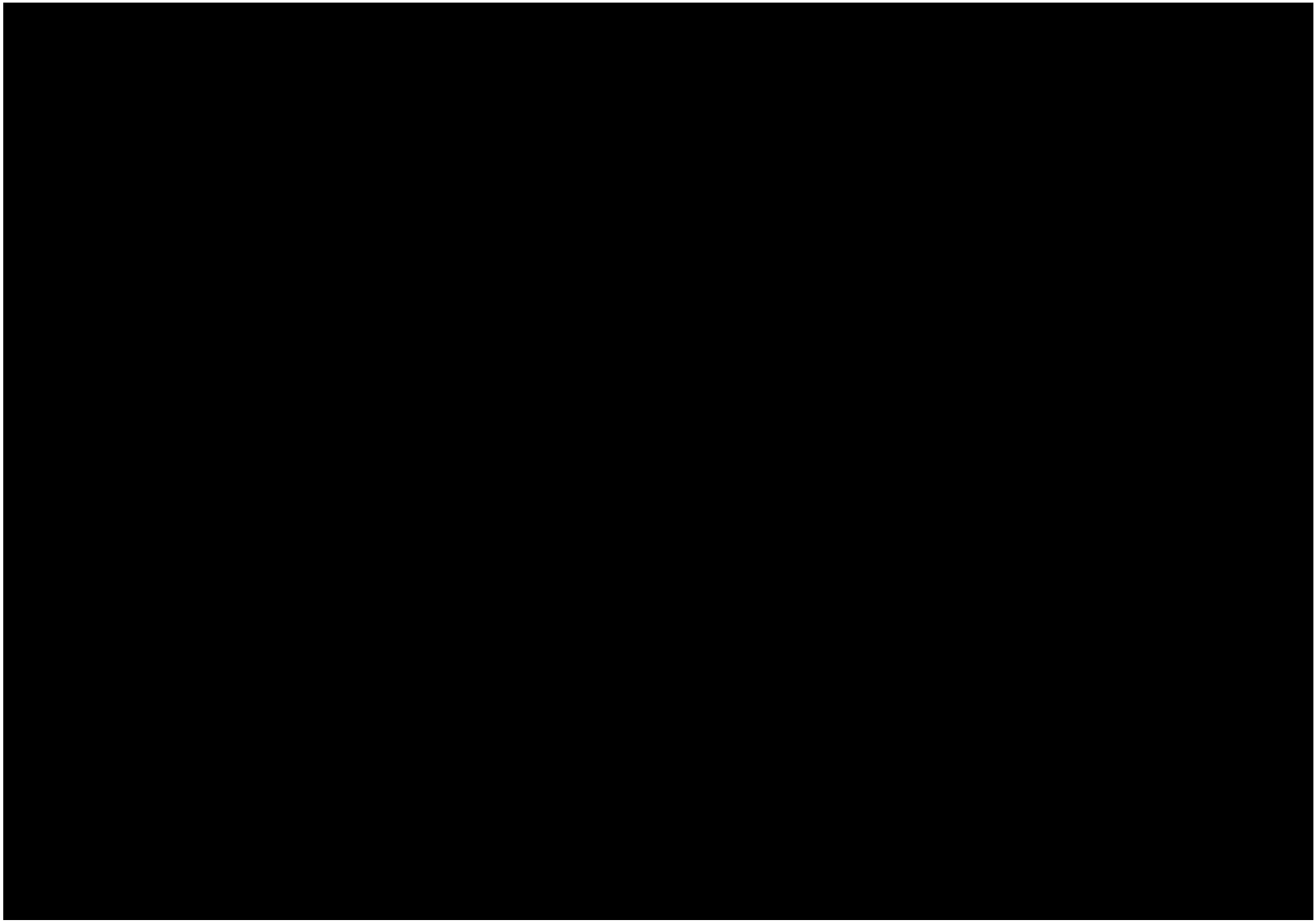
Hourly Average Day for August 2021

Southeast Colorado Power Association



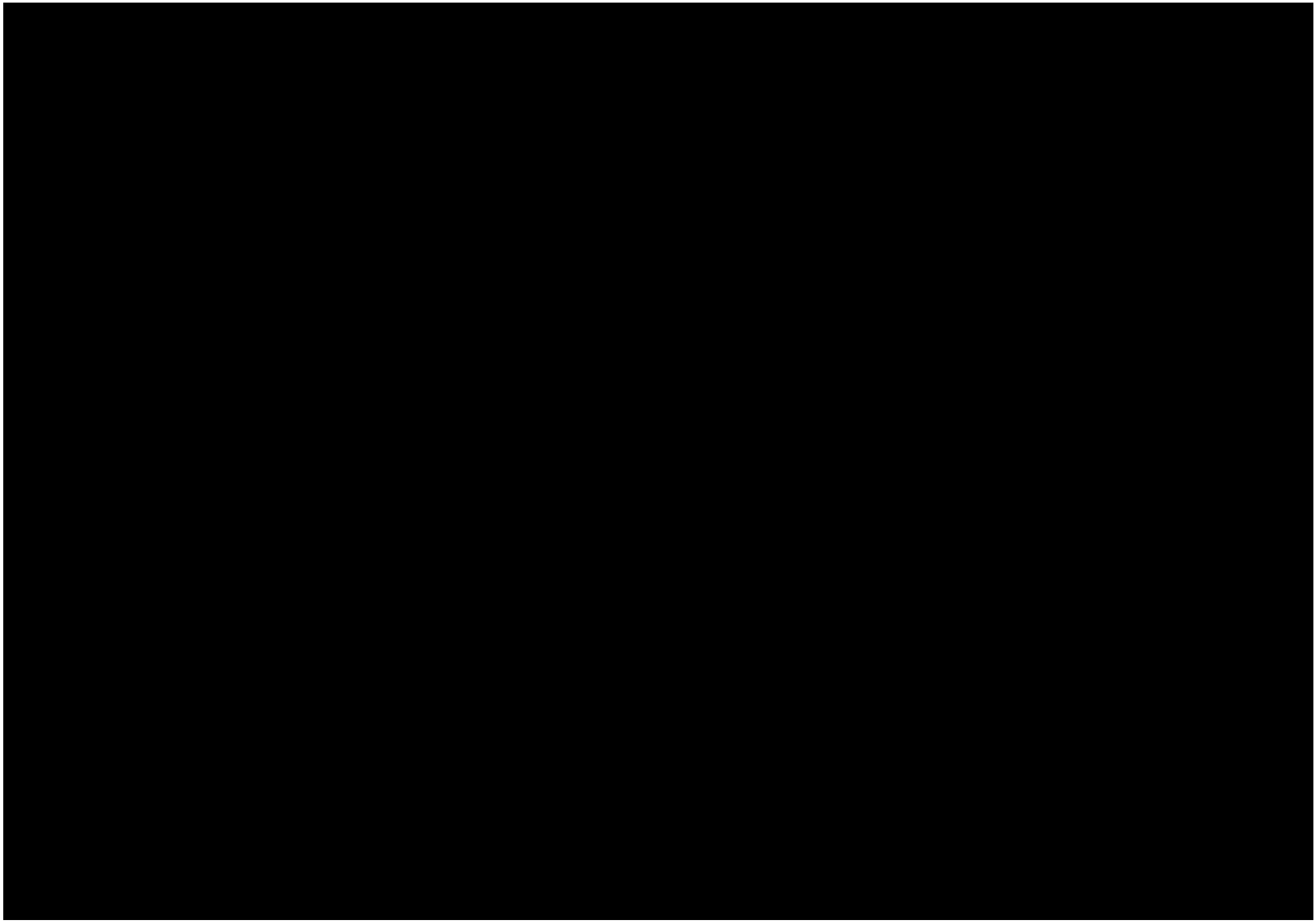
Hourly Average Day for September 2021

Southeast Colorado Power Association

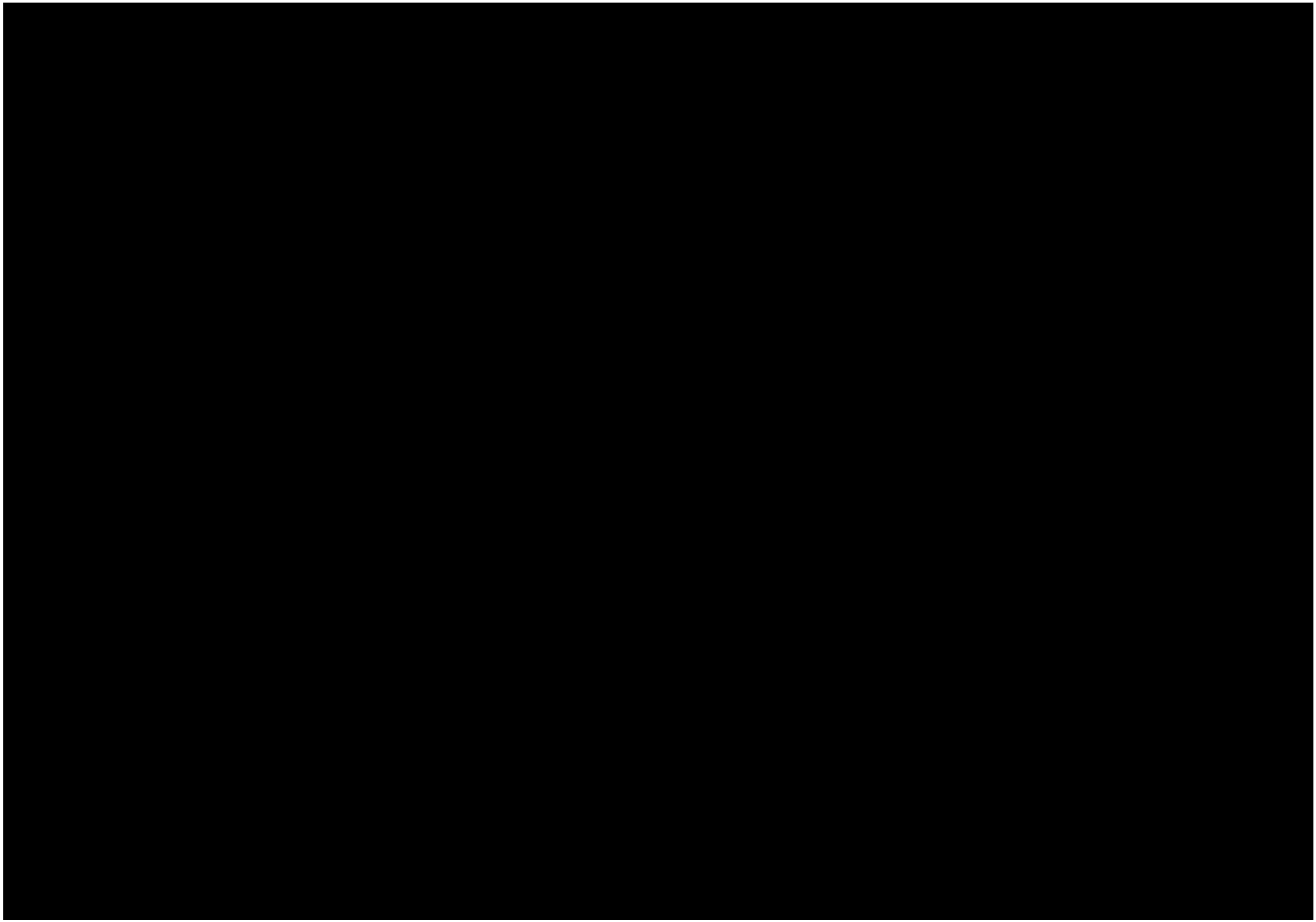


Hourly Average Day for October 2021

Southeast Colorado Power Association

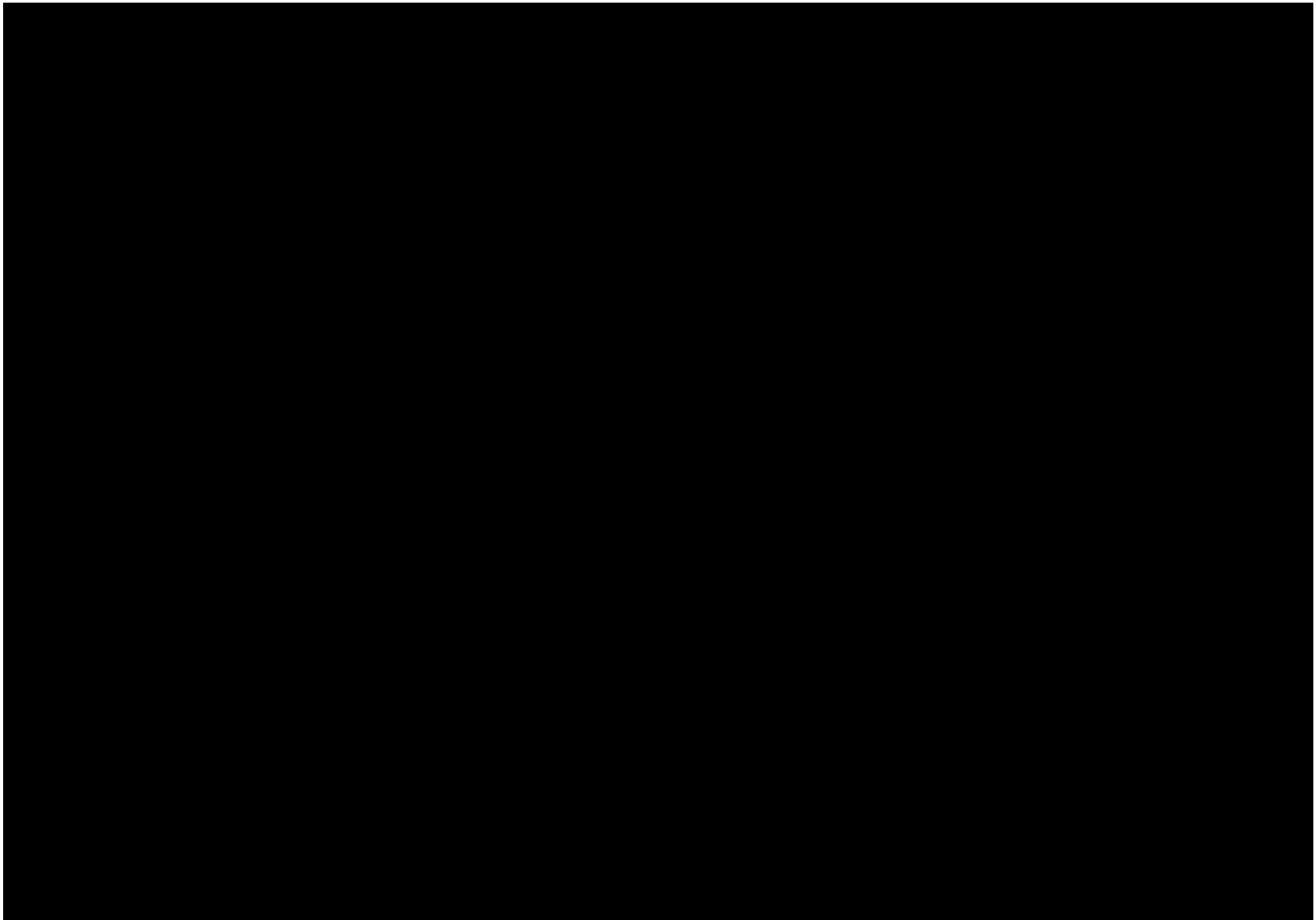


Hourly Average Day for November 2021
Southeast Colorado Power Association



Hourly Average Day for December 2021

Southeast Colorado Power Association



Hourly Average Day for January 2021

San Isabel Electric Association, Inc.

[redacted]

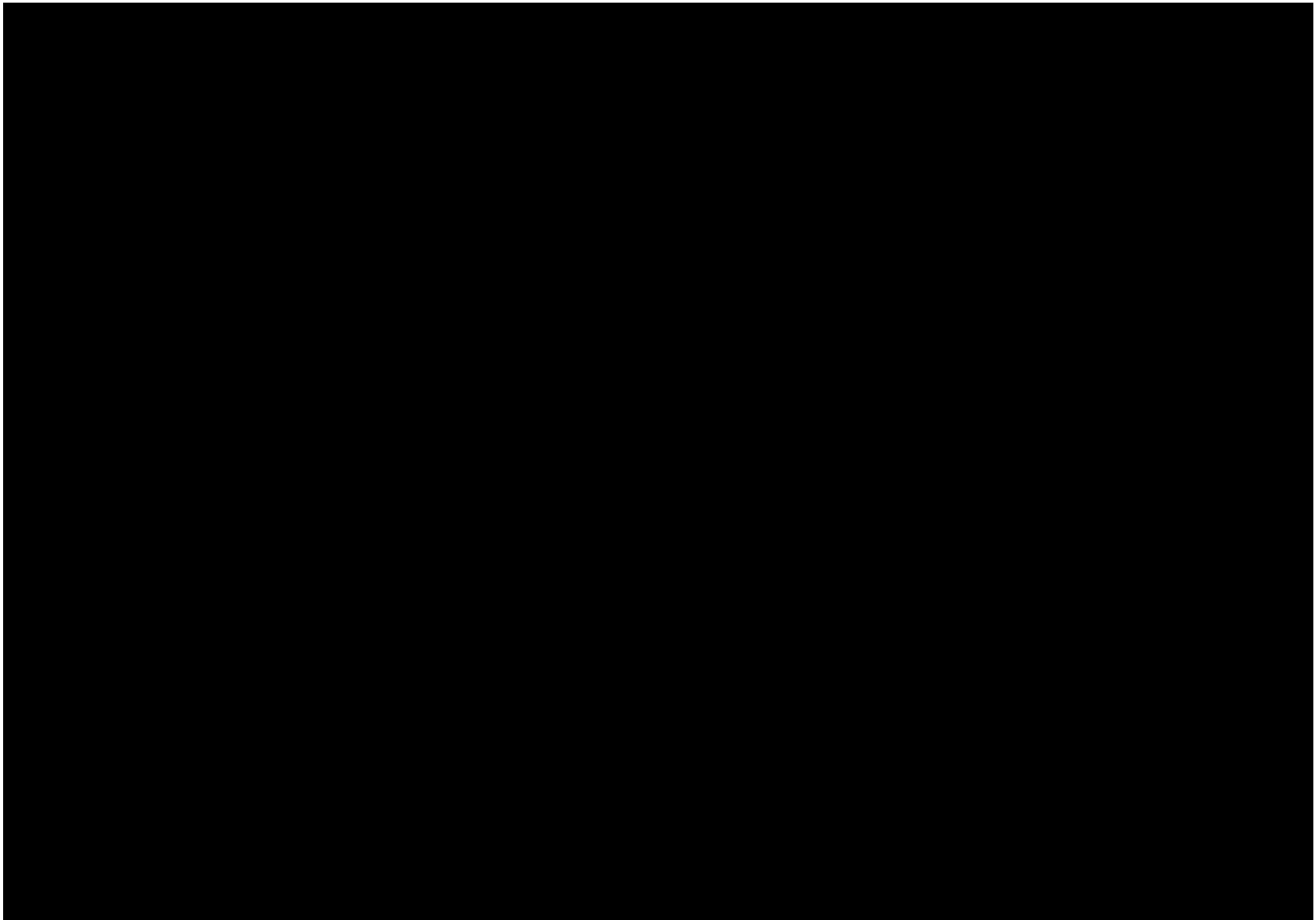
Hourly Average Day for February 2021

San Isabel Electric Association, Inc.

[redacted]

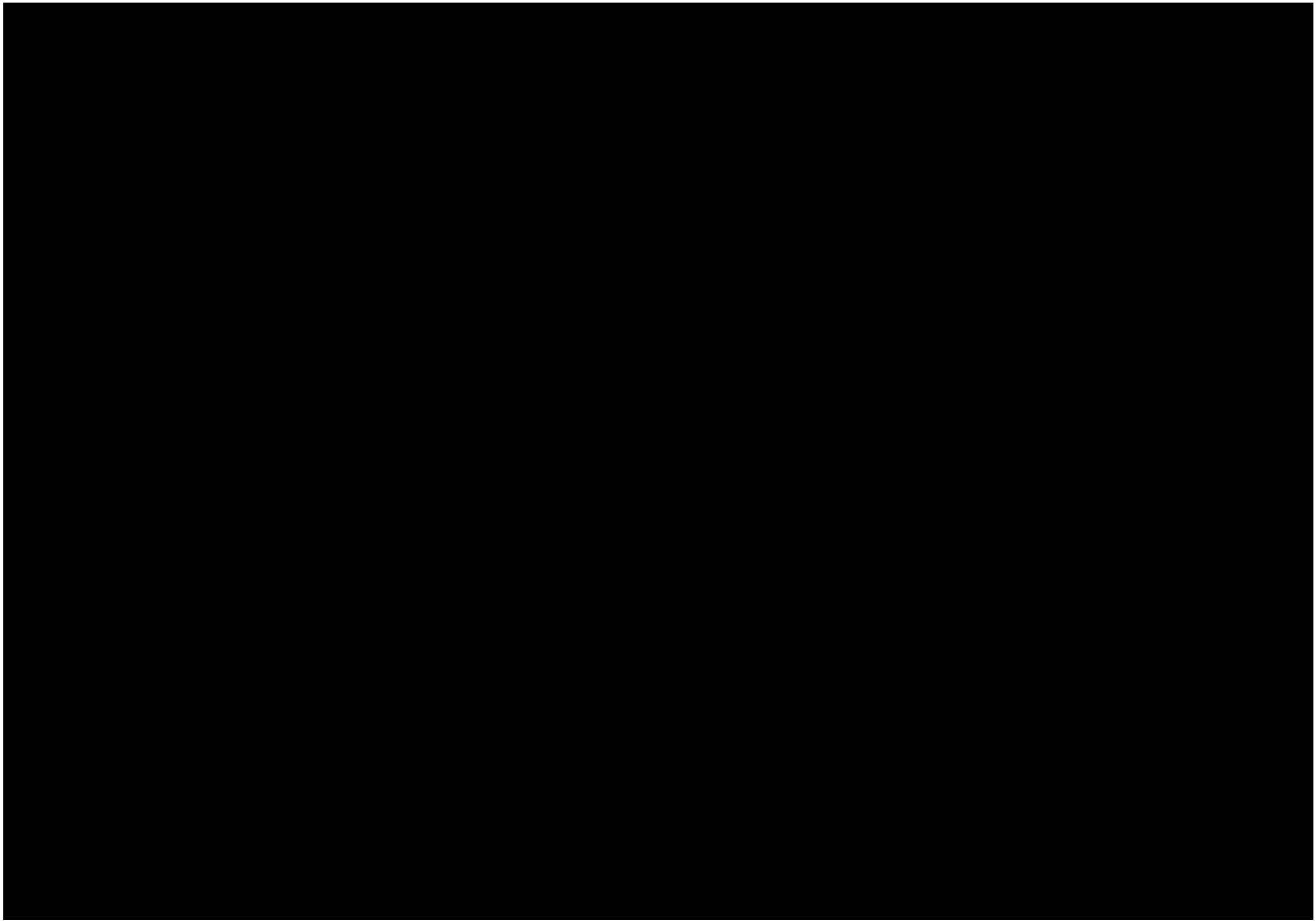
Hourly Average Day for March 2021

San Isabel Electric Association, Inc.



Hourly Average Day for April 2021

San Isabel Electric Association, Inc.



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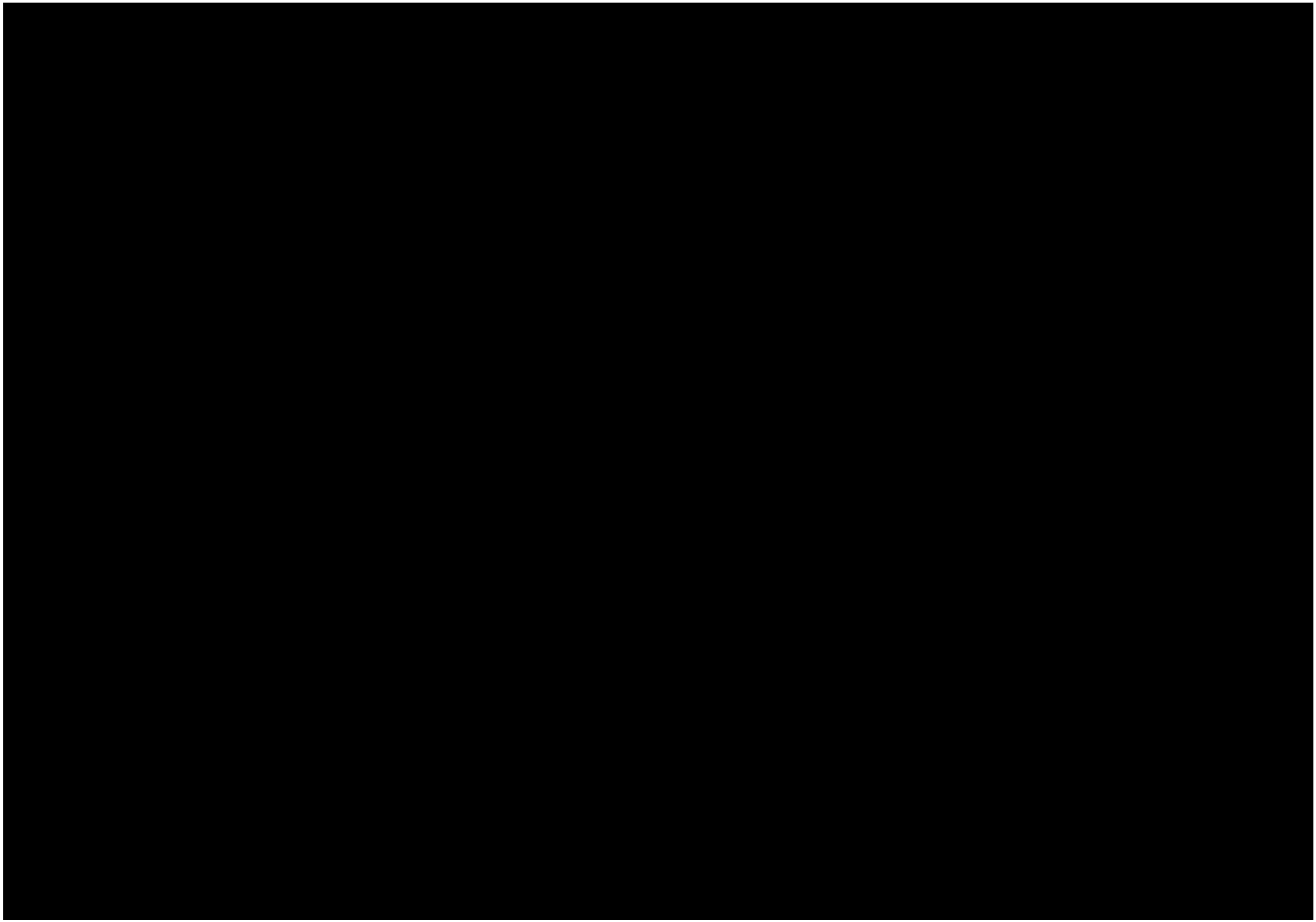
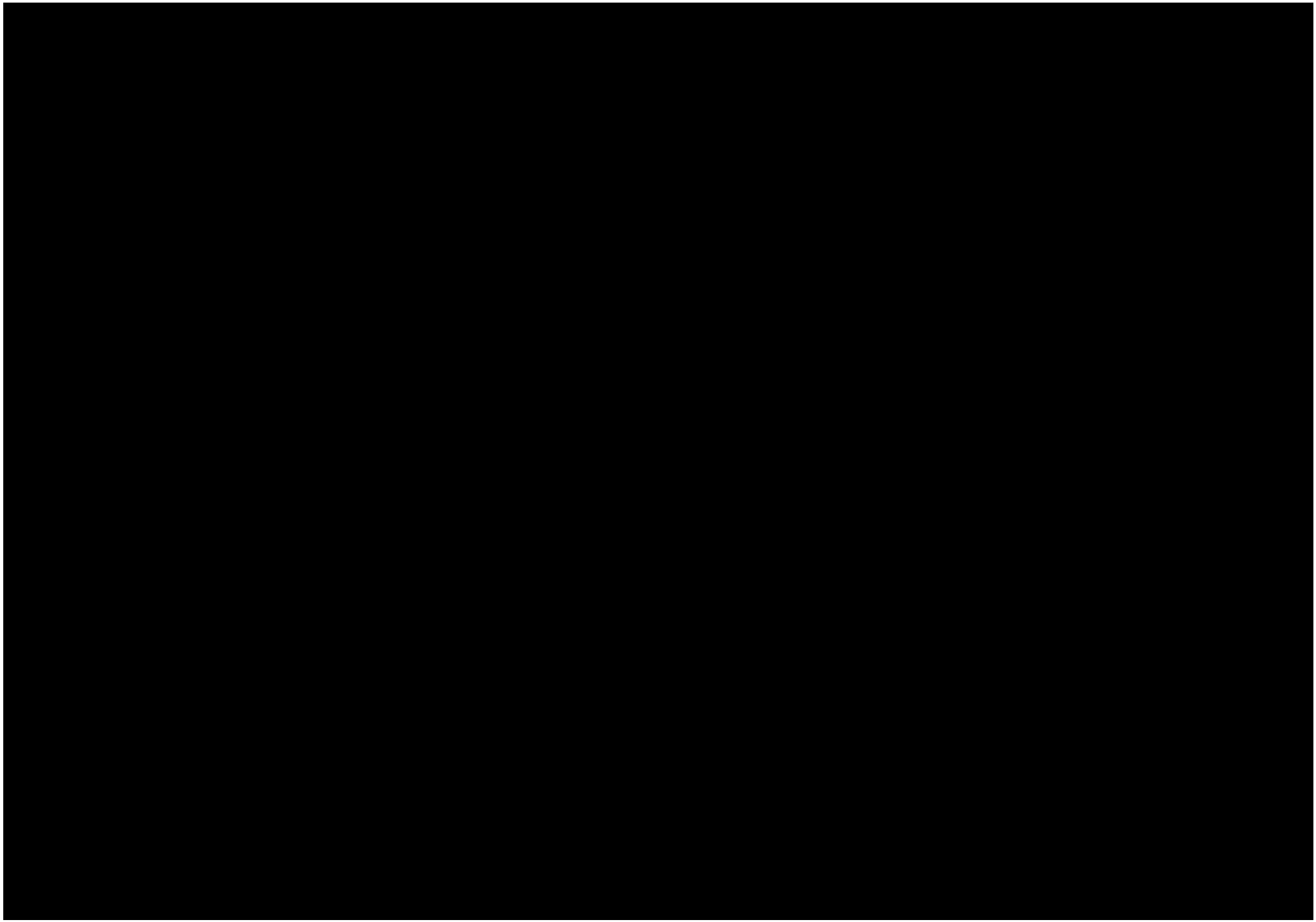
Hourly Average Day for May 2021

San Isabel Electric Association, Inc.



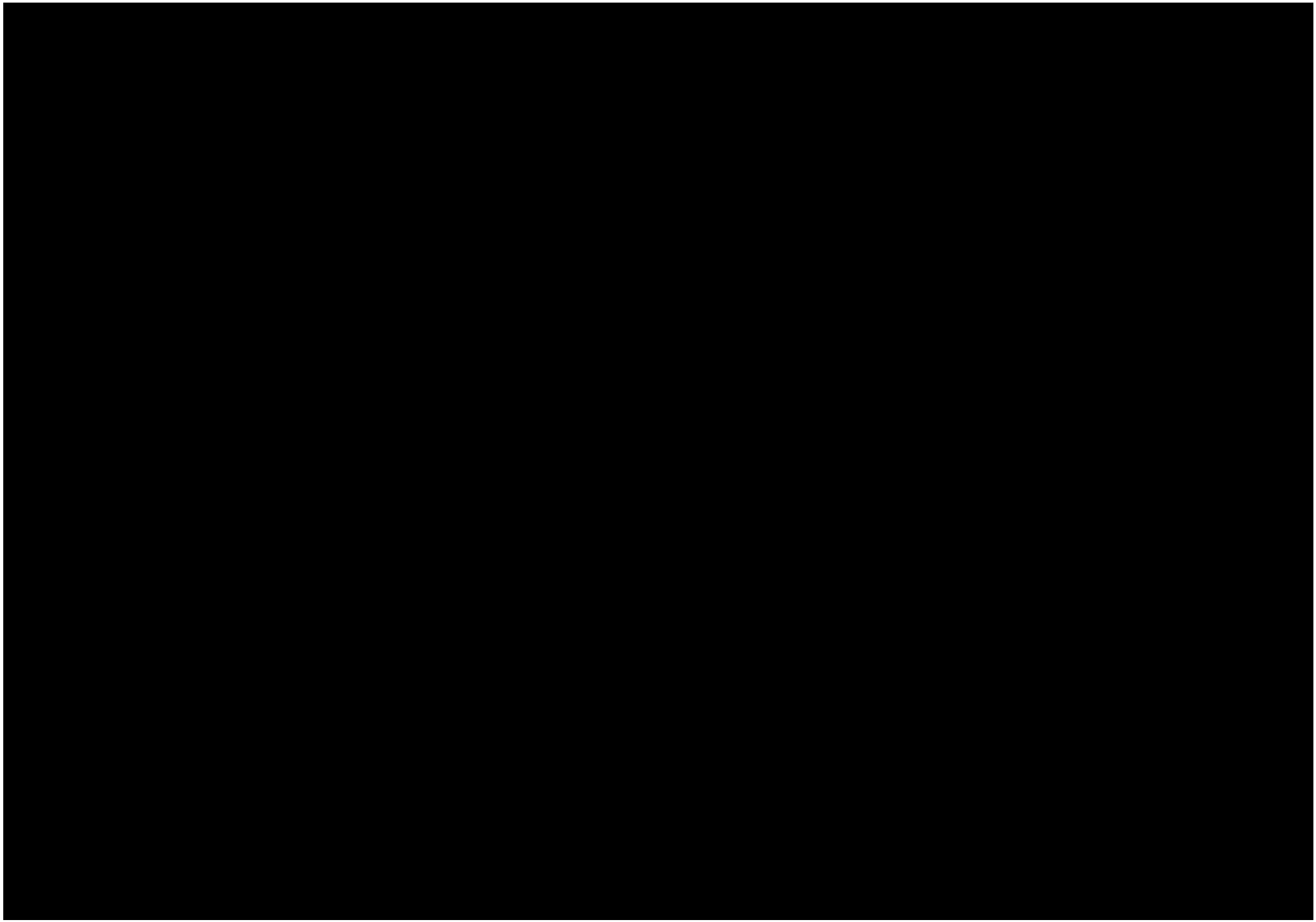
Hourly Average Day for June 2021

San Isabel Electric Association, Inc.



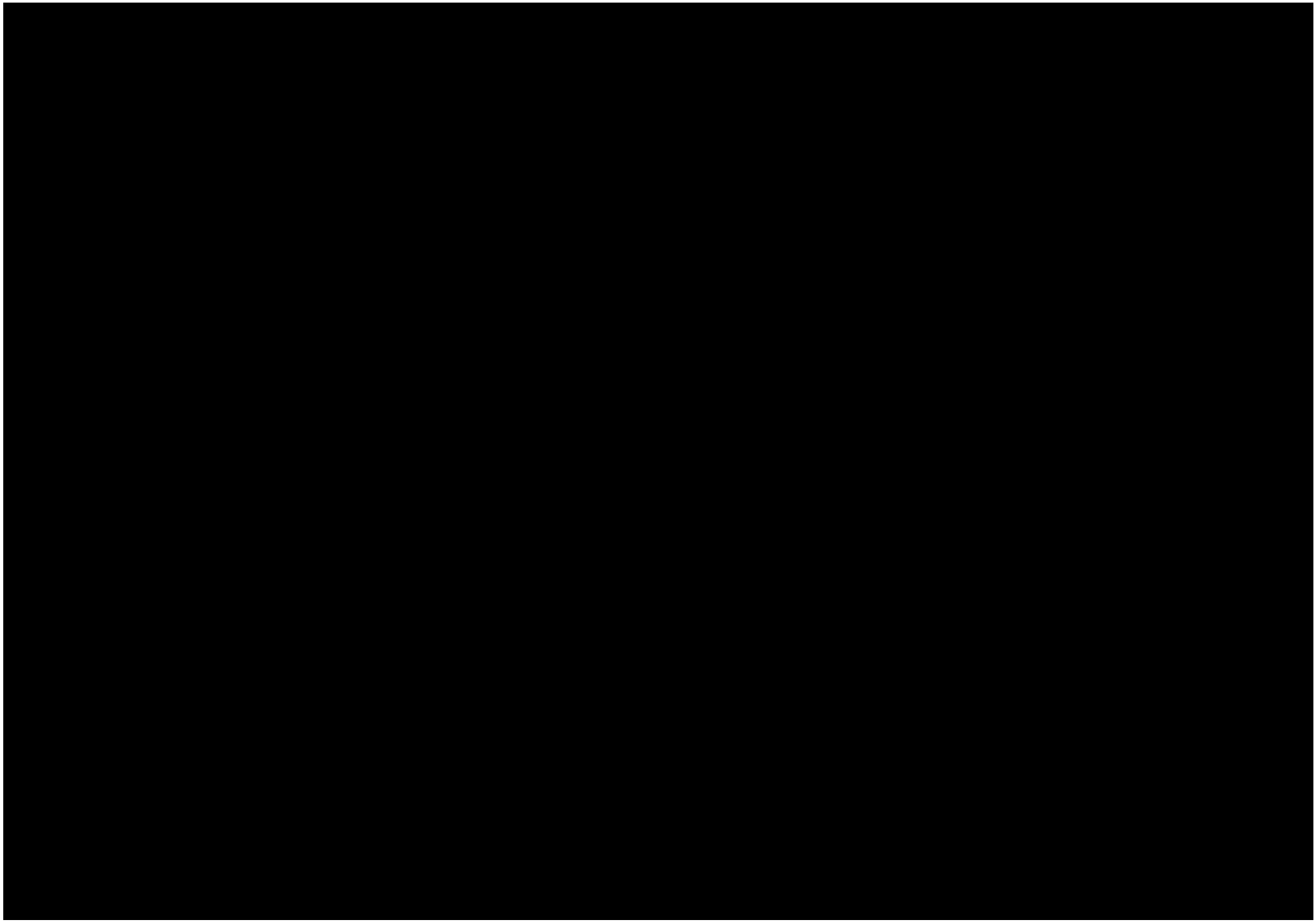
Hourly Average Day for July 2021

San Isabel Electric Association, Inc.



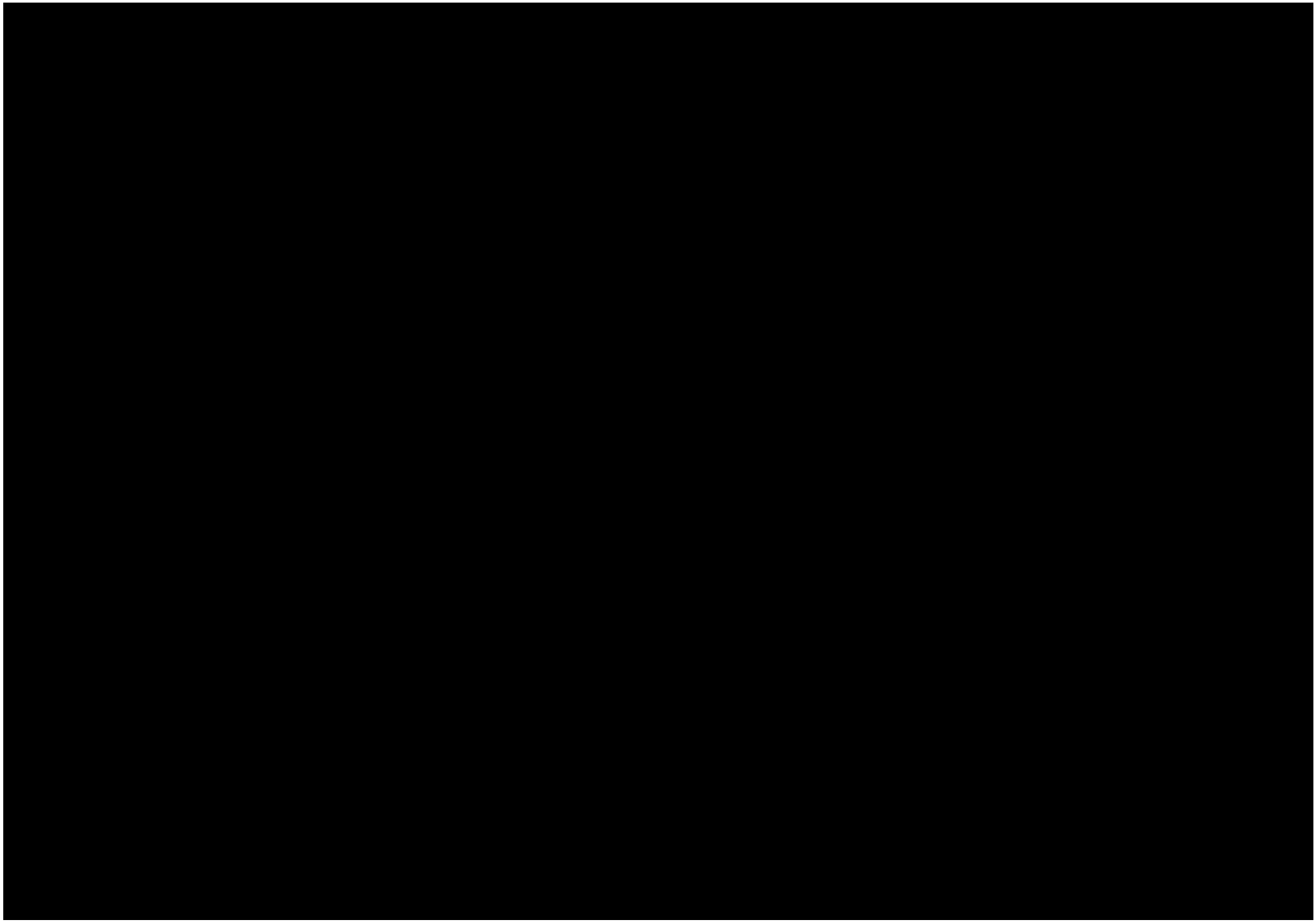
Hourly Average Day for August 2021

San Isabel Electric Association, Inc.



Hourly Average Day for September 2021

San Isabel Electric Association, Inc.



Hourly Average Day for October 2021

San Isabel Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

San Isabel Electric Association, Inc.

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Hourly Average Day for December 2021

San Isabel Electric Association, Inc.

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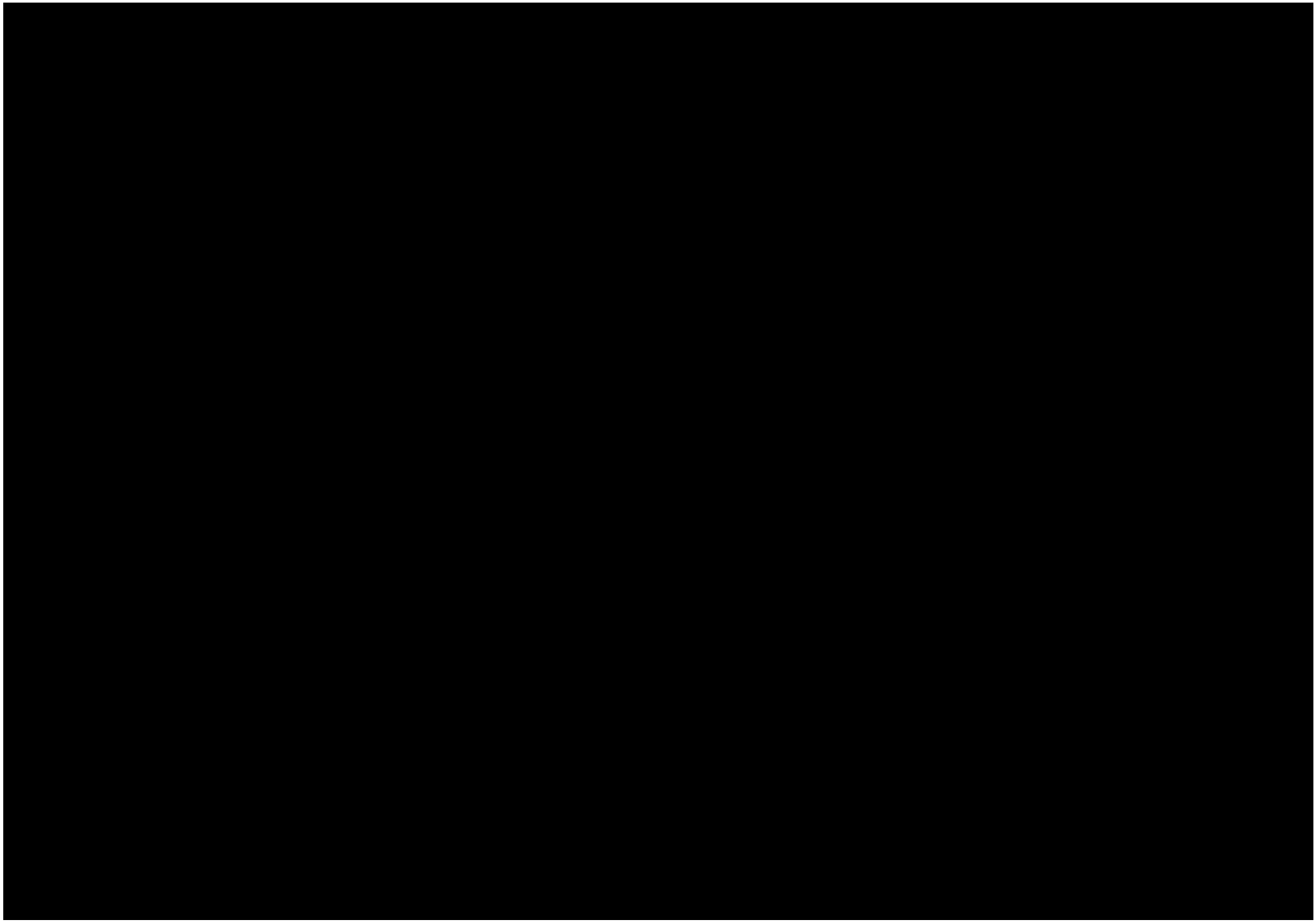
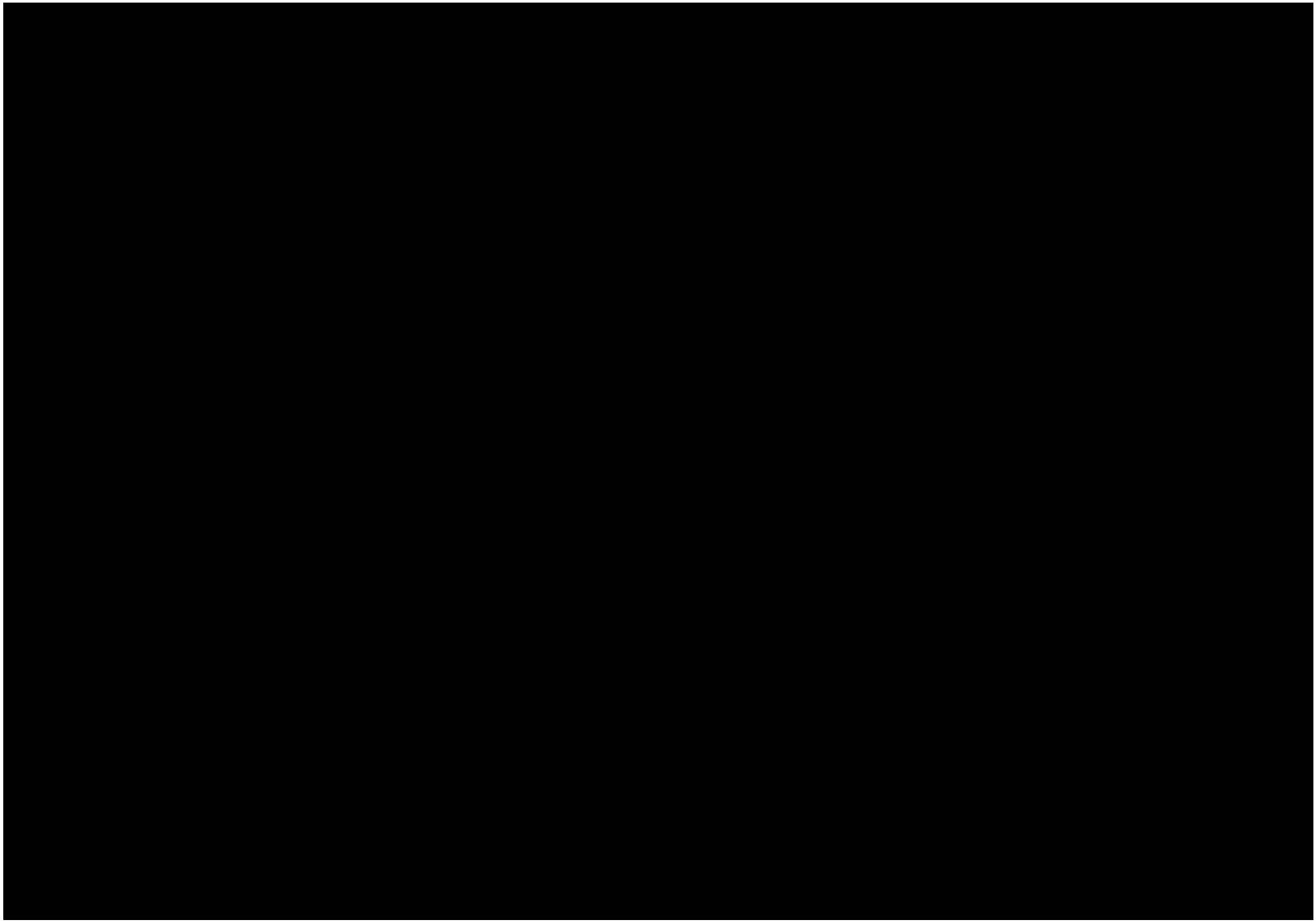
Hourly Average Day for January 2021
San Luis Valley Rural Electric Cooperative, Inc.



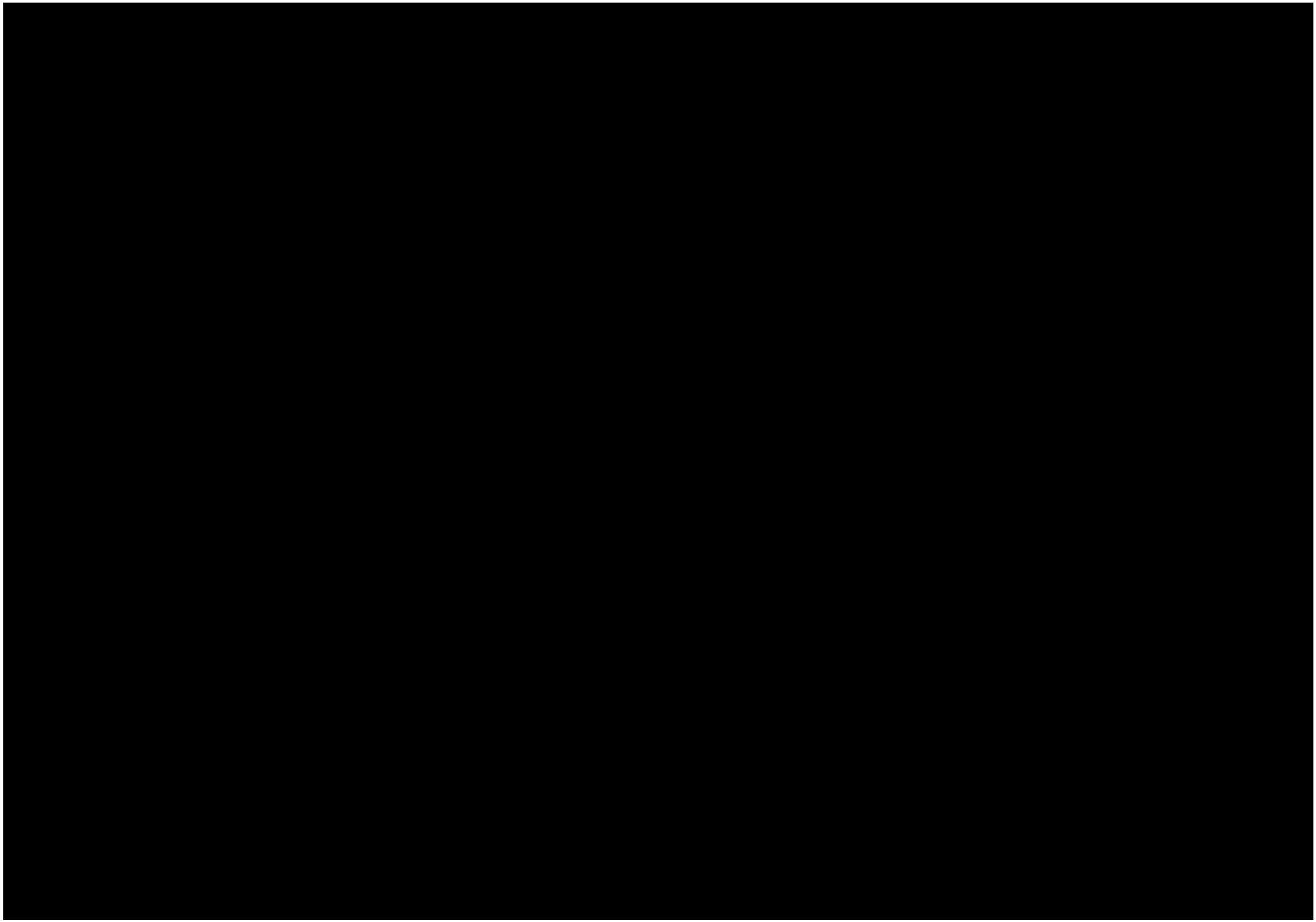
Hourly Average Day for February 2021

San Luis Valley Rural Electric Cooperative, Inc.



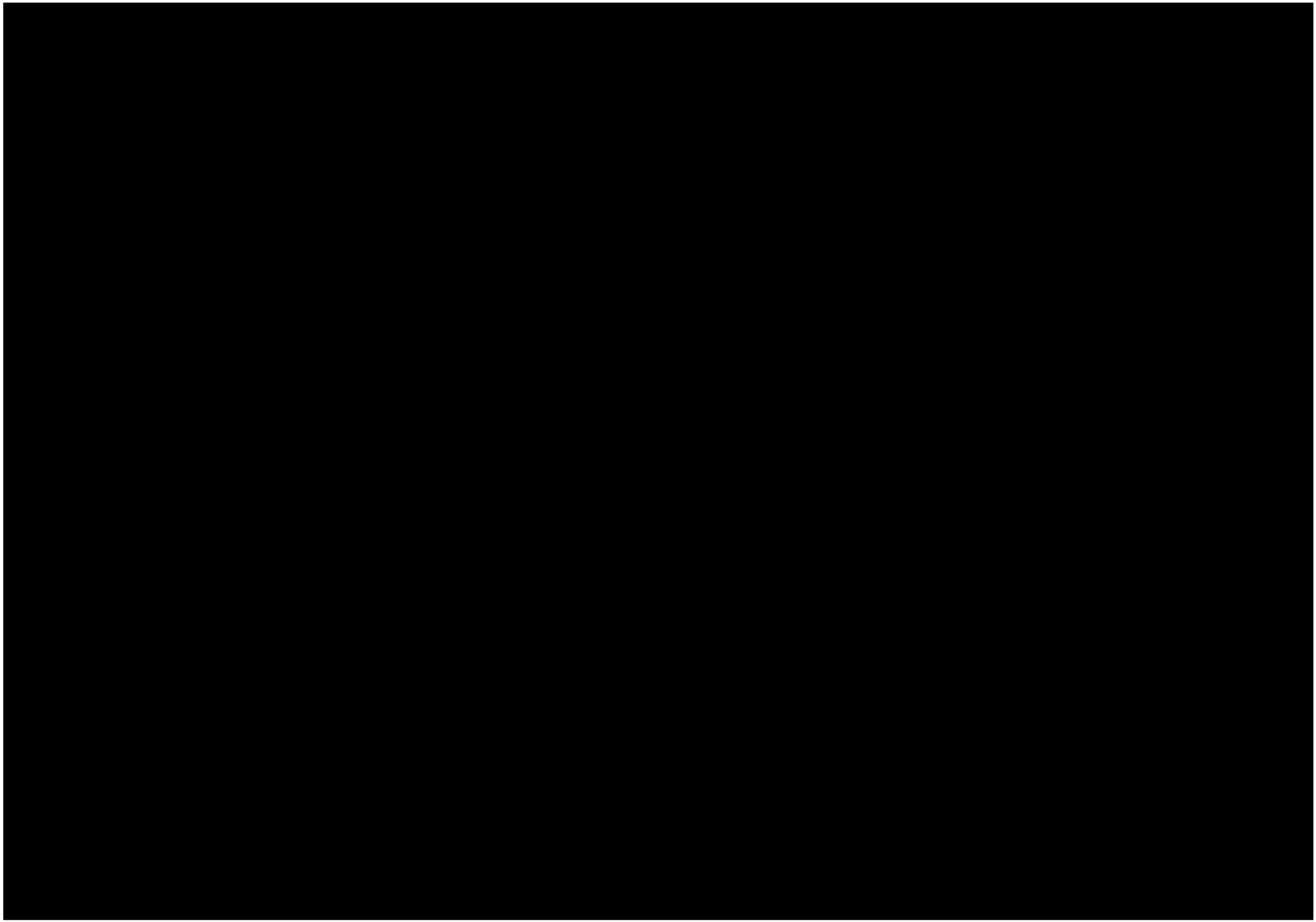
Hourly Average Day for March 2021

San Luis Valley Rural Electric Cooperative, Inc.



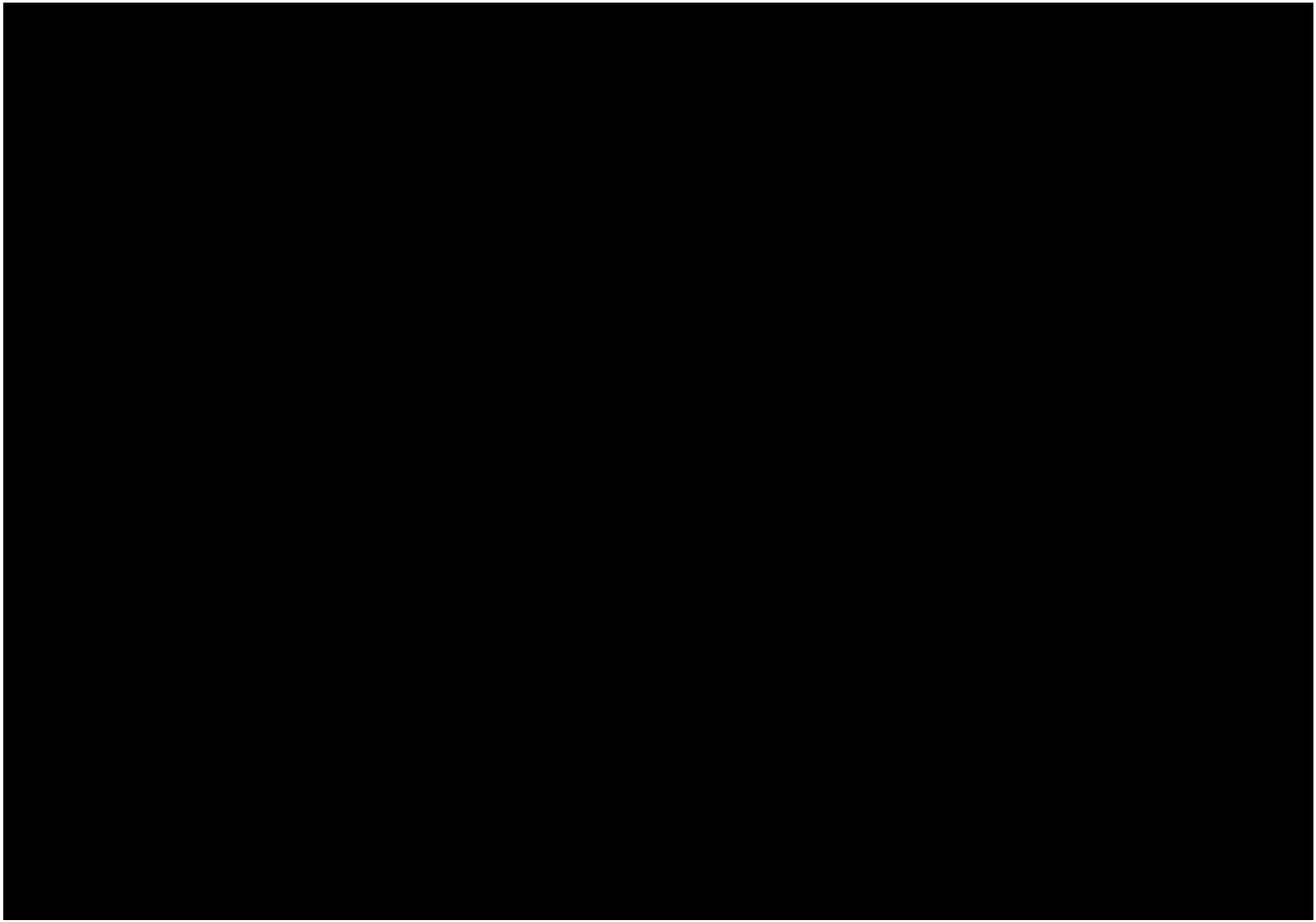
Hourly Average Day for April 2021

San Luis Valley Rural Electric Cooperative, Inc.



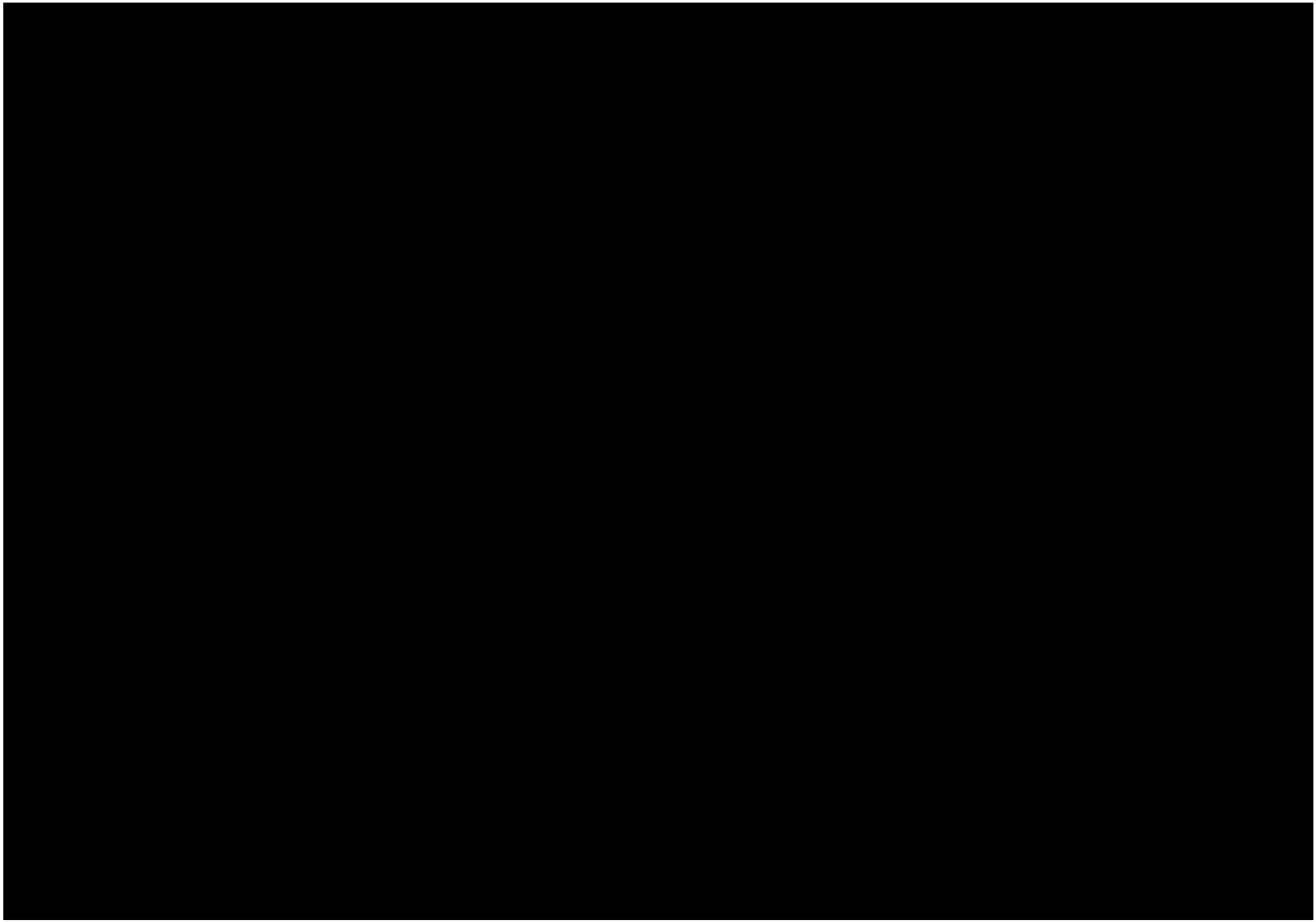
Hourly Average Day for May 2021

San Luis Valley Rural Electric Cooperative, Inc.



Hourly Average Day for June 2021

San Luis Valley Rural Electric Cooperative, Inc.



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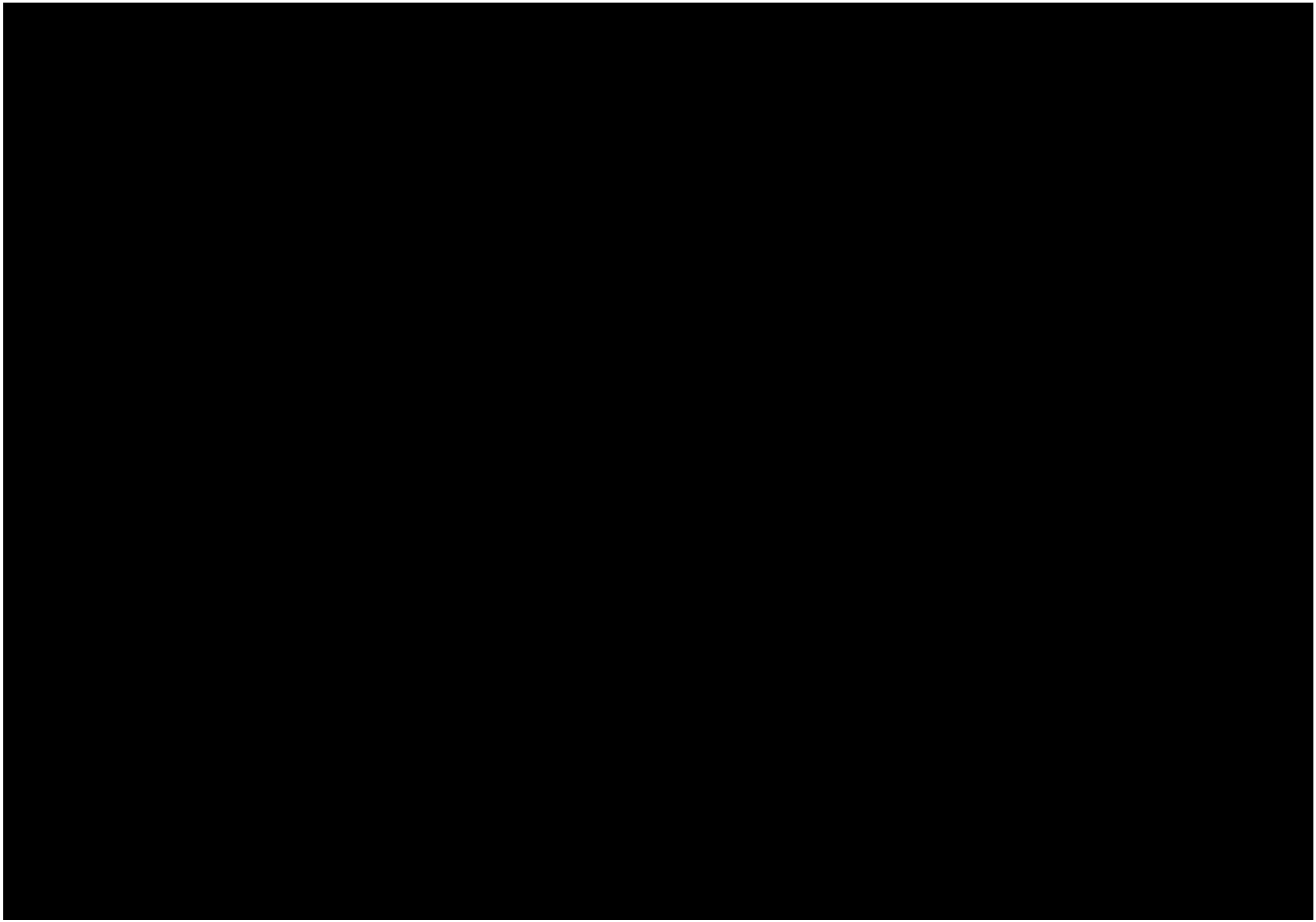
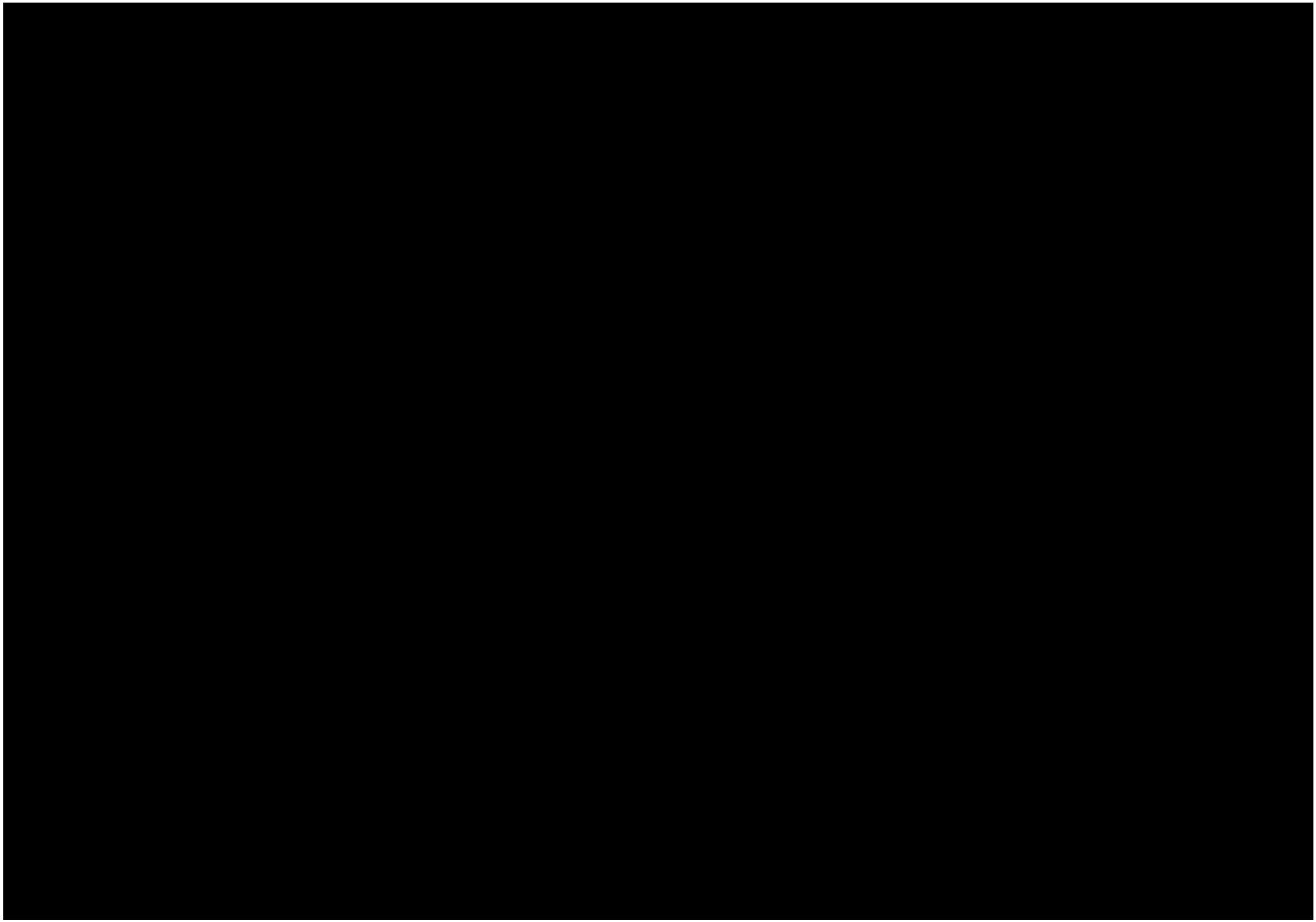
Hourly Average Day for July 2021

San Luis Valley Rural Electric Cooperative, Inc.



Hourly Average Day for August 2021

San Luis Valley Rural Electric Cooperative, Inc.



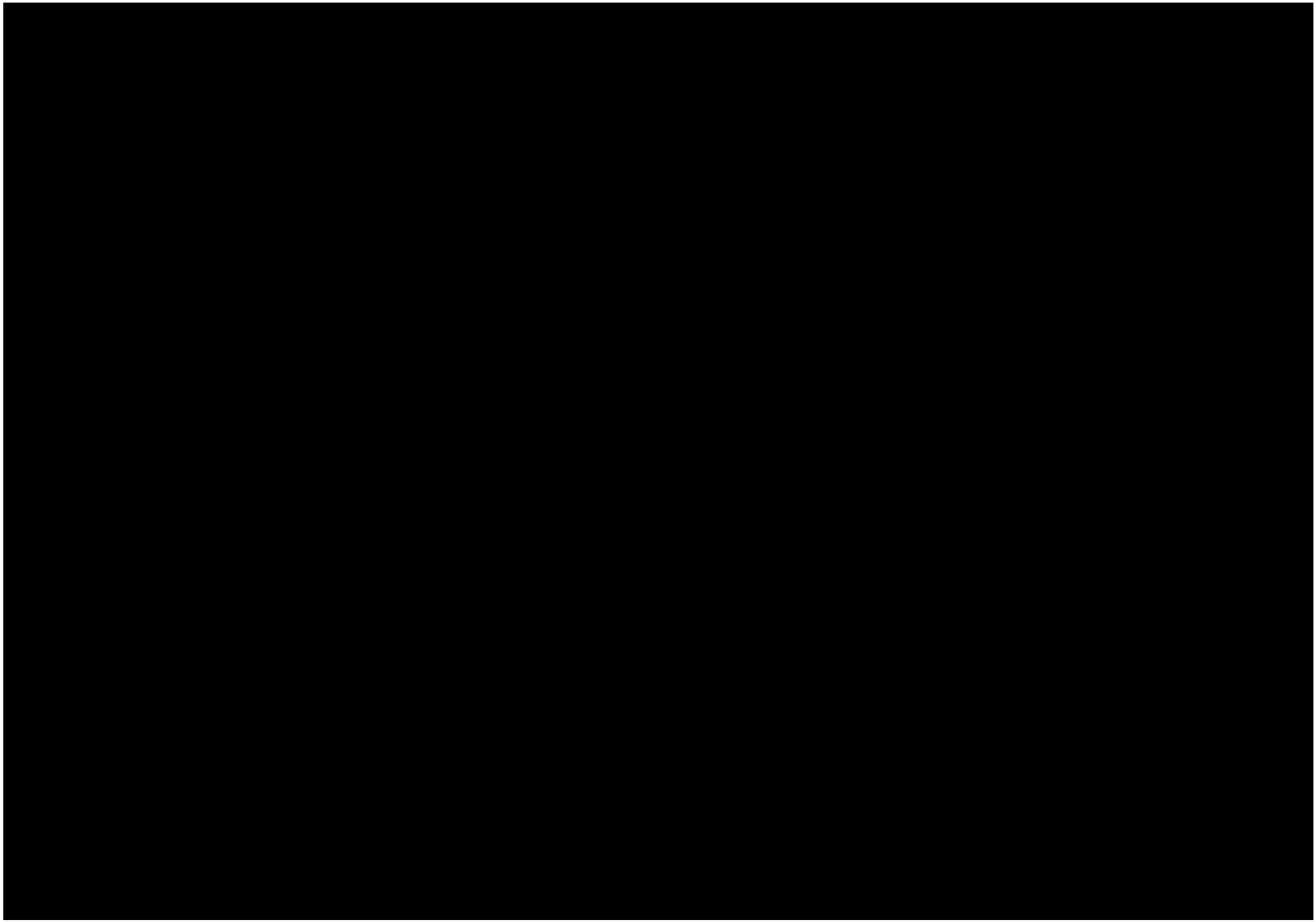
Hourly Average Day for September 2021

San Luis Valley Rural Electric Cooperative, Inc.

[redacted]

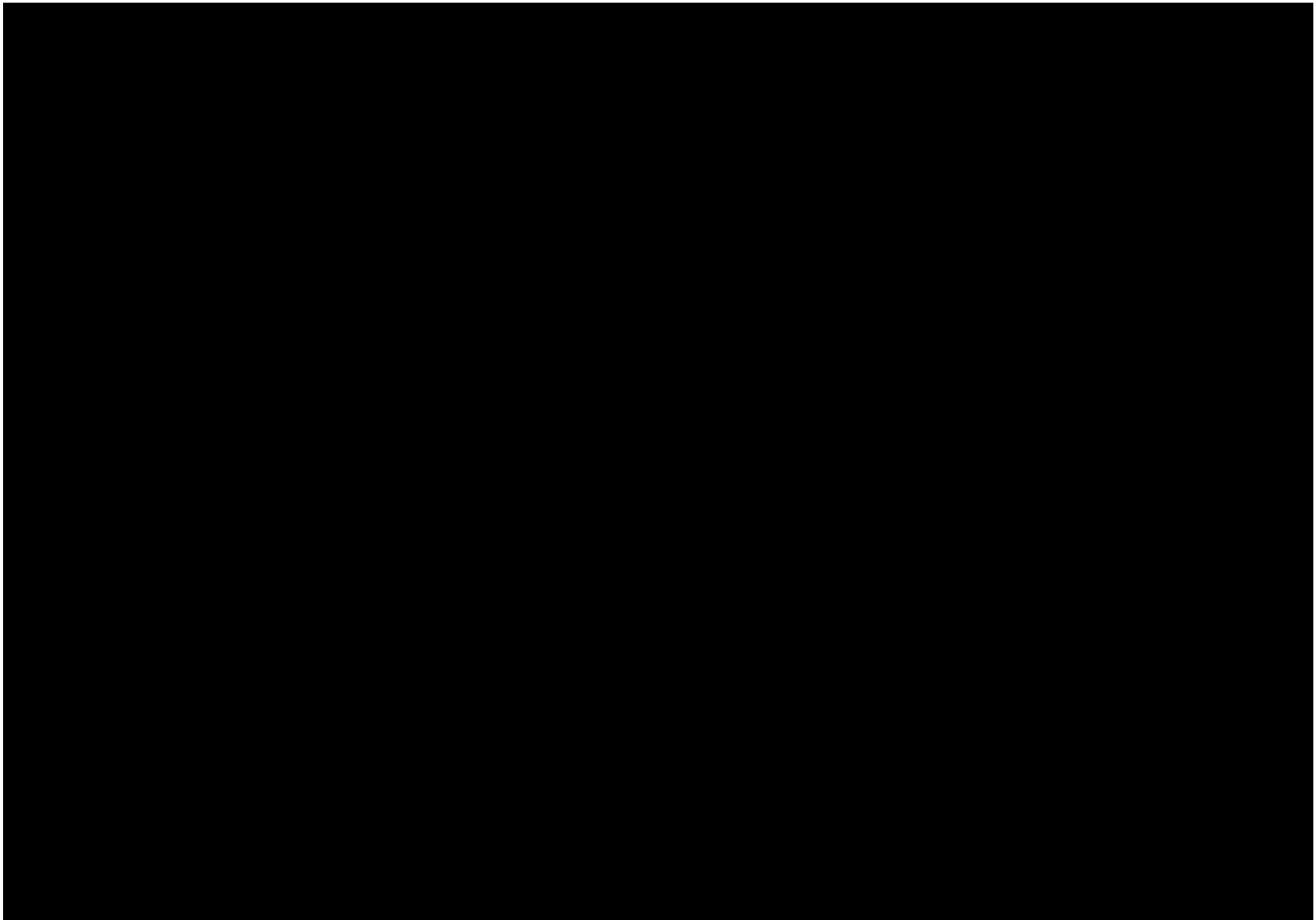
Hourly Average Day for October 2021

San Luis Valley Rural Electric Cooperative, Inc.



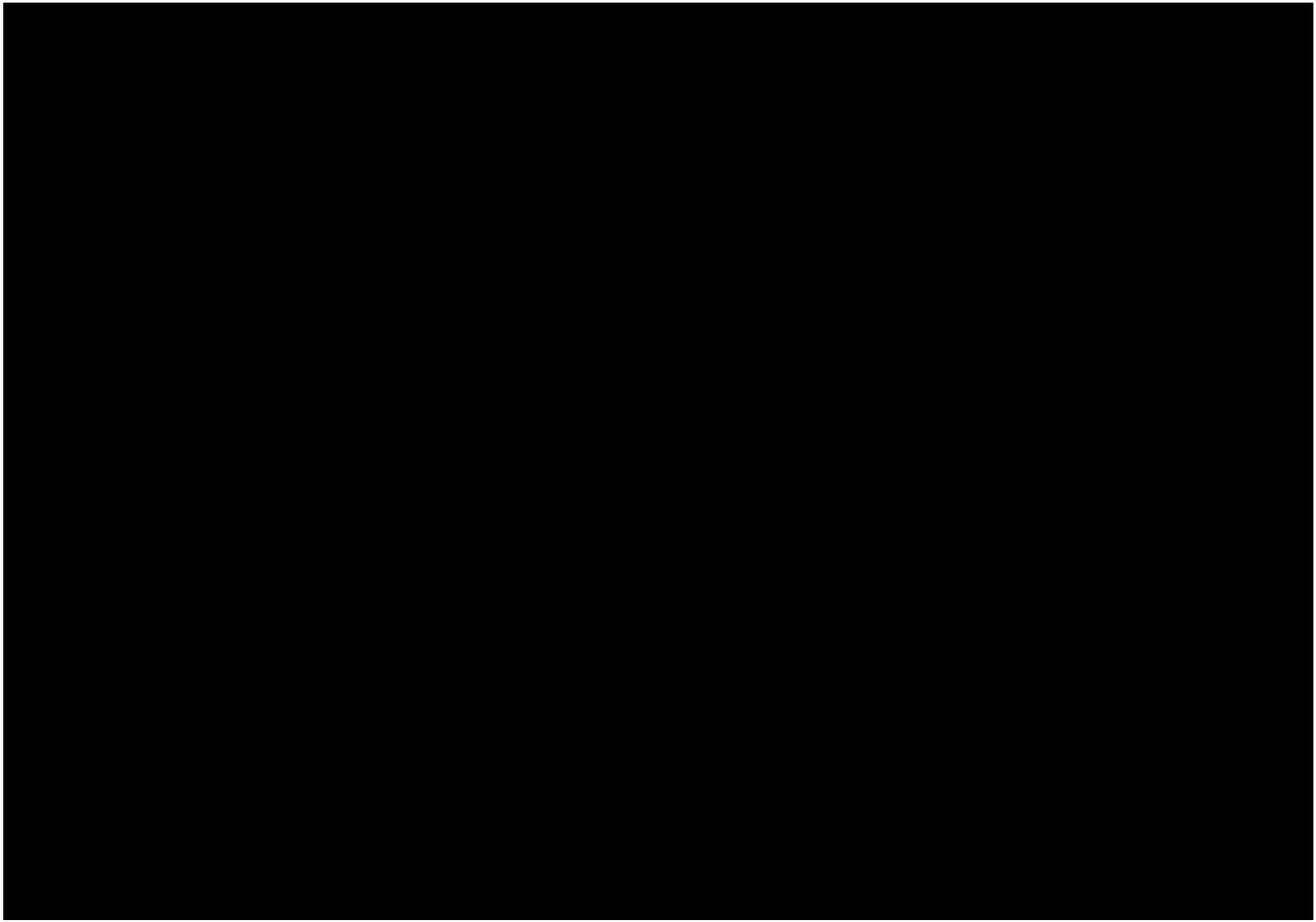
Hourly Average Day for November 2021

San Luis Valley Rural Electric Cooperative, Inc.



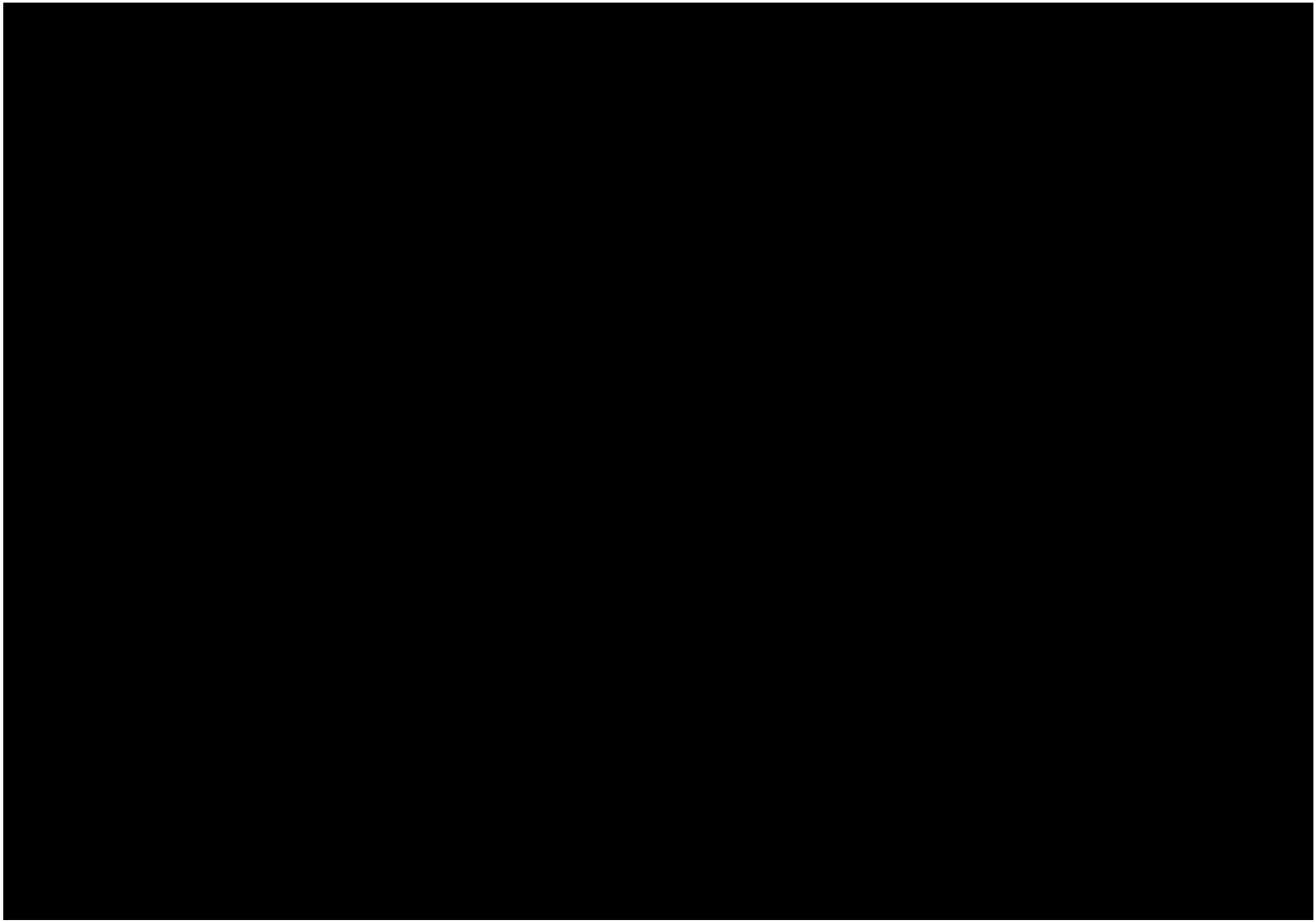
Hourly Average Day for December 2021

San Luis Valley Rural Electric Cooperative, Inc.



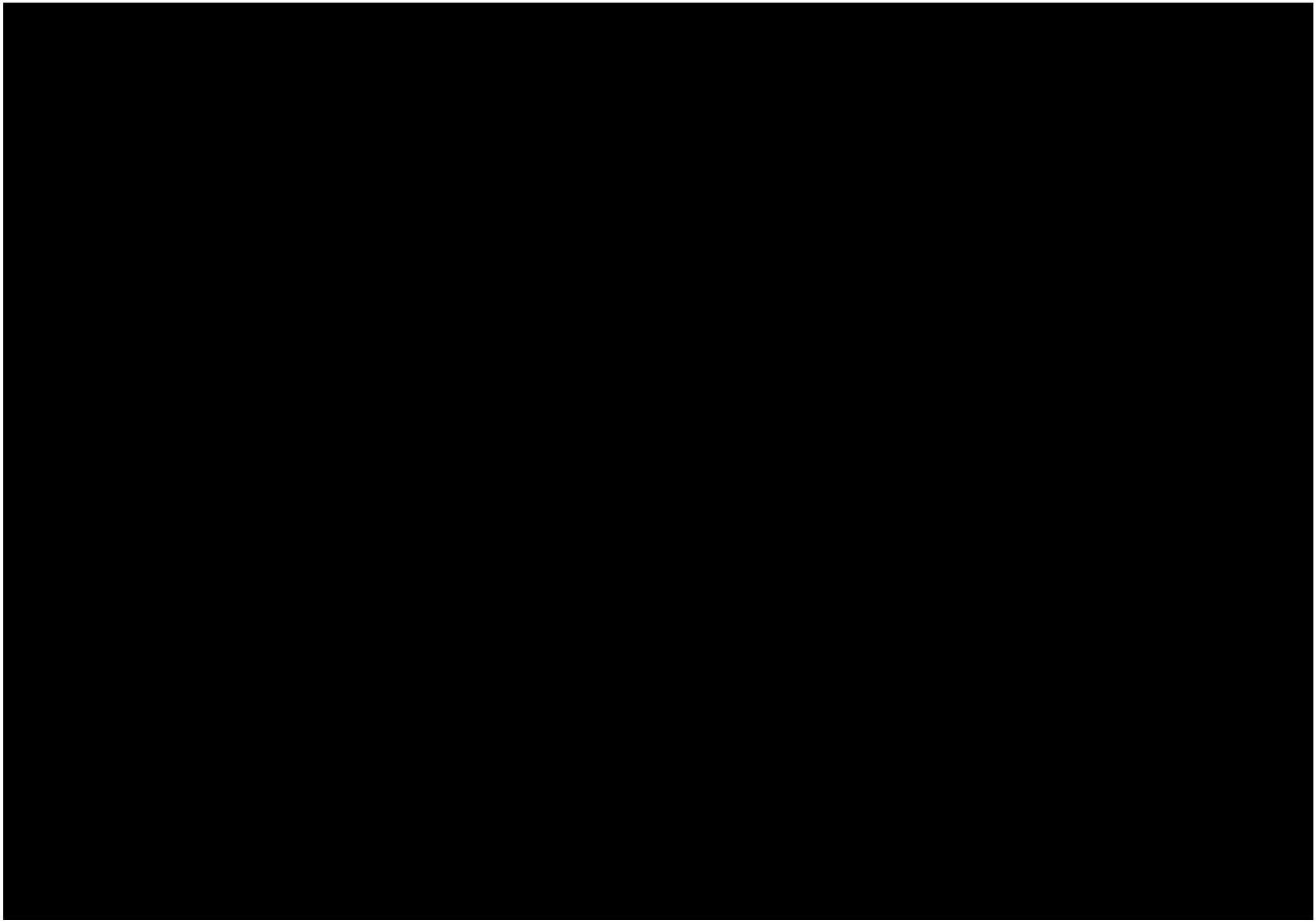
Hourly Average Day for January 2021

San Miguel Power Association, Inc.



Hourly Average Day for February 2021

San Miguel Power Association, Inc.



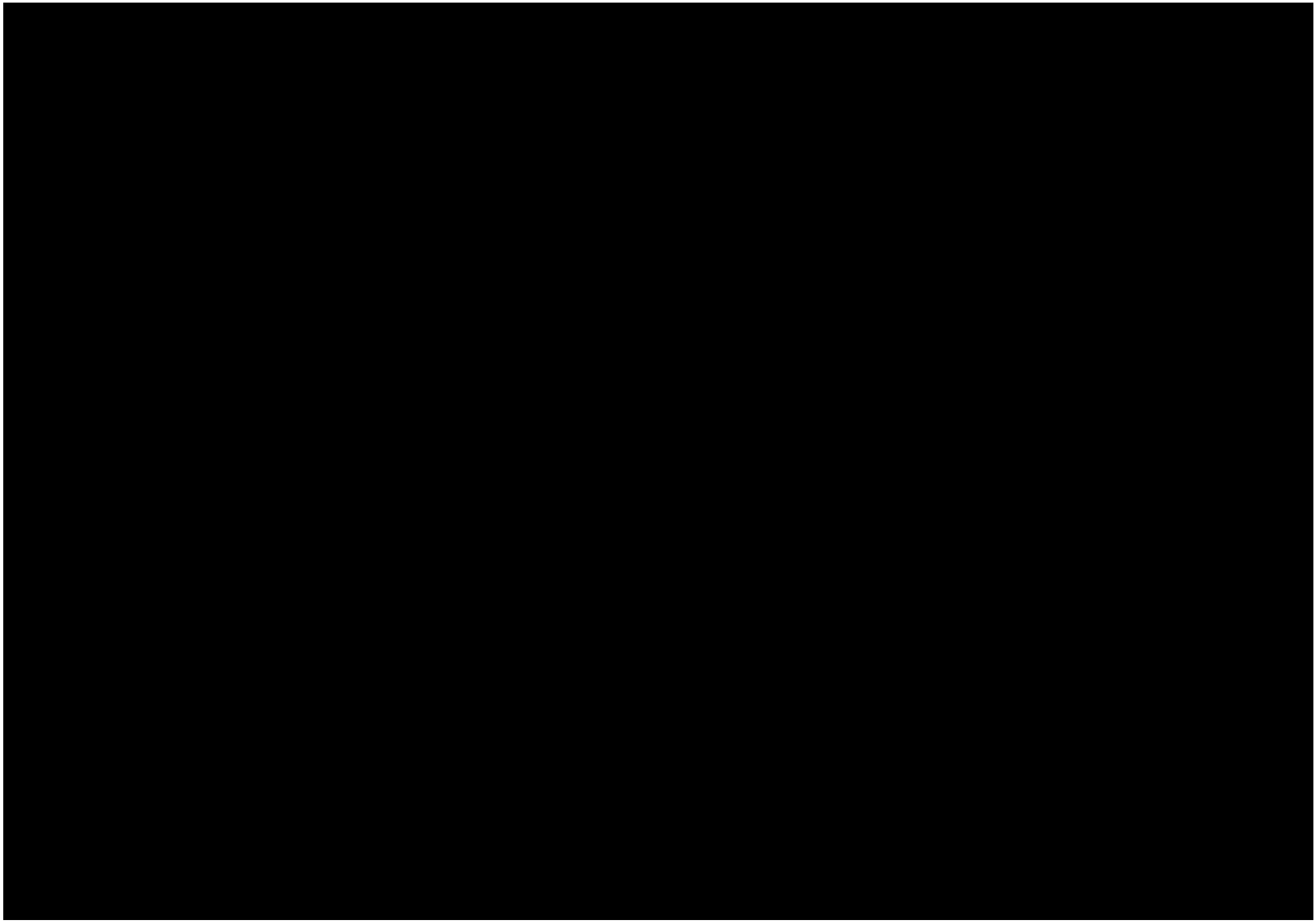
Hourly Average Day for March 2021

San Miguel Power Association, Inc.

[redacted]

Hourly Average Day for April 2021

San Miguel Power Association, Inc.



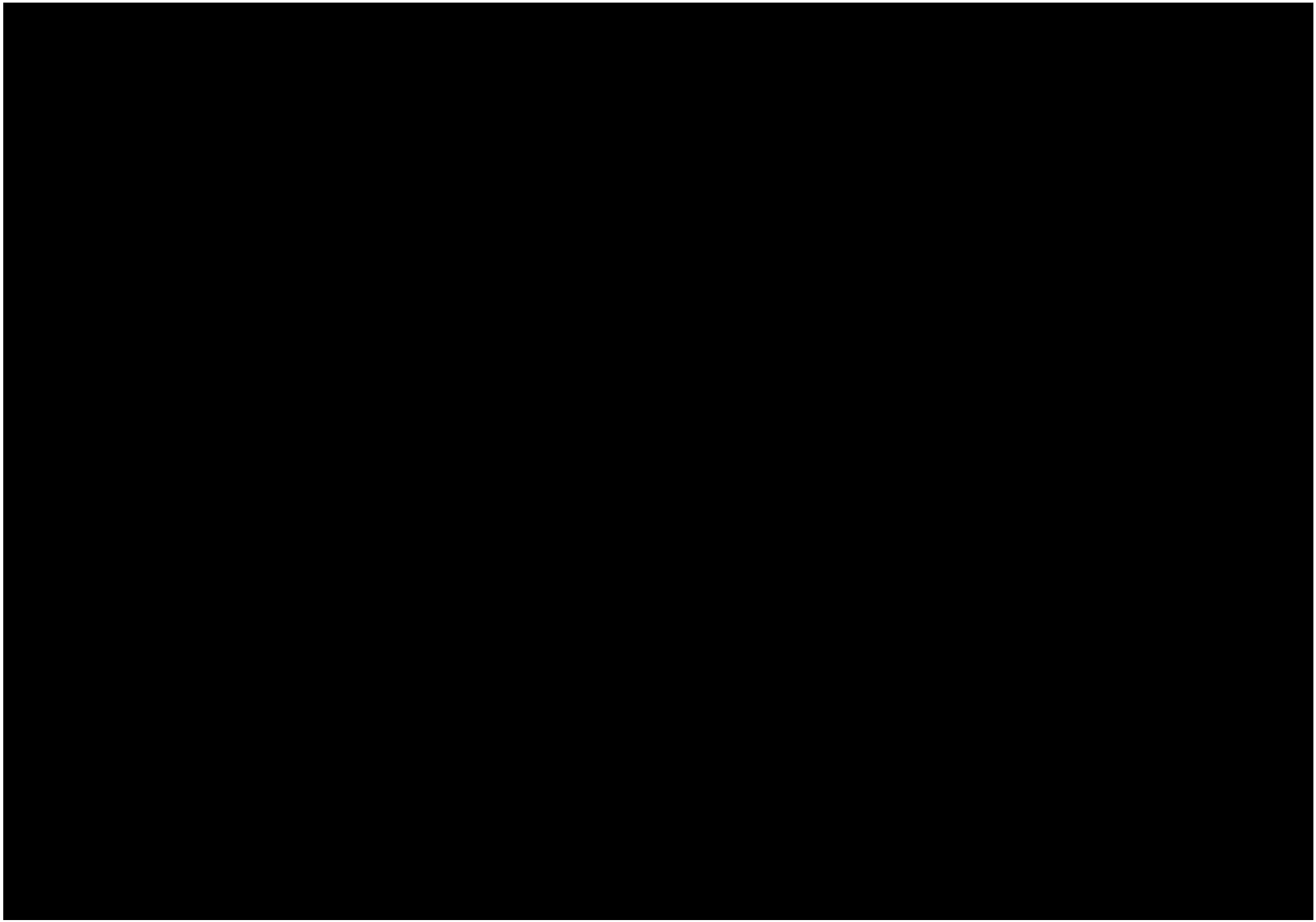
Hourly Average Day for May 2021

San Miguel Power Association, Inc.

[redacted]

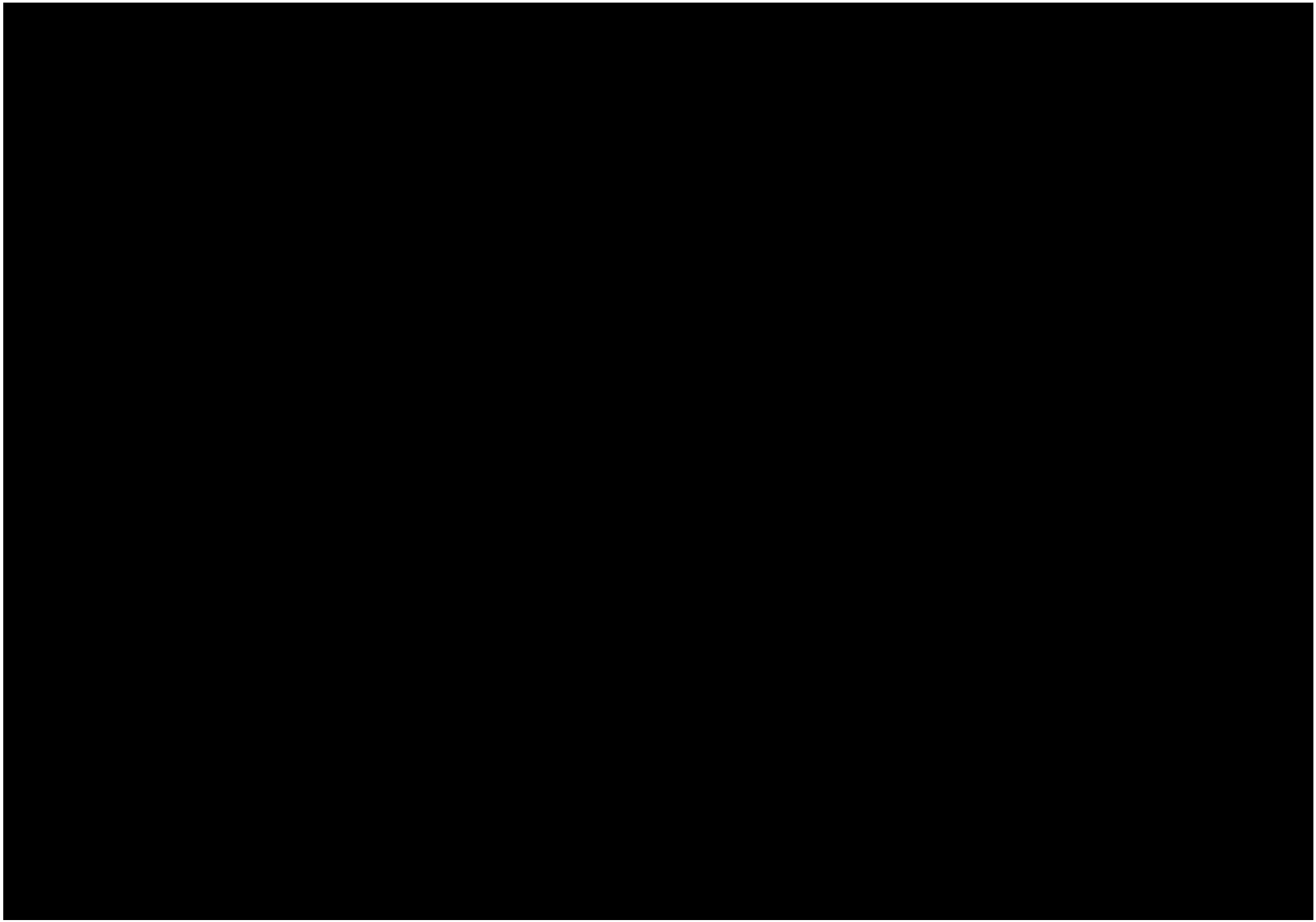
Hourly Average Day for June 2021

San Miguel Power Association, Inc.



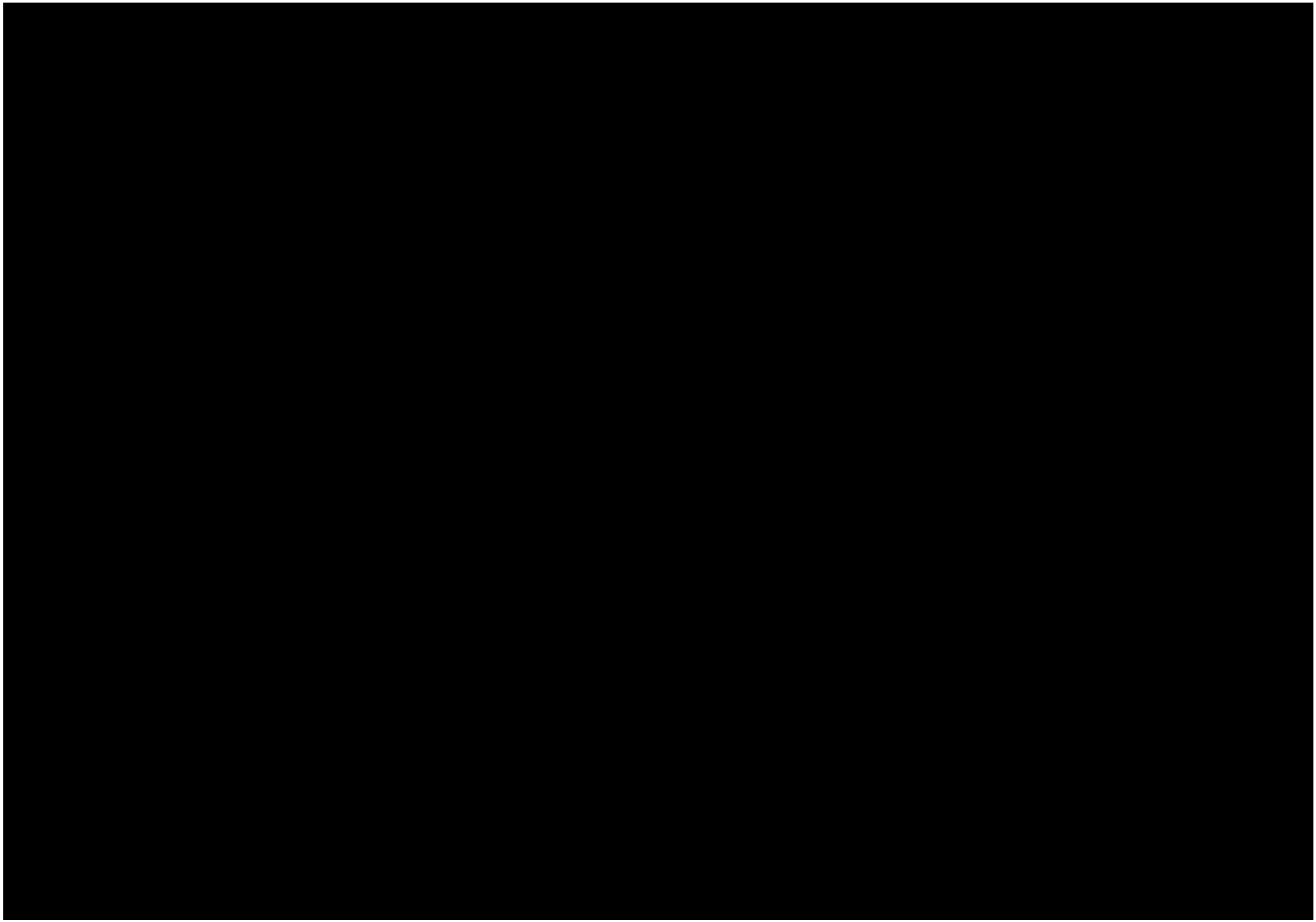
Hourly Average Day for July 2021

San Miguel Power Association, Inc.



Hourly Average Day for August 2021

San Miguel Power Association, Inc.



Hourly Average Day for September 2021

San Miguel Power Association, Inc.

[redacted]

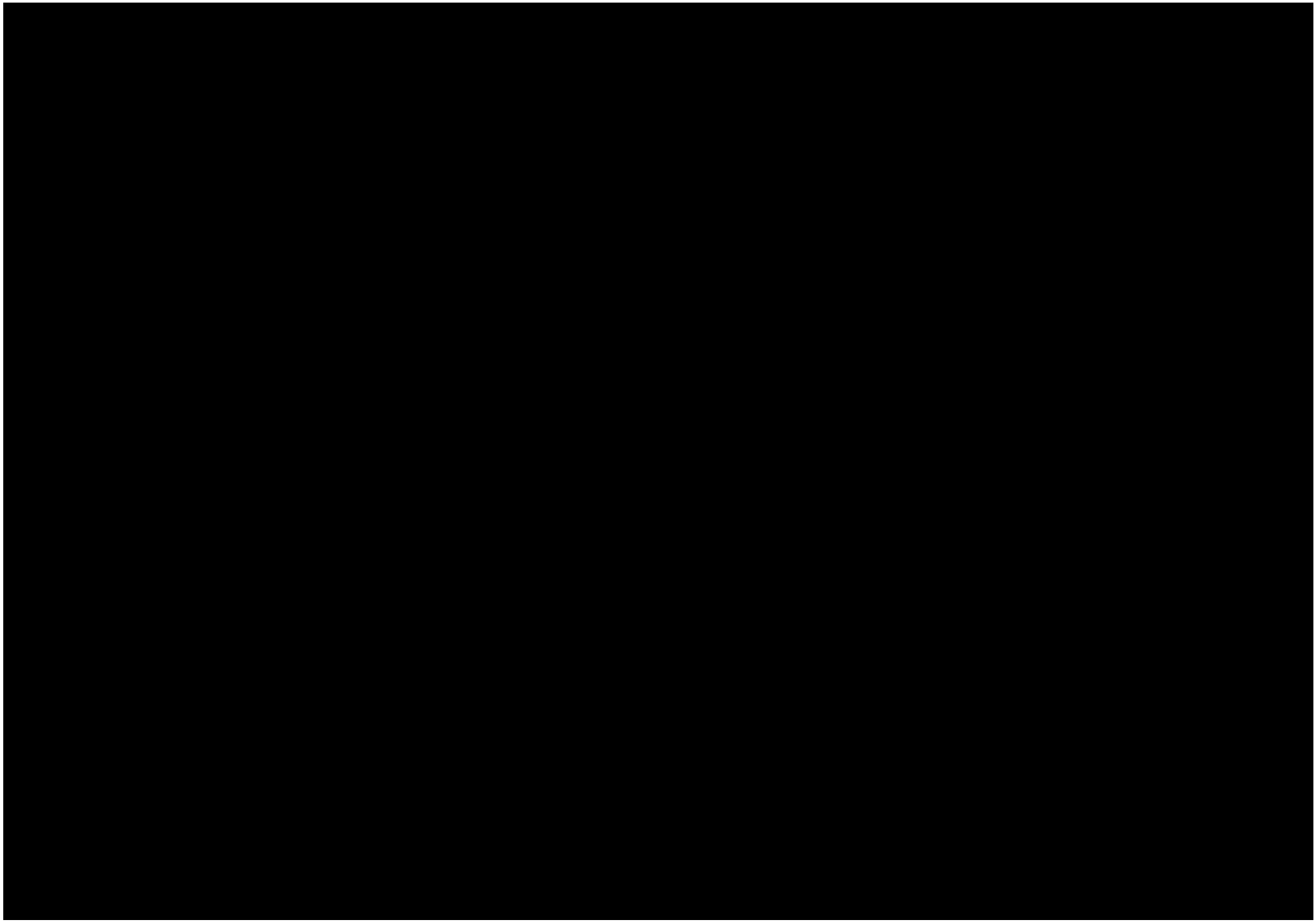
Hourly Average Day for October 2021

San Miguel Power Association, Inc.

[redacted]

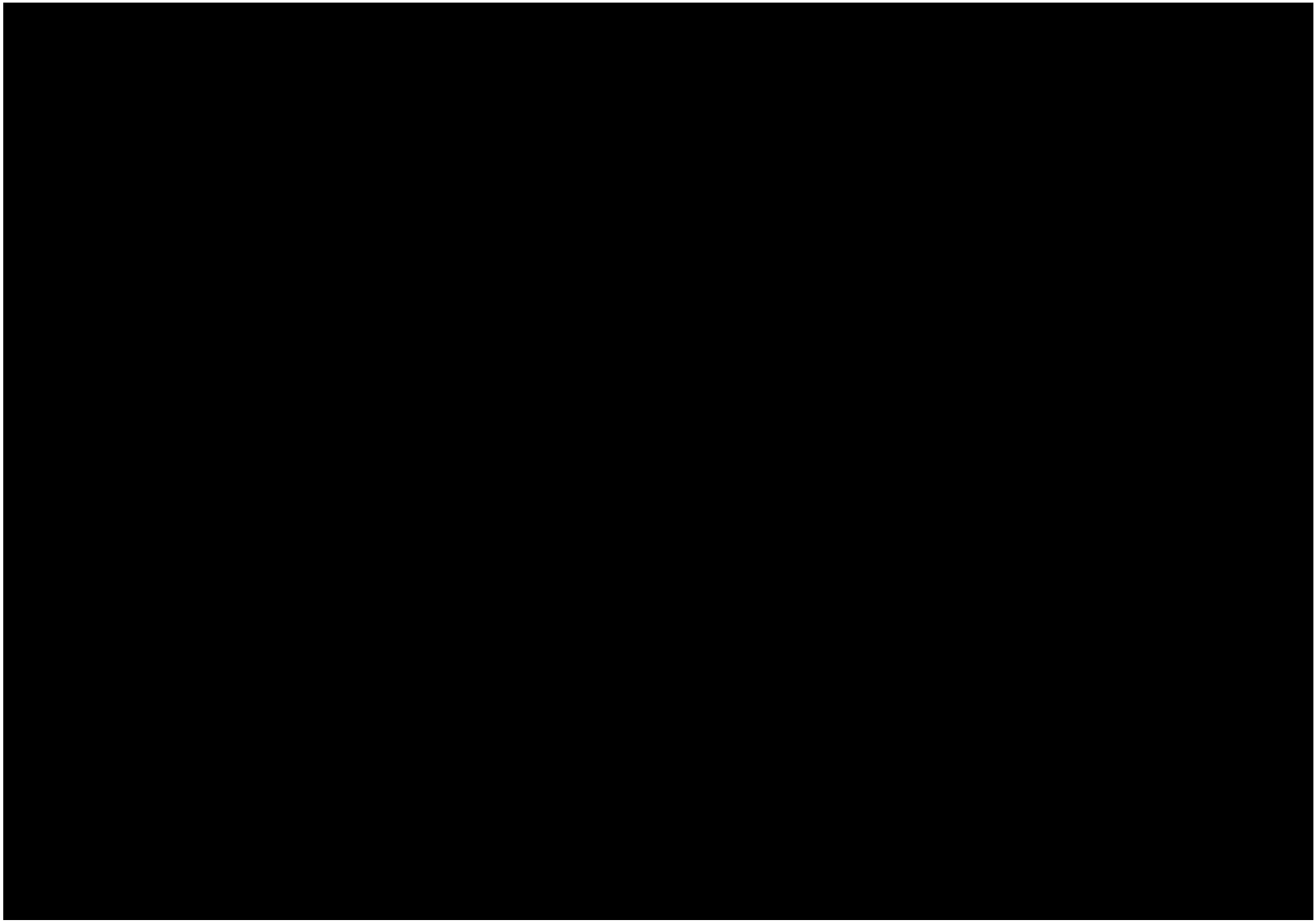
Hourly Average Day for November 2021

San Miguel Power Association, Inc.



Hourly Average Day for December 2021

San Miguel Power Association, Inc.



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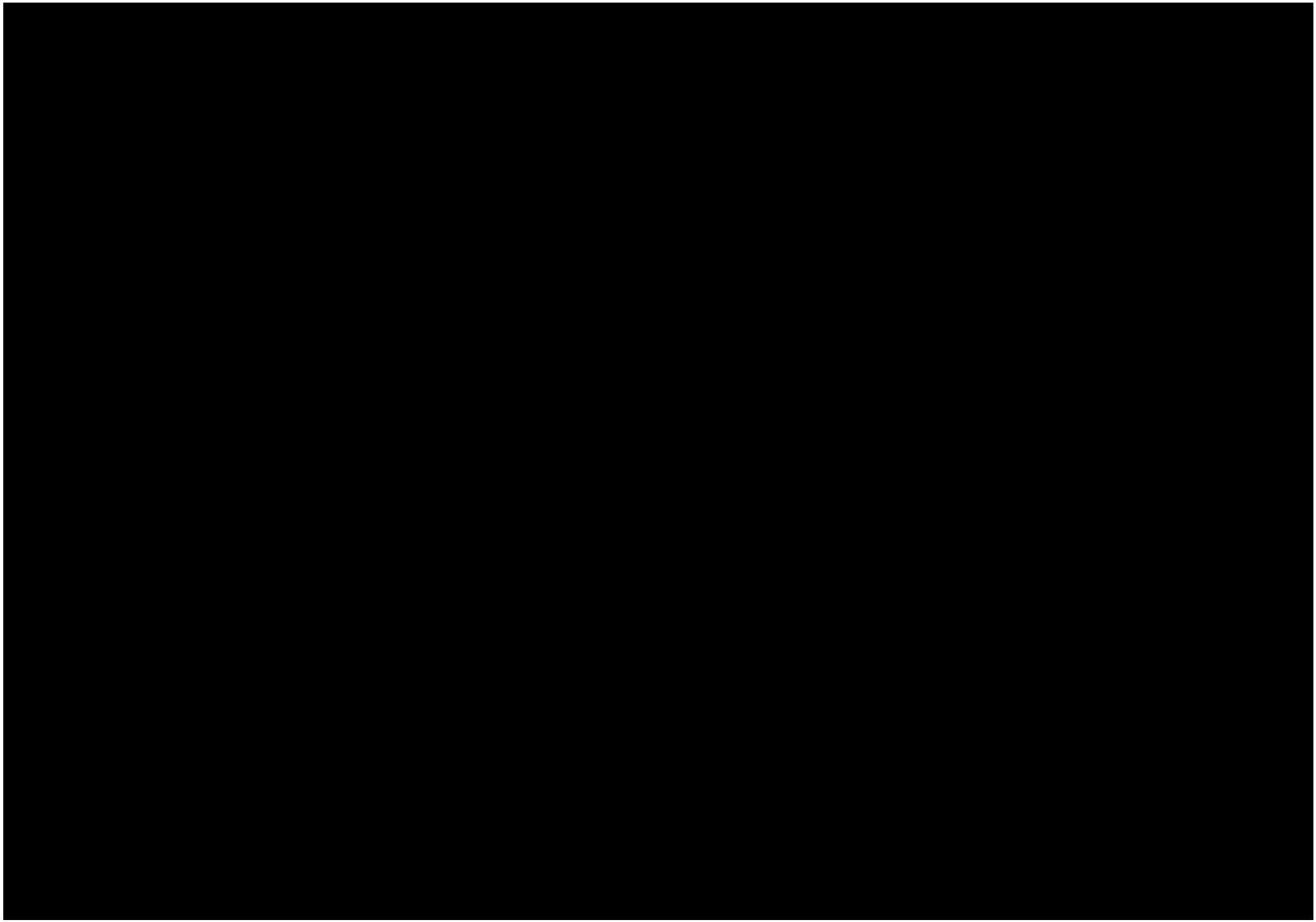
Hourly Average Day for January 2021

Socorro Electric Cooperative, Inc.

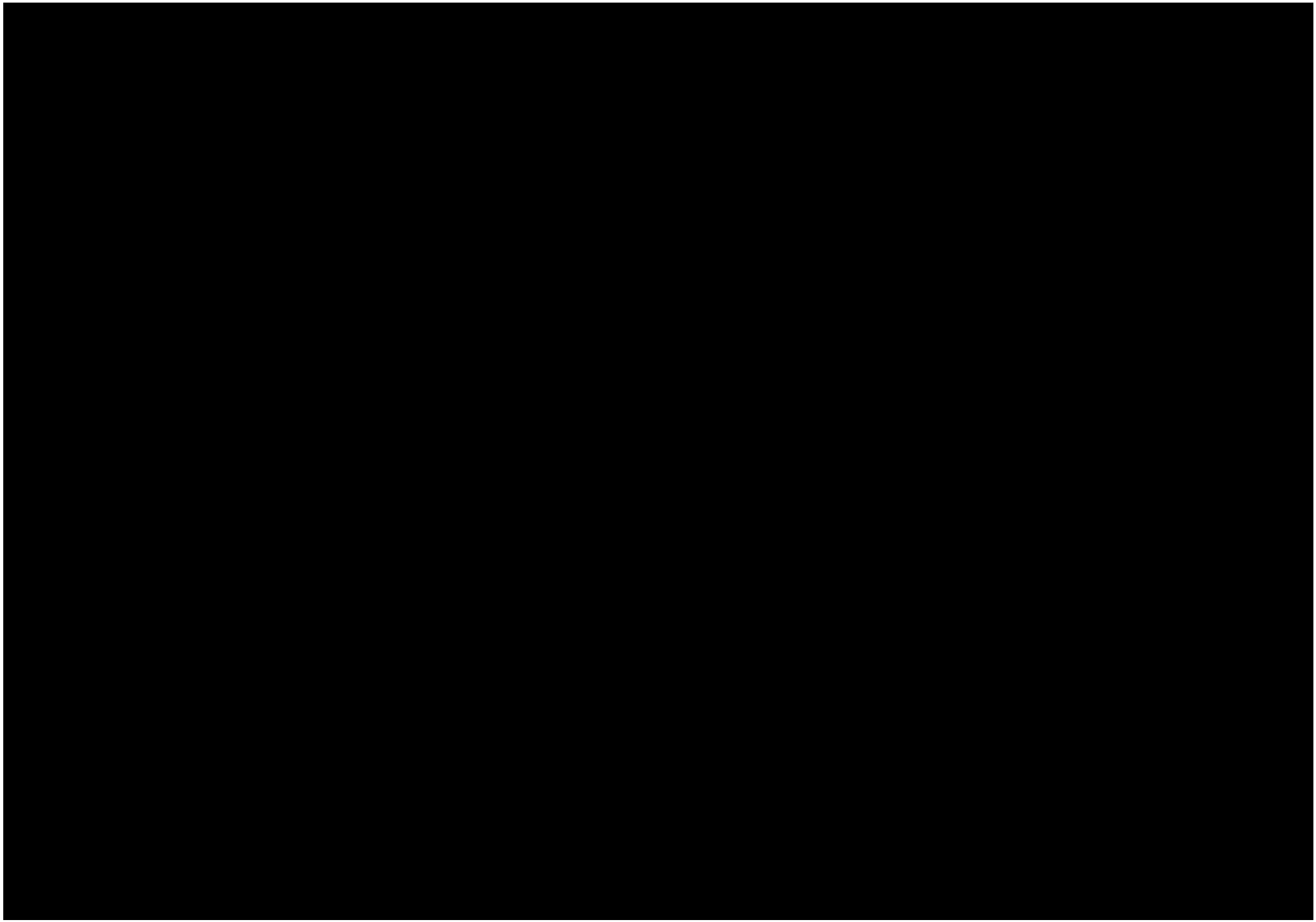


Hourly Average Day for February 2021
Socorro Electric Cooperative, Inc.

[redacted]

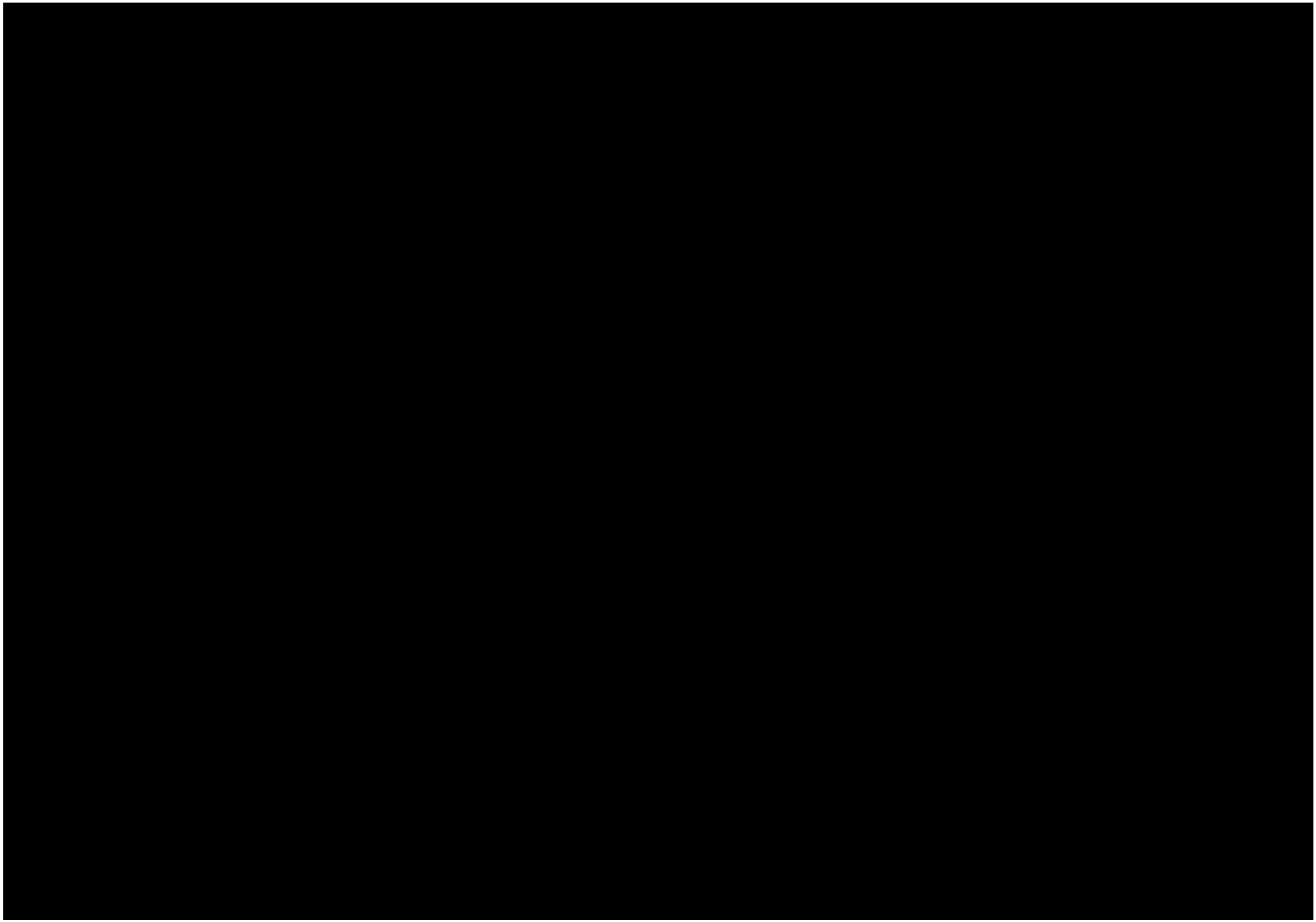
Hourly Average Day for March 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for April 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for May 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Socorro Electric Cooperative, Inc.

[redacted]

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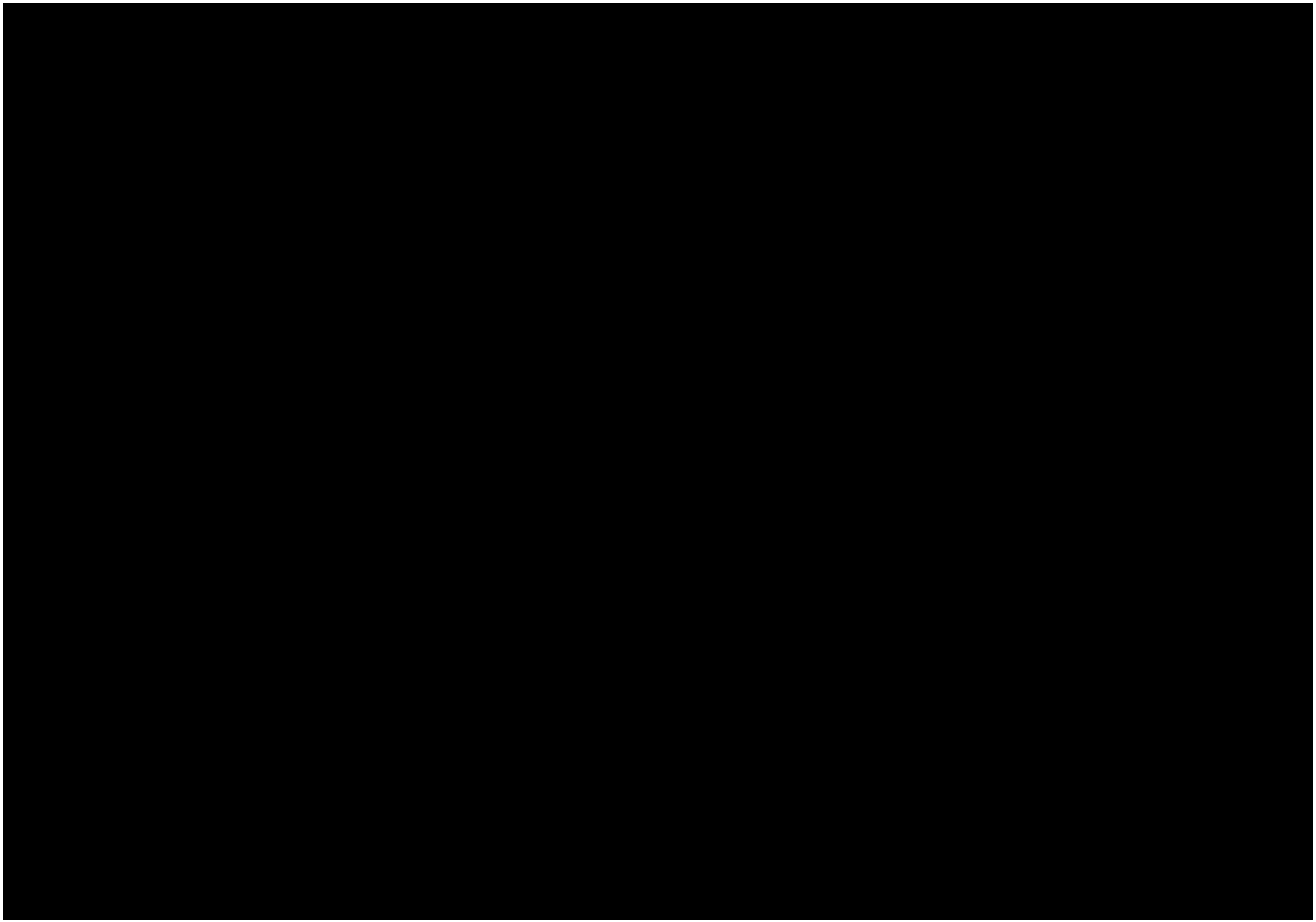
Hourly Average Day for August 2021

Socorro Electric Cooperative, Inc.

[redacted]

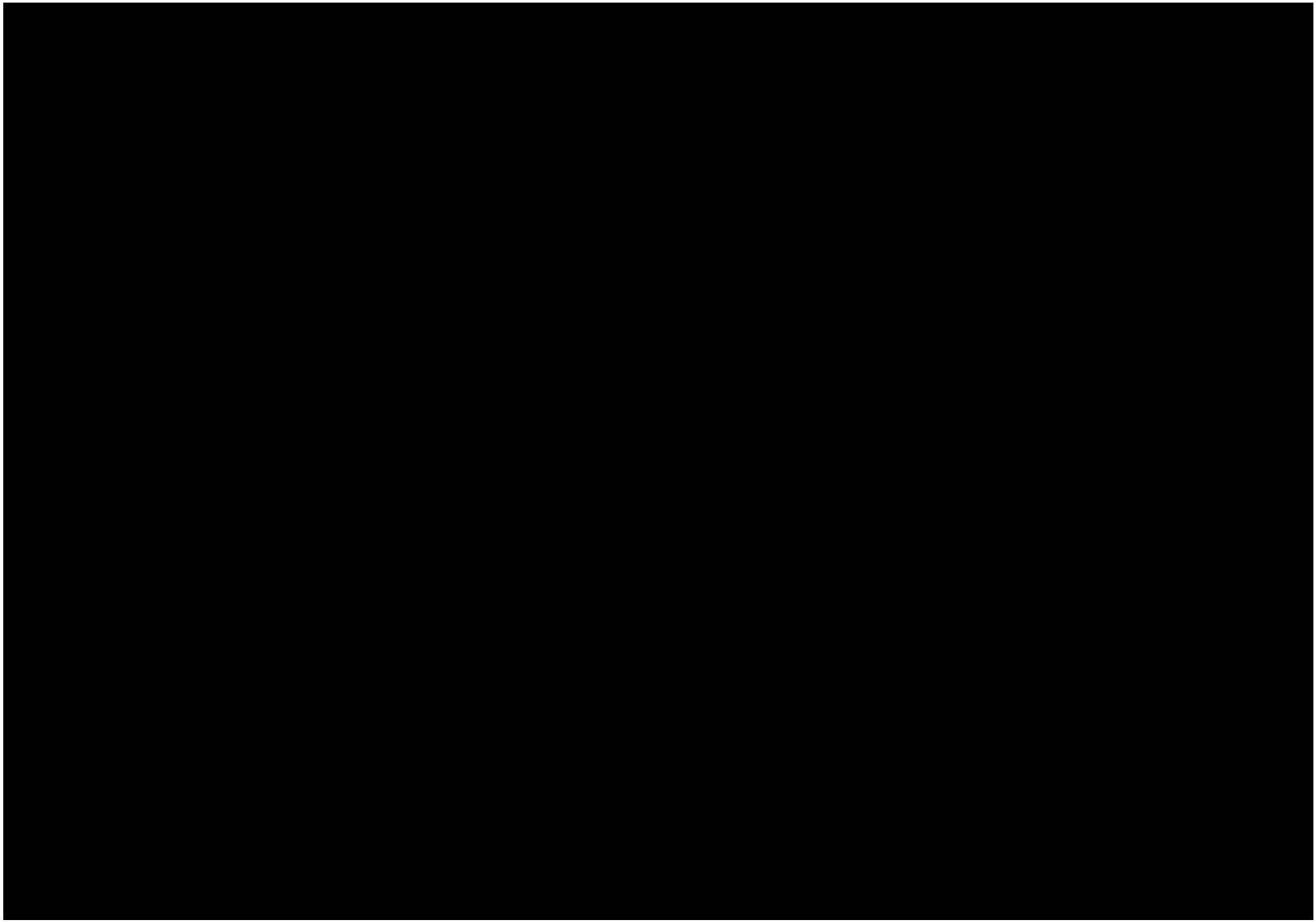
Hourly Average Day for September 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for October 2021

Socorro Electric Cooperative, Inc.



Hourly Average Day for November 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Socorro Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for February 2021
Springer Electric Cooperative, Inc.

[redacted]

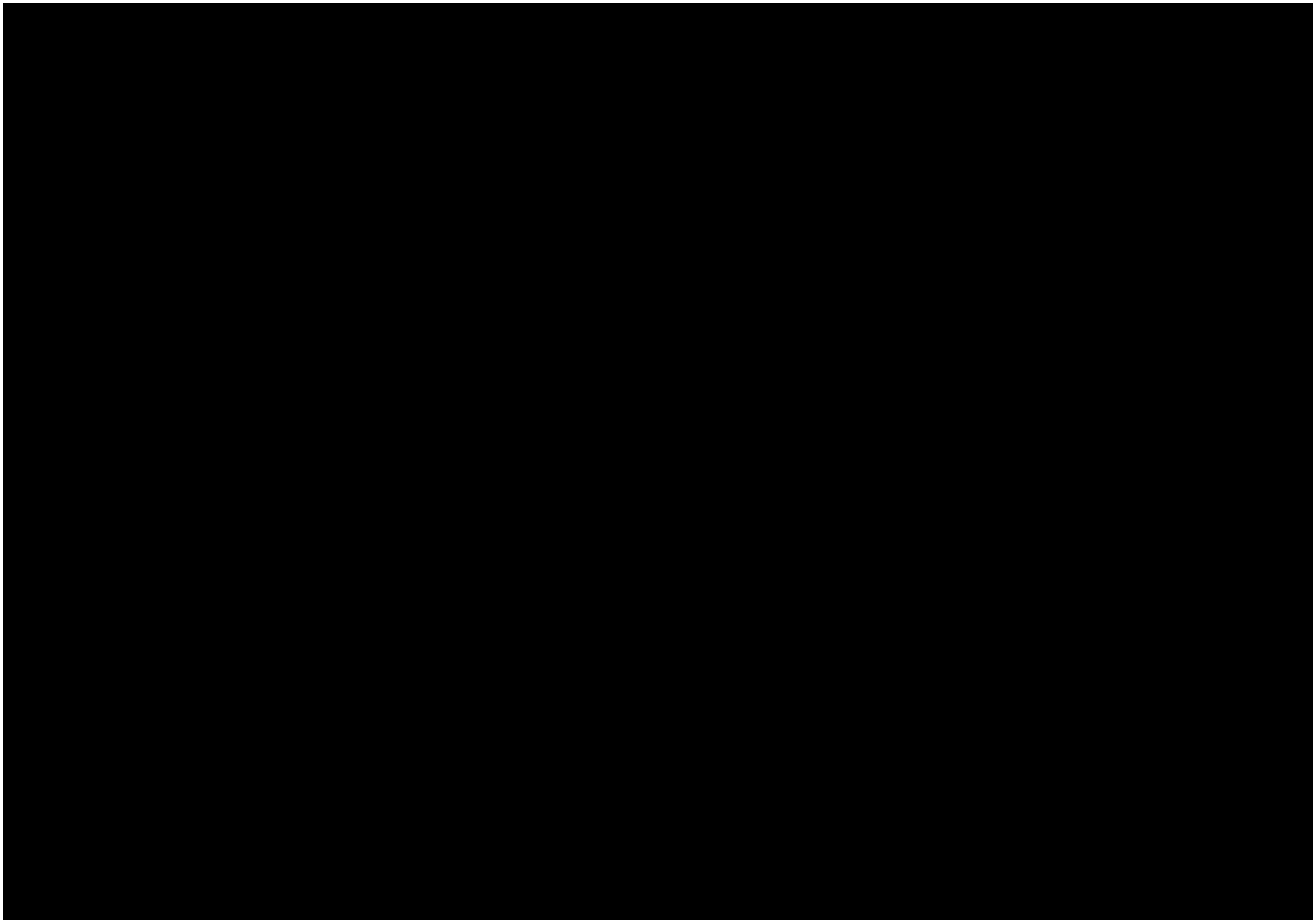
Hourly Average Day for March 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Springer Electric Cooperative, Inc.



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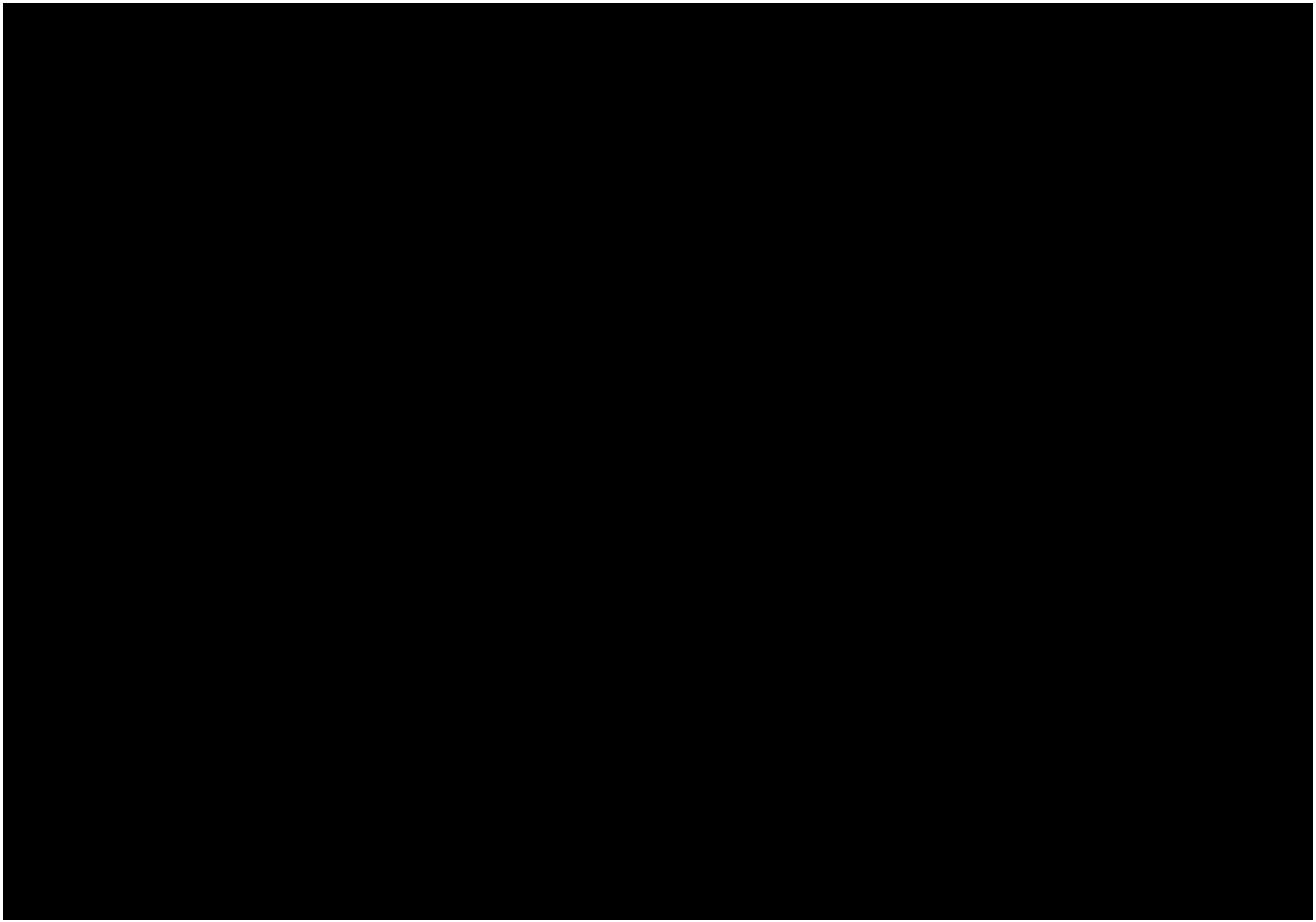
Hourly Average Day for May 2021

Springer Electric Cooperative, Inc.



Hourly Average Day for June 2021

Springer Electric Cooperative, Inc.

[redacted]

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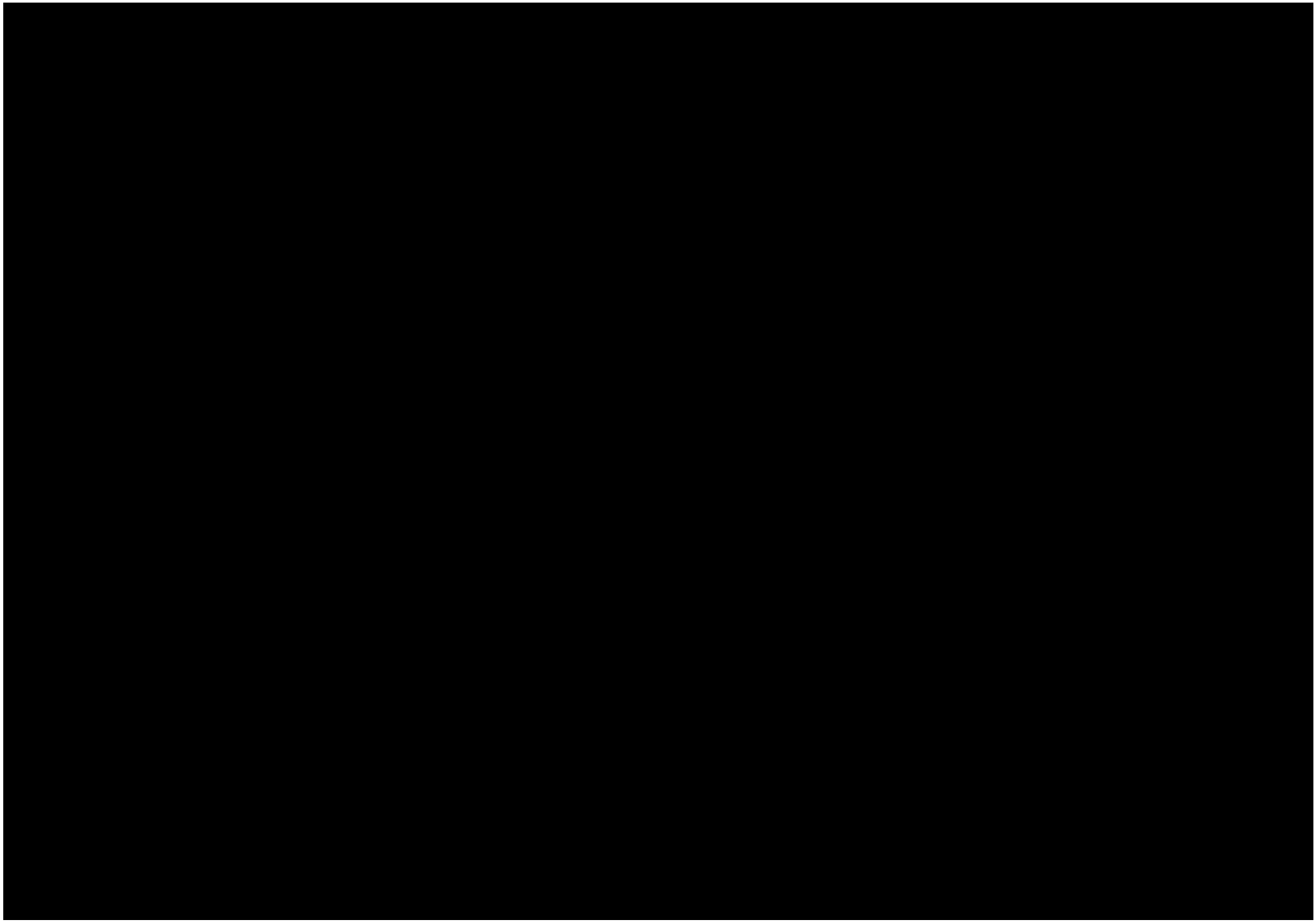
Hourly Average Day for July 2021

Springer Electric Cooperative, Inc.



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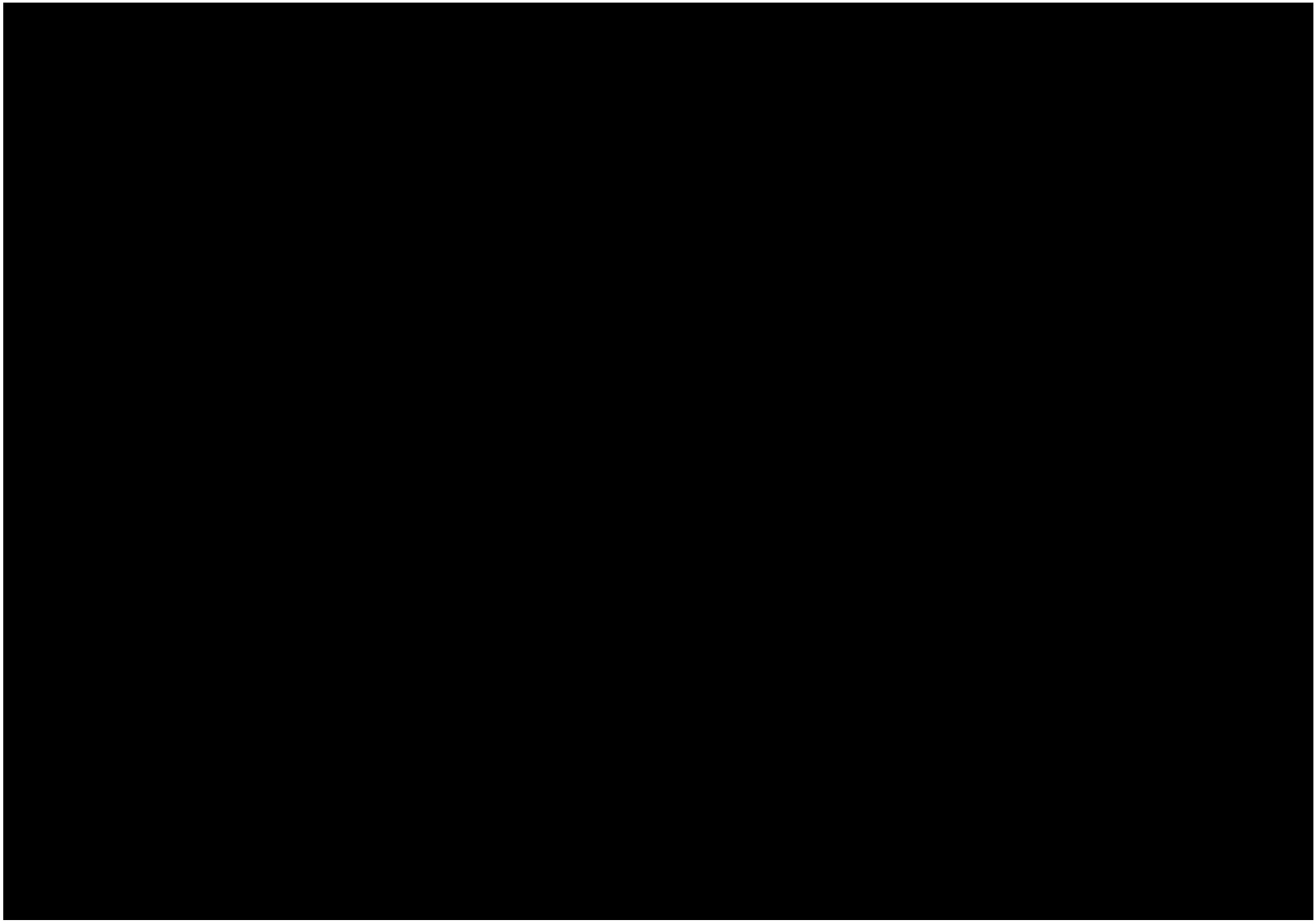
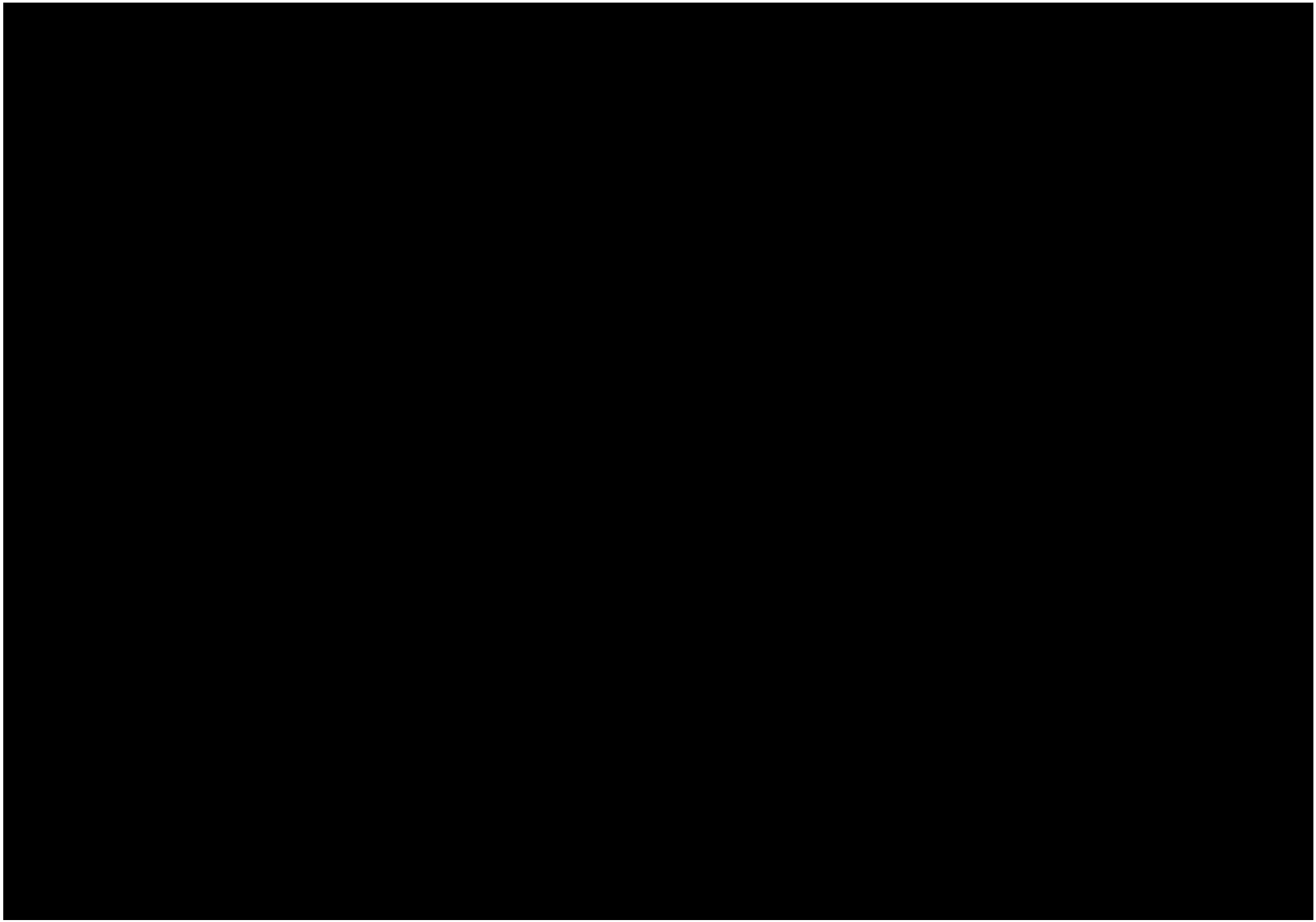
Hourly Average Day for August 2021

Springer Electric Cooperative, Inc.



Hourly Average Day for September 2021
Springer Electric Cooperative, Inc.



Hourly Average Day for October 2021

Springer Electric Cooperative, Inc.

[redacted]

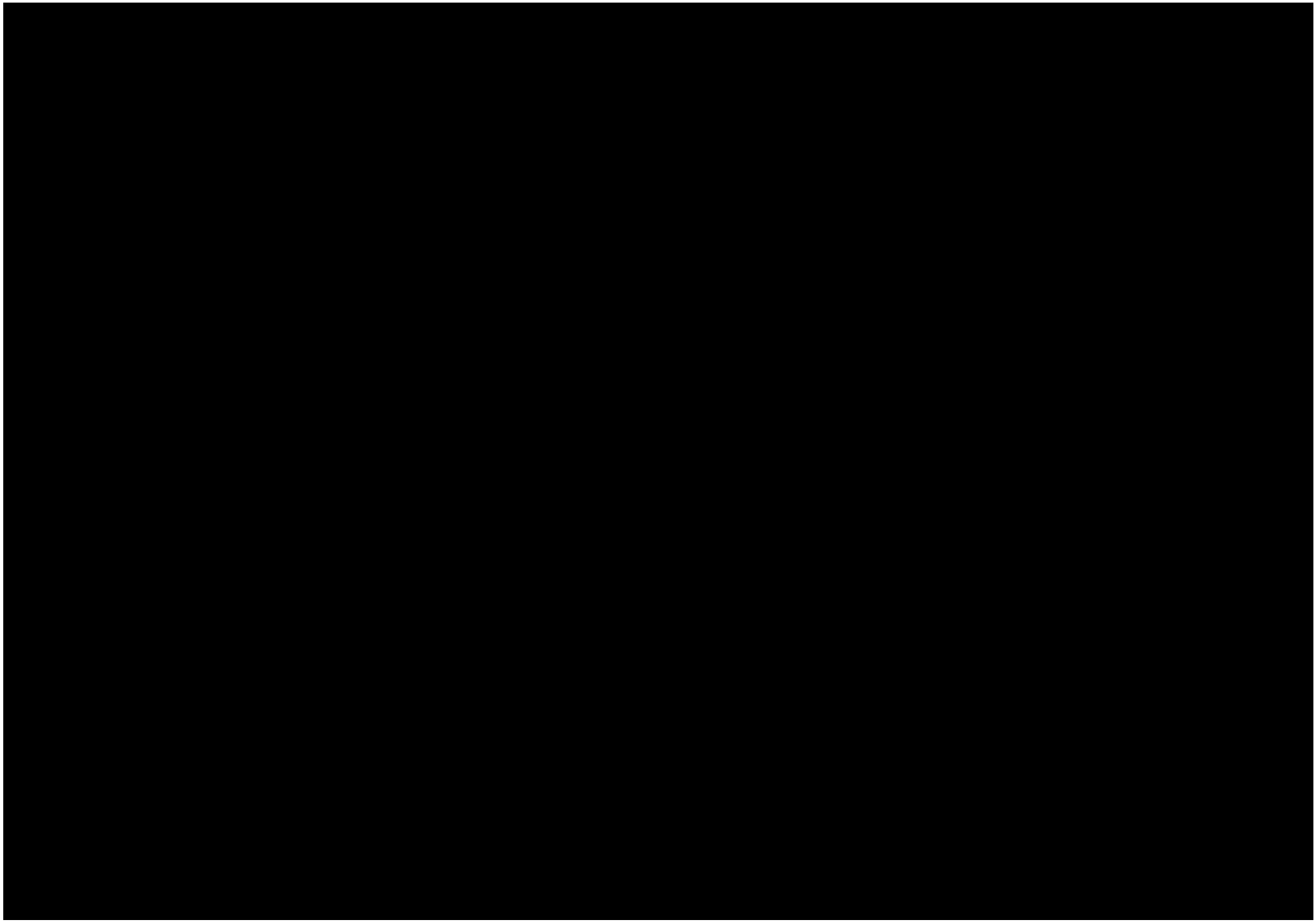
Hourly Average Day for November 2021

Springer Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Springer Electric Cooperative, Inc.



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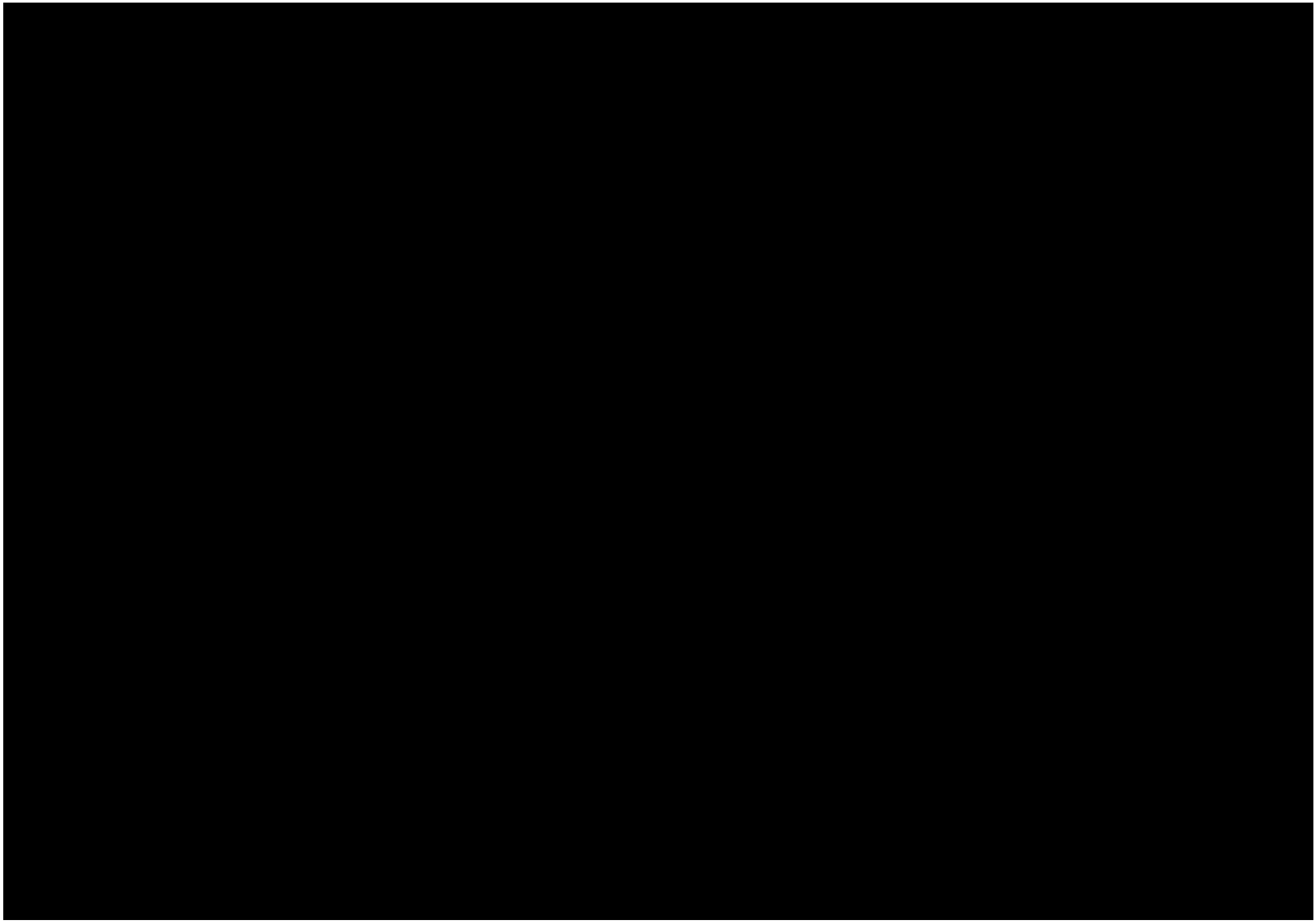
Hourly Average Day for January 2021

Southwestern Electric Cooperative, Inc.



Hourly Average Day for February 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for March 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for April 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for May 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for June 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for July 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for August 2021

Southwestern Electric Cooperative, Inc.

[redacted]

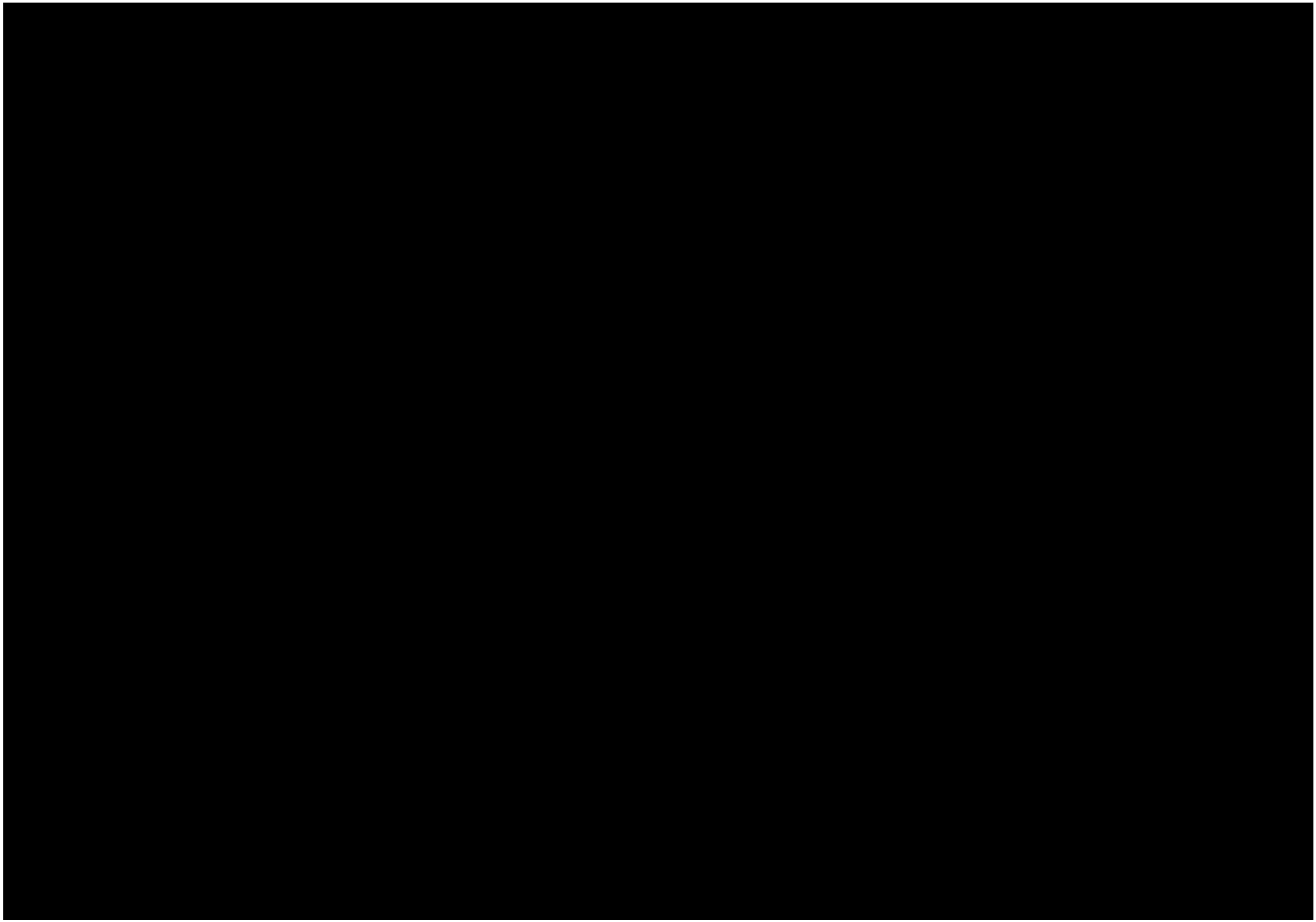
Hourly Average Day for September 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for October 2021

Southwestern Electric Cooperative, Inc.



Hourly Average Day for November 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for December 2021

Southwestern Electric Cooperative, Inc.

[redacted]

Hourly Average Day for January 2021

United Power, Inc.

[redacted]

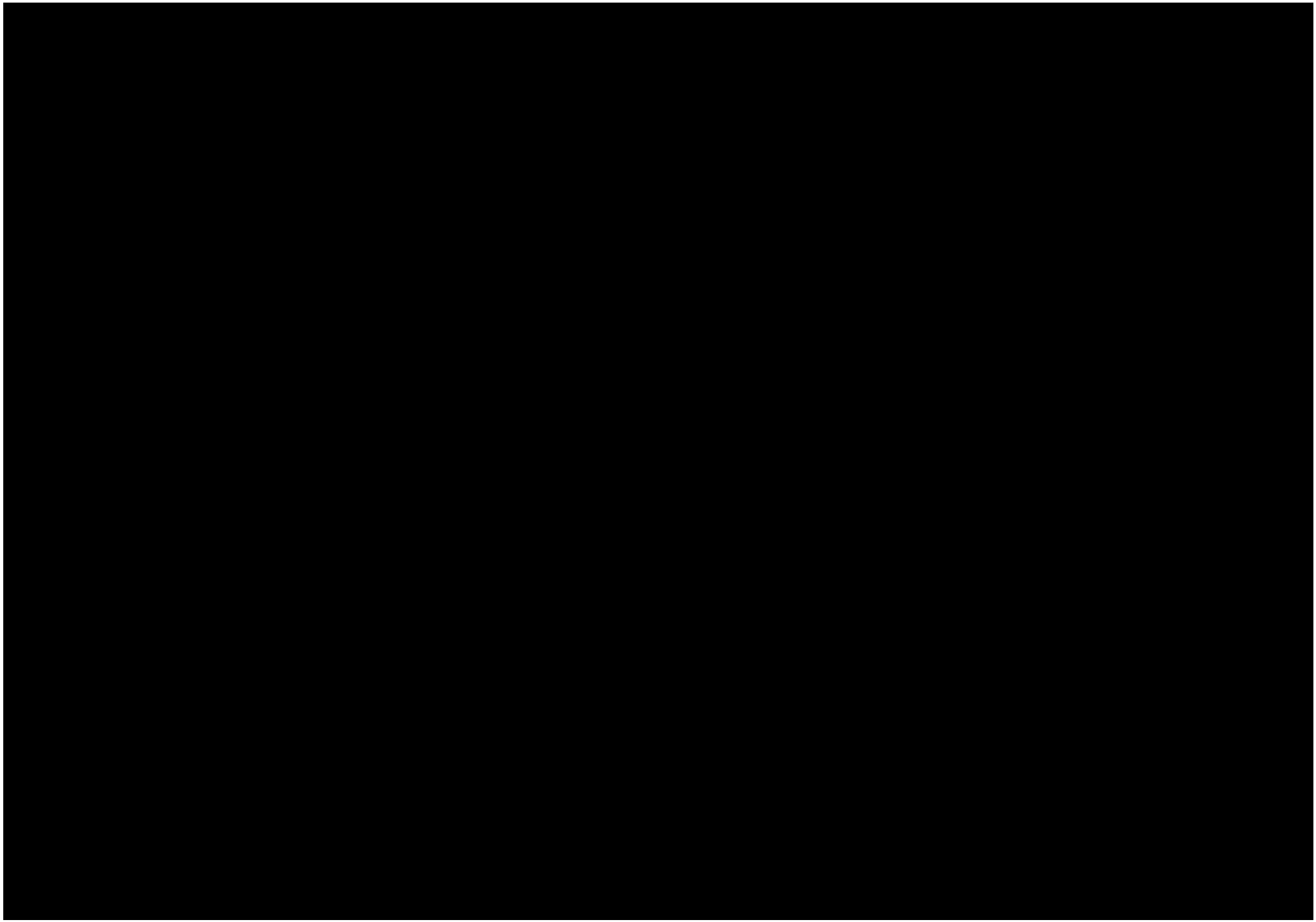
Hourly Average Day for February 2021

United Power, Inc.

[redacted]

Hourly Average Day for March 2021

United Power, Inc.



Hourly Average Day for April 2021

United Power, Inc.

[redacted]

Hourly Average Day for May 2021

United Power, Inc.

[redacted]

Hourly Average Day for June 2021

United Power, Inc.

[redacted]

Hourly Average Day for July 2021

United Power, Inc.

[redacted]

Hourly Average Day for August 2021

United Power, Inc.

[redacted]

Hourly Average Day for September 2021

United Power, Inc.

[redacted]

Hourly Average Day for October 2021

United Power, Inc.

[redacted]

Hourly Average Day for November 2021

United Power, Inc.

[redacted]

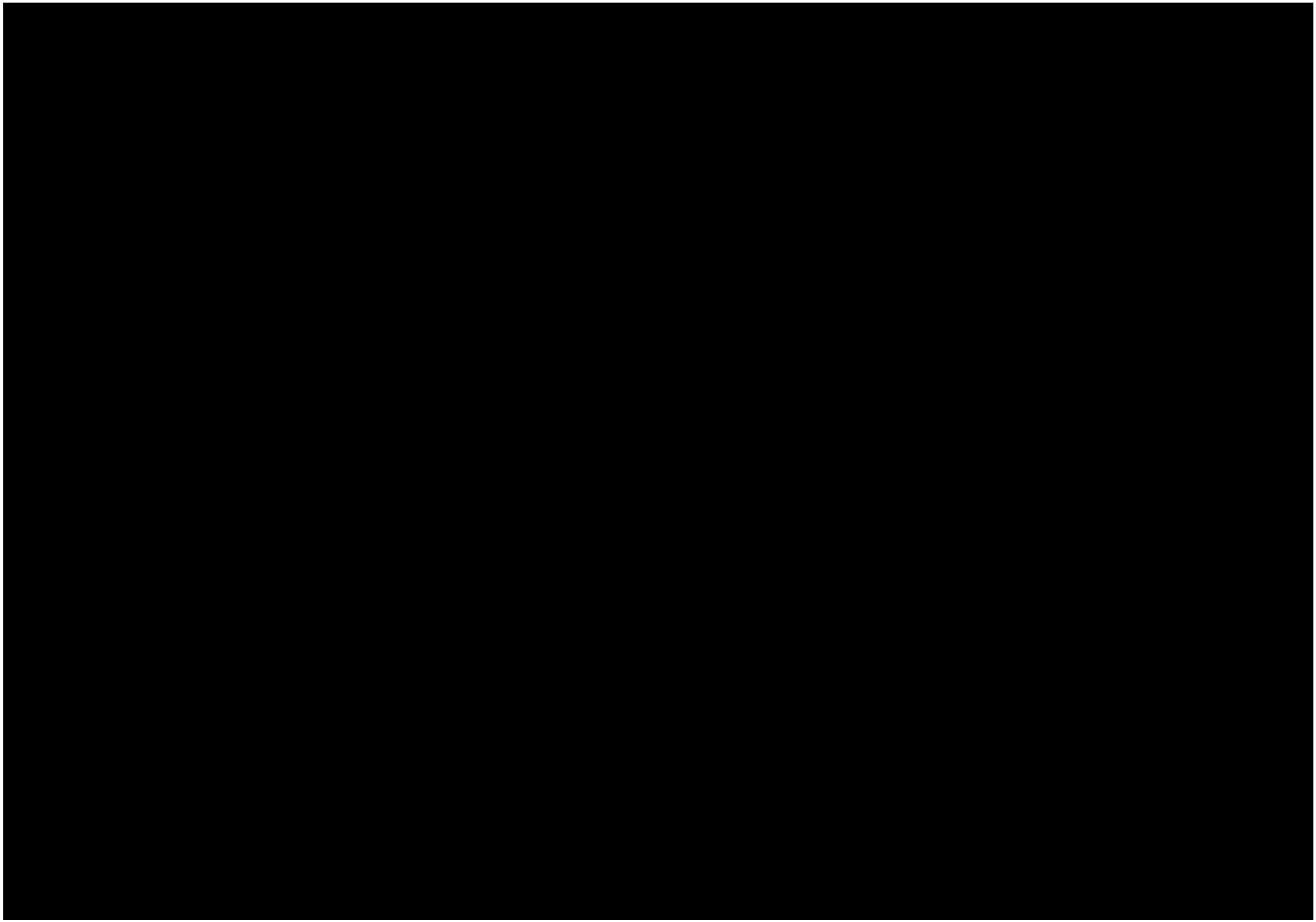
Hourly Average Day for December 2021

United Power, Inc.

[redacted]

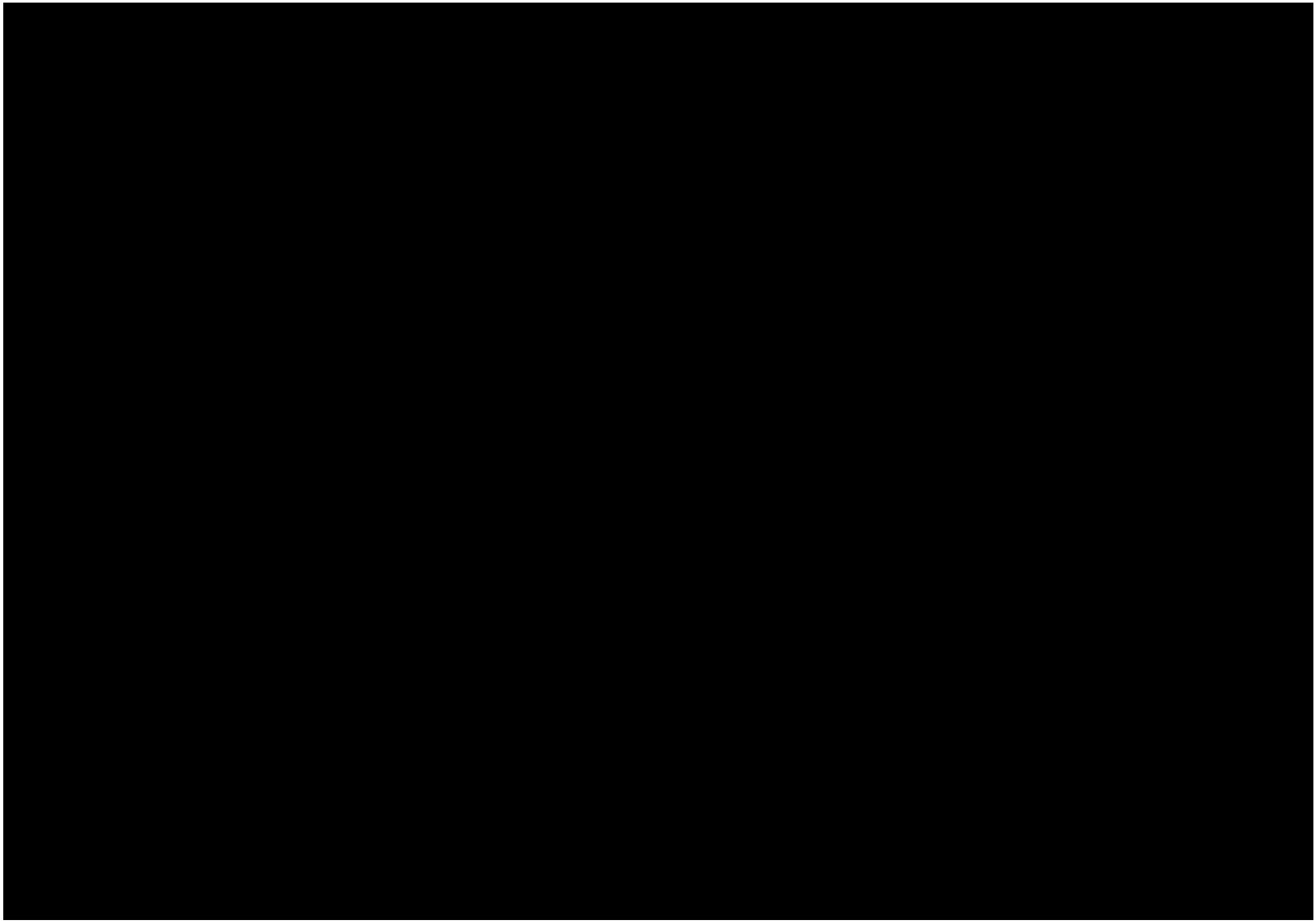
Hourly Average Day for January 2021

Wheat Belt Public Power District



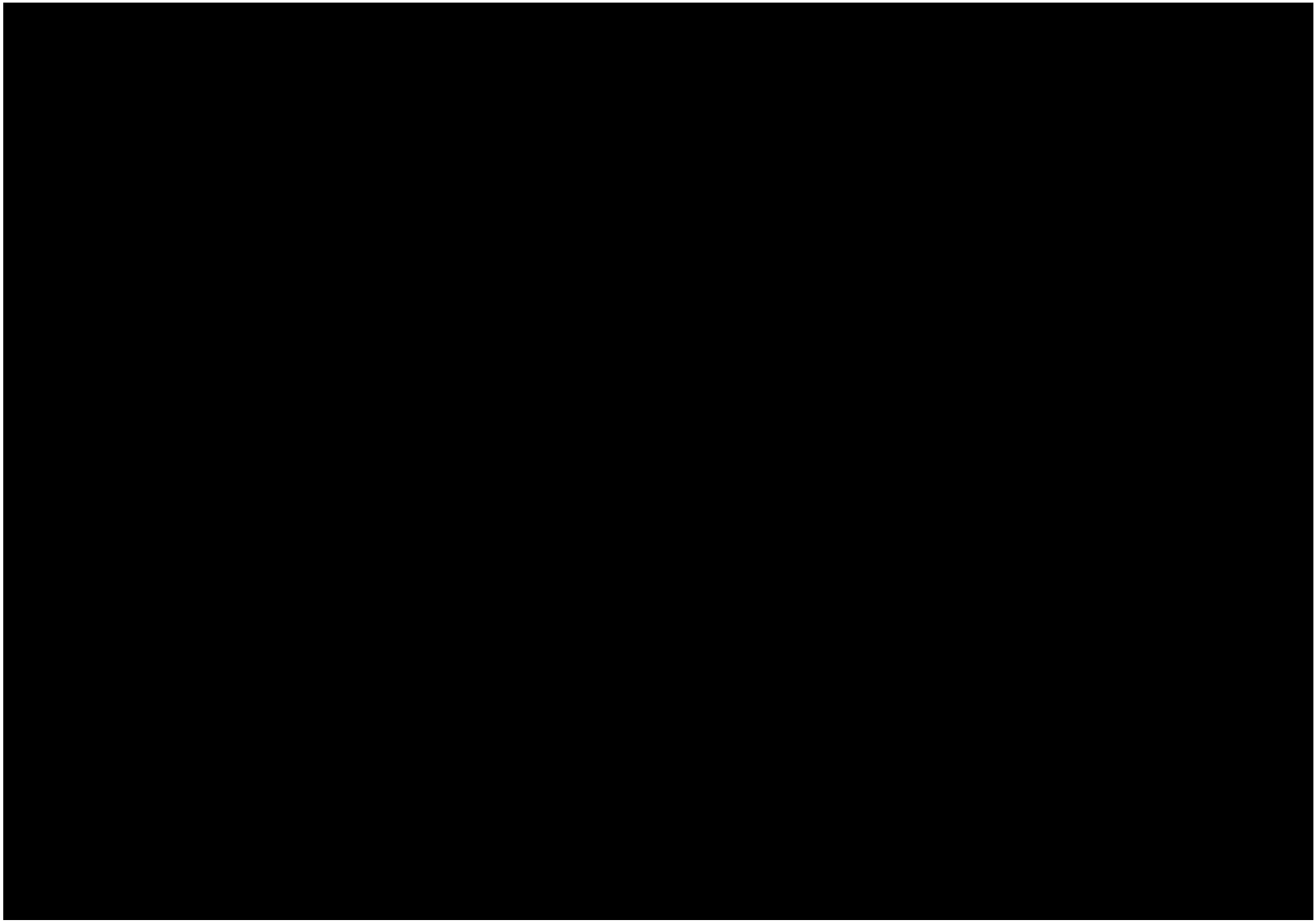
Hourly Average Day for February 2021

Wheat Belt Public Power District



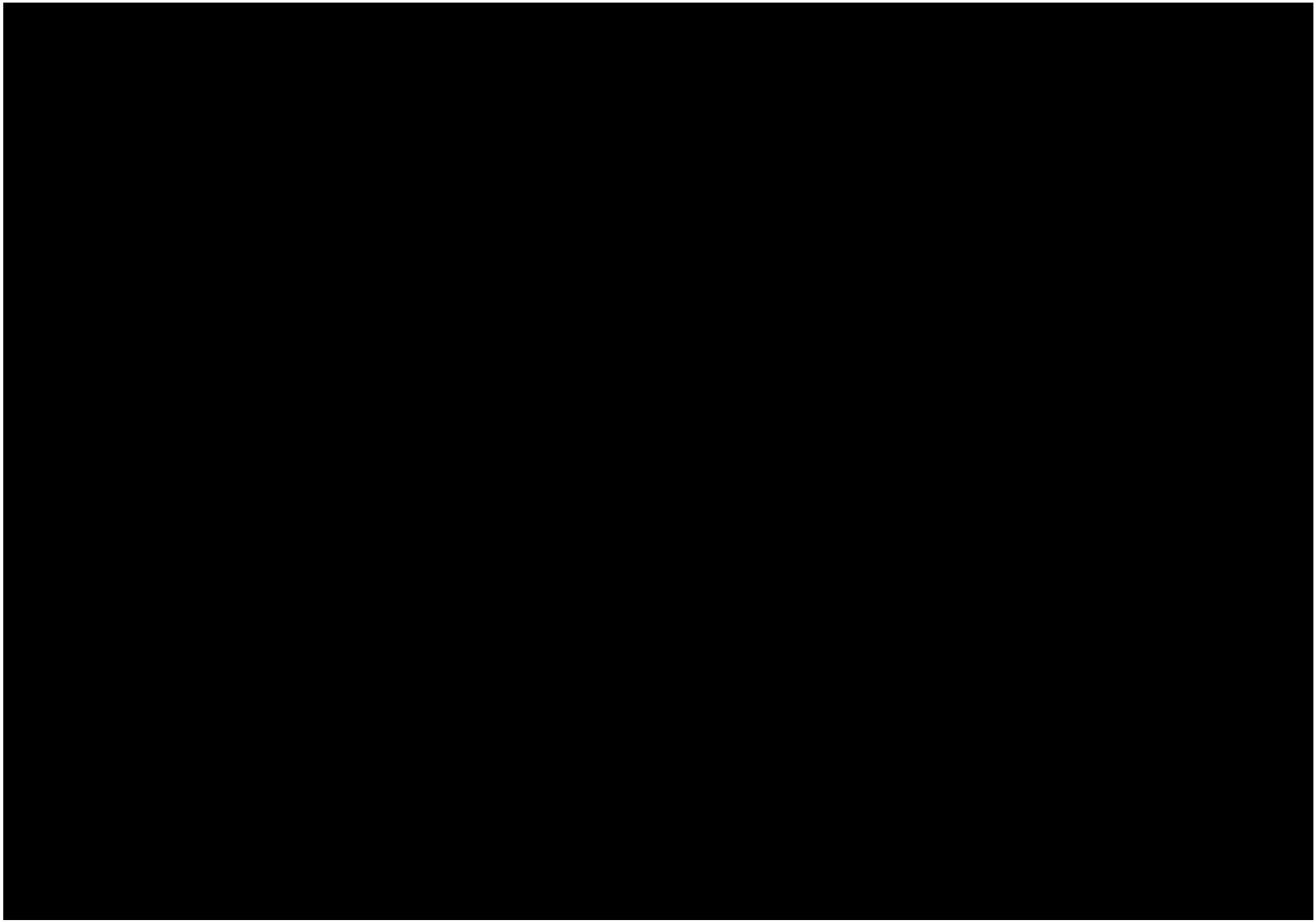
Hourly Average Day for March 2021

Wheat Belt Public Power District



Hourly Average Day for April 2021

Wheat Belt Public Power District



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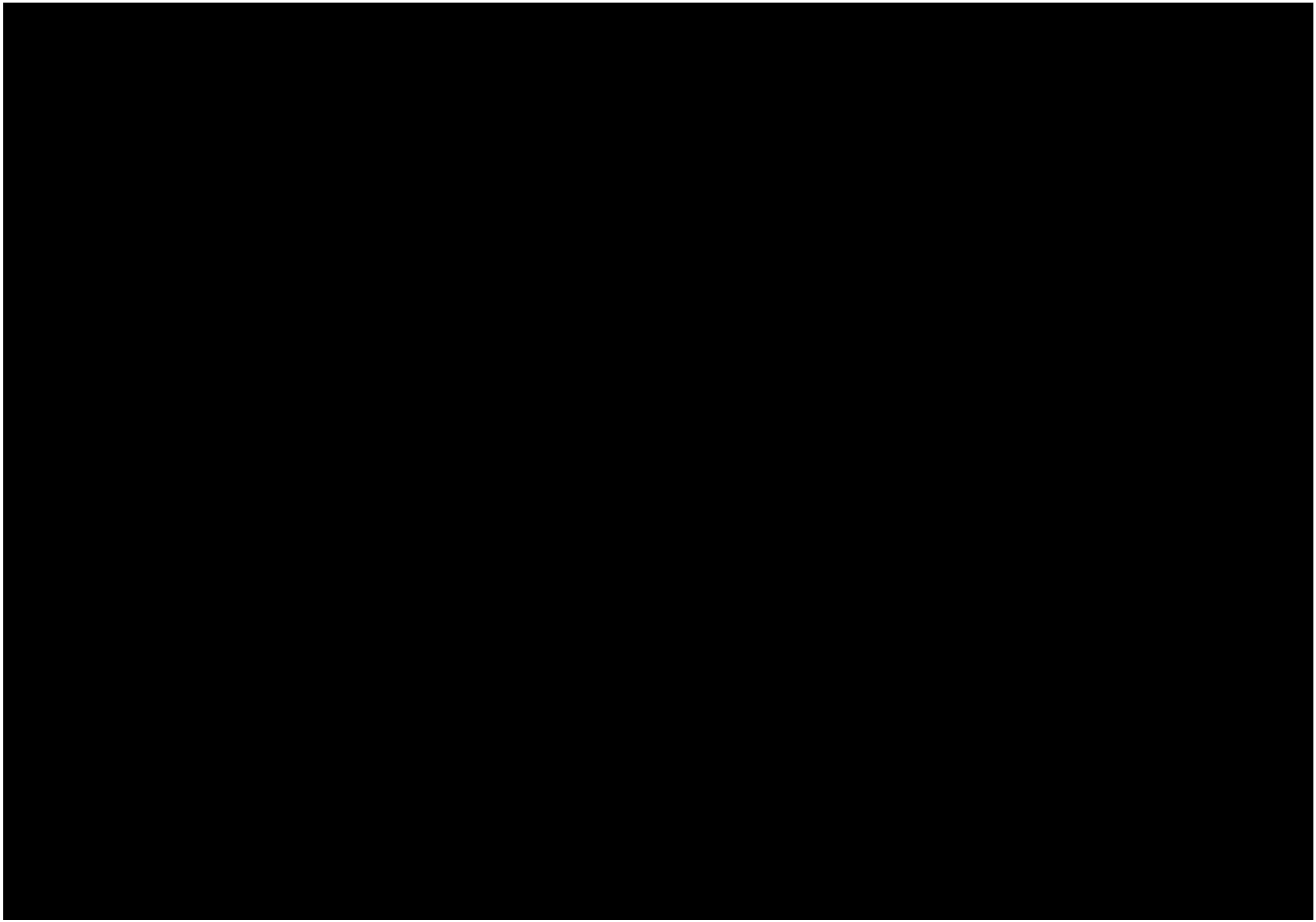
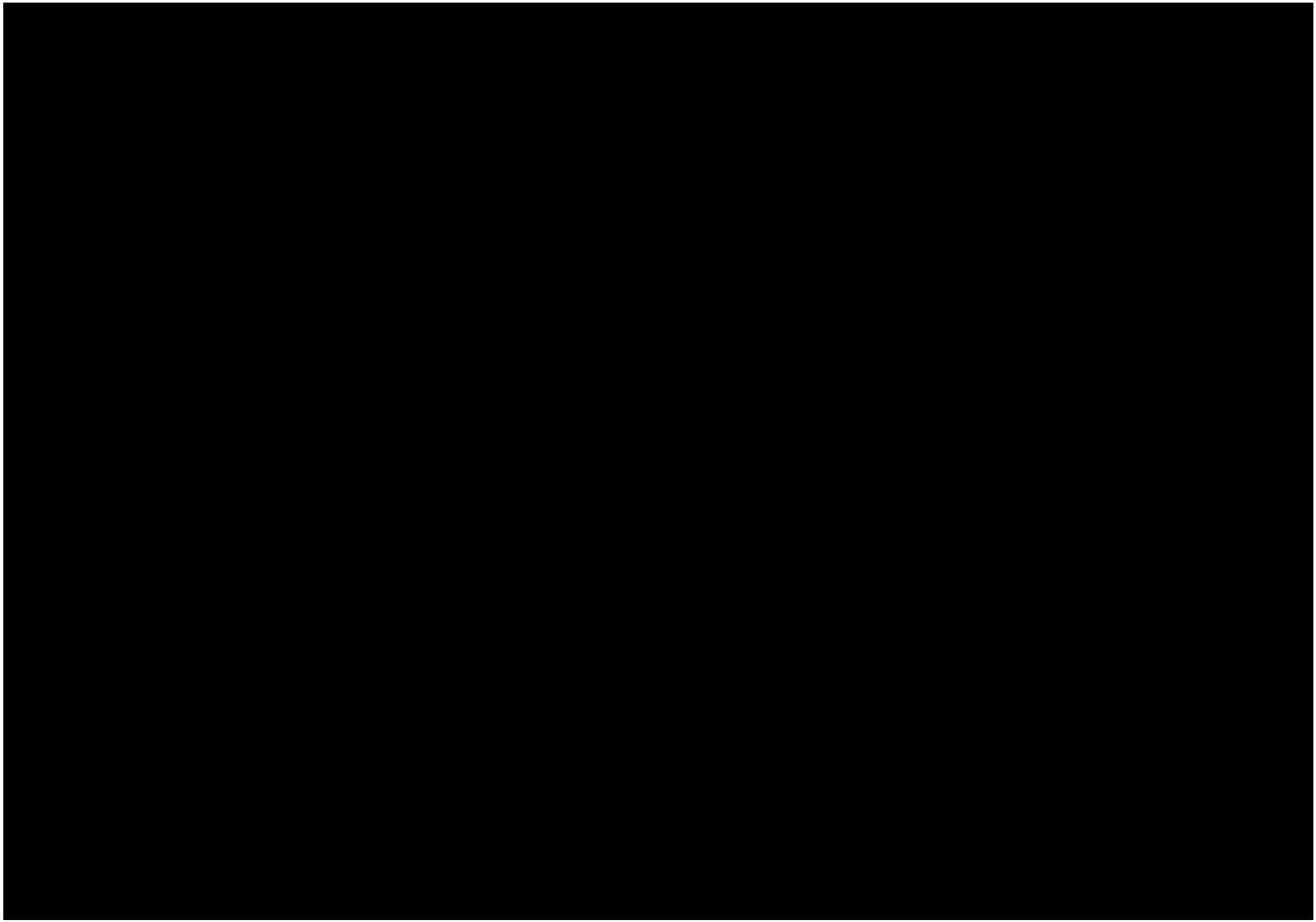
Hourly Average Day for May 2021

Wheat Belt Public Power District



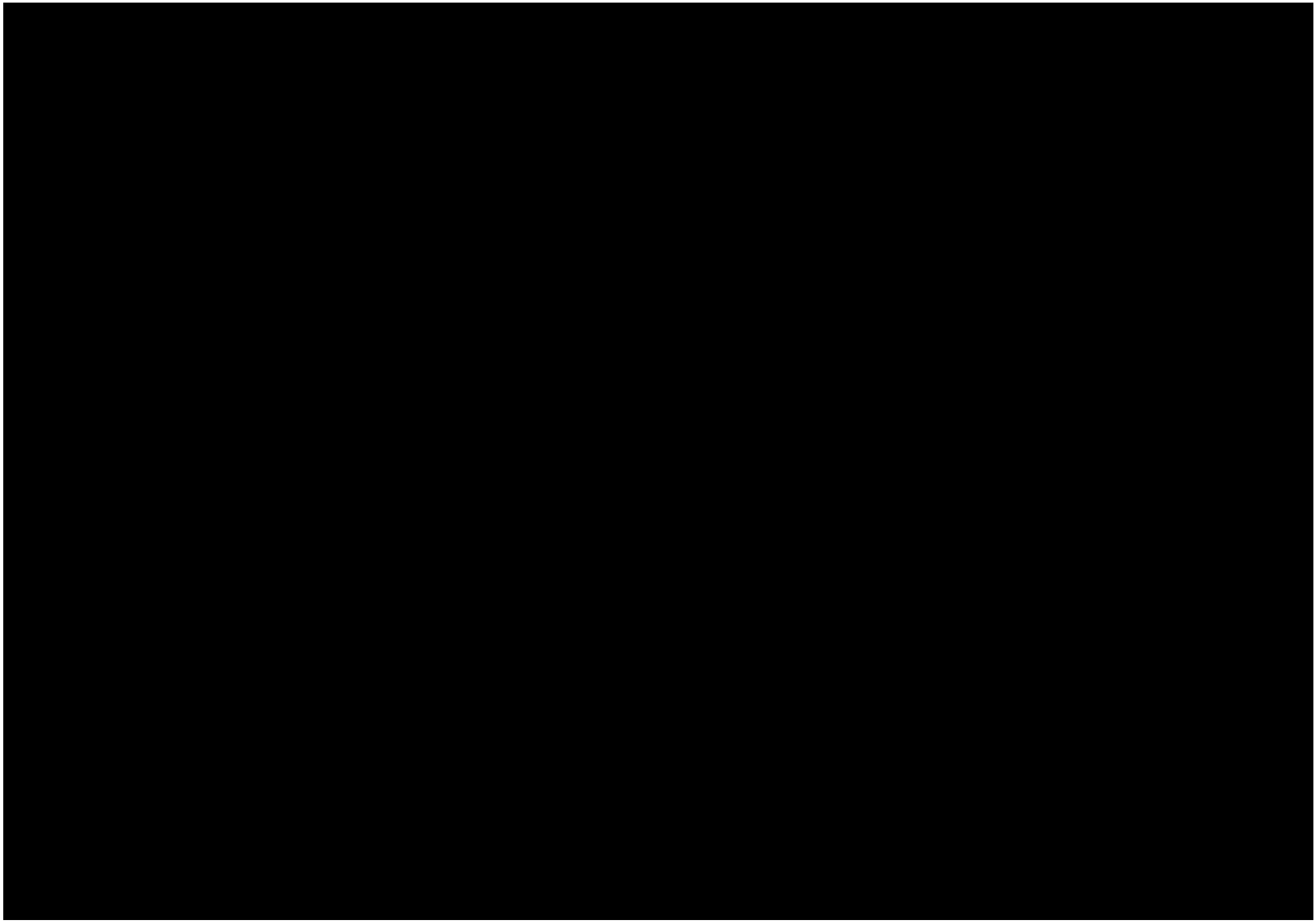
Hourly Average Day for June 2021

Wheat Belt Public Power District



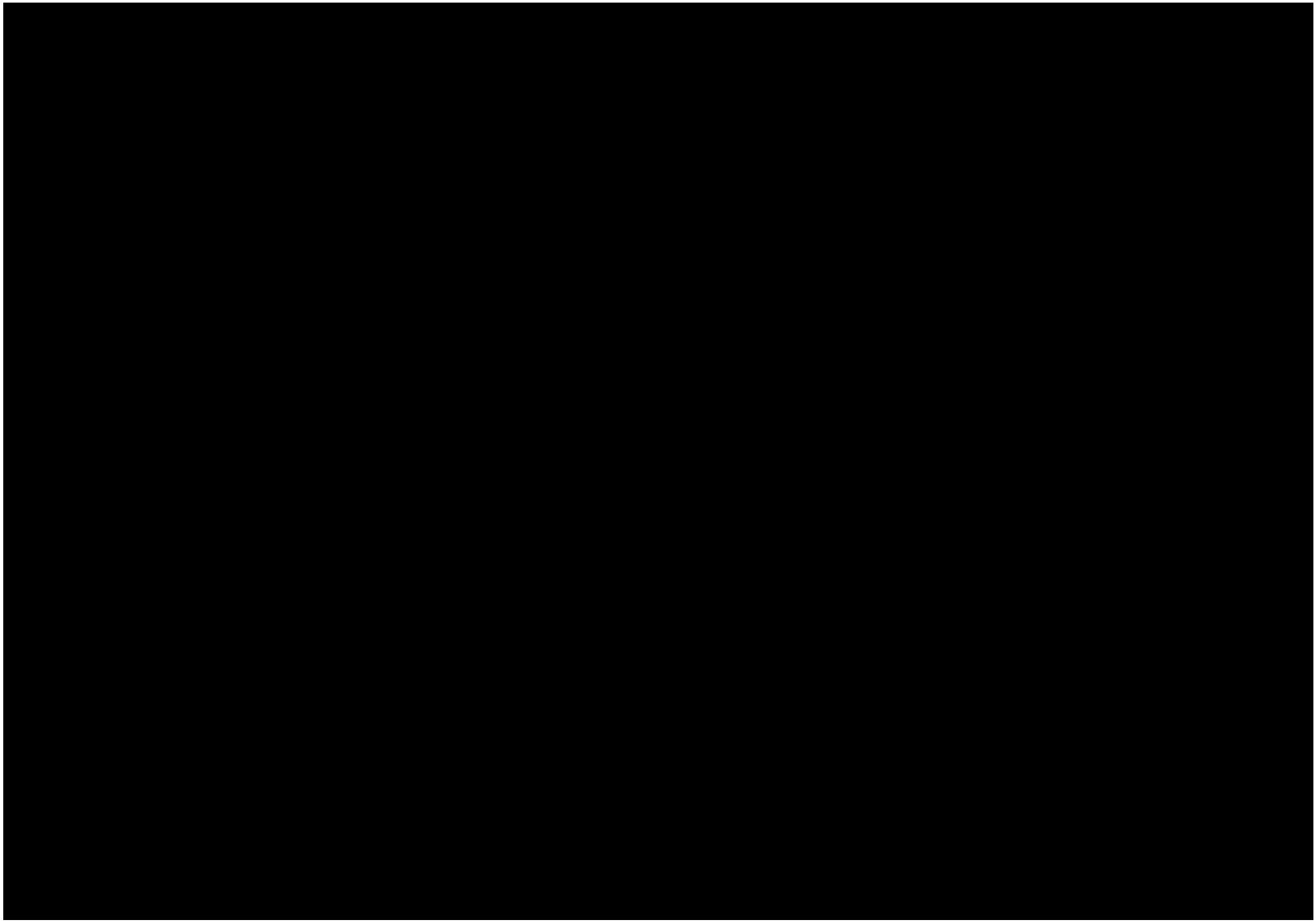
Hourly Average Day for July 2021

Wheat Belt Public Power District



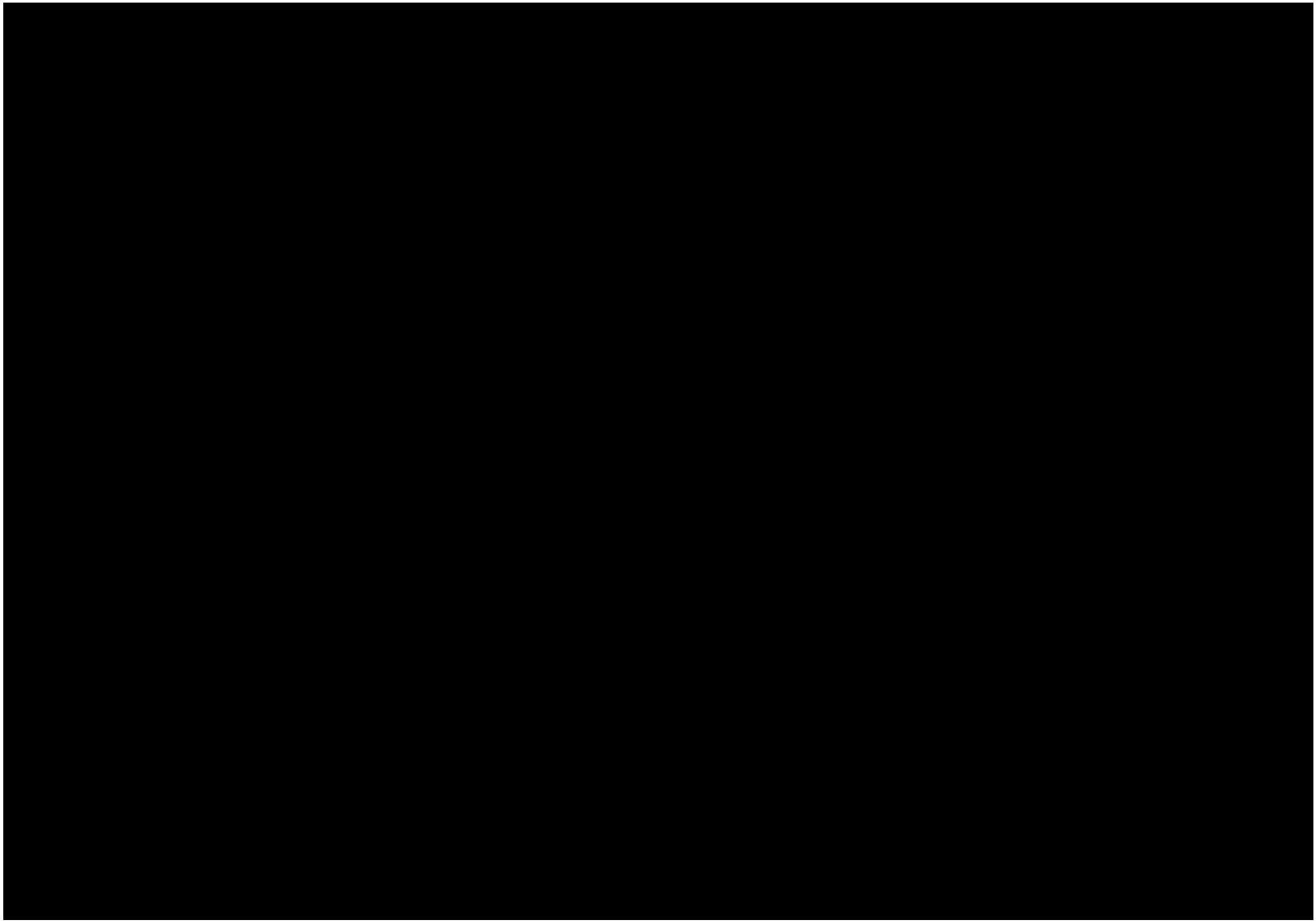
Hourly Average Day for August 2021

Wheat Belt Public Power District



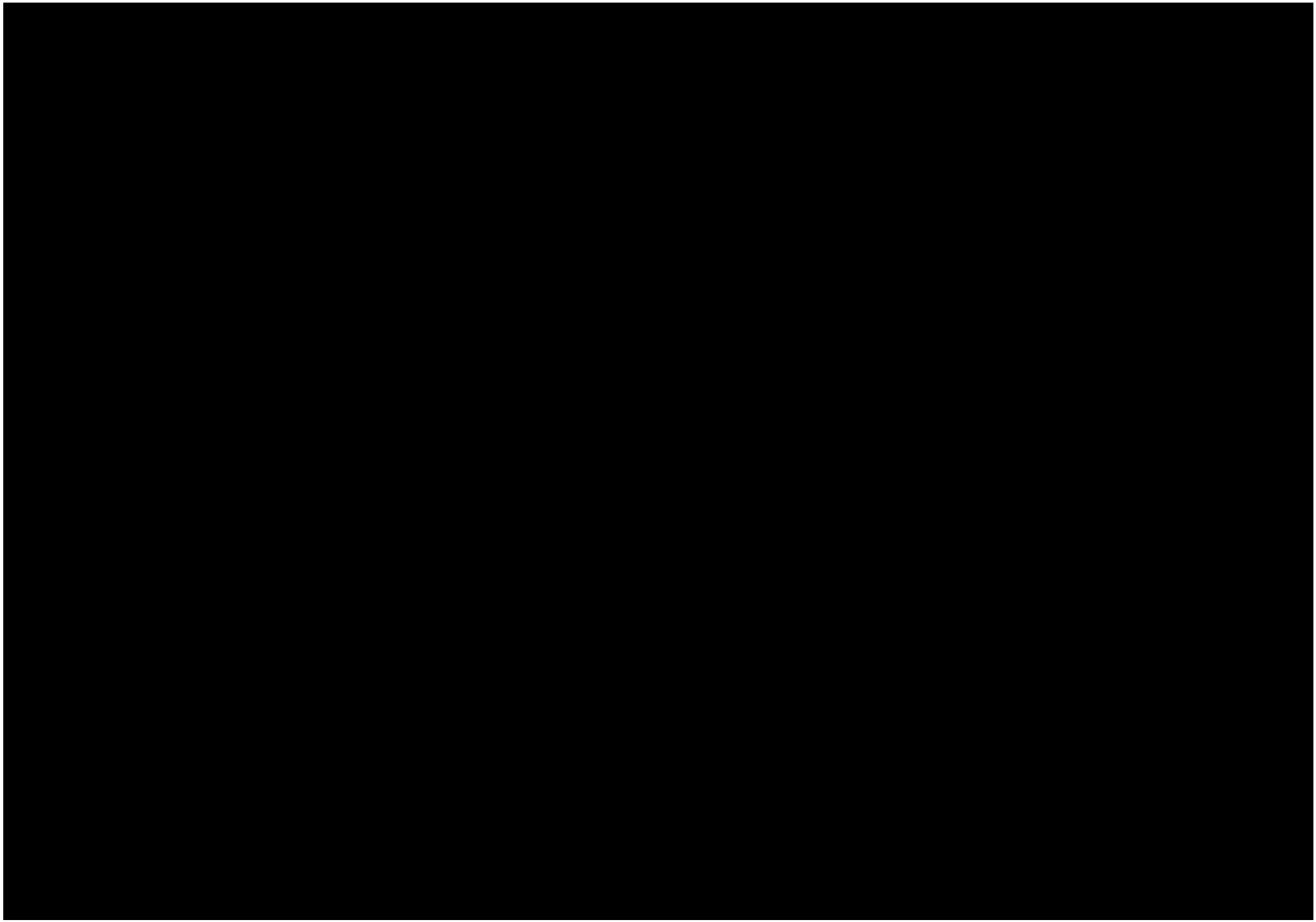
Hourly Average Day for September 2021

Wheat Belt Public Power District



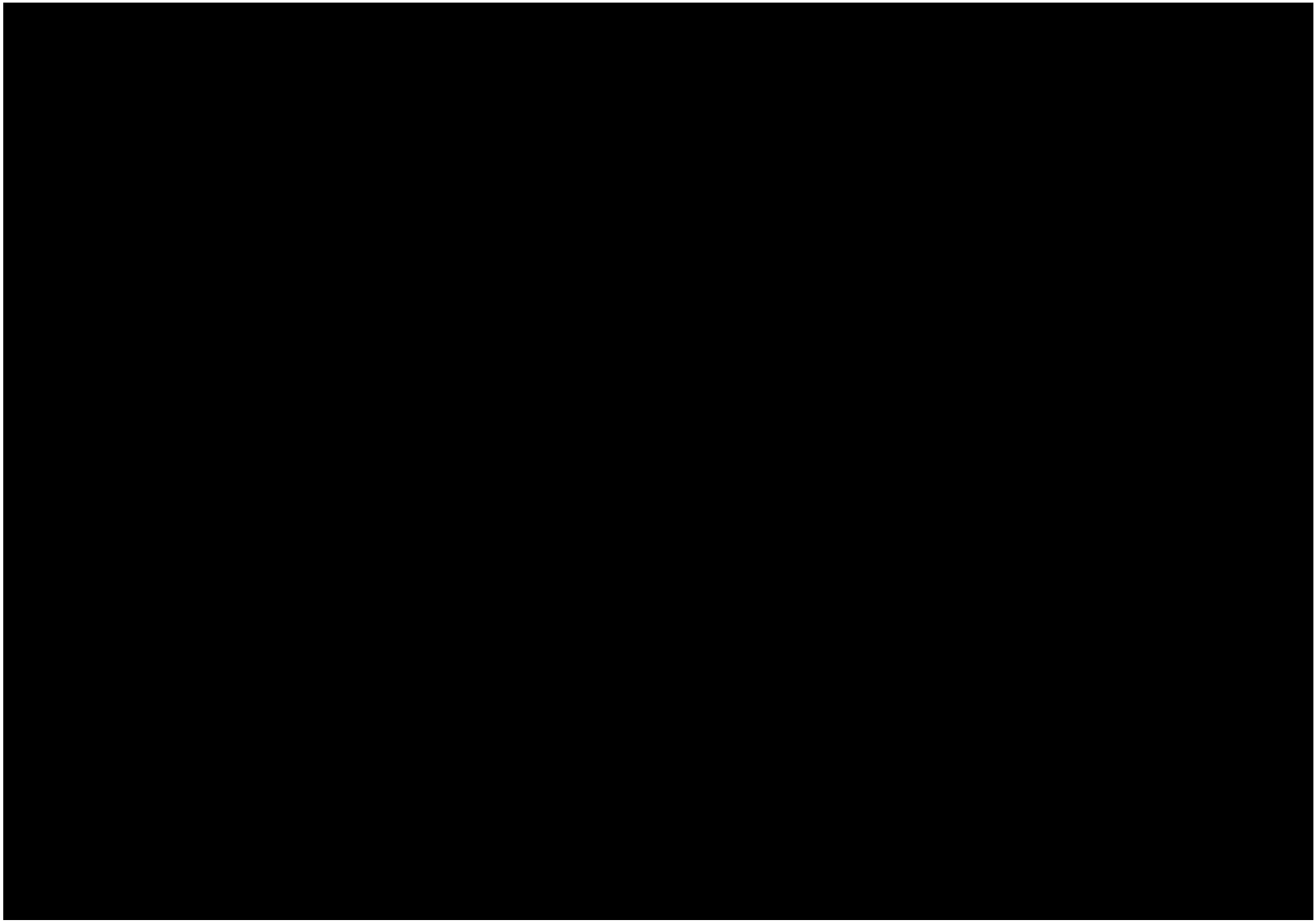
Hourly Average Day for October 2021

Wheat Belt Public Power District



Hourly Average Day for November 2021

Wheat Belt Public Power District



Hourly Average Day for December 2021

Wheat Belt Public Power District

[redacted]

Hourly Average Day for January 2021

Wheatland Rural Electric Association, Inc.

[redacted]

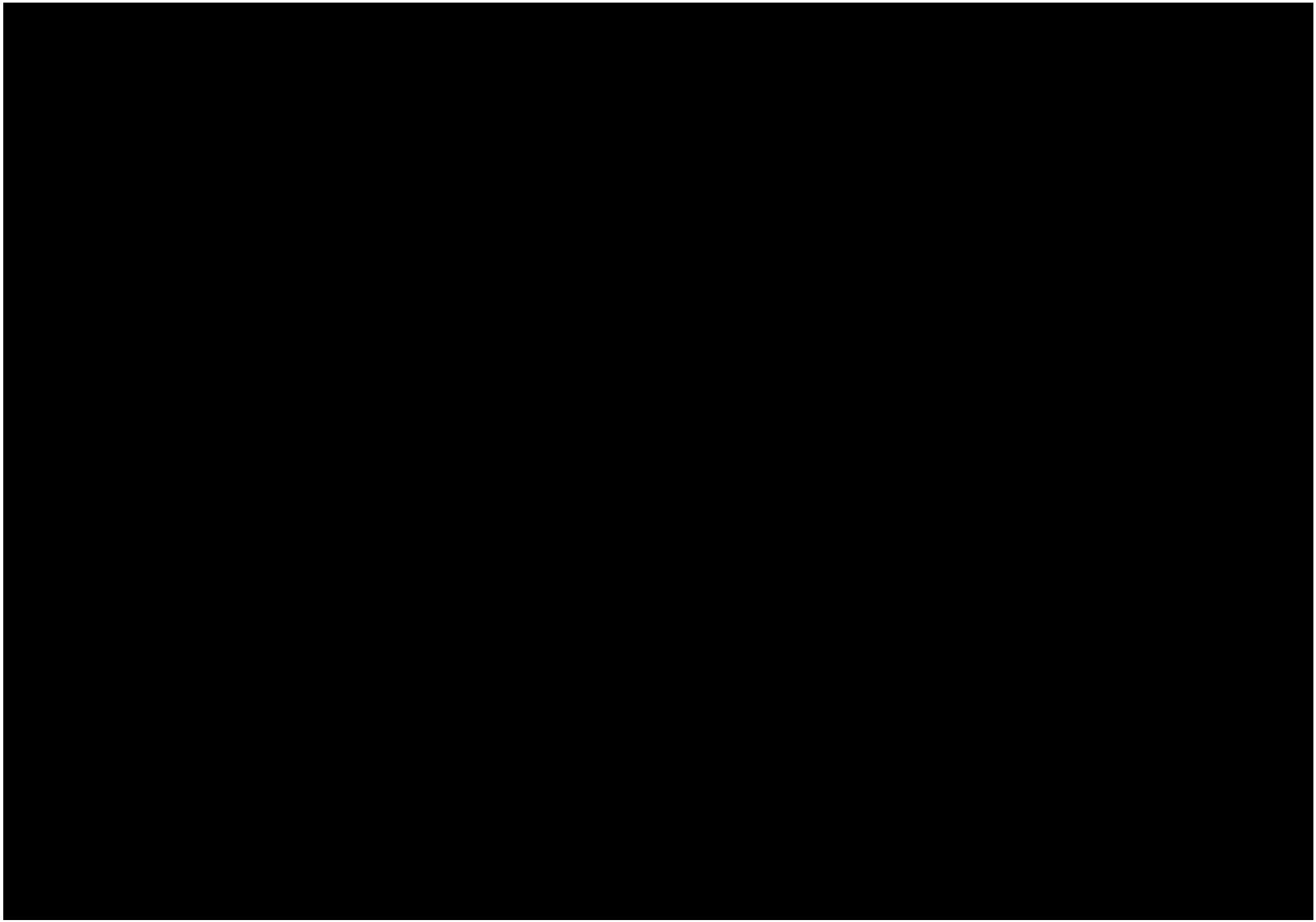
Hourly Average Day for February 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Wheatland Rural Electric Association, Inc.



Hourly Average Day for April 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for May 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for September 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Wheatland Rural Electric Association, Inc.

[redacted]

Hourly Average Day for January 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021

White River Electric Association, Inc.

[redacted]

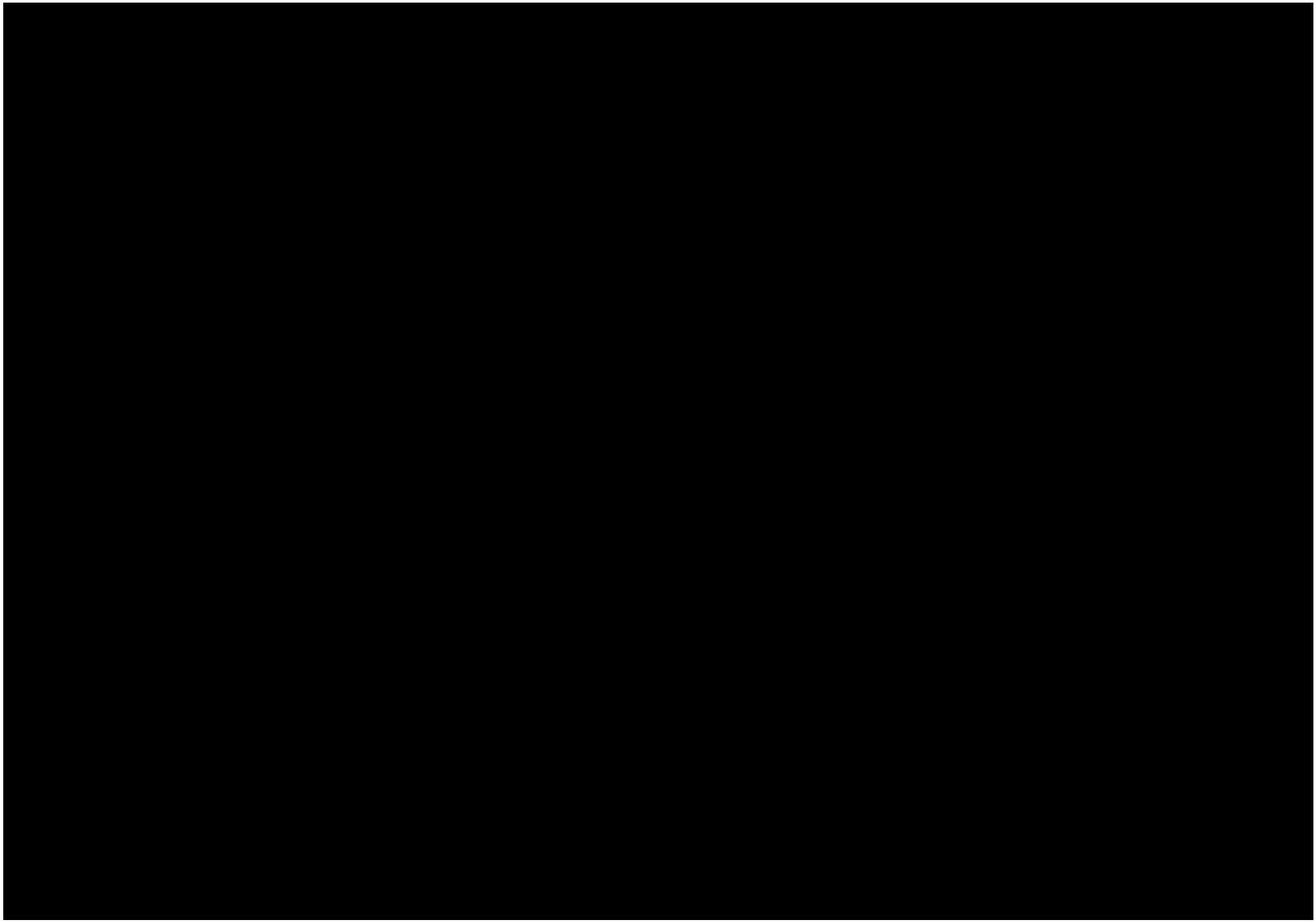
Hourly Average Day for March 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021

White River Electric Association, Inc.



Hourly Average Day for May 2021

White River Electric Association, Inc.

[redacted]

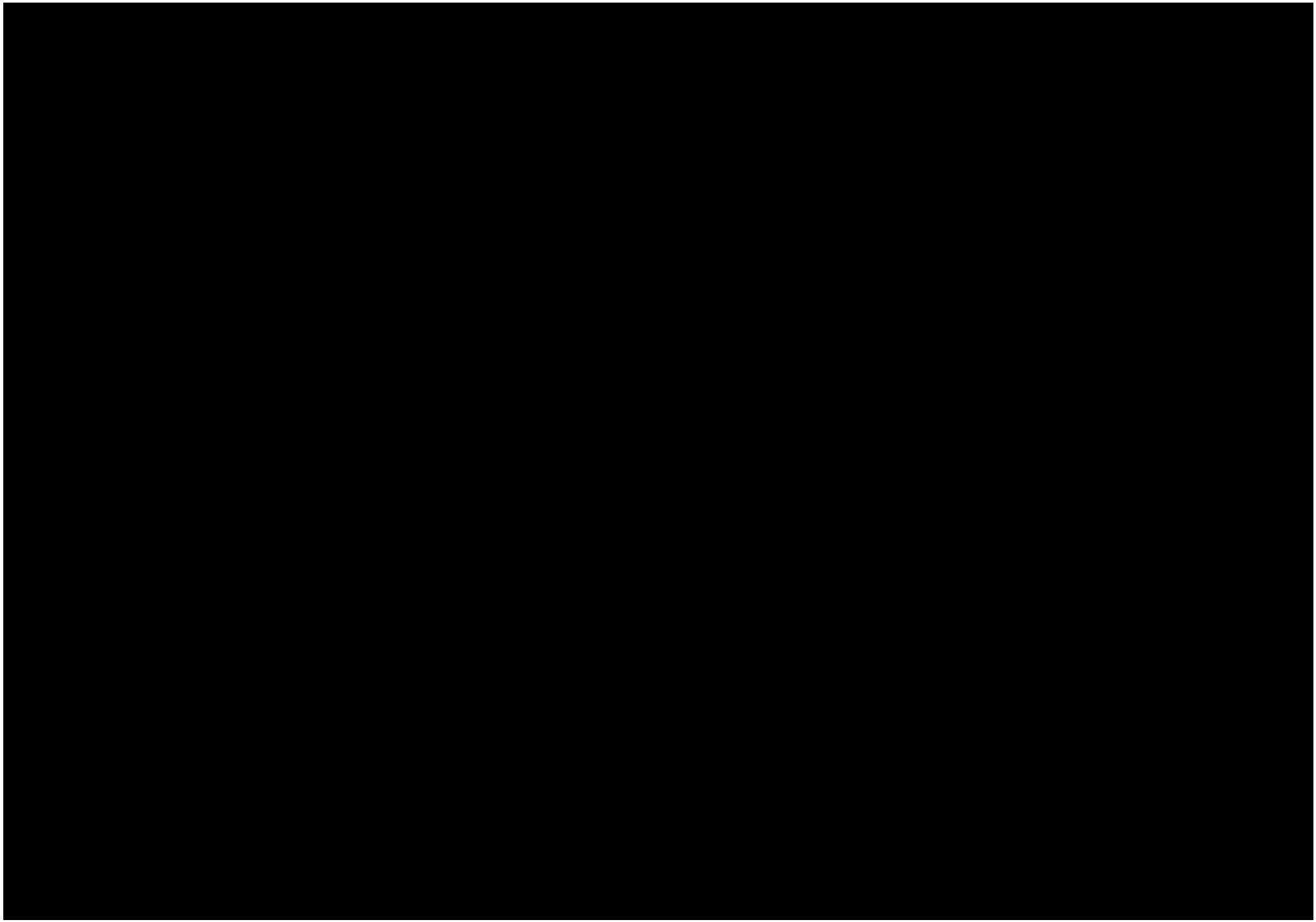
Hourly Average Day for June 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for July 2021

White River Electric Association, Inc.



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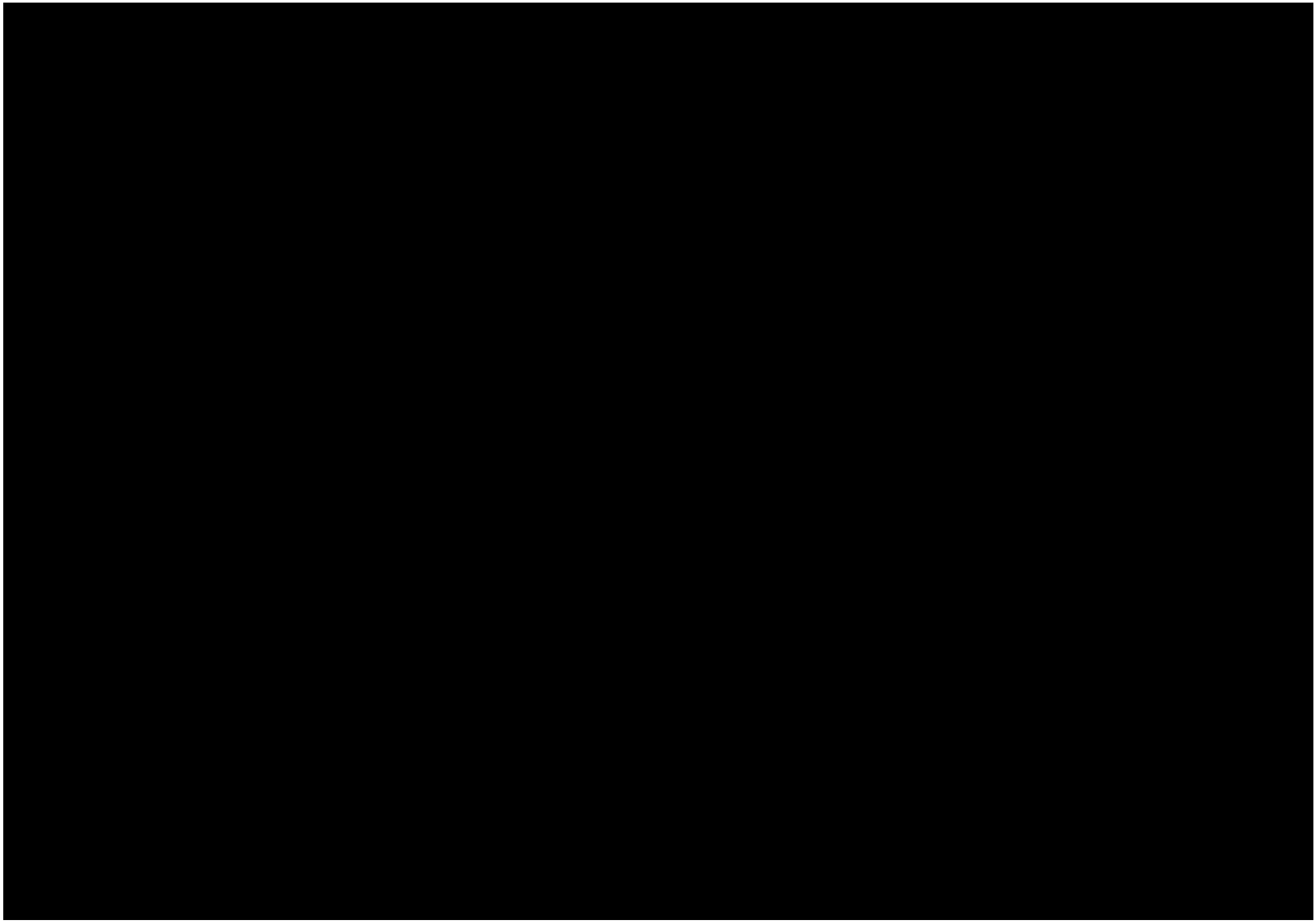
Hourly Average Day for August 2021

White River Electric Association, Inc.



Hourly Average Day for September 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

White River Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

White River Electric Association, Inc.

[redacted]

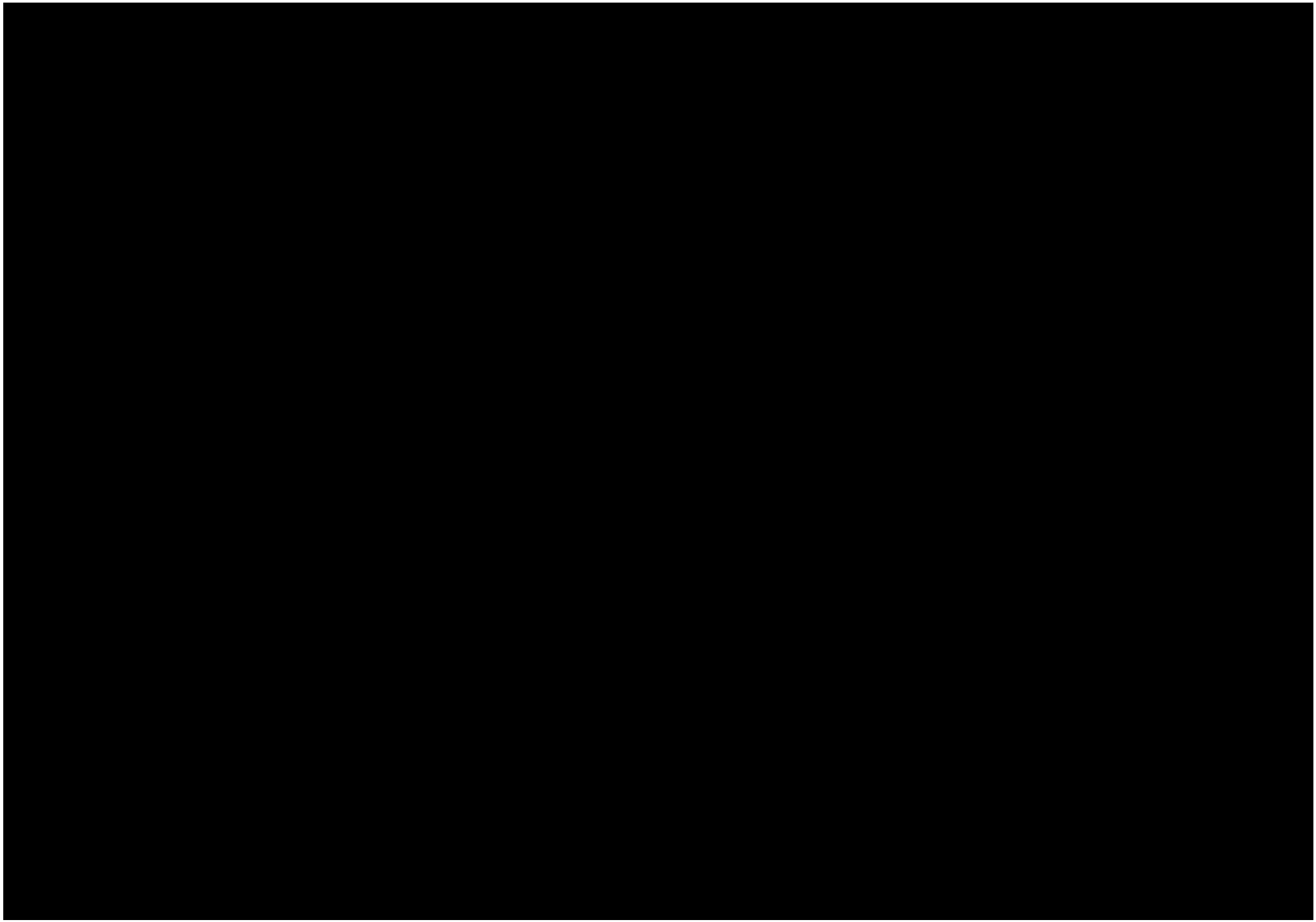
Hourly Average Day for January 2021

Wyrulec Company

[redacted]

Hourly Average Day for February 2021

Wyrulec Company



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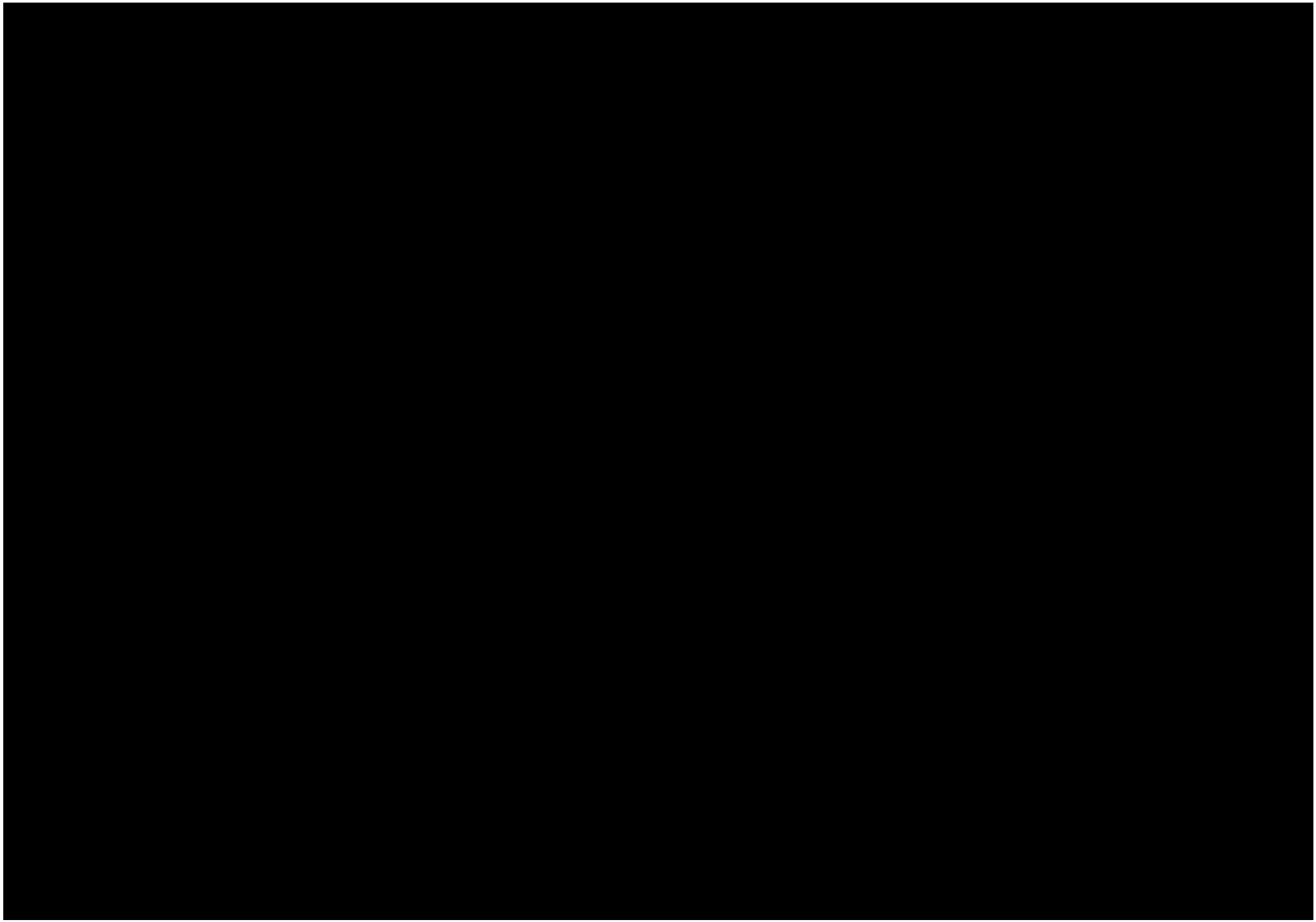
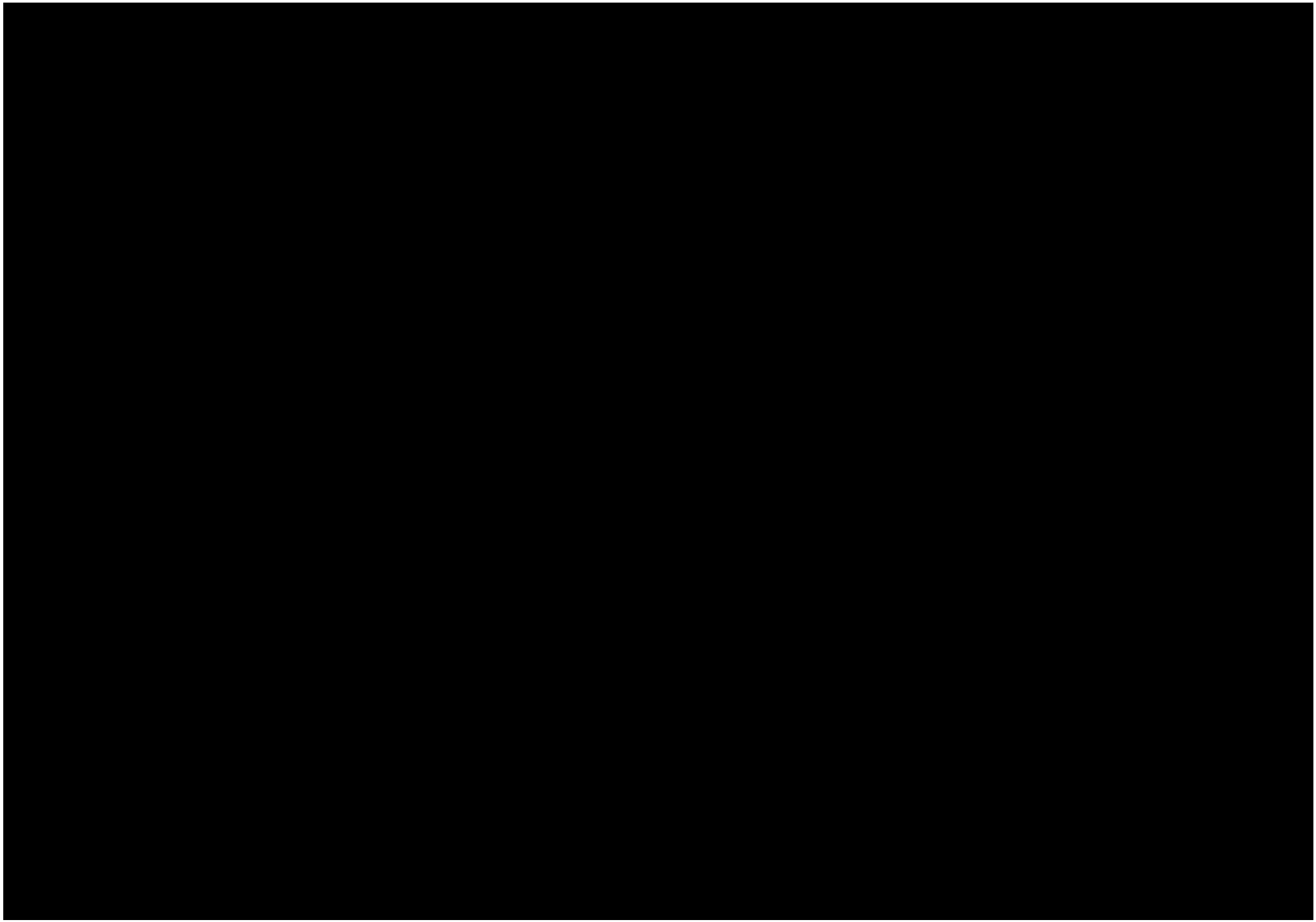
Hourly Average Day for March 2021

Wyrulec Company



Hourly Average Day for April 2021

Wyrulec Company



Hourly Average Day for May 2021

Wyrulec Company

[redacted]

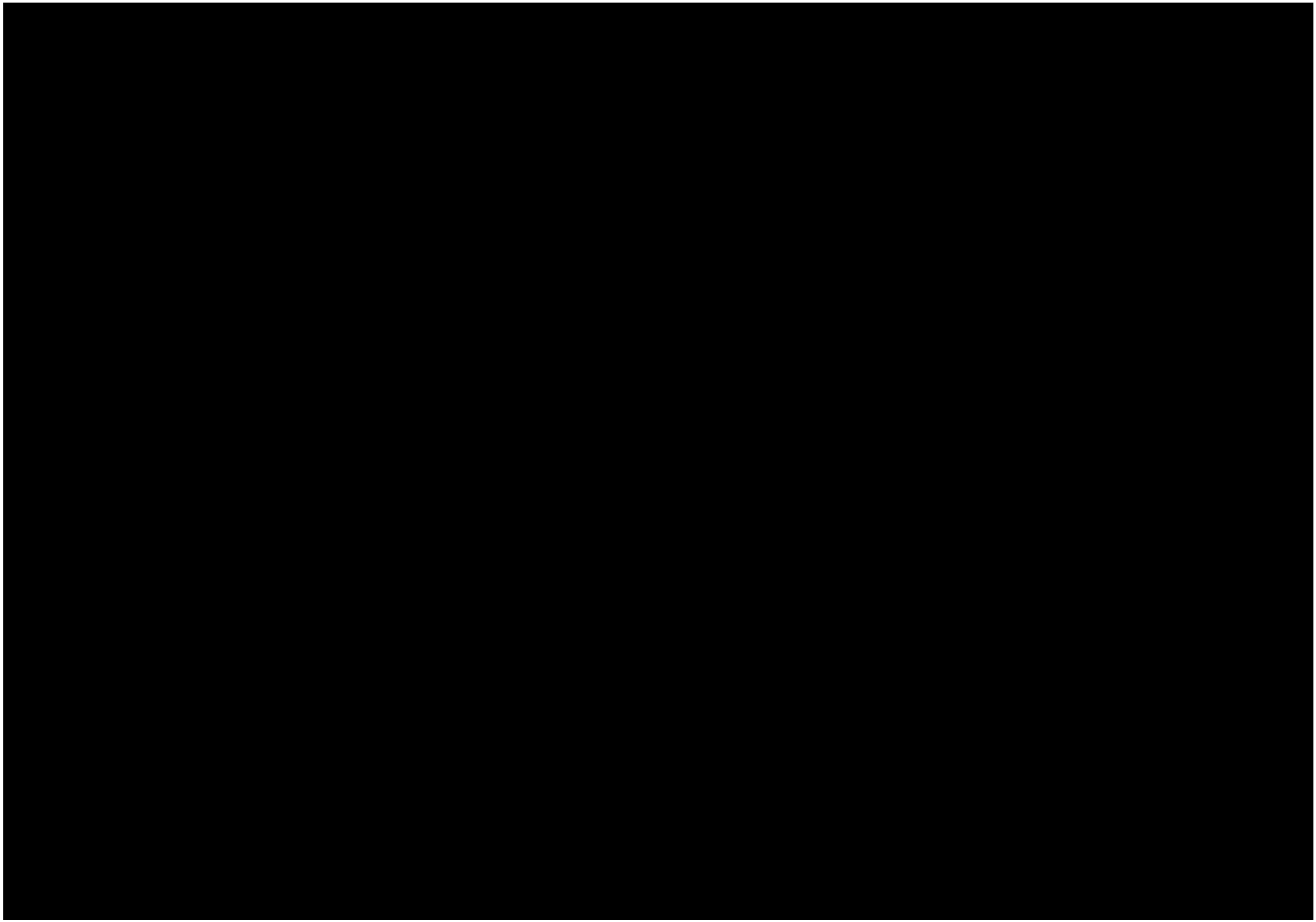
Hourly Average Day for June 2021

Wyrulec Company

[redacted]

Hourly Average Day for July 2021

Wyrulec Company



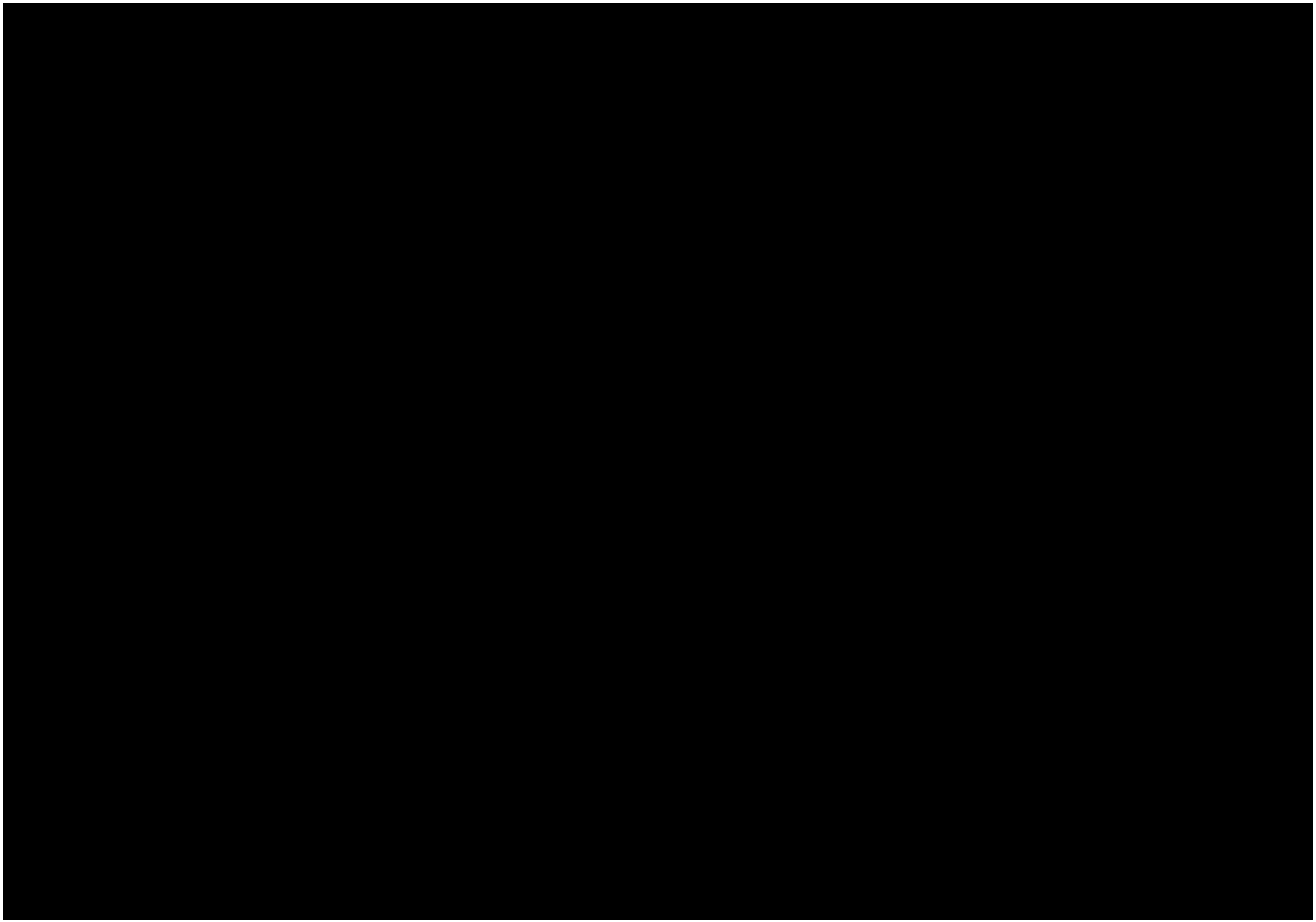
Hourly Average Day for August 2021

Wyrulec Company

[redacted]

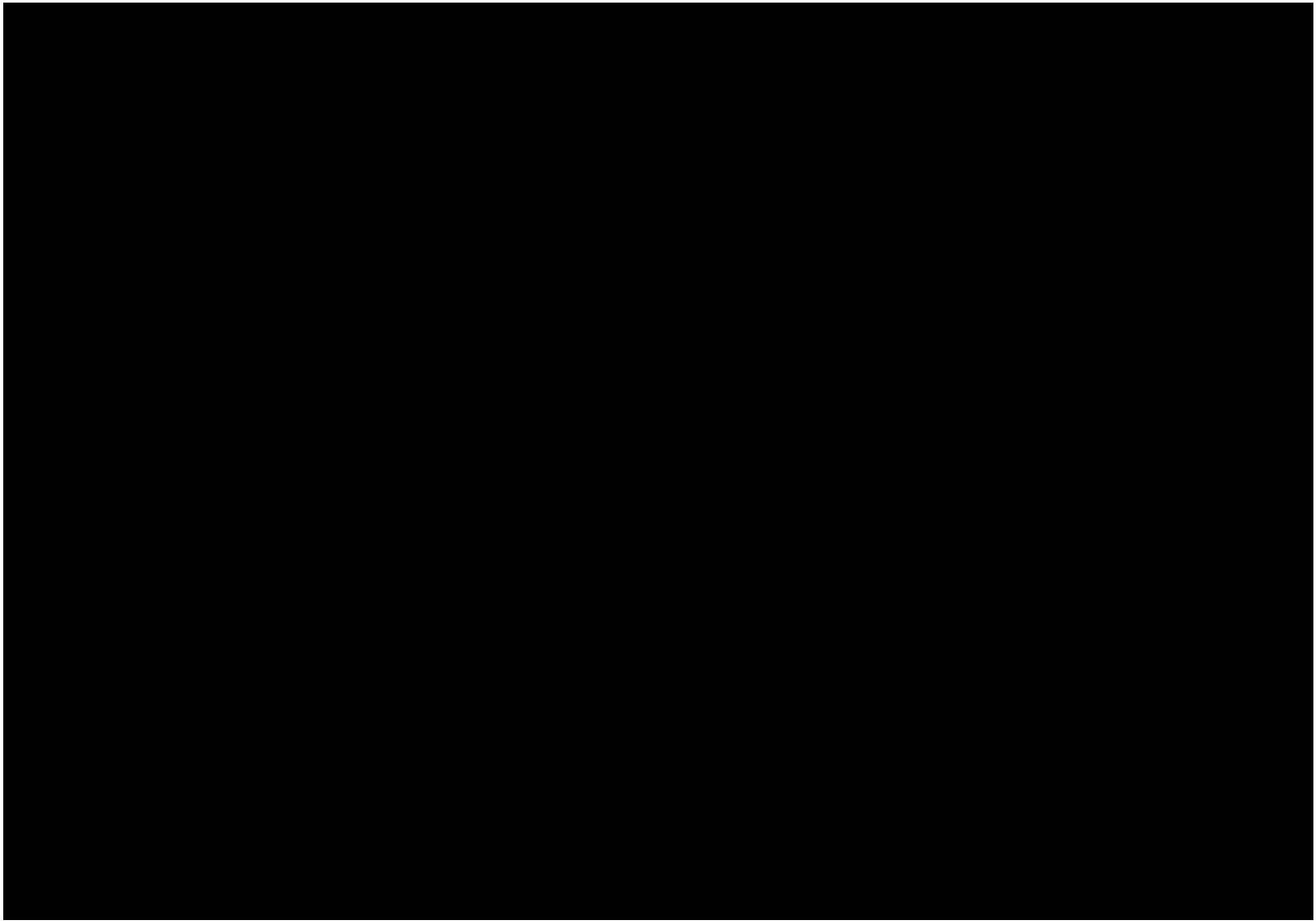
Hourly Average Day for September 2021

Wyrulec Company



Hourly Average Day for October 2021

Wyrulec Company



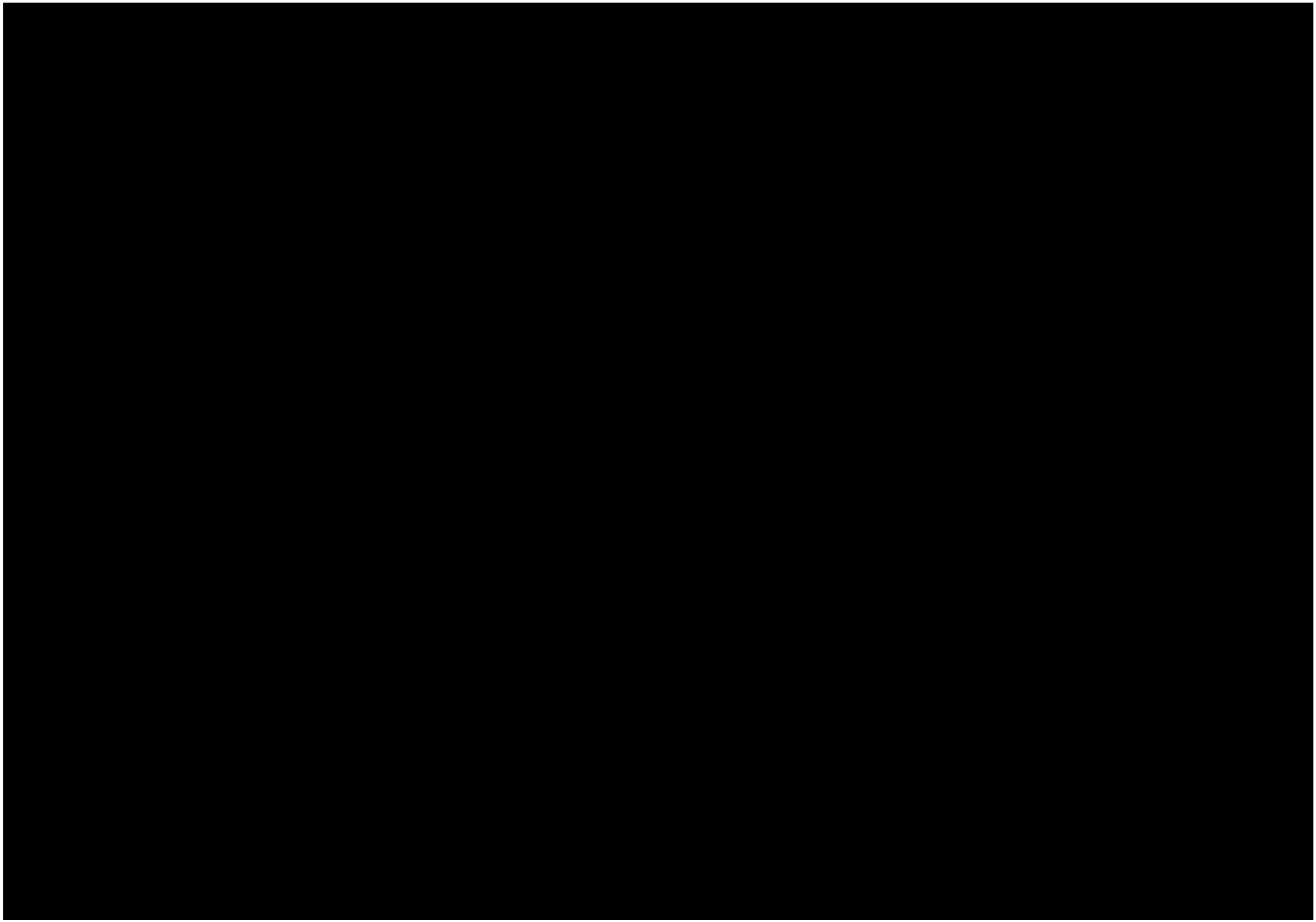
Hourly Average Day for November 2021

Wyrulec Company

[redacted]

Hourly Average Day for December 2021

Wyrulec Company



Hourly Average Day for January 2021
Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for February 2021
Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for March 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for April 2021
Y-W Electric Association, Inc.

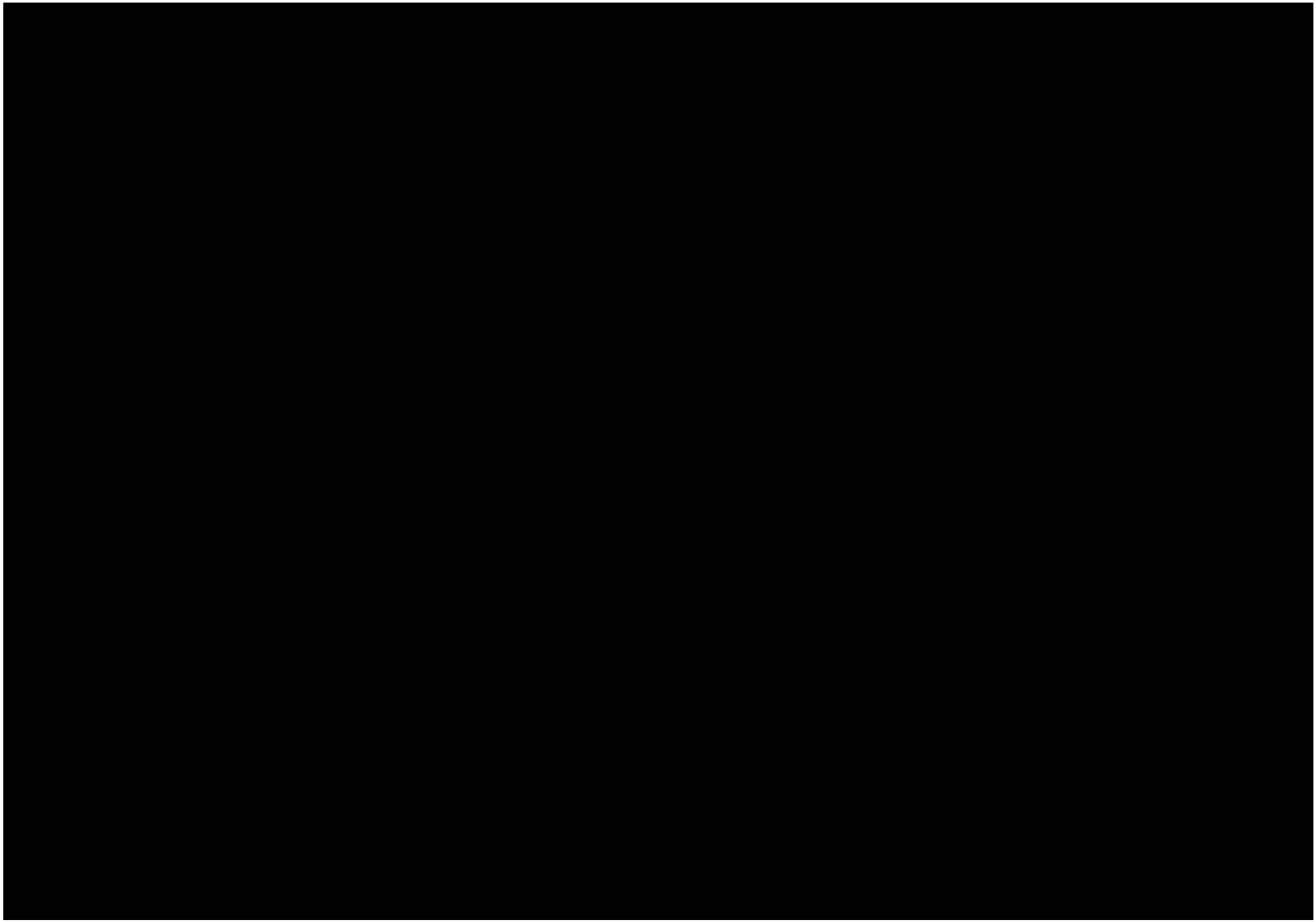
[redacted]

Hourly Average Day for May 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for June 2021
Y-W Electric Association, Inc.



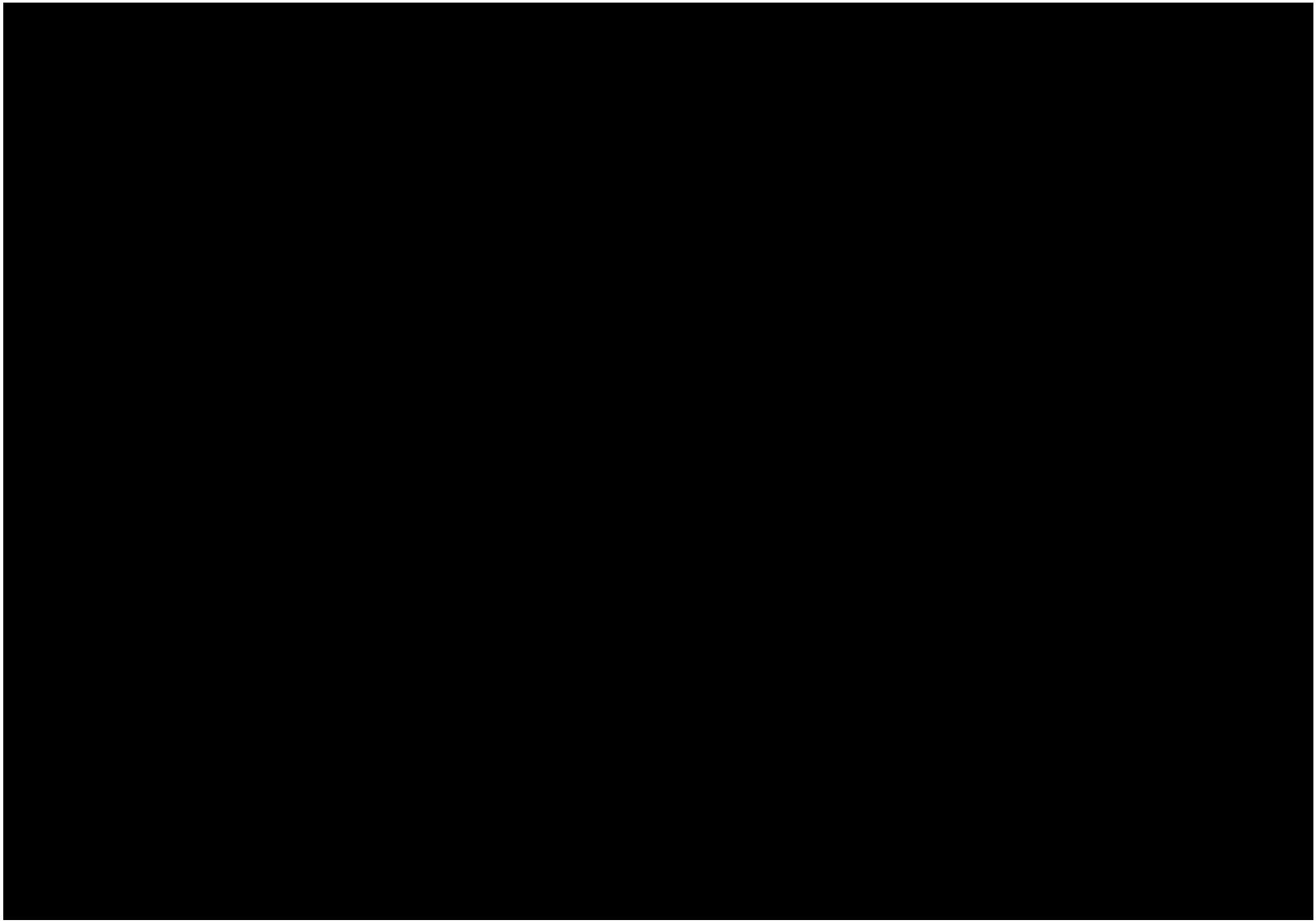
Hourly Average Day for July 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for August 2021

Y-W Electric Association, Inc.



Hourly Average Day for September 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for October 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for November 2021

Y-W Electric Association, Inc.

[redacted]

Hourly Average Day for December 2021

Y-W Electric Association, Inc.

[redacted]

Attachment Vol II 4-1 Tri-State Facility Rating Report

TSGT 69 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
CAMT_HAMD_69_1	88	CARTER MOUNTAIN	CT	53	91	HAMILTON DOME	METER	84	84
CLAP_CLAY_69_1	32	CLAPHAM	METER	37	37	CLAYTON	***	***	***
COYJ_ABIQ_69_1	51	COYOTE JUNCTION	CT	17	18	ABIQUIU	***	***	***
COYJ_HERN_69_1	33	COYOTE JUNCTION	METER	50	50	HERNANDEZ	METER	41	41
COYJ_LJAR_69_1	33	COYOTE JUNCTION	CT	35	37	LA JARA	RELAY	35	35
CZCN_NBHL_69_1	100	CARRIZO CANYON	CT	71	94	NORTH BISCUIT HILL	***	***	***
EADS_WILC_69_1	54	EADS	***	***	***	WILLOW CREEK	RELAY	20	20
GRAN_WIGA_69_1	***	GRANBY	***	***	***	WINDY GAP	METER	42	42
GRANADA TAP_WILC_69_1	54****	GRANADA TAP	***	***	***	WILLOW CREEK	METER	31	31
HILLTOP TAP_VILA_69_1	54	HILLTOP TAP	***	***	***	VILAS	METER	42	42
HOOPER TAP_SALV_69_1	40	HOOPER TAP	***	***	***	SAN LUIS VALLEY	CT	47	50
HUGO_LIMO_69_1	32****	HUGO	***	***	***	LIMON (WACM)	CT	23	25
LAJT_LAJU_69_1	***	CITY OF LA JUNTA	***	***	***	LA JUNTA	RELAY	33	33
LBUF_CAMT_69_1	***	LITTLE BUFFALO BASI	***	***	***	CARTER MOUNTAIN	CT	23	25
MEEK_RIFP_69_1	40	MEEKER	CT	47	81	RIFLE (PSCO)	***	***	***
MONU_RUSS_69_1	***	MONUMENT	CT	59	62	RUSSELVILLE	***	***	***
RAMO_SFRK_69_1	57****	RAMON	NLSWITCH	71	87	SOUTH FORK (SLV)	***	***	***
RAMO_SFRK_69_2	57****	RAMON	NLSWITCH	71	87	SOUTH FORK (SLV)	***	***	***
SPGR_WAGM_69_1	32	SPRINGER	RELAY	17	17	WAGON MOUND	***	***	***
VILA_WLSH_69_1	54****	VILAS	METER	42	42	WALSH	METER	42	42

TSGT 115 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AIPD_APTP_115_1	261	AIR PRODUCTS	METER	14	14	AIR PRODUCTS TAP	JUMPER	261	261
AKRO_OTIS_115_1	***	AKRON (WACM)	***	***	***	OTIS	NLSWITCH	119	119
ALGO_SYSI_115_1	74	ALGODONES (PNM)	RELAY	115	115	SAN YSIDRO	BUS	74	74
ALGR_ALGT_115_1	48	ALAMOGORDO (TS)	JUMPER	88	88	ALAMOGORDO (PNM)	JUMPER	88	88
ALGT_BLZR_115_1	167	ALAMOGORDO (PNM)	***	***	***	BLAZER	JUMPER	167	167
ALGT_HOLT_115_1	234	ALAMOGORDO (PNM)	METER	215	215	HOLLOMAN TAP	JUMPER	234	234
ALKA_CRBU_115_1	143	ALKALI	JUMPER	229	229	CRESTED BUTTE	NLSWITCH	119	145
ALKA_SKIT_115_1	143	ALKALI	JUMPER	229	229	SKITO	METER	36	36
ALTP_CABA_115_1	47	ALTA LUNA TAP	JUMPER	88	88	CABALLO	RELAY	110	110
ALTP_MIMB_115_1	47	ALTA LUNA TAP	JUMPER	88	88	MIMBRES (PNM)	***	***	***
ALVI_CRSW_115_1	97	ALVIN	BUS	99	99	CRETE SWITCH	SWITCH	119	145

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TSGT 115 kV Facilities

PUBLIC

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ALVI_SAND_115_1	97	ALVIN	BUS	99****	99****	SANDHILLS	JUMPER	175	175
ALVI_WAUN_115_1	68	ALVIN	BUS	99****	99****	WAUNETA	JUMPER	119	119
AMBR_TAYL_115_1	***	AMBROSIA LAKE (PNM	***	***	***	TAYLOR	NLSWITCH	119	145
AMES_BUBR_115_1	143	AMES (PSCO)	JUMPER	170	170	BURRO BRIDGE	NLSWITCH	119	145
AMES_SUNT_115_1	143	AMES (PSCO)	JUMPER	170	170	SUNSHINE	JUMPER	170	170
AMOE_BAYF_115_1	***	AMOCO EAST	***	***	***	BAYFIELD	METER	129	129
ANSZ_DOCN_115_1	142****	ANASAZI	JUMPER	315	315	DOE CANYON	JUMPER	170****	170****
ANSZ_YJSW_115_1	142****	ANASAZI	JUMPER	315	315	YELLOW JACKET SWIT	SWITCH	119****	145****
ANTO_ARIC_115_1	56	ANTON	SWITCH	119	145	ARICKAREE	JUMPER	92	92
ANTO_LDTP_115_1	68	ANTON	SWITCH	119	145	LINDON TAP	JUMPER	175	175
APTP_DOCN_115_1	261	AIR PRODUCTS TAP	JUMPER	261	261	DOE CANYON	CT	79	135
ARAP_WAAN_115_1	64	ARAPAHOE	JUMPER	118	118	WAANIBE	JUMPER	118	118
ARCH_MYRT_115_1	***	ARCHER (WACM)	***	***	***	MYERS TAP	JUMPER	175	175
ARCO_WALT_115_1	***	ARCO	***	***	***	WALSENBURG	CT	29	32
ARIC_JOES_115_1	97	ARICKAREE	SWITCH	119	145	JOES	RELAY	148	148
ARTH_HYAN_115_1	87	ARTHUR	SWITCH	119	145	HYANNIS	CT	7	12
ARTH_MCCO_115_1	87	ARTHUR	SWITCH	119	145	MCCONAUGHY	SWITCH	119	145
ATHE_CRET_115_1	147	ATHEY (IPPD)	***	***	***	CRETE	BUS	175****	175****
ATHE_ENDE_115_1	147	ATHEY (IPPD)	***	***	***	ENDERS (NPPD)	METER	207	207
AULT_BLAC_115_1	***	AULT (WACM)	***	***	***	BLACKHOLLOW	SWITCH	239	268
AULT_PIER_115_1	244	AULT (WACM)	***	***	***	PIERCE	JUMPER	244	244
BAYF_PAGO_115_1	85	BAYFIELD	NLSWITCH	119	145	PAGOSA	CT	39	67
BECK_BECT_115_1	271	BEAVER CREEK (WAC	SWITCH	239	291	BEAVER CREEK (TS)	JUMPER	324	324
BELL_BLVT_115_1	56	BELLEVUE	JUMPER	92	92	BELLVUE TAP	JUMPER	92	92
BELT_BERN_115_1	74	BELEN SWITCH (PNM)	RELAY	79	79	BERNARDO	BUS	148	148
BELT_WSWT_115_1	***	BELEN SWITCH (PNM)	METER	199	199	WILLARD SWITCH	BUS	197	216
BERN_SOCO_115_1	74	BERNARDO	BUS	148	148	SOCORRO	METER	90	90
BETH_ECKL_115_1	68	BETHEL	SWITCH	119	119	ECKLEY	RELAY	113	113
BETH_VRNN_115_1	68	BETHEL	SWITCH	119	119	VERNON	SWITCH	119	119
BFOR_BLACK FOREST TAP_115_1	173	BLACK FOREST	JUMPER	92	92	BLACK FOREST TAP	JUMPER	173	173
BGEO_ICTP_115_1	147	BIG GEORGE (WACM)	***	***	***	IRON CREEK TAP	JUMPER	175	175
BLAC_COBL_115_1	***	BLACKHOLLOW	SWITCH	239	268	COBB LAKE	***	***	***
BLACK FOREST TAP_BLSQ_115_1	173	BLACK FOREST TAP	JUMPER	173	173	BLACK SQUIRREL	METER	143	143
BLACK FOREST TAP_GRES_115_1	173	BLACK FOREST TAP	JUMPER	173	173	GRESHAM	JUMPER	173	173
BLCR_WLDH_115_1	147	BLUE CREEK	BUS	155	175	WILDHORSE	JUMPER	175	175
BLDR_CORT_115_1	143	BLUE DOOR	JUMPER	170	170	CORTEZ	NLSWITCH	239	291
BLDR_ECOR_115_1	143	BLUE DOOR	JUMPER	170	170	EAST CORTEZ	JUMPER	170	170
BLLK_SPGR_115_1	242	BLACK LAKE	SWITCH	239	242	SPRINGER	SWITCH	239	242

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
BLLK_TAOS_115_1	238	BLACK LAKE	SWITCH	239	242	TAOS	CT	239	284
BLME_LACY_115_1	104	BLUE MESA	***	***	***	LAKE CITY	WAVETRAP	79	102
BLSQ_FULL_115_1	173	BLACK SQUIRREL	METER	143	143	FULLER	JUMPER	173	173
BLSQ_MERA_115_1	242	BLACK SQUIRREL	METER	143	143	MERIDIAN RANCH	NLSWITCH	239	242
BLVT_LAPO_115_1	68	BELLVUE TAP	JUMPER	92	92	LAPORTE	METER	21	21
BLVT_RIPP_115_1	56	BELLVUE TAP	JUMPER	92	92	RIPPLE	JUMPER	119	119
BLZR_CZCN_115_1	167	BLAZER	JUMPER	167	167	CARRIZO CANYON	CT	119	167
BMKR_YEJW_115_1	261	BASKET MAKER	SWITCH	239	261	YELLOWJACKET WES	SWITCH	119	145
BMRD_STBE_115_1	173	BURNT MILL	SWITCH	179	218	STEM BEACH	SWITCH	119	145
BODO_DURA_115_1	200	BODO PARK	CT	137	229	DURANGO	CT	168	229
BODO_HESP_115_1	200	BODO PARK	RELAY	115	115	HESPERUS	CT	194	241
BONN_BURL_115_1	173	BONNY CREEK	JUMPER	175	175	BURLINGTON	JUMPER	173	173
BONN_SFOR_115_1	147	BONNY CREEK	JUMPER	175	175	SOUTH FORK	BUS	197	215
BOOM_KERW_115_1	***	BOOMERANG	***	***	***	KERSEY WEST (WACM	***	***	***
BOOM_WELD_115_1	***	BOOMERANG	***	***	***	WELD	***	***	***
BOON_LAJU_115_1	130	BOONE	RELAY	164	164	LA JUNTA	CT	119	144
BOXB_ALLW_115_1	***	BOX BUTTE	METER	108	108	ALLIANCE (WACM)	***	***	***
BOXB_DUNL_115_1	***	BOX BUTTE	METER	108	108	DUNLAP (WACM)	***	***	***
BOXB_HEMI_115_1	87	BOX BUTTE	METER	53	53	HEMINGFORD	BUS	197	211
BOXE_TIMT_115_1	87	BOX ELDER	SWITCH	119	145	TIMNATH TAP	SWITCH	119	145
BOYD_GTWY_115_1	147	BOYD (PRPA)	***	***	***	GATEWAY	SWITCH	239	244
BRAC_WHIT_115_1	***	BRACEWELL	NLSWITCH	239	244	WHITNEY	NLCB	239	244
BRAC_WHIT_115_2	***	BRACEWELL	NLSWITCH	239	244	WHITNEY	NLCT	239	244
BRID_BRIW_115_1	***	BRIDGEPORT	BUS	113	134	BRIDGEPORT (WACM)	***	***	***
BRIG_ERSW_115_1	***	BRIGHTON (WAPA)	***	***	***	ERIE SWITCH	METER	215	215
BRIW_MCGR_115_1	***	BRIDGEPORT (WACM)	***	***	***	MCGREW	JUMPER	155	155
BROM_HNLK_115_1	175	BROMLEY	JUMPER	175	175	HENRY LAKE	CT	239	244
BROM_PRAI_115_1	244	BROMLEY	JUMPER	175	175	PRAIRIE CENTER	JUMPER	175	175
BRTT_MORI_115_1	***	BRITTON	RELAY	129	129	MORIARTY	BUS	148	148
BSAN_LACH_115_1	***	BIG SANDY	RELAY	125	125	LAST CHANCE	NLSWITCH	239	244
BSAN_LIMO_115_1	129	BIG SANDY	RELAY	219	219	LIMON	JUMPER	202	202
BSPR_BLCR_115_1	131	BIG SPRINGS (NPPD)	***	***	***	BLUE CREEK	BUS	155	175
BSPR_BRUL_115_1	***	BIG SPRINGS (NPPD)	***	***	***	BRULE (MECC)	SWITCH	119	145
BTHD_GTWY_115_1	131	BERTHOUD (PSCO)	***	***	***	GATEWAY	RELAY	76	76
BTHD_LNTR_115_1	131	BERTHOUD (PSCO)	***	***	***	LONE TREE	SWITCH	239	244
BUBR_SITP_115_1	143	BURRO BRIDGE	NLSWITCH	119	145	SILVERTON TAP	JUMPER	170	170
BUCN_LUDL_115_1	145	BURRO CANYON	RELAY	74	74	LUDLOW	JUMPER	173	173
BUCN_TERC_115_1	173	BURRO CANYON	METER	32	32	TERCIO	JUMPER	173	173

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TSGT 115 kV Facilities

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BULL_HACN_115_1	85	BULLOCK	CT	79	135	HAPPY CANYON	WAVETRAP	79	102
BULL_SCTP_115_1	85	BULLOCK	CT	79	135	SPRING CREEK TAP	JUMPER	151	151
BURK_BURP_115_1	64	BURLINGTON (KC)	JUMPER	192	192	BURLINGTON (PSCO)	JUMPER	118	118
BURL_BURK_115_1	64	BURLINGTON	RELAY	123	123	BURLINGTON (KC)	JUMPER	192	192
BURP_WAAT_115_1	64	BURLINGTON (PSCO)	JUMPER	118	118	WAANIBE TAP	METER	35	35
BUSH_BUST_115_1	97	BUSHNELL	SWITCH	119	119	BUSHNELL TAP	SWITCH	119	145
BUST_KIMB_115_1	***	BUSHNELL TAP	SWITCH	119	145	KIMBALL (WACM)	***	***	***
BUST_PINE_115_1	***	BUSHNELL TAP	SWITCH	119	145	PINE BLUFFS (WACM)	***	***	***
BUVI_BUENA VISTA TAP_115_1	55	BUENA VISTA	NLSWITCH	119	145	BUENA VISTA TAP (PS	***	***	***
BWAT_GRTP_115_1	***	BLUE WATER	JUMPER	114	114	GRANTS TAP	JUMPER	114	114
BWAT_PEGS_115_1	310	BLUE WATER	BUS	197	232	ESCALANTE	SWITCH	239	259
BWAT_TAYL_115_1	***	BLUE WATER	JUMPER	148	148	TAYLOR	SWITCH	119	145
BWCK_RWCK_115_1	175	BLACKWOOD CREEK	JUMPER	175	175	RED WILLOW CREEK	JUMPER	175	175
CABA_COPPER FLATS_115_1	74	CABALLO	BUS	148	148	COPPER FLATS	***	***	***
CABA_HOT SPRINGS TAP_115_1	167	CABALLO	CT	119	148	HOT SPRINGS TAP	JUMPER	167	167
CAHO_DOCN_115_1	142****	CAHONE	METER	215	215	DOE CANYON	JUMPER	170****	170****
CAHO_GCTP_115_1	77	CAHONE	WAVETRAP	79	102	GREAT CUT TAP	JUMPER	135	135
CAHO_MAVR_115_1	315	CAHONE	CT	168	261	MAVERICK	JUMPER	315	315
CALK_CLTP_115_1	119	CARTER LAKE	JUMPER	92	92	CARTER LAKE TAP	***	***	***
CARM_WAVE_115_1	170	CARMEL	JUMPER	170	170	WAVERLY (TS)	JUMPER	238	238
CARM_ZINZ_115_1	238	CARMEL	JUMPER	170	170	ZINZER	JUMPER	170	170
CASC_COBA_115_1	143	CASCADE	CT	79	108	COAL BANK	JUMPER	170	170
CASC_TAMT_115_1	***	CASCADE	CT	79	132	TAMARRON TAP	***	***	***
CECK_SITP_115_1	143	CEMENT CREEK	JUMPER	170	170	SILVERTON TAP	JUMPER	170	170
CGUL_EL PASO TAP_115_1	85****	COYOTE GULCH	JUMPER	151****	151****	EL PASO TAP	JUMPER	151****	151****
CGUL_HESP_115_1	85	COYOTE GULCH	JUMPER	151****	151****	HESPERUS	SWITCH	239	291
CHEY_PONN_115_1	324	CHEYENNE (WACM)	***	***	***	PONNEQUIN (PSCO)	***	***	***
CINI_FWNT_115_1	114	CINIZA	METER	215	215	FORT WINGATE TAP	JUMPER	114	114
CINI_PEGS_115_1	114	CINIZA	METER	215	215	ESCALANTE	CT	239	244
CLAP_BRVD_115_1	184	CLAPHAM	METER	86	86	ROSEBUD (BRAVO DO	***	***	***
CLAP_GLAD_115_1	184	CLAPHAM	CT	119	129	GLADSTONE	CT	199	242
CMTP_CAMT_115_1	175	CARTER MOUNTAIN T	***	***	***	CARTER MOUNTAIN	NLCT	119	175
COBA_MOLAS LAKE TAP_115_1	143	COAL BANK	JUMPER	170	170	MOLAS LAKE TAP	JUMPER	170	170
COBL_TIMT_115_1	***	COBB LAKE	***	***	***	TIMNATH TAP	SWITCH	119	145
COLD_COVA_115_1	147	COLDWATER CREEK	SWITCH	239	244	COVALT	JUMPER	175	175
COLD_WLDH_115_1	147	COLDWATER CREEK	NLSWITCH	239	244	WILDHORSE	METER	107	107
COLF_GHSE_115_1	324	COLFER	JUMPER	324	324	GREENHOUSE	JUMPER	324	324
COLT_SIDN_115_1	***	COLTON (WACM)	***	***	***	SIDNEY (TS)	RELAY	164	164

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TSGT 115 kV Facilities

PUBLIC

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CORT_EMPI_115_1	143	CORTEZ	NLSWITCH	239	291	EMPIRE	JUMPER	170	170
COVA_LYNN_115_1	205	COVALT	SWITCH	239	244	LYNN	JUMPER	175	175
CRET_CRSW_115_1	147	CRETE	BUS	175****	175****	CRETE SWITCH	SWITCH	119	145
CRSW_LAMA_115_1	97	CRETE SWITCH	SWITCH	119	145	LAMAR NE	METER	107	107
CUCH_RODEO TAP_115_1	167	CUCHILLO	BUS	113	134	RODEO TAP	SWITCH	239	291
CURE_SCAL_115_1	***	CURECANTI (WACM)	***	***	***	SOUTH CANAL	JUMPER	170	170
CWCK_DACK_115_1	170	COW CREEK	JUMPER	170	170	DALLAS CREEK	SWITCH	119	145
CWCK_SCAL_115_1	170	COW CREEK	JUMPER	170	170	SOUTH CANAL	CT	14	16
CWCY_HOVE_115_1	142****	COW CANYON	CT	119****	203****	HOVENWEEP	SWITCH	119****	145****
CWCY_YJSW_115_1	142****	COW CANYON	CT	119****	203****	YELLOW JACKET SWIT	NLSWITCH	119****	145****
CZCN_HOWD_115_1	167	CARRIZO CANYON	METER	43	43	HOLLYWOOD (PNM)	***	***	***
CZPL_TOWA_115_1	169****	CORTEZ PIPELINE	SWITCH	119****	145****	TOWAOC CANAL	JUMPER	315****	315****
DACO_ERSW_115_1	175	DACONO	JUMPER	175	175	ERIE SWITCH	NLCT	239	323
DACO_RNVL_115_1	175	DACONO	JUMPER	175	175	RINN VALLEY	RELAY	196	196
DALT_GRWO_115_1	***	DALTON	SWITCH	119	134	GREENWOOD (WACM)	***	***	***
DALT_SIDW_115_1	***	DALTON	SWITCH	119	134	SIDNEY (WACM)	***	***	***
DAVP_DAVS_115_1	244	DAVIS TAP (PSCO)	***	***	***	DAVIS	JUMPER	244	244
DAVS_GHSE_115_1	244	DAVIS	JUMPER	244	244	GREENHOUSE	JUMPER	324	324
DAVS_GHSE_115_2	244	DAVIS	JUMPER	244	244	GREENHOUSE	JUMPER	324	324
DBKT_PUEW_115_1	173	DIAMONDBACK TAP	JUMPER	173	173	PUEBLO WEST	CT	79	135
DBKT_SWAL_115_1	173	DIAMONDBACK TAP	JUMPER	173	173	SWALLOWS	NLSWITCH	239	242
DELK_EYTP_115_1	***	DEERING LAKE	BUS	175	175	EAST YUMA TAP (WAC	***	***	***
DELK_NYUM_115_1	147	DEERING LAKE	JUMPER	175	175	NORTH YUMA	CT	168	175
DELK_OTIS_115_1	***	DEERING LAKE	RELAY	131	131	OTIS	SWITCH	119	119
DELK_YUMW_115_1	***	DEERING LAKE	RELAY	93	93	YUMA (WACM)	***	***	***
DELS_RNVL_115_1	175	DEL CAMINO SWITCH	JUMPER	175	175	RINN VALLEY	JUMPER	236	236
DELS_SLTR_115_1	131	DEL CAMINO SWITCH	METER	172	172	SLATER	NLSWITCH	239	244
DELT_LOPK_115_1	***	DEL CAMINO TAP	SWITCH	239	268	LONGS PEAK	***	***	***
DELT_MEAD_115_1	268	DEL CAMINO TAP	SWITCH	239	268	MEADOW (PRPA)	***	***	***
DICK_HORT_115_1	***	DIXON CREEK (PRPA)	***	***	***	HORSETOOTH TAP	SWITCH	119	145
DONA_LCRU_115_1	153	DONA ANA	JUMPER	234	234	LAS CRUCES	RELAY	254	254
DONA_PICA_115_1	153	DONA ANA	RELAY	183	183	PICACHO (PNM)	FAC008_PNM	159	183
DONA_WSAT_115_1	234	DONA ANA	JUMPER	234	234	WHITE SANDS TAP	JUMPER	234	234
DOSP_GNVY_115_1	170	DOUGHSPOON	JUMPER	170	170	GUNNISON VALLEY	JUMPER	170	170
DOSP_STAR_115_1	170	DOUGHSPOON	JUMPER	170	170	STARR NELSON	METER	129	129
DOWF_CEMX_115_1	68	DOWE FLATS	JUMPER	119	119	CEMEX	JUMPER	119	119
DUBA_ERVB_115_1	108	DUTTON BASIN	SWITCH	119	145	ERVAY BASIN	CT	19	21
DURA_ANRV_115_1	***	DURANGO	METER	64	64	ANIMAS RIVER (WACM	***	***	***

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TSGT 115 kV Facilities

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DURA_GRVW_115_1	238	DURANGO	BUS	238	238	GRANDVIEW	JUMPER	238****	238****
DURA_HESP_115_1	127	DURANGO	JUMPER	151	151	HESPERUS	NLSWITCH	239	244
DURA_SHEN_115_1	238	DURANGO	BUS	229	238	SHENANDOAH	JUMPER	238	238
ECKL_ROBB_115_1	68	ECKLEY	METER	10	10	ROBB	CB	83	99
ECKL_WRCT_115_1	***	ECKLEY	METER	86	86	WRAY TAP	***	***	***
ECOR_LOCN_115_1	143	EAST CORTEZ	JUMPER	170	170	LOST CANYON	SWITCH	119	145
ELBU_FRNT_115_1	48	ELEPHANT BUTTE	***	***	***	FRONTIER	CT	119	193
ELBU_SOCO_115_1	97	ELEPHANT BUTTE	***	***	***	SOCORRO	METER	90	90
ELPT_GLTP_115_1	85	EL PASO TAP	JUMPER	151	151	GLADE (FEU)	***	***	***
ELSI_ELST_115_1	97	ELSIE	JUMPER	175	175	ELSIE TAP	METER	64	64
ELSI_RWCK_115_1	175	ELSIE	JUMPER	175	175	RED WILLOW CREEK	JUMPER	175	175
ELST_PAXT_115_1	131	ELSIE TAP	METER	143	143	PAXTON	BUS	155	155
ELST_ROSC_115_1	244	ELSIE TAP	METER	215	215	ROSCOE	SWITCH	239	244
EMAN_FOLK_115_1	242	EMIL ANDERSON	JUMPER	173	173	FOREST LAKES	METER	107	107
EMAN_MONU_115_1	145	EMIL ANDERSON	JUMPER	173	173	MONUMENT	CT	168	173
EMIG_WILD_115_1	147	EMIGRANT	SWITCH	119	145	WILDCAT	SWITCH	119	145
EMNT_PEVY_115_1	238	EAST MONTROSE	CT	119	203	PEACH VALLEY	JUMPER	238	238
EMPI_GCTP_115_1	77	EMPIRE	RELAY	165	165	GREAT CUT TAP	JUMPER	135	135
EMPI_LOCN_115_1	77	EMPIRE	RELAY	130	130	LOST CANYON	WAVETRAP	79	102
ERSW_LZDG_115_1	***	ERIE SWITCH	METER	216	216	LAZY DOG	SWITCH	239	244
ERVB_RADE_115_1	108	ERVAY BASIN	CT	19	21	RADERVILLE (WACM)	***	***	***
ESTN_MORI_115_1	***	ESTANCIA	***	***	***	MORIARTY	BUS	148	148
ESTN_WSWT_115_1	***	ESTANCIA	***	***	***	WILLARD SWITCH	JUMPER	148	148
EYTP_ECKL_115_1	***	EAST YUMA TAP (WAC	***	***	***	ECKLEY	METER	86	86
EYTP_SHRM_115_1	68	EAST YUMA TAP (WAC	***	***	***	SCHRAMM	JUMPER	119	119
FALC_FULL_115_1	173	FALCON	JUMPER	173	173	FULLER	JUMPER	173	173
FALC_GEES_115_1	92	FALCON	JUMPER	173	173	GEESEN	RELAY	140	140
FLAT_HORT_115_1	***	FLATIRON (WACM)	***	***	***	HORSETOOTH TAP	SWITCH	119	145
FLAT_WAGW_115_1	***	FLATIRON (WACM)	***	***	***	WAGON WHEEL	JUMPER	155	155
FLYH_MONU_115_1	***	FLYING HORSE	***	***	***	MONUMENT	CT	168	173
FRAS_MILL_115_1	170	METTLER (FRASER)	METER	108	108	MILL (PSCO)	CT	168	170
FRNT_PICA_115_1	48	FRONTIER	RELAY	112	112	PICACHO (PNM)	CT	79	96
FULT_PKWY_115_1	***	FULTON	***	***	***	PARKWAY	SWITCH	239	291
FWNT_MDTP_115_1	114	FORT WINGATE TAP	BUS	114	114	MENDOZA TAP	JUMPER	114	114
GALL_MDTP_115_1	114	GALLUP	BUS	114	114	MENDOZA TAP	JUMPER	114	114
GALL_YATH_115_1	112	GALLUP	JUMPER	167	167	YA-TA-HEY (PNM)	***	***	***
GARY_BECK_115_1	***	GARY	SWITCH	239	291	BEAVER CREEK (WAC	***	***	***
GARY_WOOD_115_1	***	GARY	SWITCH	239	291	WOODROW	***	***	***

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GEES_LRSN_115_1	92	GEESEN	RELAY	163	163	LORSON RANCH	JUMPER	173	173
GEES_SAFB_115_1	92	GEESEN	METER	21	21	SHREIVER	JUMPER	173	173
GERI_EMIG_115_1	***	GERING (WACM)	***	***	***	EMIGRANT	NLSWITCH	119	145
GERI_MCGR_115_1	***	GERING (WACM)	***	***	***	MCGREW	JUMPER	155	155
GLAD_BVDW_115_1	321****	GLADSTONE	CT	199	321	BRAVO DOME WEST	***	***	***
GLAD_SPGR_115_1	184	GLADSTONE	CT	199	242	SPRINGER	METER	215	215
GLDO_PODO_115_1	***	GLENDO (WACM)	***	***	***	PODOLAK	SWITCH	119	145
GMES_GMET_115_1	143	GARNET MESA	JUMPER	170	170	GARNET MESA TAP	JUMPER	170	170
GMES_GNVY_115_1	170	GARNET MESA	JUMPER	170	170	GUNNISON VALLEY	JUMPER	170	170
GMET_HOTC_115_1	151	GARNET MESA TAP	JUMPER	170	170	HOTCHKISS	SWITCH	119	145
GMET_PEVY_115_1	151	GARNET MESA TAP	JUMPER	170	170	PEACH VALLEY	JUMPER	238	238
GOPT_MAIN_115_1	142****	GOODMAN POINT	NLSWITCH	239****	261****	MAIN	SWITCH	119****	145****
GOPT_SACN_115_1	142****	GOODMAN POINT	SWITCH	239****	261****	SAND CANYON	NLCT	119****	145****
GRES_MONU_115_1	145	GRESHAM	JUMPER	173	173	MONUMENT	CT	159	172
GRJC_STAR_115_1	95	GRAND JUNCTION (PS	***	***	***	STARR NELSON	JUMPER	170	170
GRNP_GRTP_115_1	58	GRANTS	BUS	114	114	GRANTS TAP	BUS	114	114
GRNT_OGAL_115_1	147	GRANT	CT	159	162	OGALLALA	RELAY	221	221
GRNT_OGAN_115_2	175	GRANT	CT	159	175	OGALLALA (NPPD)	JUMPER	175	175
GRNT_SPCK_115_1	147	GRANT	SWITCH	119	143	SPRING CREEK (MECC	SWITCH	119	145
GRTP_SFIT_115_1	***	GRANTS TAP	JUMPER	114	114	SAN FIDEL TAP	***	***	***
GRVW_BAYF_115_1	238	GRANDVIEW	JUMPER	238****	238****	BAYFIELD	SWITCH	119	145
HACN_MONT_115_1	95	HAPPY CANYON	WAVETRAP	79	102	MONTROSE	SWITCH	119	145
HAMD_JIM READY TAP_115_1	88	HAMILTON DOME	JUMPER	139	139	JIM READY TAP	JUMPER	155	155
HARB_BOYS_115_1	***	HARRIS BRIDGE	JUMPER	175	175	BOYSEN (WACM)	***	***	***
HARB_PIBU_115_1	***	HARRIS BRIDGE	JUMPER	175	175	PILOT BUTTE (WACM)	***	***	***
HECK_HELT_115_1	97	HELL CREEK	SWITCH	119	145	HELL CREEK TAP	JUMPER	175	175
HECK_SAGE_115_1	97	HELL CREEK	SWITCH	119	145	SAGEBRUSH	SWITCH	119	145
HELT_LIBE_115_1	97	HELL CREEK TAP	JUMPER	175	175	LIBERTY	CT	59	64
HELT_SFOR_115_1	97	HELL CREEK TAP	JUMPER	175	175	SOUTH FORK	RELAY	148	148
HERN_NRTN_115_1	***	HERNANDEZ	JUMPER	238	238	NORTON (PNM)	***	***	***
HERN_OCTP_115_1	169	HERNANDEZ	WAVETRAP	159	205	OJO CALIENTE TAP	SWITCH	239	291
HERN_OJO_115_1	***	HERNANDEZ	BUS	238	238	OJO (PNM)	***	***	***
HESP_SPCT_115_1	95	HESPERUS	CT	119	129	SPRING CREEK TAP (L	***	***	***
HIDA_PYRA_115_1	215	HIDALGO (PNM/EPE)	***	***	***	PYRAMID SWITCH	METER	216	216
HIDA_PYRA_115_2	212	HIDALGO (PNM/EPE)	***	***	***	PYRAMID SWITCH	METER	216	216
HOLO_HOLT_115_1	47	HOLLOMAN	***	***	***	HOLLOMAN TAP	JUMPER	88	88
HOLT_WSAT_115_1	234	HOLLOMAN TAP	JUMPER	234	234	WHITE SANDS TAP	JUMPER	234	234
HORT_MASO_115_1	147	HORSETOOTH TAP	METER	27	27	MASONVILLE	JUMPER	175	175

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HORT_TRIL_115_1	268	HORSETOOTH TAP	METER	27	27	TRILBY	SWITCH	119	145
HOSP_HOT SPRINGS TAP_115_1	48	HOT SPRINGS	***	***	***	HOT SPRINGS TAP	***	***	***
HOTC_NFOR_115_1	143	HOTCHKISS	CT	119	145	NORTH FORK	CT	194	208
HOVE_SACN_115_1	142****	HOVENWEEP	NLSWITCH	119****	145****	SAND CANYON	NLCT	119****	145****
HYGI_LYON_115_1	***	HYGIENE	***	***	***	LYONS	SWITCH	119	145
ICTP_IRNC_115_1	244	IRON CREEK TAP	SWITCH	239	244	IRON CREEK	JUMPER	244	244
ICTP_LVLL_115_1	147	IRON CREEK TAP	JUMPER	175	175	LOVELL (WACM)	CT	168	175
IDAL_SFOR_115_1	147	IDALIA	BUS	175	175	SOUTH FORK	BUS	197	215
IDAL_VERT_115_1	147	IDALIA	BUS	175	175	VERNON SWITCH	RELAY	224	224
INTP_INTE_115_1	119	HIGHLINE INTERSTAT	JUMPER	119	119	INTERSTATE	METER	72	72
JACI_KIMB_115_1	***	JACINTO	SWITCH	119	145	KIMBALL (WACM)	***	***	***
JACI_SIDW_115_1	***	JACINTO	SWITCH	119	145	SIDNEY (WACM)	***	***	***
JARI_OROG_115_1	148	JARILLA	SWITCH	119	145	ORO GRANDE (EPE)	***	***	***
JIM READY TAP_THET_115_1	88	JIM READY TAP	JUMPER	155	155	THERMOPOLIS (TS)	JUMPER	155	155
JOES_LIBE_115_1	68	JOES	JUMPER	119	119	LIBERTY	JUMPER	99	99
JRDY_JIM READY TAP_115_1	108	JIM READY	JUMPER	139	139	JIM READY TAP	JUMPER	193	193
JUAN_NFOR_115_1	143	JUANITA	***	***	***	NORTH FORK	CT	194	215
KEOT_CLKB_115_1	244	KEOTA	JUMPER	244	244	CHALK BLUFFS	JUMPER	175	175
KEOT_RDBX_115_1	244	KEOTA	JUMPER	244	244	REDBOX	JUMPER	244	244
KEOT_RDBX_115_2	244	KEOTA	JUMPER	244	244	REDBOX	JUMPER	244	244
KERW_SKER_115_1	244	KERSEY WEST (WACM	***	***	***	SOUTH KERSEY	JUMPER	244	244
KRTP_KERS_115_1	***	KERSEY TAP	***	***	***	KERSEY	CT	79	135
LACH_LDTP_115_1	68	LAST CHANCE	JUMPER	119	119	LINDON TAP	JUMPER	175	175
LACH_SWOD_115_1	***	LAST CHANCE	NLSWITCH	239	244	SOUTH WOODROW	***	***	***
LAGT_LAGR_115_1	***	LAGRANGE TAP (WAC	***	***	***	LAGRANGE	BUS	175	175
LAGT_ROUN_115_1	***	LAGRANGE TAP (WAC	***	***	***	ROUND TOP	JUMPER	92	92
LAJU_LAMS_115_1	130	LA JUNTA	METER	107	107	LAMSO (LAMAR SOUT	JUMPER	173	173
LAMA_SPCK_115_1	147	LAMAR NE	METER	144	144	SPRING CREEK (MECC	SWITCH	119	145
LAMR_VILA_115_1	202	LAMAR CO (TS)	NLCT	194	242	VILAS	METER	107	107
LAMR_WILC_115_1	202	LAMAR CO (TS)	NLCT	194	242	WILLOW CREEK	METER	107	107
LAMS_WILC_115_1	130	LAMSO (LAMAR SOUT	JUMPER	173	173	WILLOW CREEK	METER	107	107
LARA_OASI_115_1	***	LARAMIE (WACM)	***	***	***	OASIS	SWITCH	119	145
LJAR_TREO_115_1	74	LA JARA	RELAY	80	80	TORREON	JUMPER	238	238
LOCK_LOCT_115_1	56	LOST CREEK	JUMPER	92	92	LOST CREEK TAP	JUMPER	92	92
LOCN_MANCOS TAP_115_1	238	LOST CANYON	NLCT	239	261	MANCOS TAP	JUMPER	238	238
LOCN_TOWA_115_1	169****	LOST CANYON	CT	168	170	TOWAOC CANAL	JUMPER	315****	315****
LORE_YOCN_115_1	138	LORENCITO	***	***	***	YORK CANYON	CT	39	43
LRSN_RANC_115_1	92	LORSON RANCH	JUMPER	173	173	RANCHO	SWITCH	119	145

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LUDL_TYTP_115_1	92	LUDLOW	CT	39	43	TYRONE TAP	SWITCH	239	242
LUDL_WALT_115_1	145	LUDLOW	JUMPER	173	173	WALSENBURG	METER	64	64
LYNN_SNCK_115_1	97	LYNN	JUMPER	175	175	SNAKE CREEK	NLSWITCH	119	145
LYON_DOWF_115_1	68	LYONS	METER	21	21	DOWE FLATS	JUMPER	119	119
LYON_WAGW_115_1	***	LYONS	SWITCH	119	145	WAGON WHEEL	JUMPER	155	155
LZDG_TERR_115_1	***	LAZY DOG	NLSWITCH	239	244	TERRY STREET (PRPA	***	***	***
MAIN_CZPL_115_1	169****	MAIN	NLSWITCH	119****	145****	CORTEZ PIPELINE	SWITCH	119****	145****
MAIN_MOQI_115_1	95****	MAIN	SWITCH	119****	145****	MOQUI C	JUMPER	170****	170****
MAIN_YEJW_115_1	142****	MAIN	NLSWITCH	119****	145****	YELLOW JACKET WES	CT	119****	145****
MANC_MANCOS TAP_115_1	77****	MANCOS	SWITCH	119	145	MANCOS TAP	JUMPER	135	135
MANCOS TAP_SHEN_115_1	238	MANCOS TAP	JUMPER	238	238	SHENANDOAH	JUMPER	238	238
MAVR_MONT_115_1	315	MAVERICK	JUMPER	315	315	MONTROSE	NLCT	194	238
MAVR_NORW_115_1	170	MAVERICK	JUMPER	170	170	NORWOOD	JUMPER	238	238
MAY_OASI_115_1	97	MAY	JUMPER	175	175	OASIS	CT	19	21
MBWT_OASI_115_1	***	MEDICINE BOW TAP (	***	***	***	OASIS	SWITCH	119	145
MCCO_OGAL_115_1	87	MCCONAUGHY	SWITCH	119	145	OGALLALA	CTMAXRATIO	19	21
MERA_PEYT_115_1	242	MERIDIAN RANCH	SWITCH	239	242	PEYTON	NLSWITCH	239	242
MIDW_RANC_115_1	92	MIDWAY (WACM)	CT	119	145	RANCHO	SWITCH	119	145
MLTH_MLTP_115_1	244	MONOLITH	SWITCH	179	218	MONOLITH TAP	JUMPER	244	244
MODL_PICN_115_1	92	MODEL TAP	SWITCH	119	145	PINON CANYON	JUMPER	173	173
MODL_PRGA_115_1	92	MODEL TAP	SWITCH	119	145	PURGATOIRE	SWITCH	119	145
MODL_TYTP_115_1	92	MODEL TAP	SWITCH	119	145	TYRONE TAP	SWITCH	239	242
MOLA_MOLAS TAP_115_1	143	MOLAS	JUMPER	57	57	MOLAS TAP	JUMPER	170	170
MOLAS TAP_SITP_115_1	143	MOLAS TAP	JUMPER	170	170	SILVERTON TAP	JUMPER	170	170
MONT_SCAL_115_1	***	MONTROSE	RELAY	160	160	SOUTH CANAL	JUMPER	170	170
MONT_SCTP_115_1	95	MONTROSE	SWITCH	119	145	SPRING CREEK TAP	JUMPER	170	170
MONU_PALK_115_1	***	MONUMENT	CT	159	173	PALMER LAKE	***	***	***
MYRS_MYRT_115_1	147	MYERS	CTMAXRATIO	14	25	MYERS TAP	JUMPER	175	175
MYRT_POCK_115_1	***	MYERS TAP	JUMPER	175	175	POLE CREEK	CT	119	145
NMES_PEVY_115_1	151	NORTH MESA	BUS	151	151	PEACH VALLEY	JUMPER	238	238
NMES_SCTP_115_1	151	NORTH MESA	NLSWITCH	119	145	SPRING CREEK TAP	JUMPER	151	151
NORW_WIME_115_1	133	NORWOOD	JUMPER	238	238	WILSON MESA	SWITCH	179	218
NUNT_PIER_115_1	244	NUNN TAP (WACM)	***	***	***	PIERCE	JUMPER	244	244
NUNT_ROCK_115_1	324	NUNN TAP (WACM)	***	***	***	ROCKPORT	SWITCH	119	145
NYUM_BRDT_115_1	175	NORTH YUMA	METER	10	10	BURDETT	SWITCH	59	72
NYUM_RWIL_115_1	175	NORTH YUMA	CT	79	129	RED WILLOW	BUS	175	175
OCTP_TAOS_115_1	169	OJO CALIENTE TAP	SWITCH	239	291	TAOS	CT	239	269
OGAL_BRUL_115_1	***	OGALLALA	RELAY	208	208	BRULE (MECC)	SWITCH	119	145

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OGAL_OGAN_115_1	***	OGALLALA	BUS	260	268	OGALLALA (NPPD)	***	***	***
OGAL_OGAW_115_1	268	OGALLALA	RELAY	31	31	OGALLALA (WACM)	***	***	***
OGAL_ROSC_115_1	244	OGALLALA	SWITCH	239	268	ROSCOE	SWITCH	239	244
OLTP_OLCK_115_1	175	OLIVE CREEK TAP	JUMPER	175	175	OLIVE CREEK	CT	19	33
OLTP_VERT_115_1	147	OLIVE CREEK TAP	JUMPER	175	175	VERNON SWITCH	RELAY	224	224
OLTP_WRAY_115_1	147	OLIVE CREEK TAP	JUMPER	175	175	WRAY (TS)	METER	216	216
OWCK_PONN_115_1	324	OWL CREEK	SWITCH	239	291	PONNEQUIN (PSCO)	***	***	***
OWCK_ROCK_115_1	324	OWL CREEK	NLSWITCH	239	291	ROCKPORT	SWITCH	119	145
PEYT_CALH_115_1	242	PEYTON	NLSWITCH	239	242	CALHAN	RELAY	56	56
PHDO_PLAY_115_1	74	PHELPS DODGE	JUMPER	167	167	PLAYAS	JUMPER	148	148
PIBU_WIND RIVER TAP_115_1	147	PILOT BUTTE (WACM)	CT	168	287	WIND RIVER TAP	JUMPER	175	175
PIEW_PUET_115_1	92	PUEBLO WEST	JUMPER	173	173	PUEBLO WEST TAP	BUS	173	173
PKWY_LAFA_115_1	***	PARKWAY	NLSWITCH	239	291	LAFAYETTE (PSCO)	***	***	***
PLAI_PATP_115_1	175	PLAINSVIEW	JUMPER	175	175	PLAINSVIEW TAP	***	***	***
PLAP_WALC_115_1	97	PLATTE (PACE)	JUMPER	155	155	WALCOTT	JUMPER	175	175
PLAY_PYRA_115_1	74	PLAYAS	JUMPER	148	148	PYRAMID SWITCH	RELAY	78	78
PLAZ_RAMO_115_1	143	PLAZA	JUMPER	238	238	RAMON	CB	239	261
PLAZ_STAN_115_1	143	PLAZA	JUMPER	238	238	STANLEY	JUMPER	170****	170****
PLAZ_ZINZ_115_1	238	PLAZA	JUMPER	238	238	ZINZER	JUMPER	170	170
POCK_QUAL_115_1	97	POLE CREEK	METER	53	53	QUALLS	SWITCH	119	145
POCK_ROUN_115_1	***	POLE CREEK	CT	119	145	ROUND TOP	JUMPER	92	92
PRAI_REUN_115_1	244	PRAIRIE CENTER	JUMPER	175	175	REUNION	CT	119	203
PROV_LOCT_115_1	***	PROSPECT VALLEY (W	***	***	***	LOST CREEK TAP	JUMPER	92	92
PUET_STBE_115_1	92	PUEBLO WEST TAP	BUS	173	173	STEM BEACH	SWITCH	119	142
PUET_WSTA_115_1	145	PUEBLO WEST TAP	BUS	173	173	WEST STATION (BHCE	***	***	***
RDBX_RTAL_115_1	244	REDBOX	JUMPER	244	244	REDTAIL	JUMPER	244	244
RDBX_RTAL_115_2	244	REDBOX	JUMPER	244	244	REDTAIL	JUMPER	244	244
RILK_WAVP_115_1	175	RICHARD LAKE (PRPA)	***	***	***	WAVERLY (PV)	JUMPER	175	175
RILT_TIMT_115_1	***	RICHARD LAKE TAP (	***	***	***	TIMNATH TAP	METER	108	108
RIPP_WELT_115_1	68	RIPPLE	JUMPER	119	119	WELLINGTON TAP	SWITCH	119	119
RIVE_WIND RIVER TAP_115_1	147	RIVERTON	METER	138	138	WIND RIVER TAP	JUMPER	175	175
RNST_RNSV_115_1	118	RAINSVILLE TAP	JUMPER	118	118	RAINSVILLE	JUMPER	118	118
RODEO TAP_ELBU_115_1	167	RODEO TAP	JUMPER	167	167	ELEPHANT BUTTE	***	***	***
RODEO TAP_HOT SPRINGS TAP_115	167	RODEO TAP	JUMPER	167	167	HOT SPRINGS TAP	JUMPER	167	167
ROUN_SENT_115_1	97	ROUND TOP	SWITCH	119	145	SENTINEL	SWITCH	119	119
ROWE_ROWT_115_1	74	ROWE	JUMPER	114	114	ROWE TAP (PNM)	***	***	***
RWIL_WAGE_115_1	175	RED WILLOW	JUMPER	175	175	WAGES	BUS	175	175
SALV_STAN_115_1	143	SAN LUIS VALLEY	NLSWITCH	119	145	STANLEY	JUMPER	170	170

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TSGT 115 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
SALV_WAVE_115_1	143	SAN LUIS VALLEY	SWITCH	119	145	WAVERLY (TS)	JUMPER	238	238
SAND_WREM_115_1	97	SANDHILLS	JUMPER	175	175	WRAY EMERGENCY T	JUMPER	175	175
SHRH_SHTP_115_1	175	SHERIDAN HILL	METER	10	10	SHERIDAN HILL TAP	***	***	***
SKIT_SKIW_115_1	143	SKITO	SWITCH	119	145	SKITO (WACM)	***	***	***
SKIT_SKIW_115_2	143	SKITO	SWITCH	119	145	SKITO (WACM)	***	***	***
SLTR_DELT_115_1	175	SLATER	METER	150	150	DEL CAMINO TAP	JUMPER	175	175
SMOK_WAAT_115_1	64	SMOKY HILL	JUMPER	118	118	WAANIBE TAP	CTMAXRATIO	39	67
SNCK_ALLW_115_1	***	SNAKE CREEK	SWITCH	119	145	ALLIANCE (WACM)	***	***	***
SNCK_MORL_115_1	***	SNAKE CREEK	SWITCH	119	145	MORRILL COUNTY	***	***	***
SPGR_BISN_115_1	82	SPRINGER	NLCT	239	242	BISON	JUMPER	154	154
SPGR_RNST_115_1	92	SPRINGER	RELAY	215	215	RAINSVILLE TAP	JUMPER	173	173
STAR_MONT_115_1	95	STARR NELSON	RELAY	138	138	MONTROSE	NLSWITCH	119	129
STBE_GCCP_115_1	92	STEM BEACH	METER	32	32	GCC CEMENT PLANT	***	***	***
STBE_WALT_115_1	92	STEM BEACH	RELAY	103	103	WALSENBURG	SWITCH	119	139
STEW_EMIG_115_1	***	STEGALL (WACM)	***	***	***	EMIGRANT	SWITCH	119	145
STLK_RNST_115_1	92	STORRIE LAKE	RELAY	149	149	RAINSVILLE TAP	JUMPER	173	173
STLK_VALN_115_1	***	STORRIE LAKE	METER	129	129	VALENCIA (PNM)	***	***	***
STOC_WAVE_115_1	143	STOCKADE	JUMPER	170	170	WAVERLY (TS)	METER	10	10
SUNT_TELL_115_1	143	SUNSHINE	JUMPER	238	238	TELLURIDE	RELAY	65	65
SUNT_WIME_115_1	133	SUNSHINE	JUMPER	170	170	WILSON MESA	SWITCH	179	218
SUNY_HESP_115_1	200	SUNNYSIDE	RELAY	392	392	HESPERUS	METER	129	129
SUTH_PAXT_115_1	131	SUTHERLAND (NPPD)	***	***	***	PAXTON	BUS	155	155
SYSI_TREO_115_1	74	SAN YSIDRO	BUS	74	74	TORREON	JUMPER	238	238
THET_THEW_115_1	98	THERMOPOLIS (TS)	JUMPER	155	155	THERMOPOLIS (WACM	***	***	***
TROW_WALC_115_1	68	TROWBRIDGE	JUMPER	119	119	WALCOTT	JUMPER	119	119
VANB_BISN_115_1	82	VAN BREMMER	BUS	173	173	BISON	JUMPER	154	154
VANB_YOCN_115_1	82	VAN BREMMER	JUMPER	173	173	YORK CANYON	WAVETRAP	79	102
VRNN_VERT_115_1	68	VERNON	SWITCH	119	119	VERNON SWITCH	NLSWITCH	239	244
WAAN_WAAT_115_1	92	WAANIBE	JUMPER	118	118	WAANIBE TAP	JUMPER	118	118
WAGE_WAUN_115_1	68	WAGES	JUMPER	155	155	WAUNETA	JUMPER	119	119
WALS_SPPK_115_1	92	WALSENBURG	CT	29	32	SPANISH PEAKS	JUMPER	173	173
WAVP_WELT_115_1	175	WAVERLY (PV)	JUMPER	175	175	WELLINGTON TAP	SWITCH	119	145
WELD_WHIT_115_1	133	WELD	***	***	***	WHITNEY	NLCB	239	244
WELL_WELT_115_1	68	WELLINGTON	JUMPER	169	169	WELLINGTON TAP	SWITCH	119	119
WHIT_WDTP_115_1	133	WHITNEY	SWITCH	239	244	WINDSOR TAP (WAPA)	***	***	***
WIBY_LOCT_115_1	***	WILLOBY	***	***	***	LOST CREEK TAP	JUMPER	92	92
WILL_WSWT_115_1	97	WILLARD	BUS	160	167	WILLARD SWITCH	RELAY	39	39
WINR_WIND RIVER TAP_115_1	147	WIND RIVER	CT	59	64	WIND RIVER TAP	JUMPER	175	175

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TSGT 115 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
WRAW_WREM_115_1	97	WRAY (WACM)	***	***	***	WRAY EMERGENCY T	JUMPER	175	175
WRAY_WRAW_115_1	***	WRAY (TS)	NLCT	239	244	WRAY (WACM)	***	***	***
WRAY_WRCT_115_1	***	WRAY (TS)	CT	239	244	WRAY TAP	***	***	***
WRAY_WREM_115_1	97	WRAY (TS)	CT	168	180	WRAY EMERGENCY T	JUMPER	175	175
WSWT_DRAN_115_1	***	WILLARD SWITCH	METER	32	32	DURAN	***	***	***
WSWT_HLMS_115_1	***	WILLARD SWITCH	NLCT	119	120	HIGH LONESOME MES	***	***	***
YJSW_YEJW_115_1	142****	YELLOW JACKET SWIT	NLSWITCH	119****	145****	YELLOW JACKET WES	SWITCH	119****	145****

TSGT 138 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AXBA_HAYD_138_1	125	AXIAL BASIN	RELAY	130	130	HAYDEN (WACM)	***	***	***
AXBA_MEEK_138_1	125	AXIAL BASIN	RELAY	129	129	MEEKER	CT	202	204
CALR_WRCY_138_1	114	CALAMITY RIDGE	***	***	***	WHITE RIVER CITY	JUMPER	204	204
FRAS_WIGA_138_1	172	METTLER (FRASER)	METER	168	168	WINDY GAP	JUMPER	204	204
GORP_KREM_138_1	***	GORE PASS	JUMPER	204	204	KREMMLING (WACM)	***	***	***
GORP_OACK_138_1	***	GORE PASS	CT	143	151	OAK CREEK TAP	***	***	***
GORP_WIGA_138_1	282	GORE PASS	SWITCH	286	349	WINDY GAP	SWITCH	286	327
MEEK_MASW_138_1	***	MEEKER	METER	100	100	MAGNOLIA SWITCH	***	***	***
MEEK_RIFP_138_1	125	MEEKER	RELAY	137	137	RIFLE (PSCO)	***	***	***
MEEK_WRCY_138_1	114	MEEKER	RELAY	137	137	WHITE RIVER CITY	JUMPER	204	204
NCWCD_WIGA_138_1	114	NCWCD	***	***	***	WINDY GAP	METER	100	100
TROU_WIGA_138_1	***	TROUBLESOME	***	***	***	WINDY GAP	JUMPER	204	204

TSGT 230 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AMBR_PEGS_230_1	328	AMBROSIA LAKE (PNM	RELAY	1527	1527	ESCALANTE	CT	398	431
AMSA_DIFF_230_1	***	AMASA (PACE)	***	***	***	DIFFICULTY	NLSWITCH	478	583
ARCH_WYCH_230_1	648	ARCHER (WACM)	***	***	***	WAYNE CHILD	METER	327	327
ARLI_FTCK_230_1	489	ARLINGTON	NLCT	239	406	FOOT CREEK (PACE)	***	***	***
ARNO_ERSW_230_1	648	ARNOLD	JUMPER	648	648	ERIE SWITCH	JUMPER	648	648
ARNO_SIPR_230_1	648	ARNOLD	JUMPER	648	648	SIPRES	JUMPER	648	648

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TSGT 230 kV Facilities

PUBLIC

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AULT_CARY_230_1	***	AULT (WACM)	***	***	***	CAREY	NLCB	796	947
BALK_KNUT_230_1	648	BARR LAKE (PSCO)	NLSWITCH	637	648	KNUTSON	METER	288	288
BECP_STO2_230_1	***	BEAVER CREEK (PSC	***	***	***	STORY (TS)	METER	276	276
BECT_STO2_230_1	292	BEAVER CREEK (TS)	JUMPER	537	537	STORY (TS)	METER	415	415
BFHD_GRFD_230_1	647	BUFFALO HEAD (WAP	***	***	***	GRIEVE FIELD	***	***	***
BLRR_GORP_230_1	***	BLUE RIVER (PSCO)	***	***	***	GORE PASS	WAVETRAP	463	598
BOYD_GTWY_230_1	***	BOYD (PRPA)	***	***	***	GATEWAY	JUMPER	648	648
BSAN_LINC_230_1	642	BIG SANDY	METER	576	576	LINCOLN	METER	576	576
BSAN_WDTK_230_1	274	BIG SANDY	METER	432	432	WINDTALKER	JUMPER	642	642
BURL_CARO_230_1	642	BURLINGTON	METER	327	327	CAROUSEL	***	***	***
BURL_LMCK_230_1	274	BURLINGTON	RELAY	412	412	LANDSMAN CREEK	RELAY	412	412
BURL_WRAY_230_1	642	BURLINGTON	NLCT	478	583	WRAY (TS)	JUMPER	642	642
CARY_TIMB_230_1	***	CAREY	NLSWITCH	796	947	TIMBERLINE (PRPA)	***	***	***
COMA_MIDP_230_1	***	COMANCHE (PSCO)	WAVETRAP	478	616	MIDWAY (PSCO)	***	***	***
COMA_WALT_230_1	642	COMANCHE (PSCO)	***	***	***	WALSENBURG	CT	358	609
CRAI_CRAT_230_1	***	CRAIG	CT	159	270	CRAIG TRANSFER (PS	***	***	***
CRAI_HAYD_230_1	***	CRAIG	METER	518	518	HAYDEN (WACM)	***	***	***
CRAI_HAYD_230_2	528	CRAIG	JUMPER	621	621	HAYDEN (WACM)	***	***	***
CRAI_RIFL_230_1	***	CRAIG	NLCB	796	863	RIFLE (WACM/PSCO)	***	***	***
CRT1_WDTK_230_1	***	CROSSING TRAILS 1	***	***	***	WINDTALKER	CT	637	642
DAJO_LRS2_230_1	542	DAVE JOHNSTON (PA	***	***	***	LARAMIE RIVER (MBP	METER	831	831
DIFF_SHBN_230_1	***	DIFFICULTY	NLSWITCH	478	583	SHIRLEY BASIN (PACE	***	***	***
FLUP_JLGR_230_1	***	FORT LUPTON (PSCO)	***	***	***	J L GREEN	NLCB	637	648
FLUP_JMSH_230_1	***	FORT LUPTON (PSCO)	***	***	***	J M SHAFER	NLCT	637	648
GHSE_HNLK_230_1	648	GREENHOUSE	JUMPER	648	648	HENRY LAKE	JUMPER	648	648
GHSE_JMSH_230_1	648	GREENHOUSE	CT	637	648	J M SHAFER	JUMPER	648	648
GLAD_WALT_230_1	642	GLADSTONE	NLCT	637	642	WALSENBURG	CT	358	518
GORP_HAYD_230_1	612	GORE PASS	METER	719	719	HAYDEN (WACM)	***	***	***
GTWY_LOPK_230_1	***	GATEWAY	JUMPER	648	648	LONGS PEAK	***	***	***
HNLK_FLUP_230_1	***	HENRY LAKE	JUMPER	648	648	FORT LUPTON (PSCO)	***	***	***
HNLK_RVDL_230_1	***	HENRY LAKE	JUMPER	648	648	RIVERDALE (PSCO)	***	***	***
HNLK_STO2_230_1	648	HENRY LAKE	METER	518	518	STORY (TS)	CT	637	844
JLGR_WSHT_230_1	***	J L GREEN	SWITCH	637	648	WASHINGTON (XCEL)	***	***	***
LAMP_LAMR_230_1	325	LAMAR CO (PSCO)	***	***	***	LAMAR CO (TS)	CT	337	433
LINC_MIDW_230_1	642	LINCOLN	METER	576	576	MIDWAY (WACM)	***	***	***
LMCK_WDTK_230_1	274	LANDSMAN CREEK	RELAY	414	414	WINDTALKER	JUMPER	642	642
LOCN_CURE_230_1	***	LOST CANYON	JUMPER	476	476	CURECANTI (WACM)	***	***	***
LOCN_SHIP_230_1	***	LOST CANYON	JUMPER	476	476	SHIPROCK (WACM)	***	***	***

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TSGT 230 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
NFOR_CURE_230_1	***	NORTH FORK	RELAY	717	717	CURECANTI (WACM)	***	***	***
NFOR_RIFL_230_1	***	NORTH FORK	RELAY	669	669	RIFLE (WACM/PSCO)	***	***	***
NYUM_SPCY_230_1	***	NORTH YUMA	SWITCH	478	583	SPRING CANYON (PSC	***	***	***
NYUM_STO2_230_1	292	NORTH YUMA	WAVETRAP	318	411	STORY (TS)	METER	287	287
NYUM_WRAY_230_1	292	NORTH YUMA	SWITCH	478	583	WRAY (TS)	METER	327	327
PAWN_STO2_230_1	***	PAWNEE (PSCO)	***	***	***	STORY (TS)	JUMPER	648	648
PONC_SALV_230_1	693	PONCHA (WACM)	***	***	***	SAN LUIS VALLEY	METER	180	180
REUN_BALK_230_1	***	REUNION	JUMPER	648	648	BARR LAKE (PSCO)	NLSWITCH	637	648
REUN_SSAD_230_1	***	REUNION	JUMPER	648	648	SILVER SADDLE (PSC	***	***	***
RIFP_RIFL_230_1	631	RIFLE (PSCO)	***	***	***	RIFLE (WACM/PSCO)	***	***	***
RIGS_RIFL_230_1	***	RIFLE GENERATION	WAVETRAP	159	172	RIFLE (WACM/PSCO)	***	***	***
RIVE_RIVP_230_1	630	RIVERTON	BUS	630	647	RIVERTON (PACE)	CB	796	948
SIDN_SPCY_230_1	***	SIDNEY	JUMPER	537	537	SPRING CANYON (PSC	***	***	***
SIDN_STEW_230_1	451	SIDNEY	WAVETRAP	318	411	STEGALL (WACM)	BUS	394	465
SIPR_HNLK_230_1	648	SIPRES	JUMPER	648	648	HENRY LAKE	JUMPER	648	648
THEP_RIVP_230_1	***	THERMOPOLIS (PACE)	NLSWITCH	478	583	RIVERTON (PACE)	***	***	***

TSGT 345 kV Facilities

Section	Conductor Rating MVA*	Terminal 1	Terminal 1 Equipment	Terminal 1 Rating MVA*	Terminal 1 30 Min MVA**	Terminal 2	Terminal 2 Equipment	Terminal 2 Rating MVA*	Terminal 2 30 Min MVA**
AULT_CRAI_345_1	1014	AULT (WACM)	***	***	***	CRAIG	WAVETRAP	717	924
AULT_LRS3_345_1	1627	AULT (WACM)	***	***	***	LARAMIE RIVER (MBP	***	***	***
BONA_CRAI_345_1	***	CRAIG	CT	896	971	BONANZA (PACE)	***	***	***
CRAI_MEE3_345_1	1014	CRAIG	CT	896	946	MEEKER345	WAVETRAP	956	1233
GRJC_MONT_345_1	1585	GRAND JUNCTION (PS	***	***	***	MONTROSE	CT	925	1166
GRJC_RIFP_345_1	***	GRAND JUNCTION (PS	***	***	***	RIFLE (PSCO)	***	***	***
HESP_MONT_345_1	1585	HESPERUS	CT	717	1115	MONTROSE	CT	925	971
HESP_SJUA_345_1	1585	HESPERUS	CT	717	1115	SAN JUAN (PNM)	***	***	***
KEOT_STO3_345_1	1627	KEOTA	NLCB	1792	1944	STORY (MBPP)	FAC008_PSCO	956	1233
LRS3_KEOT_345_1	1627	LARAMIE RIVER (MBP	***	***	***	KEOTA	RELAY	1438	1438
MEE3_MCBR_345_1	***	MEEKER345	METER	647	647	MCBRYDE (WREA)	RELAY	3633	3633
MEE3_RIFP_345_1	1014	MEEKER345	WAVETRAP	956	1233	RIFLE (PSCO)	***	***	***
OJO_TAOS_345_1	782	OJO (PNM)	RELAY	1190	1190	TAOS	CT	755	1242

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Attachment Vol II 4-2 Tri-State 10-year Transmission Plan

AMENDED

10-YEAR TRANSMISSION PLAN

For the State of Colorado

To comply with

Rule 3627

of the

Colorado Public Utilities Commission

Rules Regulating Electric Utilities

February 3, 2020

Web addresses updated as of 6/08/2020

Colorado PUC E-Filings System

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Term
2018 Filing	2018 Rule 3627 10-Year Transmission Plan
2020 Plan	2020 10-Year Transmission Plan for the State of Colorado
AQCC	Air Quality Control Commission
ARPA	Arkansas River Power Authority
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
BES	Bulk Electric System
Black Hills	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCE	Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy
BHCT	Black Hills/Colorado Transmission
CBM	Capacity Benefit Margin
CBMID	Capacity Benefit Margin Implementation Document
CCOD	City and County of Denver
CCPG	Colorado Coordinated Planning Group
CDOT	Colorado Department of Transportation
CDPHE	Colorado Department of Public Health and Environment
CEII	Critical Energy Infrastructure Information
CEO	Colorado Energy Office
CEP	Clean Energy Plan
CEPP	Colorado Energy Plan Portfolio
City of Raton	Raton Public Service Company
Commission or CPUC	Colorado Public Utilities Commission
Companies	Black Hills, Tri-State and Public Service
Company	Black Hills, Tri-State or Public Service
CPCN	Certificate of Public Convenience and Necessity
CSG	Community Solar Garden
CSU	Colorado Springs Utilities
DSM	Demand-Side Management
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005
ERP	Electric Resource Plan
ERP/APR	Electric Resource Plan Annual Progress Report
ERZ	Energy Resource Zone

Acronym or Abbreviation	Term
Executive Order B 2019 008	The Zero Emission Vehicle Mandate
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse Gas
HB18-1270	Colorado House Bill 18-1270 (the Energy Storage Procurement Act)
HB19-1261	Colorado House Bill 19-1261 (the GHG Reduction Bill)
HVDC	High Voltage Direct Current
IREA	Intermountain Rural Electric Association
KCEA	K.C. Electric Association
KCEC	K.C. Electric Association
kV	Kilovolt
LEV	Low Emission Vehicle
L&R	Load and Resource
LFRTF	Lamar Front Range Task Force
LGIP	Large Generator Interconnection Procedures
LTC	Load Tap-Changing
LTP	Local Transmission Plan
MEAN	Municipal Electric Agency of Nebraska
MW	Megawatts
MVAR	Mega Volt Ampere Reactive
MVEA	Mountain View Electric Association
NECO	Northeast Colorado
NERC	North American Electric Reliability Corporation
NREL	U.S. Department of Energy's National Renewable Energy Laboratory
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCC	Colorado Office of Consumer Counsel
Order 1000	FERC Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities
PA	Planning Authority
PNM	Public Service Company of New Mexico
PRPA	Platte River Power Authority
PST	Phase Shifting Transformer

Acronym or Abbreviation	Term
Public Service	Public Service Company of Colorado
PV	Photovoltaic
P-V	Voltage Stability
RCTF	Rush Creek Task Force
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RTO	Regional Transmission Organization
SB07-100	Colorado Senate Bill 07-100
SB18-009	Colorado Senate Bill 18-009 (the Energy Storage Rights Bill)
SB19-236	Colorado Senate Bill 19-236 (the PUC Sunset Bill)
Sierra	Sierra Subregional Planning Group
SLV	San Luis Valley
SOL	System Operating Limits
SPG	Sub-regional planning group
SPP	Southwest Power Pool
SWAT	Southwest Area Transmission Group
SWEP	Southwest Weld Expansion Project
TBD	To Be Determined
TCPC	Transmission Coordination and Planning Committee
TP	Transmission Provider
Tri-State	Tri-State Generation and Transmission Association, Inc.
TRMID	Transmission Reliability Margin Implementation Document
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council
Western/WAPA	Western Area Power Administration (also WAPA)

I. Executive Summary

The purpose of transmission planning is to ensure the present and future reliability of the interconnected bulk electric transmission system. Planning is performed to meet customer needs by facilitating the timely and coordinated development of transmission infrastructure projects on a cost-effective and reliable basis. In order to promote an efficient utilization of the transmission system, planning also takes into account drivers such as public policy initiatives, environmental concerns, and stakeholder interests, which are collected via numerous meaningful input opportunities throughout the planning process.

In 2011, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rules 3625 through 3627, which set forth requirements for transmission planning applicable to Commission-regulated utilities. The rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner. The process is to be conducted on a statewide basis and is to take into account the needs of all stakeholders. This 2020 10-Year Transmission Plan for the State of Colorado ("2020 Plan") is the result of a cooperative effort among Black Hills Colorado Electric, LLC, d/b/a Black Hills Energy ("Black Hills"), Tri-State Generation and Transmission Association, Inc. ("Tri-State"), and Public Service Company of Colorado ("Public Service") (each a "Company" and collectively the "Companies"), and is the fifth 10-Year transmission plan that the Companies have filed under Rule 3627.

Since filing the first 10-Year transmission plan in 2012, the Companies have continued to coordinate the transmission planning process with all Colorado Transmission Providers ("TPs") and interested stakeholders through active outreach efforts and coordinated planning activities in a variety of transmission planning venues. The 2020 Plan is the culmination of a collaborative process and includes transmission facilities that the Companies, individually or jointly, may construct or participate in over the next 10 years in the state of Colorado. The 2020 Plan includes two types of projects.

"Planned Projects" are projects for which the companies generally have a level of commitment such that proposed schedules for completion have been drafted, site control has been established, or the project has received budgetary approvals. These include projects that are required to meet reliability and load growth needs, planned interconnection of new generation, or to meet enacted public policy requirements. "Conceptual Projects", on the other hand, may not have specific in-service dates, and their implementation depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development.

The Companies are confident that the 2020 Plan and the individual transmission projects included in the 2020 Plan meet all applicable reliability criteria and do not negatively impact the system of any other TP or the overall transmission system in the near-term and long-term planning horizons. Projects included in the 2020 Plan do not duplicate existing or planned transmission facilities of any other transmission provider in Colorado. Finally, the Companies are confident that the coordination and stakeholder outreach processes described herein effectively have solicited and addressed the interests of stakeholders.

When possible, individual transmission projects have been designed to accommodate the collective needs of multiple TPs and stakeholders. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation or transmission expansions, economic issues, and other utilities' plans may impact this 2020 Plan and could result in changes to in-service dates or project scopes.

Public policy initiatives, such as recent and future federal and local mandates, also may impact the 2020 Plan and the transmission planning process in general. Examples of public policies and legislation potentially impacting the Companies include Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill 19-077, Executive Order B 2019 002, Colorado's

Renewable Energy Standard, Senate Bill 07-100, and the U.S. Environmental Protection Agency's ("EPA") Affordable Clean Energy Rule.

Section II provides background information about the transmission planning process—including coordinated regional and statewide efforts, as well as internal practices of each Company. Sections III and IV of this report provide additional details for these and other projects that the Companies have identified in their transmission planning processes; complete details and supporting information can be found in Appendices D-I. Sections V to VIII address compliance with specific legal, regulatory and technical requirements of Rule 3627 and Federal Energy Regulatory Commission ("FERC") Orders, with an emphasis on stakeholder outreach efforts.

This 2020 Plan identifies 74 significant transmission projects. These projects are listed in Table 1 and shown geographically in Figure 1. Figures 2 and 3 are maps depicting transmission projects in the Denver-Metro area and in Black Hills' 10-Year Transmission Plan, respectively. Larger maps of the state plan showing chronological stages of development are provided in Appendix A. Larger versions of the Denver-Metro and Black Hills maps are provided in Appendices B and C.

Table 1. Significant transmission projects included in the 2020 Plan

Map #	Project Name	In-Svc (1)	Cost (MIL)	BH	TS	PS	Other	Purpose
1	Arequa Gulch 115 kV Capacitor	2018	$0.85	√				R
2	Boyd 230/115 kV Substation Expansion	2018	$10.0				PRPA	R
3	Missile Site – Shortgrass 345kV Transmission	2018	$104.9			√		G
4	Moon Gulch 230 kV Substation	2018	$1.7			√		L
5	Two Basins Relocation Project	2018	$24.1			√		R
6	Bluestone Valley Substation Phase 1	2019	$12.0			√		R
7	Cottonwood 230/115 kV Autotransformer Replacement	2019	$3.0				CSU	R
8	La Junta 115 kV Area Upgrades	2019	$3.9	√				R

Map #	Project Name	In-Svc [1]	Cost (MIL)	BH	TS	PS	Other	Purpose
9	Pawnee-Daniels Park 345 kV	2019	$169.4			√		G,R
10	Portland 115/69 kV Transformer Replacement	2019	$3.7	√				R
11	Sunshine-Telluride Line Uprate	2019	$3.1		√			R
12	Thornton Substation	2019	$21.4			√		L
13	West Station 115 kV Substation Upgrades	2019	$6.5	√				R
14	Ault 345/230 kV XFMR Replacement	2020	$7.8				WAPA	R
15	Boone-La Junta 115 kV Rebuild	2020	$20.9	√				R
16	CEPP Voltage Support	2020	$93.6			√		G
17	Midway KV1A Replacement	2020	$2.0				WAPA	R
18	Nixon-Kelker 230kV Transmission	2020	$0.5				CSU	R
19	NREL Substation	2020	$10.4			√		G
20	Shortgrass – Cheyenne Ridge 345kV Transmission	2020	$62.3			√		G
21	Shortgrass Switching Station	2020	$20.6			√		G
22	Sisson Project	2020	$18.8		√			L
23	Western Colorado Trans Upgrade	2020	$57.2		√			R
24	Williams Creek 230kV Switching Station	2020	$9.1				CSU	G
25	Avery Substation	2021	$10.3			√		L
26	Barker Distribution Substation	2021	$29.8			√		L
27	Del Camino-Slater 115kV Line Uprate	2021	$1.4		√			L,R
28	Desert Cove-Fountain Valley-Midway 115kV	2021	$5.08	√				R
29	Hogback Ranch 115kV Substation	2021	$9.9	√				R
30	Pueblo West 115kV Distribution Sub	2021	$4.5	√				R
31	Salt Creek 115kV Sub	2021	$6.4	√				R
32	South Fowler Substation	2021	$5.1	√				R
33	Airport Memorial-Nyberg 115kV Rebuild	2022	$3.7	√				R
34	Ault-Cloverly 230/115 kV Transmission Project	2022	$66.7			√		L,R
35	Avon-Gilman 115 kV Transmission	2022	$11.4			√		R

Map #	Project Name	In-Svc [(1)]	Cost (MIL)	BH	TS	PS	Other	Purpose
36	Boone-South Fowler 69/115kV Conversion	2022	$6.6	√				R
37	Burlington-Burlington (KCEA) Rebuild	2022	$0.7		√			R
38	CEPP Switching Station Bid S085	2022	$12.0			√		G
39	CEPP Switching Station Bid X645	2022	$20.0			√		G
40	CSU Flow Mitigation	2022	TBD			√	CSU	R
41	Falcon-Midway 115 kV Line Uprate	2022	$3.8		√			R
42	Greenwood-Denver Terminal 230kV Line	2022	$50.3			√		G,L,R
43	High Point Distribution Substation	2022	$9.0			√		L
44	JG Kalcevik Project	2022	$14.8		√			L,R
45	Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0			√		G
46	North Penrose 115kV Distribution Sub	2022	$4.5	√				R
47	Titan Distribution Substation	2022	$13.0			√		L
48	Vollmer Project	2022	$7.1		√			L
49	West Station-Greenhorn 115kV Line Rebuild	2022	$4.5	√				R
50	West Station to Hogback 115 kV Transmission Project	2022	$24.0	√				L,R
51	Dove Valley Distribution Substation	2023	TBD			√		L
52	Southwest Weld Expansion Project	2023	$70.0		√			L,R
53	Burlington-Lamar 230 kV	2024	$58.4		√			G,L,R
54	San Luis Valley-Poncha 230 kV #2[2]	2025	$58.0		√	√		R, G
55	Stock Show Distribution Substation	2026	TBD			√		L
56	Bluestone Valley Substation Phase 2	TBD	TBD			√		L
57	Falcon-Paddock-Calhan 115 kV	TBD	$33.4		√			R
58	Glenwood-Rifle 115 kV Transmission	TBD	TBD			√		L,R

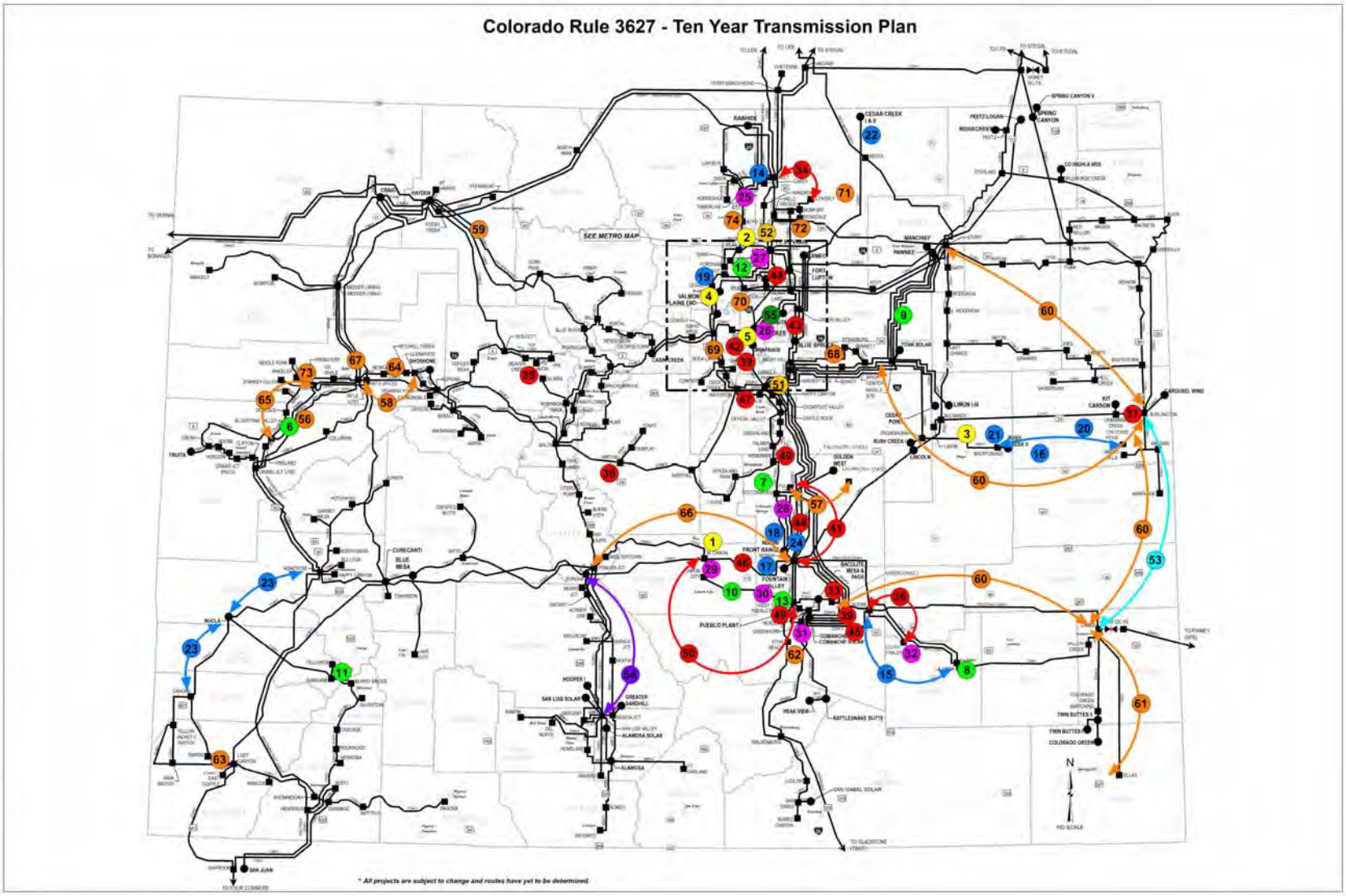
[2] The in-service date and cost for this project are Tri-State estimates and not that of Public Service, though a project may be jointly proposed at some future date.

Map #	Project Name	In-Svc [1]	Cost (MIL)	BH	TS	PS	Other	Purpose
59	Hayden-Foidel-Gore 230 kV	TBD	TBD			√		R
60	Lamar Front Range Transmission	TBD	TBD		√	√		G,R
61	Lamar-Vilas 230 kV Transmission	TBD	TBD		√	√		G
62	Lime Road Delivery Point	TBD	$8.1		√			L
63	Lost Canyon-Main Switch 115 kV	TBD	$22.6		√			L,R
64	New Castle Distribution Substation	TBD	TBD			√		L
65	Parachute-Cameo 230 kV #2	TBD	TBD			√		L,R
66	Poncha – Front Range 230 kV	TBD	TBD			√		G
67	Rifle-Story Gulch 230 kV Transmission	TBD	TBD			√		L
68	Sandy Creek Distribution Substation	TBD	TBD			√		L
69	Solterra Distribution Substation	TBD	TBD			√		L
70	Superior Distribution Substation	TBD	TBD			√		L
71	Weld County Expansion Transmission	TBD	TBD			√		G,R
72	Weld-Rosedale-Box Elder-Ennis 230/115 kV	TBD	TBD			√		L,R
73	Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD			√		L
74	Wilson Distribution Substation	TBD	$4.0			√		L

Key: R – Reliability, L – Load-serving, G – Generation, TBD – To Be Determined

Note 1: In-service dates are based on best estimates at the time of this filing. Changed needs, load forecasts, permitting activities, timelines for delivery of major equipment, etc. can and will impact project viability and final in-service dates.

Figure 1. Statewide map of significant transmission projects in the 2020 Plan



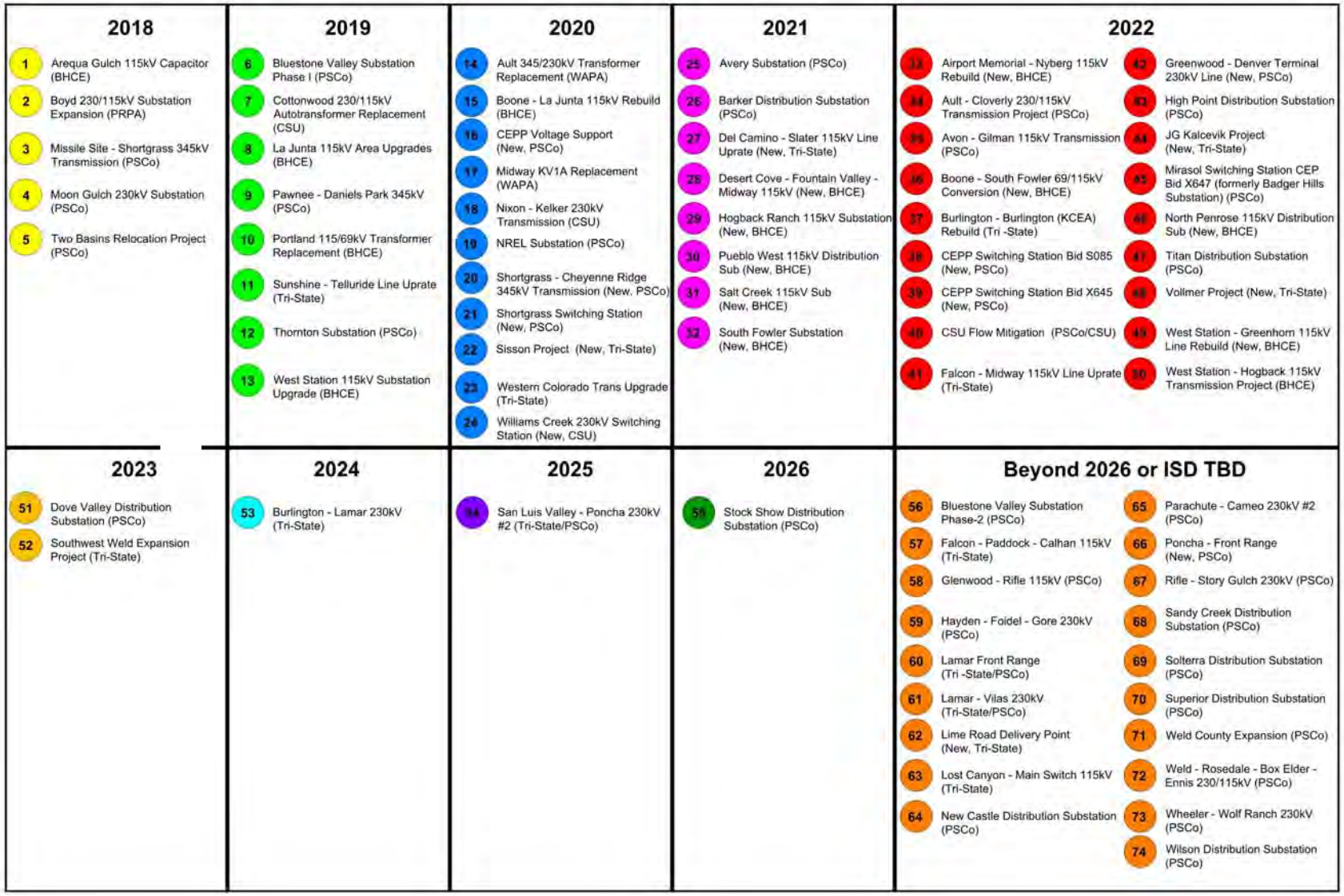

2018
1 Arequa Gulch 115kV Capacitor (BHCE)
2 Boyd 230/115kV Substation Expansion (PRPA)
3 Missile Site - Shortgrass 345kV Transmission (PSCo)
4 Moon Gulch 230kV Substation (PSCo)
5 Two Basins Relocation Project (PSCo)
2019
6 Bluestone Valley Substation Phase I (PSCo)
7 Cottonwood 230/115kV Autotransformer Replacement (CSU)
8 La Junta 115kV Area Upgrades (BHCE)
9 Pawnee - Daniels Park 345kV (PSCo)
10 Portland 115/69kV Transformer Replacement (BHCE)
11 Sunshine - Telluride Line Uprate (Tri-State)
12 Thornton Substation (PSCo)
13 West Station 115kV Substation Upgrade (BHCE)
2020
14 Ault 345/230kV Transformer Replacement (WAPA)
15 Boone - La Junta 115kV Rebuild (BHCE)
16 CEPP Voltage Support (New, PSCo)
17 Midway KV1A Replacement (WAPA)
18 Nixon - Kelker 230kV Transmission (CSU)
19 NREL Substation (PSCo)
20 Shortgrass - Cheyenne Ridge 345kV Transmission (New, PSCo)
21 Shortgrass Switching Station (New, PSCo)
22 Sisson Project (New, Tri-State)
23 Western Colorado Trans Upgrade (Tri-State)
24 Williams Creek 230kV Switching Station (New, CSU)
2021
25 Avery Substation (PSCo)
26 Barker Distribution Substation (PSCo)
27 Del Camino - Slater 115kV Line Uprate (New, Tri-State)
28 Desert Cove - Fountain Valley - Midway 115kV (New, BHCE)
29 Hogback Ranch 115kV Substation (New, BHCE)
30 Pueblo West 115kV Distribution Sub (New, BHCE)
31 Salt Creek 115kV Sub (New, BHCE)
32 South Fowler Substation (New, BHCE)
2022
33 Airport Memorial - Nyberg 115kV Rebuild (New, BHCE)
34 Ault - Cloverly 230/115kV Transmission Project (PSCo)
35 Avon - Gilman 115kV Transmission (PSCo)
36 Boone - South Fowler 69/115kV Conversion (New, BHCE)
37 Burlington - Burlington (KCEA) Rebuild (Tri -State)
38 CEPP Switching Station Bid S085 (New, PSCo)
39 CEPP Switching Station Bid X645 (New, PSCo)
40 CSU Flow Mitigation (PSCo/CSU)
41 Falcon - Midway 115kV Line Uprate (Tri-State)
42 Greenwood - Denver Terminal 230kV Line (New, PSCo)
43 High Point Distribution Substation (PSCo)
44 JG Kalcevik Project (New, Tri-State)
45 Mirasol Switching Station CEP Bid X647 (formerly Badger Hills Substation) (PSCo)
46 North Penrose 115kV Distribution Sub (New, BHCE)
47 Titan Distribution Substation (PSCo)
48 Vollmer Project (New, Tri-State)
49 West Station - Greenhorn 115kV Line Rebuild (New, BHCE)
50 West Station - Hogback 115kV Transmission Project (BHCE)
2023
51 Dove Valley Distribution Substation (PSCo)
52 Southwest Weld Expansion Project (Tri-State)
2024
53 Burlington - Lamar 230kV (Tri-State)
2025
54 San Luis Valley - Poncha 230kV #2 (Tri-State/PSCo)
2026
55 Stock Show Distribution Substation (PSCo)
Beyond 2026 or ISD TBD
56 Bluestone Valley Substation Phase-2 (PSCo)
57 Falcon - Paddock - Calhan 115kV (Tri-State)
58 Glenwood - Rifle 115kV (PSCo)
59 Hayden - Foidel - Gore 230kV (PSCo)
60 Lamar Front Range (Tri -State/PSCo)
61 Lamar - Vilas 230kV (Tri-State/PSCo)
62 Lime Road Delivery Point (New, Tri-State)
63 Lost Canyon - Main Switch 115kV (Tri-State)
64 New Castle Distribution Substation (PSCo)
65 Parachute - Cameo 230kV #2 (PSCo)
66 Poncha - Front Range (New, PSCo)
67 Rifle - Story Gulch 230kV (PSCo)
68 Sandy Creek Distribution Substation (PSCo)
69 Solterra Distribution Substation (PSCo)
70 Superior Distribution Substation (PSCo)
71 Weld County Expansion (PSCo)
72 Weld - Rosedale - Box Elder - Ennis 230/115kV (PSCo)
73 Wheeler - Wolf Ranch 230kV (PSCo)
74 Wilson Distribution Substation (PSCo)

Figure 2. Denver-Metro map of transmission projects in the 2020 Plan

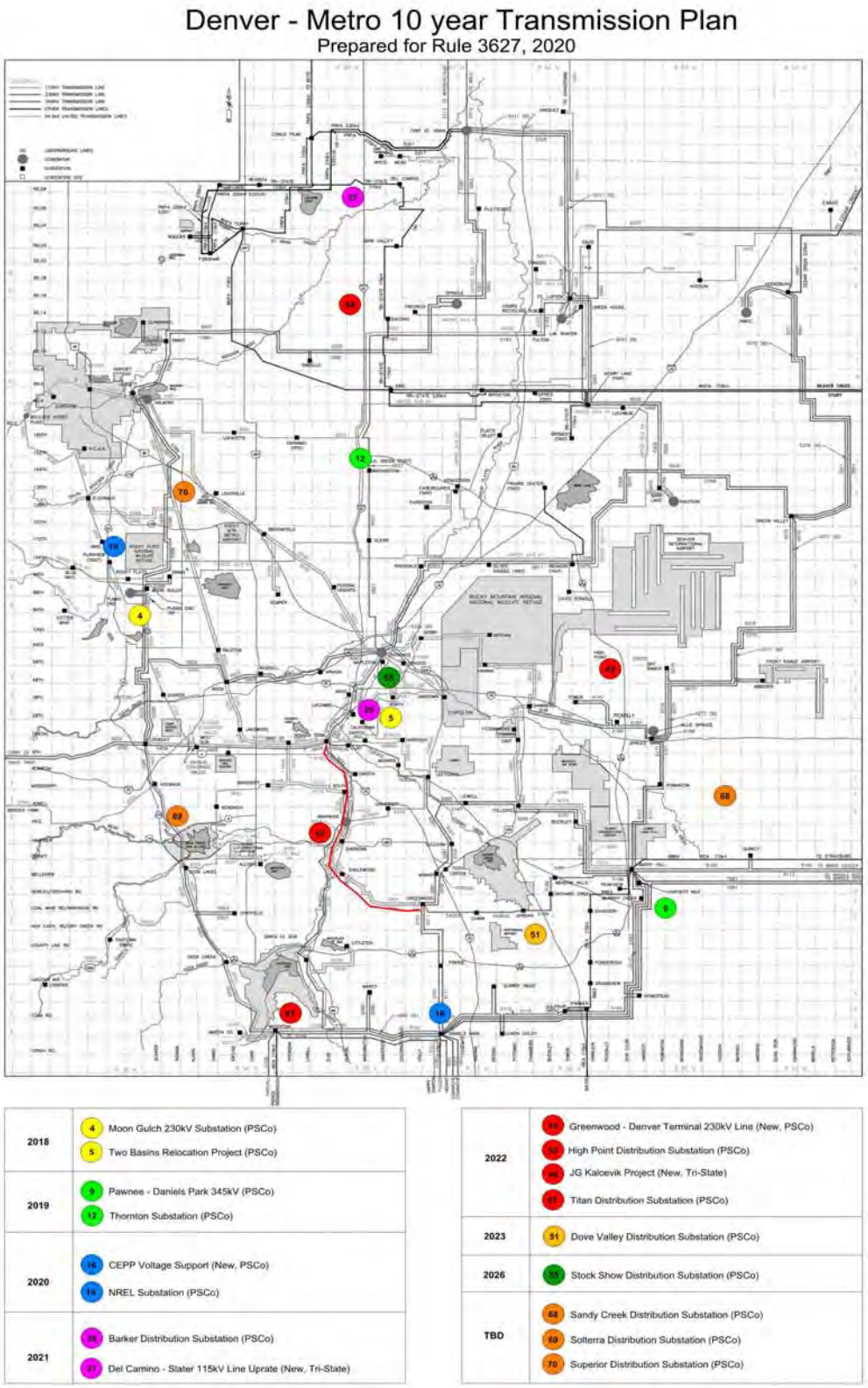
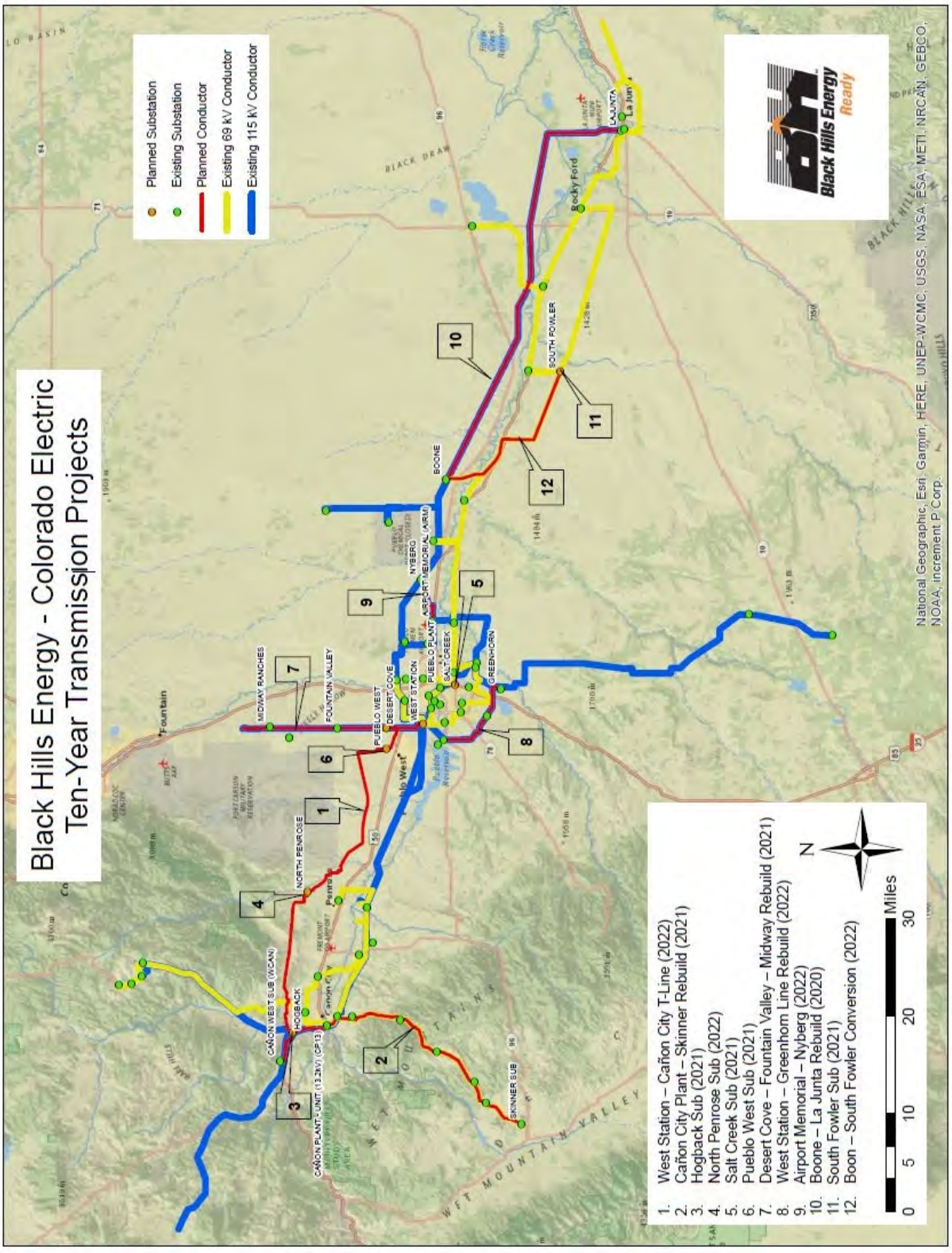


Figure 3. Pueblo area map of transmission projects in the 2020 Plan



II. Transmission Planning in Colorado

A. Coordinated Planning

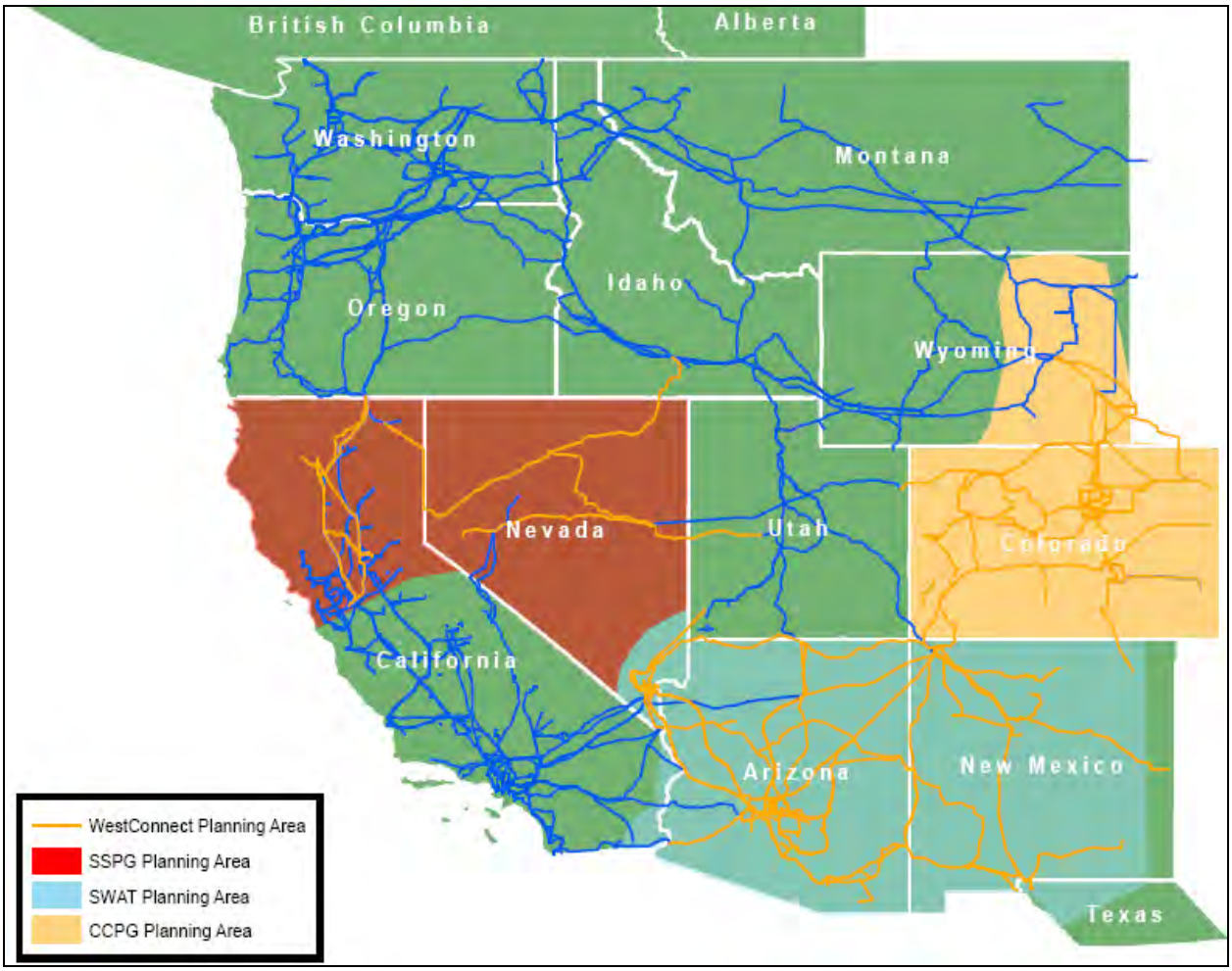
The Companies' transmission planning processes are intended to facilitate the development of electric infrastructure that maintains reliability and meets load growth. Because Colorado does not have a Regional Transmission Organization ("RTO"), each TP in the State is responsible for planning its own transmission system. To ensure that this process is as seamless and efficient as possible, the Companies participate in coordinated transmission planning at regional, sub-regional, and local levels.

The Companies are active members and participants in regional and subregional transmission planning organizations, including the WECC, WestConnect, and the Colorado Coordinated Planning Group ("CCPG"). WECC is the forum responsible for coordinating and promoting Bulk Electric System ("BES") reliability in the entire Western Interconnection.

WestConnect is one of four planning "regions"[3] within WECC established for regional transmission planning to comply with FERC Order No. 1000*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). WestConnect includes three sub-regional planning groups ("SPGs"): CCPG, Southwest Area Transmission Group ("SWAT"), and Sierra Subregional Planning Group ("Sierra").

[3] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

Figure 4. WestConnect Planning Subregional Group Footprints



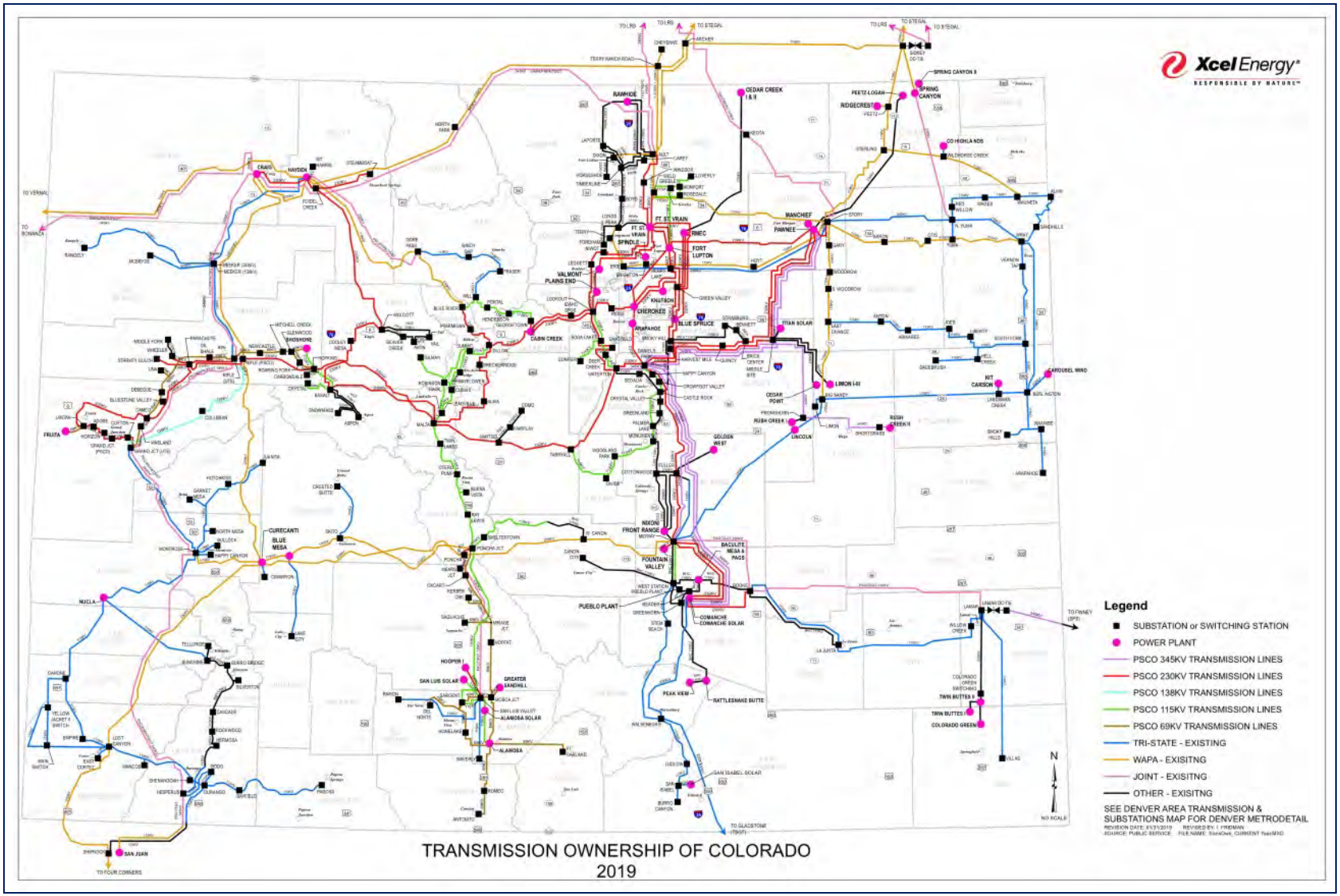
CCPG, which was formed in 1991, is a planning forum that cooperates with state and regional agencies to ensure a high degree of reliability in planning, development and operation of the transmission system in the Rocky Mountain Region. Figure 4 shows the planning areas of the CCPG and other subgroups of WestConnect.

The Companies have a long history of coordinated transmission planning with each other and other Transmission Planners in Colorado. As shown in Figure 5, the Colorado transmission system includes many jointly owned lines. Given the integrated nature and ownership of the transmission grid in Colorado, coordinated transmission

planning has been commonplace in Colorado since even before the adoption of Rule 3627.

As part of the Large Generator Interconnection Procedures ("LGIP"), the Companies often coordinate with each other as well as with other TPs in Colorado on the impacts of any proposed generation projects on the transmission system.

Figure 5. Transmission Ownership in the State of Colorado (2019)



Internally, and through WestConnect and CCPG, each Company performs annual system assessments to verify compliance with reliability standards, to determine related system improvements, and to demonstrate adherence to the standards and criteria set forth by North American Electric Reliability Corporation ("NERC") and WECC. Compliance is certified annually.

During the coordinated planning process, a wide range of factors and interests are considered by the Companies, including, but not limited to:

- The needs of network transmission service customers to integrate loads and resources;
- Transmission infrastructure upgrades necessary to interconnect new generation resources;
- The minimum reliability standard requirements promulgated by NERC and WECC;
- Bulk electric system considerations above and beyond the NERC and WECC minimum reliability standard requirements;
- Transmission system operational flexibility, which supports economic dispatch of interconnected generation resources; and
- Various regional and sub-regional transmission projects planned by other utilities and stakeholders.

This comprehensive internal, regional, and sub-regional planning process ensures that transmission plans continue to be carefully coordinated with all TPs in the State of Colorado.

B. Public Policy Issues

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policy initiatives, such as Colorado House Bill 19-1261, Senate Bill 19-236 (including the "Colorado Transmission Coordination Act"), Senate Bill

19-077, Executive Order B 2019 002, Colorado's Renewable Energy Standard, Colorado Senate Bill 07-100 ("SB07-100"), and the U.S. EPA Affordable Clean Energy Rule. Two of the Companies, Black Hills and Public Service, are subject to the requirements of SB07-100, which requires Colorado's rate-regulated electric utilities to identify areas that have a high potential for beneficial resource development. A discussion of SB07-100 and other public policy-related planning is included in Section V.

Colorado's Seventy-Second General Assembly enacted climate-action legislation in the 2019 Regular Session. The legislation will transition the state toward a clean-energy, low-carbon economy. The legislation establishes public policy requirements applicable to transmission planning for the 10- and 20-year periods of this Rule 3627 Report. We describe the applicable parts of this legislation for Colorado's transmission infrastructure, as follows:

Senate Bill 19-236 ("the PUC Sunset Bill")

The primary purpose of this bill is to reauthorize the CPUC, by appropriations, for a seven-year period to September 1, 2026. Reauthorization is required by the sunset process. Additionally, the bill carries numerous requirements for utilities and the CPUC to achieve an affordable, reliable, clean electric system. Of these requirements, four are viewed as significant drivers for transmission development in Colorado.

1. Clean Energy Plan ("CEP")

Senate Bill 19-236's CEP requirement is only mandatory for retail utilities providing electric service to more than 500,000 customers. *See* C.R.S. 40-2-125.5. While Public Service is the only public utility subject to this mandatory requirement to formulate a CEP, the legislation provides that other public utilities may "opt in" to CEP regulation upon notification to the Commission. However, the statute expressly excludes municipally owned utilities from CEP regulation. Public utilities that are

subject to the CEP requirement must include a CEP as part of the first Electric Resource Plan ("ERP") the public utility files after January 1, 2020. The PUC determines whether a CEP/ERP, as filed, is in the public interest.

A CEP seeks to reduce the qualifying retail utility's carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by 80 percent from 2005 levels by 2030. Further, a CEP seeks to achieve providing a qualifying retail utility's customers with energy generated from 100% clean energy resources by 2050.

Clean energy resources generate or store electricity without emitting carbon dioxide into the atmosphere. Clean energy resources include, without limitation, those generating resources deemed eligible energy resources under the state's Renewable Energy Standard ("RES") pursuant to C.R.S. § 40-2-124(1)(a). CEP activities that may be undertaken to meet the CEP targets under Senate Bill 19-236 include retirements of existing generation facilities, changes in system operations, or other necessary actions to achieve the reduction targets.

A CEP must ensure rate stability for customers served by the utility. Senate Bill 19-236 provides that the "Commission shall establish a maximum electric retail rate impact of 1.5 percent of the total electric bill annually for each customer for implementation of the approved additional clean energy plan activities" through at least 2030 through a CEP revenue rider to afford customers certainty of this maximum rate impact.

New transmission development for a CEP will be reviewed by the PUC under existing transmission planning processes and cost recovery, namely: Rule 3206, Rule 3627, SB07-100, and the Transmission Cost Adjustment. Senate Bill 07-100 Energy Resource Zones will apply to the beneficial resources required for CEP compliance.

In summary, a CEP will present significant drivers for transmission planning, namely:

- New interconnection facilities for clean energy resources;
- Decommissioning, or redevelopment, of existing transmission facilities associated with the potential for accelerated fossil-fuel retirements.

Transmission planning must enable a transition from plant retirements to new generating resources that ensures reliability and resiliency.

2. Cost of Carbon

Senate Bill 19-236 additionally requires public utilities to perform a "cost of carbon" analysis under certain circumstances. *See* C.R.S. §40-3.2-106. This "cost of carbon" analysis requirement applies to the following categories of proceedings: ERPs or any utility plan or application that considers or proposes the acquisition of new electric generating resources or the retirement of existing utility generation; proceedings pertaining to RES; electric demand-side management proceedings; and plans or applications for transportation electrification or other forms of beneficial electrification. The cost of carbon dioxide emissions is based on the social cost of carbon dioxide developed by the federal government. This equals $46 per short ton starting in 2020 and escalates thereafter.

In ERP proceedings, the cost of carbon dioxide emissions must apply to the evaluation of all existing electric generation resources and to any new resources evaluated or proposed as part of the resource modelling. The statute prescribes modeling and analysis steps for evaluating resource portfolios, with and without the cost of carbon dioxide.

In summary, cost-of-carbon planning will result in similar requirements as a CEP for transmission planners, namely: new interconnection facilities and accelerated

decommissioning, or redevelopment, of existing transmission facilities, which together may serve to reduce carbon intensity of the electric utility sector while ensuring reliability and resiliency of the grid.

3. Colorado Transmission Coordination Act

The Colorado Transmission Coordination Act, C.R.S. § 40-2.3-101 *et seq.*, requires the CPUC to open an investigatory proceeding on the potential costs and benefits of participation by Colorado's electric public utilities in a centralized market: specifically, an energy imbalance market, a regional transmission organization, a power pool, or a joint tariff. The statutory timeline is prescribed as follows:

(1) On or before July 1, 2021, the CPUC shall hold a public comment hearing to consider whether electric public utilities should participate in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

(2) On or before December 1, 2021, the CPUC shall issue a decision determining whether participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest.

(3) On or before July 1, 2022, if the CPUC determines that electric utility participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff is in the public interest, the CPUC shall direct electric utilities to take appropriate actions and conduct proceedings the CPUC deems appropriate to pursue participation in an energy imbalance market, regional transmission organization, power pool, or joint tariff.

Adoption of a centralized market is uncertain. If adopted and implemented, a centralized market could be transformative but is highly dependent on the form and function of the determined market design. A centralized market has the potential to

change the locational mix of generating resources and provide congestion relief on the grid through market operations. While relieving congestion is a driver of transmission planning now, a centralized market also may give a market price signal at zones or nodes along the grid. These market prices are known as "Locational Marginal Price" or "LMP". An LMP is a market-clearing price that includes the energy charge, a congestion charge, and transmission system losses. High LMPs at zones/nodes mean more transmission congestion. LMPs may drive investment needs for, and locations of, new transmission facilities to relieve congestion.

4. Wholesale Electric Coops and Resource Planning

Senate Bill 19-236 additionally directs the Commission to promulgate new rules that require wholesale electric cooperatives to submit an application for approval of an integrated or ERP. *See* C.R.S. § 40-2-134. In developing such rules, the Commission must consider, among other factors determined by the Commission, whether wholesale electric cooperatives: serve a multistate operational jurisdiction; have a not-for-profit ownership structure; and have a resource plan that meets the energy policy goals of Colorado.

The Commission issued a Notice of Proposed Rulemaking on July 31, 2019, addressing this statutory requirement and proposing an electric resource planning process applicable to wholesale electric cooperatives. Final rules are pending.

Consistent with this rulemaking, Tri-State expects to continue to interconnect new renewable facilities while retiring certain legacy facilities, and anticipates making transmission improvements as appropriate to accommodate these changes.

House Bill 19-1261 ("the GHG Reduction Bill")

House Bill 19-1261 requires the Air Quality Control Commission ("AQCC") to promulgate rules and regulations for statewide greenhouse gas ("GHG") pollution abatement. *See* C.R.S. § 25-7-105.

Because these rules and regulations will target statewide GHG abatement from all sources, multiple sectors of Colorado's economy will be considered for compliance (transportation, electric generation, industrial manufacturing, etc.). The statewide goals are, at a minimum, a 26 percent reduction in statewide GHG pollution by 2025, a 50 percent reduction in GHG pollution by 2030, and a 90 percent reduction in GHG pollution by 2050 measured relative to statewide GHG pollution levels.

It is anticipated that the AQCC will consider opportunities to incentivize renewable energy resources, issues related to the beneficial use of electricity to reduce GHG, and whether program design could enhance the reliability of electric service.

For transmission planning, the GHG Reduction Bill presents the potential for new load growth and/or changing demand levels and characteristics (beneficial electrification), and shifting generation resources and locational mix (renewable energy and clean-energy adoptions).

Senate Bill 19-077 ("the Electric Vehicles Bill")

Statutory provisions enacted through Senate Bill 19-077 in C.R.S. §§40-1-103.3, 40-3-116, and 40-5-107 may expand electric vehicle infrastructure in Colorado. Charging ports and fueling stations are presently operated by third parties and as non-regulated services of public utilities. Senate Bill 19-077 authorizes utility ownership of electric vehicle charging infrastructure. The bill enables a regulatory approval process for electric utilities to invest in charging facilities and provide incentive rebates; thus, the investments and rebates may earn a return at the utility's authorized weighted-average

cost of capital. Where approved, the costs for the investments and rebates may be recovered from all customers of the electric utility similar to recovery of distribution system investments. Natural gas public utilities may provide fueling stations for alternative fuel vehicles as non-regulated services only.

The regulatory process for electric utilities will commence by May 15, 2020, and every three years thereafter, with the filing of a transportation electrification plan application by each jurisdictional utility. The application filing will request Commission authorization of a proposed transportation electrification program in the utility's certificated service territory; specifically, regulated activities and capital spending for electric vehicle charging facilities, electric vehicle make-ready infrastructure investments, and associated electrical equipment. The transportation electrification program may include community-based, multifamily charging infrastructure, car share programs, and electrification of public transit. The regulatory process will consider impacts on low-income customers, and access by low-income, moderate income, and underserved communities. The legislation provides that the retail rate impact from the development of electric vehicle infrastructure must not exceed one-half of 1 percent of the total annual revenue requirements of the utility. The legislation specifies that in evaluating the retail rate impact, the Commission "shall consider revenues from electric vehicles in the utility's service territory."

Widespread deployment of electric vehicles will represent load growth for transmission planning requirements within the 10-year period of this report. Further, adoption of electric vehicles will provide benefits to the grid. With charging electric vehicles essentially acting as energy storage, there may be an ability to integrate variable renewable resources and off-peak generation.

House Bill 18-1270 ("the Energy Storage Procurement Act")

House Bill 18-1270 directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. *See*

C.R.S. § 40-2-201, *et seq*. The legislation broadly addresses resource acquisition and resource planning, and transmission and distribution system planning functions of electric utilities. Energy storage systems may be owned by an electric utility or any other person.

House Bill 18-1270 required the Commission to adopt rules for procurement and planning by February 1, 2019, to create conditions under which the procurement or ownership of energy storage systems by an electric utility will provide systemic benefits. These benefits include increased integration of energy into the grid; improved reliability of the grid; a reduction in the need for increased generation during periods of peak demand; and, the avoidance, reduction, or deferral of investment by the electric utility.

Decision C18-1124 in Proceeding No. 18R-0623E, mailed on December 12, 2018, adopted permanent rules in 4 *Code of Colorado Regulations* (CCR) 723-3. The rule requirements on transmission planning are relevant to this 10-year planning period.

Governor Jared Polis Administration's "Roadmap to 100% Renewable Energy by 2040 and Bold Climate Action"

On May 30, 2019, Governor Polis unveiled a roadmap to 100% renewable energy by 2040 and bold climate action. The roadmap seeks to transition the state of Colorado to 100% renewable energy by 2040. Toward this end, the roadmap has seven components, namely:

1. Grow green jobs and save consumers money.
2. More zero emission vehicles and commuting options.
3. Support local commitment to 100% renewable energy.
4. Modernize the Public Utilities Commission.
5. Promote energy efficiency.
6. Move toward zero emissions buildings.
7. Ensure a just and equitable transition for all of Colorado.

A transition to 100% renewable energy would have a significant impact on transmission planning in the 10-year period with load growth. Specifically, electrification of transportation will represent load growth; notably, the Governor's plan strives for 940,000 zero emission vehicles by 2030 and $14 million of transit bus fleet conversions. Similarly, electrification of buildings will represent load growth as space heating and manufacturing needs shift from direct fossil fuels to electricity. The Governor's plan has three financing programs for residential and commercial building improvements: C-Pace, RENU, and the Colorado Clean Energy Fund. In FY2019, approximately $30 million was financed by C-Pace and RENU alone.

Executive Order B 2019 008 ("the Zero Emission Vehicle Mandate")

On January 17, 2019, Executive Order B 2019 002 – Supporting a Transition to ZEV –was issued by Governor Polis. Four areas are directed in the Executive Order to further the state toward a higher electric vehicle market share:

1. Creates a transportation electrification workgroup composed of 17 members, appointed by the Governor. The members represent state agencies and offices. The workgroup will develop, coordinate, and implement state programs and strategies for transportation electrification with annual reports to the Governor.

2. Directs the Colorado Department of Public Health and Environment ("CDPHE") to develop rules for a Colorado Zero Emission Vehicle Program pursuant to Colorado's authority under section 177 of the federal Clean Air Act, 42 U.S.C. § 7507.

3. Revises the spending for the remaining funds available in Colorado's $70 million VW Beneficiary Mitigation Plan for electrification of transportation, including transit buses, school buses, and trucks. Furthermore, if additional

settlement or lawsuit funds are received by Colorado, those funds will assist consumers' transition to ZEVs.

4. Directs the Colorado Department of Transportation to develop a department-wide ZEV and clean transportation plan.

In compliance with the Executive Order, the Air Quality Control Commission ("AQCC") adopted a ZEV rule on August 16, 2019. The rule is codified at 5 *CCR* 1001-24, Part C. For the 2023 vehicle model year, a specified percentage of vehicles *offered for sale* in Colorado must be ZEV. The percentage shall be consistent with California Code of Regulations, Title 13, Section 1962.2. The percentage is more than 5 percent zero emission vehicles by 2023 and more than 6 percent zero emission vehicles by 2025. The vehicles covered by the ZEV rule are passenger car and light-duty trucks.

The ZEV rule follows the Low Emission Vehicle ("LEV") rule adopted by AQCC on November 16, 2018. The rule is codified at 5 *CCR* 1001-24, Part B. The LEV rule complied with Executive Order B 2018 006 issued by Governor John Hickenlooper on June 18, 2018. For the 2022 vehicle model year, sales of passenger cars, light-duty trucks, medium-duty passenger vehicles or medium-duty vehicles must meet the LEV III Criteria emissions and GHG emissions codified by California Code of Regulations, Title 13, Sections 1961.2 and 1961.3, respectively. The proposed ZEV program will reduce total GHG emissions by 3.5 million short tons cumulatively by 2030.

For transmission planning, electrification of transportation as directed in the ZEV rule will represent load growth. However, in the near term, there are regulatory uncertainties. The ZEV rule is facing federal challenges by the Administration of President Donald Trump under authority of the Clean Air Act.

Senate Bill 18-009 ("the Energy Storage Rights Bill")

Senate Bill 18-009, enacted in C.R.S. § 40-2-130, protects the rights of Colorado electricity consumers to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees. In particular, Senate Bill 18-009 prohibits electric utilities from requiring additional customer-sited meters to monitor the energy storage system where a single net energy meter is installed (with exceptions for certain large energy systems). Moreover, Senate Bill 18-009 ensures that statutory net metering, as provided for in C.R.S. § 40-2-124, is neither altered nor superseded.

Senate Bill 18-009 requires the CPUC to adopt conforming rules. In rulemaking Proceeding No. 19R-0096E, the CPUC has proposed additions and amendments at Rule 3850 (Interconnection Procedures and Standards) to *inter alia* implement Senate Bill 18-009. Notably, a proposed definition for "distributed energy resource" has replaced the former definition for "small generating facility". Distributed energy resources, or DERs, is proposed to be defined as customers' sources of electric power, including retail renewable distributed generation, other small generation facilities, and energy storage systems. Distributed energy resources, or DERs, will be subject to PUC-approved interconnection procedures upon adoption of final rules.

C. Emerging Issues

1. Wildfire Risk Mitigation

One only needs to look to California to see the impact a wildfire can have on the electric system and community at large. Given that, the companies believe that investment in wildfire mitigation and grid resiliency is the most prudent course of action to moderate the risks associated with extreme weather events. Wildfire mitigation efforts have been and will continue to be centered on long-term investments in projects targeted at enhancing grid resiliency, expanding vegetation management, and

accelerating system hardening and equipment maintenance throughout the companies' service territories.

2. Energy Storage and Non-wires Alternatives

Non-wires alternatives to address capacity needs and reliability constraints related to load growth is an emerging topic for consideration during transmission planning. As such, an additional work group at CCPG, the Energy Storage Work Group (ESWG), has been created to analyze the benefits and challenges for energy storage and other non-wire alternative technologies. Studies may include geo-targeted energy efficiency, demand-side management, demand response, distributed generation, energy storage, and potentially other technologies. The first meeting for the ESWG was held on January 23, 2020.

3. Distributed Energy Resources (DER)

The increase of customer-sited DER may alter transmission system requirements. Most utilities have been able to model customer DER primarily on distribution systems as net load. Increasing DER penetration presents new challenges with modeling and operation of distribution and transmission systems. DERs also may present opportunities to address load growth and provide resiliency, if planned correctly. DERs tend to be more expensive than larger-scale generation options, and so cost-effectiveness will be a factor in the growth of DERs over time. It will be important to understand policies and consider investments that may be needed in the 10-year horizon.

4. Grid Resiliency with Inverter-Based Resources

The influx of inverter-based resources combined with conventional power plant closures has raised concerns of grid resiliency. The Blue Cut Fire (2016) and Canyon 2 Fire (2017) in California triggered approximately 900 MW and 1200 MW, respectively, of

solar PV generation to cease generation during transmission system faults. These events and other system observations have led NERC to develop Reliability Guidelines to assist utilities and manufacturers in maintaining a resilient grid. Recent Reliability Guidelines include the following:

- Integrating Inverter-Based Resources into Low Short Circuit Strength Systems (December 2017)
- BPS-Connected Inverter-Based Resource Performance (September 2018)
- Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (September 2019)

At the regional level, WECC's Studies Subcommittee has a Change to System Inertia with High Renewable Implementation Task Force (SITF) evaluating the reliability impacts on the Western Interconnection as conventional resources are retired during increased implementation of inverter-based resources. The companies believe that it will be important to understand and apply the Reliability Guidelines as they are developed, as well as participate in regional study efforts to ensure proper analysis is performed to maintain grid resiliency.

III. Company Plan Narratives

A. Black Hills 10-Year Plan Overview

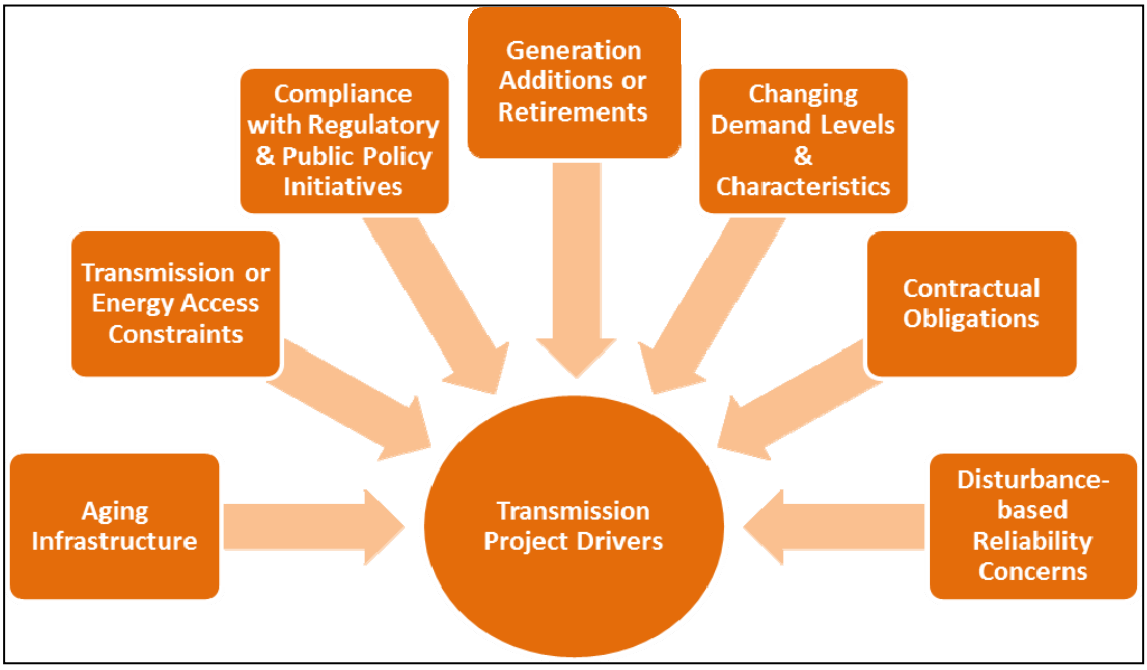
1. Black Hills Service Territory

Black Hills Colorado Electric, LLC, a division of Black Hills Corporation, serves over 98,000 customers in south-central Colorado. The counties served are parts of Crowley, Custer, El Paso, Fremont, Otero, Pueblo, and Teller. Twenty-one communities are served, and of these, the largest communities are Pueblo, Cañon City, and Rocky Ford.

The Black Hills planning process emphasizes education, participation, and coordination, with the ultimate goal of contributing to the development of an optimal long-term road map for transmission development in Colorado, consistent with Rule 3627.

Throughout its transmission planning process, Black Hills considers a number of variables and inputs, the first of which is a specific need or set of needs that drive the development of a certain project. Figure 6 shows a selection of needs that commonly give rise to projects within the Company's planning horizon.

Figure 6. Needs that Drive Transmission Development



Needs may arise from a single entity, or they may coincide with the needs of multiple entities, in which case a joint project may be appropriate. Once a need has been identified, Company planners begin searching for a solution. As solution alternatives are developed, the following considerations may come into play:

- Potential of each alternative to augment or inhibit potential future projects
- Cost of implementation and availability of project funding
- Required implementation schedule
- Environmental and societal impacts
- Project life expectancy
- Tangible benefits to customers
- Geographic and physical constraints
- Ability to integrate with existing and planned transmission projects
- Impact to telecom, transportation, and other energy-related networks

Black Hills transmission planners, through coordination with the stakeholder community, evaluate the weight of the above considerations to determine the best

overall solution to the identified need, ensuring that the solution is financially prudent, publicly acceptable and physically feasible. Often a small subset of these factors will comprise a majority of the justification for a project.

Because communication and stakeholder participation is critical at all stages of planning, Black Hills performs its planning process on an annual basis in an open, transparent, coordinated and non-discriminatory fashion to ensure the opportunity for direct participation is offered to all stakeholders. Consistent with FERC Order Nos. 890 and 1000, Black Hills promotes participation in the planning process to all interested parties, and coordinates study efforts and results with other utilities as well as regional planning organizations such as West Connect, CCPG, and various groups within WECC.

Planning reliability studies are conducted annually to satisfy NERC and WECC requirements. Additional studies are performed as necessary to address specific purposes including, but not limited to, transmission service requests, generator interconnections, transmission interconnections, load interconnections and transfer capability assessments. This process and related discussions are subject to FERC's Critical Energy Infrastructure Information ("CEII") procedures.

Black Hills planners employ software models representative of the transmission system during the timeframe of interest, including current load and resource information, existing and planned infrastructure, service commitments, facility ratings and parameters, valid disturbance events, and any operating constraints to be observed. Additionally, all guidelines, requirements and applicable criteria, as well as 10-Year load and resource projections (submitted annually by network customers), are reviewed and included in the study plan. These study models allow planners to identify conditions and timeframes during which the transmission system will or will not satisfy all reliability and economic requirements.

If a planning study identifies a deficiency in transmission system performance, various mitigation options are evaluated to determine an optimal solution to meet the long-term needs of all affected parties. Evaluation of each potential project is coordinated with interested stakeholders and neighboring transmission providers to avoid duplication, minimize impacts and the likelihood of unmet obligations, and maximize the overall benefit of a project.

Routine planning is conducted for a wide range of scenarios to evaluate the performance of the transmission system over a 10- to 20-year period. In a given study year, viable system upgrades and transmission initiatives are compiled to create the Black Hills 10-Year Local Transmission Plan, which is evaluated annually and updated as needed to reflect ongoing project needs. Potential changes in reliability requirements, planned generation, transmission, load growth, and regulations require the build-out of a flexible, robust transmission system that meets customer needs under a wide range of foreseeable circumstances within the planning horizon.

2. Black Hills Projects

A. Renewable Advantage (200 MW)

On November 22, 2019, Black Hills Colorado Electric, LLC filed an application at the Commission to amend its 2016 Electric Resource Plan with a competitive solicitation for up to 200 MW of renewable energy and energy storage. The competitive solicitation is known as Renewable Advantage. The application was docketed in Proceeding No. 19A-0660E.

The Company's expected load and resource balance was determined in Phase I of the 2016 ERP and completed in January 2017. There have been no significant changes to the load and resource balance. The Company has no material need for new capacity through December 31, 2023.

This notwithstanding, the Company's indicative analysis provides that procuring energy from renewable resources and/or energy storage, with an in-service date no later than December 31, 2023, may produce significant benefits for customers. The benefits are energy fuel cost savings and emission reductions beyond the state's Renewable Energy Standard (30% of retail electricity sales by 2020). The fuel cost savings will be implemented through the ECA rate mechanism. The procurement will have no negative impact to the RESA fund. The emission reductions could bring the Company's service territory to approximately 55-65% renewable.

The Company's indicative analysis is based, in part, on modeling of recent bid price results from PSCo's renewable competitive solicitation. The PSCo renewable competitive solicitation was held from July 1 through August 1, 2019. The median bid price was $24.00 MWh for Solar PV and $36.30 MWh for SolarPV+Storage. Black Hills Energy has modeled these median bid prices for a 200 MW generic resource, showing customers savings in every year of the life of the generic resource.

An important consideration for any procurement of renewable or storage resources under Renewable Advantage will be to minimize any transmission cost impacts to customers.

The Company has identified five existing substations where minimal or no upgrades to the broader network transmission system are expected with the addition of 200 MW. While the Company has not specifically studied these locations, there is a high degree of confidence that these five substations can accommodate the new resources with lesser amounts of upgrades and costs. The preferred locations for interconnection are:

1. West Station Substation
2. Baculite Mesa Substation
3. Nyberg Substation

4. Boone Substation
5. Midway Substation

Further, it is appropriate to limit the addition of new renewable and storage resources to 200 MW for two primary reasons. First, a contingency scenario indicates that forcing any amount beyond 200 MW on a single 222 MVA-rated line, or on a single 120 MVA- or 160 MVA-rated line, would require significant spending for line rebuilds, system improvements, and/or generation curtailment to successfully interconnect the project. Thus, 200 MW is a prudent approach for mitigating transmission cost impacts. Second, the Company's transmission planning only studies a moment in time and not real-time (minute-to-minute) operating situations that can occur when variable generation ramps quickly. As the Company's renewable penetration increases, it will be increasingly difficult to balance the Company's generation and load in real-time. The 200 MW bid amount for the Renewable Advantage is about equal to the Company's minimum system load, a prudent limit for balancing the Company's generation and load in real-time conditions.

B. Transmission Projects

Black Hills' load growth has increased over the past couple of years, driven primarily by large industrial load expansions as well as some commercial load growth. The Black Hills projects included in the 2020 Plan largely reflect the continued strategy of infrastructure upgrades of additions to enhance reliability. Since most of Black Hills' projects are reliability-driven equipment replacements or upgrades, the focus on best-cost considerations was narrowed as appropriate.

In the 2020 Plan, which was the result of an open and coordinated planning approach on regional, sub-regional and local levels, Black Hills documents a procedure to address foreseeable local reliability, integrity and load service issues. Detailed project information can be found in Appendix D.

Since the filing of the 2018 10-Year Plan, Black Hills has completed three projects: Arequa Gulch 115kV Capacitor, Portland 115/69 kV Transformer Replacement, and West Station 115 kV Substation Upgrades. Black Hills identified 11 planned projects within the upcoming 10-year planning horizon that represent $89.52 million in capital expenditures between 2020 and 2023. The projects were identified to increase reliability within Black Hills' network transmission system, to support voltage, and to meet the requirements associated with expected load growth and generation development. The reliability-driven projects are required under various NERC Reliability Standards to address anticipated system performance issues. The projects in this section were coordinated with stakeholders and neighboring entities to ensure the best solution is achieved while avoiding duplication of facilities.

Planned projects are categorized according to the three distinct geographic areas within Black Hills' Colorado service territory.

Cañon City area

Three projects, shown in Table 2, address reliability and integrity concerns in the Cañon City area. Local load growth has resulted in the need for additional capacity in the area, as well as local voltage support. A new transmission line into the area and a substation rebuild will improve load service and operational flexibility.

Table 2. Cañon City area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
West Station – Hogback Transmission Line[4]	1/2022	$24.00	Not required

[4] This line also is known as the Southern Colorado Reliability Upgrade Project.

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115/69 kV Hogback Ranch Substation Build	9/2021	$9.90	Not required
115kV North Penrose Distribution Substation	1/2022	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)

The Black Hills planning process identified these projects as solutions for expected concerns regarding reliability and anticipated load growth in the Cañon City area. The primary driver of the West Station – Cañon City Transmission Line was to increase the reliability of Black Hills' transmission system feeding Cañon City and the surrounding area. Load growth in the Cañon City area has led to reliability concerns following the loss of the two transmission lines connecting that area to the Pueblo part of the Black Hills system. To mitigate these concerns, several options were considered. The West Station – Cañon City 115 kV Transmission Line build is set to rectify the burden of load growth in the area. The new connection also enables the future replacement of stressed transmission lines at a greatly reduced operational risk.

The Hogback Ranch project provides the added benefit of adding a 115/69 kV source near the existing North Cañon 69 kV substation. This will offload the existing Cañon City transformer and add operational flexibility to the local 69 kV system. The new source may provide future improved backup service to the Cripple Creek area via the normal open 69 kV line for emergency situations. The initial scope of the West Station-West Cañon project was coordinated with other entities to explore opportunities for joint participation in the project. This was done to potentially meet a wider range of system needs while minimizing the impact to the local landscape through the potential use of double circuit towers and utilization of existing transmission corridors when possible. The project was identified as an SB07-100 project in the 2015 study because it facilitates a larger resource injection from Energy Resource Zone ("ERZ") 4. Refer to

the Black Hills Corporation 2020 SB07-100 Study Report included in Appendix L for more information.

The North Penrose Distribution Substation consists of constructing a new substation to accommodate two 115/13.2kV, 25MVA transformers. Currently, the community of Penrose is served radially on a 69kV line with limited contingency backup alternatives. This addition will provide the community with another source, while also offloading the 115/69kV transformers at Portland.

Pueblo area

Five projects, shown in Table 3, address reliability and contingency concerns in the Pueblo area. There has been unanticipated significant growth in the Pueblo area that will be accommodated through these future projects.

Table 3. Pueblo area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
115 kV Salt Creek Substation	Q3 2021	$6.4	Not required
115 kV Desert Cove - Fountain Valley – Midway Rebuild	11/20/2021	$5.08	Not required
115kV Pueblo West Distribution Substation	1/2021	$4.5	A planned project included in the 2018 Rule 3206 filing (Proceeding No. 18M-0005E)
115kV West Station-Greenhorn Line Rebuild	9/2022	$4.5	Not required
115kV Airport Memorial – Nyberg Rebuild	9/2022	$3.7	Not required

The 115 kV Salt Creek Substation project was determined by the planning team to be a way to rectify growth concerns for the increasing demand in Colorado. Salt Creek Substation would relieve some of the load from existing distributions systems, while also supplying contingency and maintenance switching options. The addition of this substation also allows for increased capacity and contingency with distribution systems within the same area. The project is currently in land negotiation phases; therefore, the total project cost is TBD.

The 115kV Desert Cove – Fountain Valley – Midway rebuild is a result of studies that determined inadequacies in heavy summer conditions. The potential for high power flows in the north-south direction could result in a Category P2 and P4 230kV breaker failure and loss of 230kV lines. This situation would lead to inadequate thermal ratings on the 115kV Desert Cover – Fountain Valley – Midway line. To mitigate this potential issue, the 14-mile line is to be rebuilt and replaced with a minimum rating of 1110A end to end.

The 115kV Pueblo West Distribution Substation will be built to ultimately accommodate two 115/13.2kV, 25MVA transformers. This project is required to serve new industrial and agricultural load as well as contingency back-up for existing distribution infrastructure. This substation additionally addresses low voltage concerns under peak demand conditions for the area.

The 115kV West Station – Greenhorn Line rebuild is to address the age of the infrastructure. The existing 336 ACSR conductor will be replaced to increase the capacity of the line. This project will be a 12.1-mile-long rebuild that uses the current right-of-way. The project, once completed, will increase the line ratings to accommodate current summer and winter ratings.

The 115kV Airport Memorial – Nyberg rebuild is to increase the thermal capability of the lines by replacing the 336 ACSR line with 795 ACSR. Overloads on this line were identified in previous 10-year planning assessments under a contingency of losing both

the Boone-Comanche 230kV and Nyberg-Baculite Mesa 115kV lines. By replacing this line, the thermal capacity can be increased to accommodate the load under the studied contingency.

Rocky Ford area

Three projects, as shown in Table 4, address reliability and contingency concerns in the Rocky Ford area.

Table 4. Rocky Ford area projects included in the Black Hills 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Boone – La Junta 115 kV Rebuild	1//2020	$15.24	Not required
South Fowler Substation	10/2021	$5.10	Not required
Boone – South Fowler 69/115kV Conversion	9/2022	$6.6	Not required

The Boone-La Junta 115 kV line rebuild is a multi-year project beginning in 2018 and ending in 2020. The entire 45-mile length of the line will be rebuilt using larger conductors to address age-related integrity issues, as well as provide additional capacity on the only transmission line serving that portion of the Black Hills system. The modest load growth forecasted for the area did not necessitate the need to implement the project at a higher operating voltage.

Previously known as “La-Junta Area Upgrades”, the South Fowler Substation and Boon-South Fowler 69/115kV conversion replaces this project. Under a study that was geared to determine the integrity of the 69kV infrastructure, it was deemed that a significant number of lines needed to be rebuilt within the near-term planning horizon. The addition of the South Fowler substation proves to be beneficial for offering additional capacity to the area, along with operational flexibility when rebuilding neighboring aged 69kV lines. The Boone-South Fowler 69/115kV conversion will be

accomplished using 795 ACSR on double circuit structures to accommodate the new line, while maintaining a connection from Boone to Huerfano. This line will be a 19-mile build and is set to improve the reliability of the line regarding increased voltage.

Information concerning the specific Colorado projects included in the Black Hills 2020 10-Year Plan is contained in Appendix D. Additional general information can be found at https://www.blackhillsenergy.com/transmission-rates-and-planning/transmission-projects

B. Tri-State 10-Year Plan Overview

1. Tri-State Planning Process

Tri-State's transmission planning process is intended to facilitate the timely and coordinated development of transmission infrastructure that maintains system reliability and meets customer needs, while continuing to provide reliable, responsible, cost-based electric power to its 43 electrical cooperatives and public power districts (Member Systems). With Member Systems in four states (Colorado, Nebraska, New Mexico, and Wyoming), Tri-State is a regional power provider with only a portion of its planned transmission facilities located in Colorado and therefore included in this plan.

The primary objectives of Tri-State's transmission planning process are to meet the needs of network and point-to-point customers, maintain reliability, accommodate load growth, and coordinate interconnections. The key elements of Tri-State's transmission planning process are:

- Maintaining safe, reliable electric service to its members at the lowest possible cost;
- Improving efficiency of electric system operations;
- Providing open and non-discriminatory access to its transmission facilities; and

- Planning new transmission infrastructure in a coordinated, open, transparent and participatory manner.

Tri-State's primary planning activities center on the preparation of the 10-Year Capital Construction Plan for approval by the Tri-State Board. All projects included in Tri-State's 10-Year Capital Construction Plan adhere to NERC and WECC Standards and Criteria, FERC Order No. 890 Planning Principles, and coordinated regional planning principles, as well as the criteria outlined in Rule 3627.

Tri-State implements its transmission planning process through various studies, including:

- Reliability studies (for both bulk system infrastructure and sub-transmission);
- System impact studies;
- Transmission service requests;
- Generator interconnection studies;
- Facilities studies; and
- Economic studies.

Tri-State's Member Systems create long-range plans and other work plans that they provide periodically to Tri-State's Transmission Planning Department. When Member Systems' plans indicate the need for system upgrades or new construction, Member Systems apply to Tri-State Transmission Planning for a new or modified delivery point to be served from the Tri-State transmission system. The application contains sufficient information for Tri-State Transmission Planning to identify and consider alternatives to meet the Member Systems' requirements in a manner consistent with immediate and long-term needs in the context of the overall transmission system development.

Tri-State's contribution to the 2020 Plan was developed through an open, transparent, and participatory process that considered the needs and requirements of a wide range of stakeholders and regulatory bodies, including Tri-State's Member

Systems; transmission service customers; national and regional reliability organizations; and other transmission providers in Colorado and the region. Tri-State solicited input from a broad and diverse community of stakeholders including Member Systems, independent power producers, independent transmission companies, renewable energy advocates, environmental advocates, and federal, state, and local government agencies in the areas potentially affected by the proposed transmission projects.

The result of this coordinated and comprehensive process is a 10-Year transmission plan that includes transmission, distribution, and substation projects. Project summary information found in the following section and Appendix E focuses on the projects that involve the construction of new transmission lines in the State of Colorado. These transmission projects consist of some projects that are primarily intended to fulfill a load-serving need, some that are primarily intended to serve an identified reliability need, and some projects that are intended to provide transmission system congestion relief to better accommodate existing and future generation resources. In addition to these primary purposes, each project is a part of the bulk electric system in Colorado and therefore provides some additional benefits to the overall Colorado electric transmission system.

To understand the context and basis of Tri-State's 2020 Plan, it is important to recognize the key differences between Tri-State and other Colorado utilities. Tri-State is a generation and transmission cooperative formed and owned by its 43 member distribution cooperatives and public power systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming. The territories served by Tri-State's Member Systems cover a total of approximately 200,000 square miles. This large service area results in a load density that is significantly lower than that served by urban utilities. As a cost-based cooperative, Tri-State does not operate for profit and its Board of Directors, elected by the 43 Members, sets the rates charged to Tri-State's Member Systems accordingly. Tri-State's primary mission is to provide its Member Systems reliable, affordable, and responsible wholesale electric power. Tri-State does not

engage in speculative investments or other activities that are not consistent with its mission.

2. Tri-State Projects

While Tri-State's overall 2020 Transmission Plan includes transmission, sub-station, and distribution projects throughout Wyoming, Nebraska, Colorado, and New Mexico, this summary focuses on the larger transmission projects in Colorado. Many of these projects provide multiple benefits in terms of load serving, reliability improvements, congestion relief, or the accommodation of new generation. It should be noted that the 2020 Plan includes some projects listed in the 2018 Plan.

In January 2020, Tri-State's board of directors approved and announced that Tri-State is implementing its Responsible Energy Plan ("REP"), a transition to clean energy that will provide reliable, affordable, and responsible electricity for its Member Systems. The REP commits Tri-State and its Member Systems to significant reductions in emissions of carbon dioxide attributable to Tri-State's electricity sales to its Colorado members, including early retirement of coal-fired electric generating stations in Colorado by 2030. That commitment is combined with a commitment to a precedent-setting investment in renewable energy resources to offset the loss of conventional resources. The implementation of the REP will directly impact transmission planning.

While the full extent of new renewable energy resources are not yet known, Tri-State anticipates significant transmission infrastructure needs in eastern Colorado in support of these new resources based on the region's high potential for economic wind generation. Studies completed in the CCPG Lamar Front Range Task Force have identified several viable transmission alternatives that would support increased generation in the region by building new 345 kV infrastructure between major transmission hubs, including Lamar, Burlington, and Story switching stations.

As explained in Tri-State's Responsible Energy Plan, there is a pressing need to streamline siting and permitting processes so that transmission and generation infrastructure can be constructed in time to meet Colorado's greenhouse gas emission reduction requirements and renewable energy goals. While such streamlining will not be developed through the Commission's transmission planning rules and processes, the current siting and permitting challenges will be factors considered as Tri-State identifies the transmission system improvements needed to implement the REP's clean energy transition.

Tri-State does not yet have enough information to include in this filing transmission alternatives that may be pursued in connection with the REP. Over the next year, as resource plans are further developed with stakeholder input and eventual approval of an ERP by the Commission, Tri-State will work with stakeholders to develop transmission plans to accommodate the future resource additions and retirements. Tri-State will keep the Commission informed through future Rule 3206 and Rule 3627 filings.

Table 5. Load serving projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115kV Line Uprate	2021	$1.4	NR
Sisson Project	2020	$18.8	NR
JG-Kalcevik Project	2022	$14.8	NR
Vollmer Project	2022	$7.1	NR
Lime Road Delivery Point**	TBD	$8.1	NR

*****These are conceptual projects***

Burlington-Lamar

Past studies in the Boone-Lamar area of Colorado have shown voltage collapse for the Boone-Lamar 230 kV line outage with cross-trips of all generation injected at Lamar 230 kV. In order to mitigate these violations and provide for future growth and potential new generation, Tri-State determined the best solution was to construct a new 230 kV transmission line from the existing Burlington substation to the existing Lamar substation.

Lost Canyon Main Switch 115kV

There is heavy load growth in the CO2 Loop consisting of the Yellow Jacket Switch-Main Switch-Sand Canyon-Hovenweep-Yellow Jacket 115 kV system. Constructing the new Lost Canyon-Main Switch 115 kV line will provide support to reliably meet the future load growth for the CO2 Loop in southwestern Colorado.

Southwest Weld Expansion Project

Due to large scale oil and gas development in southwest Weld County and native load growth, Tri-State is planning on constructing approximately 49 aggregate miles of 115 kV and 230 kV transmission lines to meet the forecasted demand of approximately 300 Megawatts (“MW”) within the next five years. Six potential 115 kV load-serving substations and/or line taps may be constructed by Tri-State, while new 69 kV transmission lines and substations will be constructed by United Power for the project.

Del Camino-Slater 115 kV Line Uprate

This project will replace all the remaining spans of 397.5 ACSR conductor on the Del-Camino Slater line with 477 ACSR. The increased line rating will address the limited load-serving capability of the line and allow continued area load growth.

Sisson Project

There is large oil and gas development in northwestern Colorado. This project will add approximately 20 miles of new 115 kV transmission to radially serve the new

Sisson substation radially north from the existing Keota substation. The line and substation addition will increase load-serving capability in northwestern Colorado.

JG Kalcevik Project

There is significant load growth and development north of Denver along the I-25 corridor. This project will add approximately 2 miles of 115 kV transmission to loop the existing Erie-Dacono 115kV line through the new JG Kalcevik substation. The line and substation addition will increase load-serving capability north of Denver.

Vollmer Project

There is significant load growth and development northeast of Colorado Springs. This project will tap the existing Jackson Fuller-Black Squirrel 115kV line and add approximately 2 miles of 115 kV transmission to serve the new Vollmer substation. The line and substation addition will increase load-serving capability in northeast Colorado Springs.

Lime Road Delivery Point

There is oil and gas development south of Pueblo. This project will tap the existing Stem Beach-GCC Cement Plant 115kV line and add approximately 3 miles of 115 kV transmission to serve the new Lime Road substation. The line and substation addition will increase load-serving capability in south Pueblo.

Table 6. Reliability projects included in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Western Colorado Transmission Upgrade Project	2020	$57.2	Issued
Burlington-Burlington (KCEA) Rebuild	2022	$0.7	NR
Burlington-Lamar 230 kV	2024	$58.4	Issued
Falcon-Midway 115 kV Line Uprate	2022	$3.8	NR

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Falcon-Paddock-Calhan 115 kV Line**	TBD	$33.4	NR
Lost Canyon-Main Switch 115 kV**	TBD	$22.6	NR
San Luis Valley-Poncha 230kV #2	2025	$58	Req'd
Southwest Weld Expansion Project	2023	$70	Issued
Del Camino-Slater 115 kV Line Uprate	2021	$1.4	NR
JG Kalcevik Project	2022	$14.8	NR
Lamar Front Range**	TBD	TBD	Req'd

These are conceptual projects

Western Colorado Transmission Upgrade Project

The 40-mile long Montrose-Nucla and Nucla-Cahone 115 kV transmission lines are old, overloaded, undersized, and must be rebuilt. To ensure continued reliability of the southwest Colorado transmission system, Tri-State is replacing them with new, higher capacity lines rated for 230 kV operation. This project will increase the load-serving capability of the southwest Colorado transmission system and also eliminate the need for the existing Nucla Remedial Action Scheme, which trips the Montrose-Nucla line when it starts to overload after contingencies/outages in the area.

Burlington-Burlington (KCEA) Rebuild

Under peak loading conditions, the K.C. Electric Association ("KCEA") 69 kV system fed from Smoky Hill substation cannot be switched to the west to pick up additional load for the loss of the Limon source after the Smoky Hill transformer is replaced with a larger unit. To mitigate this limitation, Tri-State will phase-raise the existing Burlington-Burlington KCEA line to increase the thermal rating of the line. The increased capacity will also help K.C. Electric Association serve new load in the area.

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Falcon-Midway Line Uprate

The current Falcon-Midway 115 kV transmission line has a thermal rating of 95 MVA, which leads to forecasted overloads from an outage on Tri-State's 115 kV Falcon-Fuller line. In order to mitigate this problem, Tri-State is raising, moving, or rebuilding structures along the line to increase the overall line rating to 145 MVA. The increased capacity will help serve Mountain View Electric Association's ("MVEA") customer load in the area.

Falcon-Paddock-Calhan 115 kV Line

The current Falcon-Paddock-Calhan 69 kV transmission line will be rebuilt to create a 115 kV loop in MVEA's central system. The 115 kV line will improve system reliability by looping the existing radial 115 kV and 69 kV substations in MVEA's system and provide increased voltage support. The 115 kV line also will help serve MVEA's customer load growth in the area.

Lost Canyon Main Switch

See description in Section III.B.2, Load Serving.

San Luis Valley-Poncha 230 kV #2

New high-voltage transmission must be built in the San Luis Valley ("SLV") region of south-central Colorado to maintain electric system reliability and customer load-serving capability, and to accommodate development of potential generation resources. Tri-State and Public Service, working through CCPG, facilitated a study of the transmission system immediately in and around the SLV and developed system alternatives that would improve the transmission system between the SLV and Poncha Springs, Colorado. Both Tri-State and Public Service have electric customer loads in the SLV region that are served radially from transmission that

originates at or near Poncha. The study concluded that, at a minimum, an additional 230 kV line is needed to increase system reliability. Studies show that this could be accomplished by either adding a new 230 kV line or rebuilding an existing lower voltage line and operating it at 230 kV.

Southwest Weld Expansion Project

See description in Section III.B.2, Load Serving.

Del Camino-Slater 115 kV Line Uprate

See description in Section III.B.2, Load Serving.

JG Kalcevik Project

See description in Section III.B.2, Load Serving.

Lamar Front Range

The Lamar Front Range Project was developed jointly through the CCPG to significantly improve load-serving capability, reliability, and potential resource accommodation in eastern and southeastern Colorado. The project could provide connectivity to the bulk transmission systems of Tri-State and PSCo, and provide strong “looped service” to areas with long radial transmission configurations. In concept, the project could create a transmission system capable of at least 2000 MW of new generation in eastern and southeastern Colorado. As the actual transmission needs in the original Lamar Front Range Project area have been smaller over the last few years, several projects have been implemented at a smaller scale, but in a manner consistent with the outline of the original Lamar Front Range Project.

This conceptual project is currently being re-evaluated in the Lamar Front Range Task Force under CCPG. The project identifies transmission element additions that are needed to meet both companies’ needs, including delivery of future generation to loads in the Denver and Front Range areas. The conceptual Lamar Front Range

project under study envisions 345 kV transmission lines connecting Lamar to the Pueblo area, Lamar to the Burlington area, and the Burlington area to the Missile Site, Story and Pawnee areas.

Table 7. Generation Congestion projects in the Tri-State 2020 10-Year Plan

Project Name	Estimated In-Service Date	Cost (millions)	CPCN
Burlington-Lamar 230 kV	2024	$58.4	Issued
Lamar Front Range**	TBD	TBD	Req'd
Lamar-Vilas 230 kV**	TBD	$90	Req'd

***These are conceptual projects**

Burlington-Lamar

See description in Section III.B.2, Load Serving.

Lamar Front Range

See description in Section III.B.2, Reliability.

Lamar-Vilas 230 kV Transmission

See description in Section III.C.2, Public Service Conceptual Plans.

Information concerning the specific Colorado projects included in the Tri-State 2020 10-Year plan is contained in Appendix E. Additional information and supporting documentation can be found at:
*http://*www.tristate.coop/transmission-planning

C. Public Service 10-Year Plan Overview

Public Service is one of four electric utility operating companies of Xcel Energy Inc., which is an investor-owned utility serving approximately 1.5 million electric customers in the State of Colorado. Public Service serves approximately 75 percent of the state's

population. Its electric system is summer-peaking with a 2019 peak customer demand of 6881 MW. The entire Public Service transmission network is located within the State of Colorado and consists of over 4,700 miles of transmission lines. Colorado is on the eastern edge of the WECC transmission system, which constitutes the Western Interconnection. The Western Interconnection operates asynchronously from the Eastern Interconnection. The Public Service transmission system is interconnected with the transmission system of its affiliate, Southwestern Public Service Company, via a jointly owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. Most of the Public Service retail service customers are located in the Denver-Boulder metro area. However, the Public Service retail service territory also includes the I-70 corridor to Grand Junction, the San Luis Valley region, and the cities and towns of Greeley, Sterling, and Brush. The Company's largest retail electric customer is EVRAZ North America, an industrial steel mill, located in Pueblo.

1. Public Service Planning Process

The goal of coordinated planning, as described in Commission Rule 3627 and historically practiced by Public Service and other TPs, is to develop the best possible transmission plan to meet present and future demands for electricity, taking into account a number of diverse factors. At its most basic level, transmission planning strives to meet customers' energy needs in a reliable and cost-effective manner.

The Public Service transmission planning process is intended to achieve the following objectives:

- Maintain reliable electric service;
- Improve the efficiency of electric system operations, including the provision of open and non-discriminatory access to our transmission facilities pursuant to FERC requirements;
- Identify and promote new investments in transmission infrastructure in a coordinated, open, transparent, and participatory manner; and

- Involve stakeholders during the transmission planning process and review of alternatives.

There are multiple drivers to the planning process, including customer load growth, accommodation of new resources, retirement of existing resources, compliance with state and federal rules and standards, replacement of aging infrastructure, and public policy initiatives. The planning process is coordinated with all the other transmission providers in the state to avoid duplication and reduce costs to the end use customer.

As described in earlier sections, coordinated transmission planning in the State of Colorado depends on careful consideration of numerous factors and variables, as well as thoughtful consideration of input from organizations and individuals on the regional, sub-regional, and local level.

One of the strategic priorities for Public Service is to be a leader in transitioning its generation toward cleaner energy. The goal is to serve customers with cleaner, reliable energy through increased ownership of wind and solar generation, invest in the grid, including advanced technologies and transmission that enable more renewable energy, and reduce carbon and other emissions. This strategy has impacted transmission planning over the last two years and will continue to impact planning into the future.

In September 2018, the Commission approved the 2017 Company's Preferred Colorado Energy Plan Portfolio (CEPP), which stemmed from the PSCo 2016 Electric Resource Plan. As a result of the CEPP, PSCo will be retiring 660 MW of coal-fired generation at Comanche, and adding almost 1000 MW of new wind generation and over 700 MW of new solar generation to its system. In 2019, Xcel Energy released its Corporate Responsibility Report, also referred to as Destination 2050, which describes the Company's vision for a carbon-free future by 2050.

Destination 2050 lays out an interim goal to reduce carbon emissions produced from the electricity that serves our customers by 80 percent from 2005 levels by 2030.

The 2017 CEPP, the Clean Energy Plan (to be filed by Public Service in its next Electric Resource Planning process) and Destination 2050 have had significant impacts to the Public Service transmission planning processes as will be described in later sections of this report.

2. Public Service Projects

Table 8, below, lists the Public Service projects. Note that some costs may have changed from previous filings with the PUC, due to changes in costs for issues such as materials, permitting, construction, and administration.

Table 8. Public Service 10-Year Plan

Project Name	ISD	Cost (millions)	CPCN
Completed			
Missile Site - Shortgrass 345 kV Transmission	2018	$104.9	G
Two Basins Relocation	2018	$24.1	NR
Bluestone Valley Substation Phase 1	2019	$12.0	NR
Moon Gulch 230 kV Substation	2018	$1.7	G
Thornton Substation	2019	$21.4	G
Pawnee-Daniels Park 345 kV Transmission	2019	$169.4	G
New to 2020 Filing			
Shortgrass Switching Station	2020	$20.6	G
CEPP Voltage Support	2020	$93.6	R
Greenwood – Denver Terminal 230kV line	2022	$50.3	R
CEPP Switching Station Bid X645	2022	$20.0	R
CEPP Switching Station Bid S085	2022	$12.0	R
Shortgrass – Cheyenne Ridge 345 kV Transmission	2020	$62.3	G
Previously Listed Projects			
NREL Substation	2020	$10.4	NR
Avery Substation	2021	$10.3	G
Ault-Cloverly 230/115 kV Transmission	2022	$66.7	G

Project Name	ISD	Cost (millions)	CPCN
Avon-Gilman 115 kV Transmission	2022	$11.4	NR
CSU Flow Mitigation	2022	TBD	R
Mirasol (formerly Badger Hills) Switching Station (CEPP Bid X647)	2022	$12.0	R
Conceptual			
Weld-Rosedale-Box Elder – Ennis 230/115kV	TBD	TBD	R
Weld County Expansion Transmission	TBD	TBD	R
Bluestone Valley Substation Phase 2	TBD	TBD	NR
Glenwood-Rifle 115 kV Transmission	TBD	TBD	U
Hayden-Foidel-Gore 230 kV	TBD	TBD	U
Lamar-Front Range Transmission	TBD	TBD	R
Lamar-Vilas 230 kV Transmission	TBD	TBD	R
Parachute-Cameo 230 kV #2 Transmission	TBD	TBD	R
Rifle-Story Gulch 230 kV Transmission	TBD	TBD	R
Wheeler-Wolf Ranch 230 kV Transmission	TBD	TBD	NR
San Luis Valley – Poncha 230 kV[3]	TBD	TBD	R
Poncha – Front Range 230 kV	TBD	TBD	R
Distribution Driven Projects			
Barker Distribution Substation	2021	$29.8	NR
Wilson Distribution Substation	TBD	$4.0	NR
Titan Distribution Substation	2022	$13.0	G
Dove Valley Distribution Substation	2023	TBD	NR
High Point Distribution Substation	2022	$9.0	R
Stock Show Distribution Substation	2026	TBD	NR
New Castle Distribution Substation	TBD	TBD	NR
Solterra Distribution Substation	TBD	TBD	U
Superior Distribution Substation	TBD	TBD	U
Sandy Creek Distribution Substation	TBD	TBD	U

[3] Tri-State lists as “planned” with 2025 ISD.

Key: R – Required, NR – Not Required, G – Granted, U - Uncertain

Public Service’s transmission plan does not currently include multi-state transmission projects. However, Public Service watches for such opportunities. While some of the elements of the current transmission plan could be used as components of a regional transmission project, Public Service has not identified regional project opportunities at this time to include in this plan.

Following is a brief, narrative description of each Public Service project included in Table 1 and how it fits into the overall 2020 Plan. Information for the auxiliary projects shown in Table 8, as well as maps of the Public Service projects for each of the time-frames listed below can be found in Appendix F. Projects are arranged by their anticipated in-service dates.

Planned Projects

Public Service's planned transmission projects can generally be placed in two basic categories. The first category consists of projects that are needed primarily for load growth or reliability purposes. These include both new projects as well as rebuilds or upgrades to existing transmission lines. Native load peak demand in Public Service's service territory has remained fairly flat during the past five years. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this flat load growth. Since 2009, the Public Service firm wholesale load has decreased, but the loss of wholesale load was offset by load growth within the retail sector. The level of load growth also is due to increases in energy efficiency and demand-side management programs, changes in appliance efficiency, and the increase in use of on-site photovoltaic energy systems. Public Service presently projects the native load to grow by about 0.7% from 2019 to 2026.

The second category consists of projects that are planned primarily to accommodate new generation resources. For Public Service, these projects tend to be associated with its electric resource plans, such as the 2017 CEPP. Senate Bill 07-100 also plays a role in the development of those plans, since it is intended to promote proactive planning to accommodate beneficial resources. These projects tend to include large transmission projects to access specific areas of the state that have the potential to host future generation facilities. Through the SB07-100 process, Public Service has developed plans to access each ERZ in Colorado. Some of these plans may be used or modified to accommodate the future Clean Energy Plan and Destination 2050 goals.

Projects Implemented Since 2018

This section describes the Public Service projects that have been placed in-service since the 2018 Rule 3627 10-Year Transmission Plan ("2018 Filing"). The following project(s) consisted of upgrades or additions to existing substations.

Missile Site - Shortgrass 345 kV Transmission

This project was described in the 2018 filing as the Rush Creek – Missile Site 345 kV Transmission Project, or Rush Creek Gen-tie. The project includes the 600 MW Rush Creek wind generation project and an approximately 82-mile 345 kV transmission line that has been built in parts of Arapahoe, Elbert, and Lincoln counties. Since the transmission line is a radial line that accommodates new generation, it is sometimes referred to as a "gen-tie". The Rush Creek wind project includes two collector stations. One collector is located at the new Pronghorn Switching Station, located approximately 42 miles from Missile Site Substation. The second collector is located at the new Shortgrass Switching Station, which is located at the eastern end of the gen-tie, approximately 40 miles from Pronghorn Switching Station.

Construction started on the transmission line in August 2017 and it was placed in service in July 2018 with an approximate cost of $104.9 million.

As part of the Settlement Agreement for the Rush Creek Wind Project proceedings, Public Service took a leadership role in the Rush Creek Task Force created within the CCPG. The task force analyzed the costs and benefits of 19 alternative proposals to potentially integrate the gen-tie as a network facility. The process provided a forum for stakeholder participation and comment.

Two Basins Relocation Project

This project consisted of relocating three existing 115 kV transmission lines that connect to the North Substation. The project was necessary to accommodate the City and

County of Denver ("CCOD") Two Basins Storm Water Drainage Project, which provides 100-year storm protection for certain areas of the city. The project also was required to accommodate the Colorado Department of Transportation ("CDOT") I-70 Expansion Project. The project involved: 1) Re-locating a portion of the existing North-Capitol Hill 115 kV underground line. 2) Re-locating the entire existing North-California 2.25-mile 115 kV underground line and replacing it with new conductor, and 3) Re-locating and replacing four overhead structures on the existing North-Sandown 115 kV line. The CPUC determined that the project was in the ordinary course of business and did not require a Certificate of Public Convenience and Necessity ("CPCN"). The project was placed in-service in 2018 and a cost of $24.1 million.

Bluestone Valley Substation (Phase 1)

The 2018 filing listed Bluestone Valley Substation as a new substation project to improve reliability and provide additional load interconnections for customers in the area. The original scope of this project consisted of a new Bluestone Valley 230/69 kV Substation. The substation would include a 230/69 kV transformer and would interconnect the existing Parachute-Cameo 230 kV line and the existing DeBeque-Cameo 69 kV line. From Bluestone Valley Substation, a new line would be constructed to a new Grand Valley Power Clear Creek Substation. Public Service split this project into two phases: A 69 kV phase ("Phase 1") and a 230 kV phase ("Phase 2"). To expedite reliability improvements to the lower voltage network, Public Service has completed Phase 1. Phase 2 is still considered conceptual and may be constructed at a later time based on local load growth. Phase 1 included construction of a new Bluestone Valley 69 kV Switching Station that connects to the existing DeBeque-Cameo 69 kV line. The project resulted in a DeBeque-Bluestone Valley-Cameo 69 kV line. Phase 1 of this project was placed in-service 2019, at a cost of $12.0 million.

Moon Gulch Substation

Moon Gulch Substation is a new distribution substation built in the City of Arvada within Jefferson County. The substation taps the existing Plains End-Simms 230 kV line. The substation was built to serve load growth in the Arvada area and also to provide backup

service to the existing Eldorado and Ralston distribution substations. The project was placed in-service in 2018 at a cost of $1.7 million.

Thornton Substation

This project consisted of constructing a new substation in Thornton to serve the increase in customer distribution load in that area. This new substation serves the City of Thornton in the north metro Denver area and provides back-up support to the existing Glenn and Washington distribution substations. The project was placed in-service in 2019, at a transmission cost of $21.4 million.

Pawnee-Daniels Park Transmission

The Pawnee-Daniels Park 345 kV Transmission Project consists of a new 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also resulted in the construction of a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also interconnects with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it accommodates generation in designated ERZs 1 and 2. The Pawnee-Daniels Park Project was placed in-service in December 2019, at a cost of $169.4 million.

Planned Transmission and Substation Projects (Not Previously Listed)

This section describes the Public Service projects that have not been included in previous Rule 3627 filings.

Planned Projects Related to the 2017 Colorado Energy Plan Portfolio

Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project and Shortgrass Switching Station

The Shortgrass – Cheyenne Ridge 345 kV Transmission Line Project consists of an approximately 73-mile, 345 kV transmission line which will extend from the Shortgrass Switching Station to the Cheyenne Ridge wind farm collector stations. The Shortgrass Switching Station not only provides an interconnection for part of the Rush Creek wind generation, but also will interconnect the 300 MW Bronco Plains wind project and the Cheyenne Ridge 500 MW wind project that are included in the Company's CEPP. The project is located in Lincoln, Kit Carson and Cheyenne counties. The project was granted a CPCN, is estimated to cost approximately $52.7 million, and is scheduled to go in service in 2020.

Greenwood -Denver Terminal 230 kV Transmission Project

The Greenwood – Denver Terminal Project consists of an approximately 15 miles of new 230 kV transmission line between the Company's existing Greenwood and Denver Terminal substations. The line is needed to accommodate the 2017 CEPP. The new line will be implemented by rebuilding existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The existing Greenwood, Arapahoe, and Denver Terminal substations all will require modifications to accommodate the project. The project is located in six different city boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver. The Project is estimated to cost approximately $50.3 million and it is planned to be in service by December 31, 2022. The Company plans to file a CPCN for this project early in 2020.

CEPP Voltage Control Facilities

A series of network voltage control devices need to be installed on the Public Service transmission system to accommodate the CEPP generation. The Company is proposing the facilities described in the table below.

Table 9. CEPP Voltage Control Facilities

Substation / Switchyard Location	Implementation Devices to be installed	Estimated In-Service Date	Estimated Cost (millions)
CF&I Furnace	± 95 MVAR STATCOM	Dec. 2023	$32.0
	One (1) dynamic voltage support device		
	85 MVAR of shunt capacitance		
	One (1) 85 MVAR capacitor		
Daniels Park	120 MVAR of shunt capacitance	Dec. 2020	$3.6
	One (1) 120 MVAR capacitor		
Harvest Mile	240 MVAR of shunt capacitance	June 2020	$5.4
	Two (2) 120 MVAR capacitors		
Missile Site	360 MVAR of shunt capacitance	June 2020	$9.5
	Three (3) 120 MVAR capacitors		
	Rush Creek Master Voltage Controller AVSO	Dec. 2020	$5.2
Pronghorn	± 150 MVAR STATCOM	Dec. 2020	$31.7
	One (1) dynamic voltage support device		
Shortgrass	60 MVAR of shunt reactance	April 2020	$6.2
	Two (2) 30 MVAR reactors		
Total			**$93.6**

The cost of the combined facilities is estimated to be approximately $93.6 million and they will be placed in service between 2020 and 2023. A CPCN was filed for this project in December 2019.

CEPP Generation Interconnection Facilities

In addition to the Shortgrass Pronghorn, and Mirasol (formerly Badger Hills – discussed in the Planned Transmission Projects from Previous Filings below) switching stations, other interconnection facilities must be constructed to accommodate the CEPP generation. At this time, the facilities include expanding two existing substations and constructing two new switching stations. The new switching stations include one that will connect to the Hartsel – Tarryall 230 kV line, and one that will connect to one Comanche – Daniels Park 345 kV line. The two existing substation that are proposed to be modified are the Boone and Midway 115 kV substations. The Company intends to file a CPCN for these facilities in 2020.

Planned Transmission Projects (Listed in Previous Rule 3627 Filings)

NREL Switching Station

This project consists of a new switching station that taps the existing Plainview-Eldorado 115 kV line south of Boulder. The U.S. Department of Energy's National Renewable Energy Laboratory ("NREL") operates a hybrid generation facility at its National Wind Technology Center, located approximately 1 mile east of the line. This facility is currently interconnected via distribution service, so the generation capacity is limited. This project is needed to interconnect the generation to the transmission system and allow for additional generation interconnections. The project does not require a CPCN, has a planned in-service date of 2020, with an estimated cost of $10.4 million.

CSU Flow Mitigation Project

This project was described in the 2018 filing as the addition of a phase shifting transformer ("PST") to the Monument Substation on the Monument-Flying Horse 115 kV transmission line, to control power flows through the Colorado Springs Utilities ("CSU") transmission system. Studies have shown that when there are heavy power transfers on the transmission system between Pueblo and the Denver, there is a potential for unacceptable loading to occur on the CSU transmission system. As a temporary mitigation measure, Public Service has implemented an operating procedure that opens up a 115 kV line on the north end of the system where the CSU and Public Service systems connect. The issue has been studied through the Douglas Elbert and El Paso (DEEP) Subcommittee of the CCPG. Upon completion of additional studies, the DEEP Subcommittee developed an alternative solution that consisted of a series reactor rather than a phase shifting transformer. The series reactor alternative accomplishes the same goal, but with advantages to the phase shifting transformer. The series reactor project had an estimated cost of $9.9 million and a potential in-service date of 2022. Recently, CSU has been evaluating additional alternatives. Public Service is continuing to work with CSU, TSGT, and the DEEP Subcommittee to determine a final long-term

transmission solution to mitigate the potential overloads. The project will likely require a CPCN.

Mirasol Switching Station

This project was described in the 2018 filing as a Badger Hills 345/230 kV substation. The project is presently planned as a 230 kV switching station. This project is one of several interconnecting switching stations that will be needed to accommodate generation associated with the Public Service 2017 CEPP. The Mirasol Switching Station will be located approximately 12 miles southeast of Comanche Substation, and will interconnect one of the Comanche - Midway 230 kV lines. The project is being designed to have the flexibility to allow for additional generation interconnections, as well as existing and future transmission lines. The project has a planned in-service date of 2022, with an estimated cost of $12 million. The Company intends to include this project with the other interconnection switching stations when it files a CPCN for these facilities in 2020.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly Project consists of approximately 25 miles of new 230 kV and 115 kV transmission lines originating at the existing Western Area Power Administration ("WAPA") Ault Substation near the town of Ault, and terminating at the Public Service Cloverly Substation on the northeast edge of Greeley. The transmission also will interconnect with two new PSCo substations: Husky Substation, which will replace and is planned to be built near the existing PSCo Ault 44 kV Substation, and Graham Creek Substation, which will replace and is planned to be built near the existing PSCo Eaton 44 kV Substation. One objective of the project is to improve reliability by replacing the existing 44 kV system in the area with higher voltage transmission facilities. However, the project also will increase the load-serving and generation resource capability in the area.

The project was granted a CPCN and has a planned in-service date of 2022 with an estimated cost of $66.7 million.

Avon-Gilman 115 kV Transmission Project

The Avon-Gilman 115 kV Transmission Project consists of constructing a new 10-mile 115 kV line in Eagle County for reliability and to provide an alternate transmission source to Holy Cross Energy customers. The project does not require a CPCN, has a planned in-service date of 2022, and has an estimated cost of $11.4 million.

3. Public Service Conceptual Plans

Conceptual Plans

The following transmission plans are considered conceptual in that they have no specific in-service date. Implementation of these plans is primarily affected by load forecasts and electric resource needs. Once a need is established, in-service dates can depend on many factors, including but not limited to regulatory proceedings, siting and land permitting, coordination of construction outages, and material delivery times. Public Service continues to assess the system conditions that may drive implementation for these plans.

Conceptual Plans Related to Load Growth

Bluestone Valley Substation (Phase 2)

As mentioned previously, this project has been divided into two phases. Phase 2 of the project would consist of expanding the substation to include 230 kV facilities, which would include a 230/69 kV transformer and interconnect the Rifle-Cameo 230 kV line. Implementation of Phase 2 will depend on the local load growth.

Glenwood-Rifle Transmission

This plan has been described in previous filings, and consists of upgrading the Glenwood Springs-Mitchell Creek-New Castle-Silt Tap line from 69 kV to 115 kV and new construction to reroute the Silt-Rifle line to the Rifle Substation at 115 kV. A portion

of the rerouted 115 kV line will be double-circuited with the Rifle-Hopkins 230 kV line. Costs for the plan have not been estimated, and moving forward with the plan will depend on load growth around Glenwood Springs.

Hayden-Foidel Creek-Gore Pass 230 kV Transmission

This plan has been described in previous filings and would consist of tying the Hayden-Gore Pass 230 kV line into the Foidel Creek Substation to increase reliability in the region. Reliability concerns are being mitigated by adding reactors at the Wolcott 230 kV bus, so there are no plans to move forward with this project at this time.

Parachute-Cameo 230 kV #2 Transmission

This project has been described in previous filings and is an extension of the Rifle-Parachute 230 kV line. It would consist of a new, approximately 30-mile 230 kV transmission line that would connect the existing Parachute and Cameo substations on the western slope of Colorado. Its primary purpose would be to increase reliability and to serve load growth in the region. Preliminary analysis estimated the cost to be approximately $48 million, but actual costs, and implementation of the project will depend on load growth in the area.

Rifle-Story Gulch Transmission

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 25 miles long and run between the existing Rifle (Ute) Substation to a new Story Gulch Substation. Preliminary analysis estimated the project cost to be approximately $24 million, but actual costs and implementation will depend on load growth in the area.

Wheeler-Wolf Ranch

The project has been described in previous filings and would consist of a new radial 230 kV transmission line that would be used to serve customer loads in Garfield County. The line would be approximately 18 miles long and run between the existing Wheeler

Substation to a new Wolf Ranch Substation. The line also would interconnect to the Middle Fork Substation. Preliminary analysis estimated the project to cost approximately $17 million, but actual costs and implementation will depend on load growth in the area.

Conceptual Plans Related to SB07-100 / Clean Energy Plan Goals

Weld-Rosedale-Box Elder - Ennis 230 & 115 kV Transmission Lines

This project was referred to in the 2018 filing as the Weld – Rosedale – Milton 230 kV project. However, Public Service has been evaluating alternatives that would terminate at locations other than Milton within its service territory. As mentioned in the 2018 filing, Public Service has been working through the CCPG Northeast Colorado ("NECO") Subcommittee to develop a transmission plan for the area south of Greeley. The objective is to continue the replacement of the existing 44 kV system in the area, increase the ability to accommodate future load growth, and allow for beneficial resource development. The plan also should align with other transmission projects and plans in the area, including the Ault-Cloverly Project and the Southwest Weld Expansion Project ("SWEP"). A 230 kV line from Weld to Rosedale and a 230 kV or 115 kV line from Rosedale to Box Elder to Ennis would meet the objectives. However, until the NECO studies are completed and an actual project is recommended, the projects are listed as conceptual with no specified in-service date or estimated costs.

Weld County Transmission Expansion

This plan was described in the 2018 filing as a means to allow interconnection of new resources and complement other transmission plans in Northeast Colorado such as the Ault-Cloverly 230/115kV Project and the Weld-Rosedale-Box Elder-Ennis 230 and 115kV Transmission Project. The Weld County Expansion continues to be a general planning placeholder that captures the planning efforts for Northeast Colorado, including the Greeley area. This project may be considered as a third or eastern phase of the planning efforts in the area that have been taking place in the CCPG NECO Subcommittee. The Weld County Expansion could be a combination of planned and

conceptual projects, such as the Ault-Cloverly Project, and the Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or, the Weld County Expansion could be a new project. Regardless, the Weld County Expansion may be a project that could enable Public Service to meet its Clean Energy Plan goals.

WELLINGTON
HUNN
PIERCE
AULT
AULT
FORT COLLINS
TIMNATH
SEVERANCE
EATON
CLOVERLY
WELD
WINDSOR
LOVELAND
KERSEY
LA SALLE
ROSEDALE
EVANS
JOHNSTOWN
MILLIKEN
GILCREST
BERTHOUD
BOX ELDER
ENNIS
KEENESBURG
HUDSON
Weld County
Transmission Expansion
Substation
Transmission Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
44kV Electric Transmission Line
0
5 Miles

Lamar-Front Range Transmission

The Lamar-Front Range plan originally was planned as a means to deliver an estimated 2000 MW of new generation from energy resources near Lamar and Burlington to load centers along the Front Range. The plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The original plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

The original Lamar-Front Range project was estimated to cost approximately $900 million. However, since the project is being re-evaluated, revised cost estimates have not been determined.

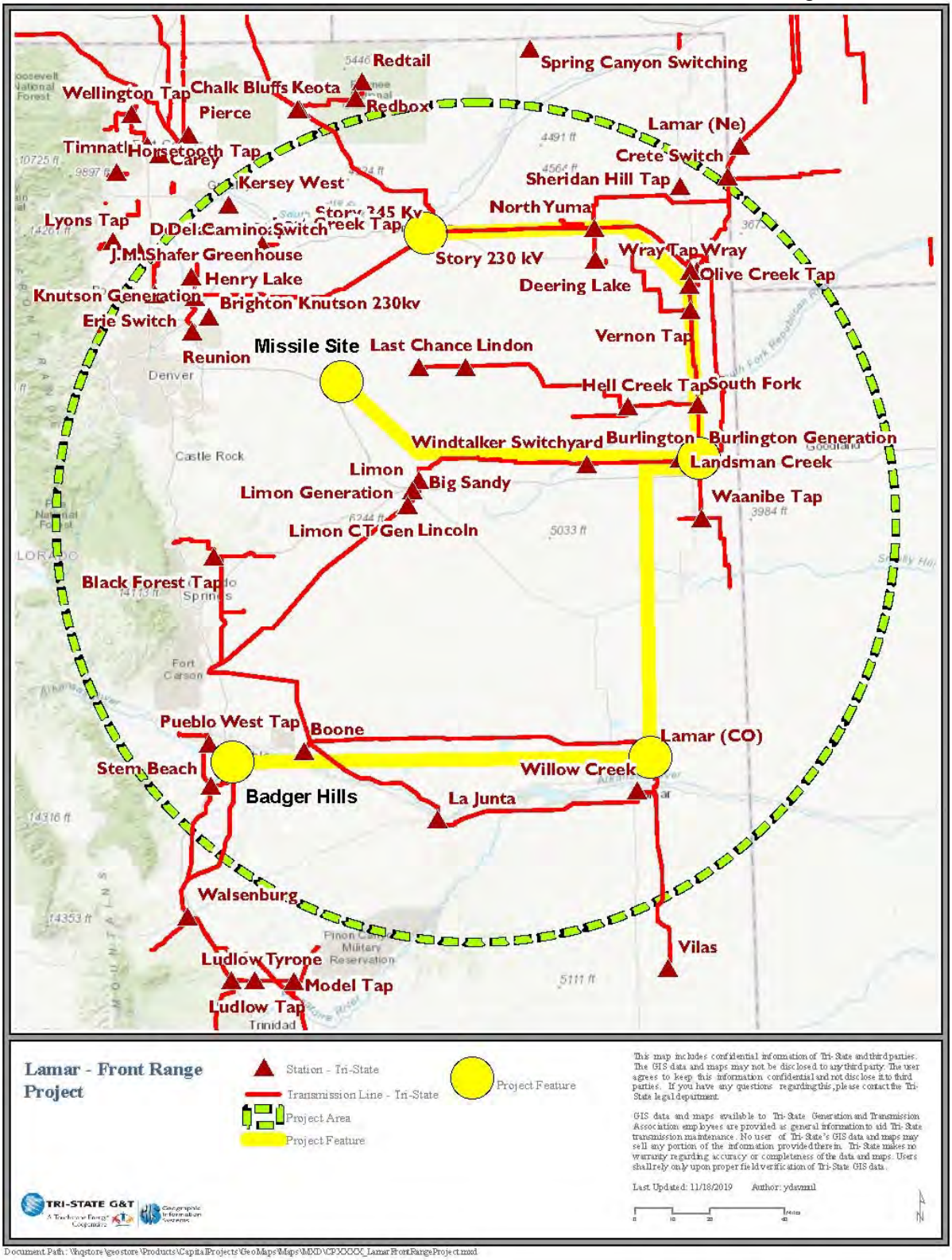
Since the plan was developed, a number of significant projects that could either be considered segments of, or are consistent with the design of the plan have been implemented or planned. These include:

- Construction of the Missile Site – Pronghorn – Shortgrass 345 kV line
- Construction of the Burlington – Wray 230 kV line
- Plans for the Shortgrass – Cheyenne Ridge 345 kV line
- Plans for a Burlington – Lamar 230 kV line

As a result, in 2019, the CCPG Lamar-Front Range Task Force (LFRTF) was formed to revisit the Lamar-Front Range Transmission Project. The objective of the task force is to evaluate transmission alternatives in eastern and southeast Colorado that will facilitate the delivery of new renewable and other low-cost generation to load centers, improve transmission system reliability, and increase the operational flexibility of both transmission and generation assets.

The LFRTF evaluated numerous transmission alternatives. No preferred alternative has been identified, but some alternatives and combinations of alternatives show technical merit and meet the overall objective. For example, a potential plan that may be able to advance Public Service's future Clean Energy Plan objectives might include the following components:

- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee



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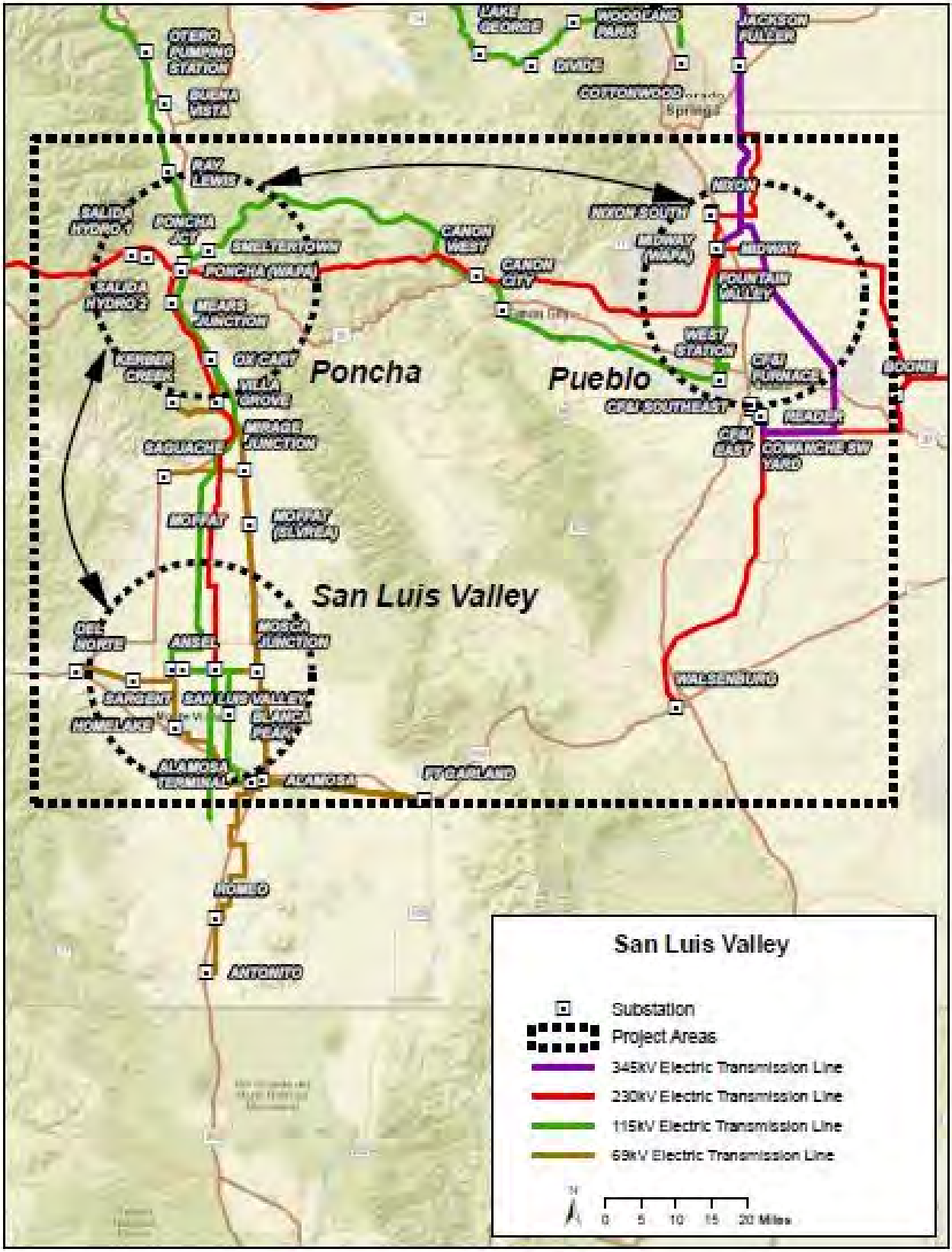
San Luis Valley

Similar to Tri-State, Public Service also recognizes that new high-voltage transmission in the San Luis Valley would improve electric system reliability and customer load-serving capability, and accommodate development of potential generation resources. Studies indicated that a new 230 kV transmission line from the San Luis Valley Substation to Poncha Substation would be a first step to accomplish the reliability objectives. Transmission beyond Poncha to the Front Range would enhance reliability and provide additional generation export out of the San Luis Valley and help meet the Public Service Clean Energy Plan goals.


Poncha
Pueblo
San Luis Valley
OTERO PUMPING STATION
BUENA VISTA
LAKE GEORGE
WOODLAND PARK
DIVIDE
COTTONWOOD Springs
JACKSON FULDER
RAY LEWIS
NIXON
NIXON SOUTH
BALIDA HYDRO 1
PONCHA JCT
SINGLE TEE TOWN
PONCHA (XCEL)
CANON WEST
CANON CITY
MIDWAY (XCEL)
MIDWAY
FOUNTAIN VALLEY
BALIDA HYDRO 2
MIAMI JUNCTION
WEST STATION
KENYON CREEK
OIL CLAY
HILL GROVE
CF&I FURNACE
BOONE
CF&I SOUTHEAST
HEADER
MIRAGE JUNCTION
CF&I EAST
COMANCHE SW YARD
SARGUACHE
MORAY
MORAY (XCEL)
DEL NORTE
ANSEL
MOSCA JUNCTION
WALSENBURG
SANGRE
SAN LUIS VALLEY
HOMELAKE
BLANCA (XCEL)
ALAMOSA TERMINAL
ALAMOSA
FT GARLAND
HOMELO
ANTONITO
San Luis Valley
Substation
Project Areas
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
69kV Electric Transmission Line
N
0 5 10 15 20 Miles

Other Long-Range Distribution Planning Substation Projects

Public Service, the Colorado Office of Consumer Counsel, ("OCC") and Staff of the Colorado Public Utilities Commission agreed through discussions related to Proceeding No. 14A-1002E to identify potential new distribution substation sites in rapidly growing areas. Below is a list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only. At this time, Public Service is not seeking Commission determination of the need for CPCNs for these projects or any Commission action. Most in-service dates for these projects are TBD.

Table 10. Long-Range Distribution Planning Substation Projects

Substation Project Name	Transmission Voltage	Approximate location	Potential ISD	Cost ($M)
Barker	230 kV	Across from Coors Field in Denver	2021	$29.8
Dove Valley	115 kV	Near I-25 and C-470 in Arapahoe County	2023	TBD
High Point	115 kV or 230 kV	Near Denver International Airport; Adams County	2022	$9
Titan	230 kV	Near Sterling Ranch in Douglas County	2022	$13
Stock Show	115 kV	Denver	2026	TBD
Wilson	115 kV	Loveland	TBD	TBD
Solterra	230 kV	Lakewood	TBD	TBD
New Castle	69 kV	New Castle	TBD	TBD
Superior	115 kV	Town of Superior	TBD	TBD
Sandy Creek	230 kV	Arapahoe County, near future Sandy Creek development	TBD	TBD

Additional Information

Information concerning the specific Colorado projects included in the Public Service 2020 10-Year Plan is contained in Appendix F. Additional information and supporting documentation can be found at:

http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

https://www.rmao.com/public/wtpp/PSCO_Studies.html

http://www.oatioasis.com/psco/index.html

IV. Projects of Other CCPG Transmission Providers

In addition to the projects planned by Black Hills, Tri-State, and Public Service contained in this 2020 Plan, a thorough understanding of all transmission projects planned in Colorado requires consideration of projects planned by other utilities and TPs.

Table 11. Colorado Springs Utilities Projects

In-Service	Project Name	Description	Purpose
2020	Williams Creek 230 kV Switching Station	Install a new substation on the Nixon-Claremont 230 kV line necessary to interconnect new Palmer Solar PV plant	Generation interconnection
2020	Nixon-Kelker 230 kV Line Uprate	Increase clearance on Nixon-Kelker 230 kV line to increase facility rating on the line.	Increase facility rating
2019	Cottonwood 230/115kV Autotransformer Replacement.	Install a new, upgraded 230/115 kV autotransformer at Cottonwood substation.	Increase system load serving capacity and provide compliance with the Long Lead Time Equipment requirement in the NERC Transmission Planning Standard TPL-001-4. (The existing Cottonwood auto will be refurbished and stored on site as a system spare.)

This information is provided voluntarily by CSU for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the CSU Plan are contained in Appendix G.

Table 12. Platte River Power Authority Projects

In-Service	Project Name	Description	Purpose
2018	Boyd 230/115kV Substation Expansion	Add 230/115kV transformer T2 and reconfigure 230kV and 115kV yards to breaker-and-a-half arrangement.	Improve system reliability in the Loveland area.

This information is provided voluntarily by Platte River Power Authority ("PRPA") for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado project included in the PRPA is contained in Appendix H.

Table 13. Western Area Power Authority Projects

In-Service	Project Name	Description	Purpose
2020	Midway KV1A Replacement	Replacing KV1A at Midway	Replacing aging equipment and increasing size
2020	Ault 345/230 kV XFMR Replacement	Replacing the 345/230 kV Transformer at Ault	Increased reliability

This information is provided voluntarily by WAPA for the purposes of making sure the CPUC has the most complete information for planned project coordination purposes only.

Additional information concerning the specific Colorado projects included in the WAPA are contained in Appendix I.

V. Senate Bill 07-100 Compliance and Other Public Policy Considerations

In addition to planning for load growth and reliability, Companies must consider proposed and enacted public policies. Two of the Companies, Black Hills and Public Service, are subject to the requirements of Colorado Senate Bill 07-100 ("SB07-100") (codified at C.R.S. § 40-2-126).

Historically, the SB07-100 filings were made by Black Hills and Public Service by October 31 of each odd-numbered year. Those filings were subsequently combined into a single Proceeding with the Rule 3627 filing pursuant to Decision No. R17-0747 in Proceeding 17R-0489E, which amended Rule 3627 to require electric utilities subject to Commission rate regulation to include their transmission plans for energy resource plans specified in C.R.S. 40-2-126(2) with their transmission plans due February 1 of each even-numbered year. As stated in SB07-100, Black Hills and Public Service are required to:

a. Designate ERZs
b. Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones
c. Consider how transmission can be provided to encourage local ownership of renewable energy facilities
d. Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review

Black Hills and Public Service have performed transmission planning activities to comply with the requirements of SB07-100 as part of the larger, coordinated planning efforts described above. As of 2017, Colorado's ERZs remain as they were defined in the 2015 SB07-100 reports, created by consulting multiple sources of information as well as public feedback. As shown in Figure 7, Colorado's five ERZs are:

ERZ 1 (Northeast Colorado)

Includes all or part of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. ERZ 1 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 2 (East-central Colorado)

Includes all or part of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa, and Cheyenne Counties. ERZ 2 presents energy development opportunities for natural gas, wind, and thermal resources.

ERZ 3 (Southeast Colorado)

Includes all of part of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. ERZ 3 represents the potential for wind resource development.

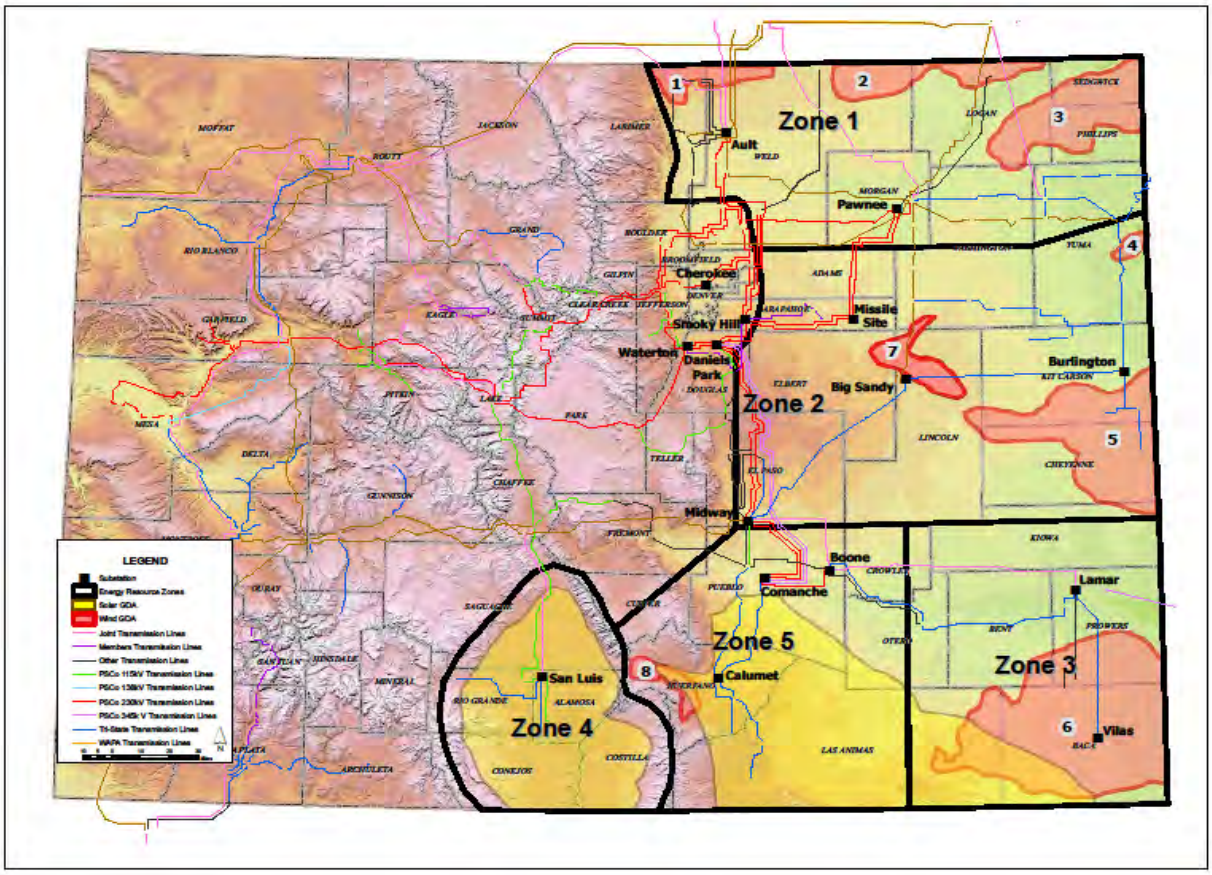
ERZ 4 (San Luis Valley)

Includes all or part of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. ERZ 4 presents energy development opportunities for solar resource development.

ERZ 5 (South-central Colorado)

Includes all or part of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas counties. ERZ 5 in South Central Colorado includes the area around Pueblo and south along the I-25 corridor which includes both potential wind and solar resources.

Figure 7. Map of SB07-100 Energy Resource Zones



In addition to the public policy requirements of SB07-100, all three Companies may be subject to federal and Colorado state regulations related to carbon emission reductions from existing power plants. The Companies will continue to coordinate with each other and stakeholders with respect to the transmission planning implications of any new federal regulations and may address issues in subsequent 10-Year transmission plans.

A. Black Hills Summary

Black Hills encouraged all interested parties to participate in the 2019 SB07-100 study process. An open stakeholder SB07-100 Kick-off Meeting was held in conjunction with the Q1 Black Hills Colorado Transmission ("BHCT") Transmission Coordination and Planning Committee ("TCPC") on April 23, 2019, to inform stakeholders of the proposed study plan and to provide an opportunity for suggestions and feedback on the study process. The kick-off meeting had no external participants. A follow-up e-mail was sent on October 10, 2019, to invite stakeholders to respond with their input while updating them on the progress of the study work. Meeting notices and presentations were distributed via e-mail and posted on the Black Hills Open Access Same-Time Information System ("OASIS") page at http://www.oatioasis.com/bhct/ as well as on a Colorado SB07-100 webpage established on the Black Hills Corporation website; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning.

For the 2019 SB07-100 cycle, Black Hills selected to re-evaluate the resource injection capacity from ERZ-5, which initially was performed as part of the 2013 SB07-100 cycle. That decision was based on the completion of transmission system upgrades since that time, as well as ongoing interest to develop generation in the area as indicated by Black Hills' generation interconnection queue. The transmission system was evaluated under 2023 peak summer load levels to identify any significant adverse impact to the reliability and operating characteristics of the Western Electricity Coordinating Council ("WECC") bulk transmission system and, more specifically, to the Black Hills and surrounding transmission systems. Steady state voltage and thermal analyses examined system performance without additional projects in order to establish a baseline for comparison. Performance was re-evaluated with resource injections modeled and compared to the baseline performance to determine the impact of the injections on area transmission reliability.

The power flow analysis was performed with pre-contingency solution parameters that allowed adjustment of load tap-changing ("LTC") transformers, static VAR devices

including switched shunt capacitors and reactors, and DC taps. Post-contingency solution parameters allowed adjustment of DC taps and automatically switched shunt devices, as well as adjustment of manually switched shunt devices outside the study area. Area interchange control was disabled and generator VAR limits were applied immediately for all solutions. The solution method implemented was a fixed-slope decoupled Newton solution.

Black Hills SB07-100 Conclusions

Black Hills utilized an open and transparent process in conducting its 2019 Colorado Senate Bill 07-100 study. Stakeholders were provided several opportunities for involvement and input into the study process and scope. Through this process, Black Hills believes it has fulfilled the requirements of Colorado Senate Bill 07-100, codified at C.R.S. § 40-2-126.

Baculite Mesa 115kV Substation: The 2023HS study results indicated that the BHCE transmission system could accommodate a 200MW injection at the Baculite Mesa 115kV substation with no required upgrades, assuming all planned projects are in service.

Nyberg 115kV Substation: Additionally, the study results indicated that the BHCE transmission system could accommodate a 75MW injection at the Nyberg 115kV substation. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg.

South Fowler 115kV Substation: The analysis also looked at injections at the planned South Fowler 115kV substation. The results indicated that the BHCE transmission system could accommodate at 75MW injection at this location. Higher levels of injection into this substation caused overloads on XCEL's Boone 230/115kV transformer during a P2 breaker failure contingency at Nyberg. The breaker failure at Nyberg cuts off the

only 115kV paths to the west portion of BHCE's system. This forces the power through the Boone 230/115kV transformer.

West Station 115kV Substation: The last injection point that was included in the analysis was the West Station 115kV substation. The results indicated that the BHCE transmission system could accommodate a 175MW injection at this location. High levels of injection caused overloads on the Fountain Valley – Midway 115kV transmission line. These results included the planned rebuild rating for this line. Increasing this rating further would require substantial terminal equipment upgrades at the Midway substation.

Designate Energy Resource Zones

On November 24, 2008, Public Service filed with the Commission an information report that identified its five ERZs within Colorado. Four of the ERZs identified by PSCo are located in close geographical proximity to the Black Hills system, specifically ERZs 2, 3, 4 and 5. In the 2011 SB07-100 study report, Black Hills identified two ERZs (ERZ-1 & ERZ-2), both of which were located within the PSCo defined ERZ-5. In order to avoid confusion, Black Hills has adopted the five PSCo defined ERZs within Colorado.

Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones.

Black Hills identified the impacts of the various resource scenarios on the Black Hills transmission system and identified projects that ensure reliable delivery of beneficial energy resources from the designated ERZ-5 to customer loads.

Consider how transmission can be provided to encourage local ownership of renewable facilities, whether through renewable energy cooperatives as provided in Colo. Rev. Stat. § 7-56-210, or otherwise.

The identified new transmission projects will facilitate renewable resource development in ERZ-5 in excess of Black Hills' forecasted resource needs. The studied resource injections are in relatively close proximity to Black Hills customers and would be facilitated by a direct physical connection to the Black Hills electric system.

Submit proposed plans, designations, and applications for Certificates of Public Convenience and Necessity to the Commission for simultaneous review.

Black Hills believes that the 115 kV transmission projects it has identified to facilitate the reliable delivery of beneficial energy resources to customer load are "in the ordinary course of its business" and do not require CPCNs, pursuant to Colo. Rev. Stat. §§ 40-2-126(3) and 40-5-101. The resource injection amounts identified in this report are indicative of potential system performance under the evaluated scenarios, but should not be construed to reflect firm system capability. In-depth analysis and coordination is required to establish a more comprehensive projection of potential system performance following implementation of the identified system upgrades.

B. Public Service Summary

Public Service began filing SB07-100 reports in October 2007. Public Service has developed plans for nine transmission projects to expand transmission capability for the delivery of beneficial energy resources from ERZs. These projects are listed in Table 14.

Public Service has completed the first five projects listed in Table 14. These projects have enabled Public Service to interconnect 1400 MW of wind in eastern and northeastern Colorado, and accommodates an additional 600 MW of wind from the Rush Creek Wind Project. The table below lists the name of the project, the ERZ that the project would serve, and a tentative schedule for implementation. The status of the projects that remain planned or conceptual are described in more detail in Section III.

Table 14. Public Service SB07-100 Projects

	Project	ERZ	ISD	Status
1	Missile Site 230 kV Switching Station	2	2010	Project placed in-service November 2010.
2	Midway-Waterton 345 kV Transmission Project	3,4,5	2011	CPCN granted on July 16, 2009. Project placed in-service May 2011.
3	Pawnee-Smoky Hill 345 kV Transmission Project	1,2	2013	CPCN granted on February 29, 2009. Project placed in-service June 2013.
4	Missile Site 345 kV Substation	2	2012	CPCN granted on June 8, 2010. Project placed in-service December 2012.
5	Pawnee-Daniels Park 345 kV	1,2	2019	CPCN granted on April 9, 2015. Project placed in service December 2019.
6	Lamar-Front Range 345 kV	2,3	TBD	Plan being re-evaluated through CCPG. Certain segments may be implemented in a phased approach.
7	Lamar-Vilas 230 kV	3	TBD	(See Lamar – Front Range)
8	Weld County Expansion	1	TBD	Studies ongoing through CCPG
9	San Luis Valley	4,5	TBD	Studies Complete

1. *Projects That Have Been Completed or Planned*

Missile Site 230 kV Switching Station (ERZ-2)

The Missile Site 230 kV Switching Station Project consisted of a new switching station near Deer Trail, Colorado, that connects the existing Pawnee-Daniels Park 230 kV transmission line into and out of the Missile Site 230 kV Switching Station. The project has allowed interconnection of new generation in ERZ-2.

The Missile Site 230 kV Switching Station was placed in-service in November 2010. Public Service interconnected the 250 MW Cedar Point wind project in 2011.

Missile Site 345 kV Switching Station (ERZ-2)

The Missile Site 345 kV Substation expanded the Missile Site 230 kV Switching Station to allow additional generation and transmission interconnections from ERZ-2 at the 345 kV voltage level. The substation bisects the Pawnee-Smoky Hill 345 kV Transmission Project. In addition to connecting the Pawnee-Smoky Hill 345 kV line, the substation also allows for future 345 kV transmission connections. These include connections to the Pawnee-Daniels Park 345 kV Project. The Missile Site 345 kV Substation was placed in-service in December 2012. The Limon Wind Energy Center brought about 600 MW of wind generation into Missile Site in 2014, and in 2018, the Rush Creek Project added another 600 MW. The Bronco Plains and Cheyenne Ridge projects will interconnect another 800 MW in 2020.

Midway-Waterton 345 kV Transmission Project (ERZs 3, 4, and 5)

The project consists of 82 miles of 345 kV transmission line from the Midway Substation, near Colorado Springs, to the Waterton Substation, southwest of Denver. The Midway-Waterton 345 kV project accommodates additional generation resources in ERZs 3, 4, and 5. The Midway-Waterton 345 kV Transmission Project was placed in-service in May 2011.

Pawnee-Smoky Hill 345 kV Transmission Project (ERZs 1 and 2)

This project consists of developing approximately 95 miles of 345 kV transmission line between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project allowed for additional resources in ERZ-1 and ERZ-2, interconnected at or near the Pawnee and Missile Site substations. The project was designed to facilitate construction of the Pawnee-Daniels Park 345 kV Project. This project was placed in-service in June 2013.

Pawnee-Daniels Park 345 kV (ERZs 1 and 2)

The Pawnee-Daniels Park 345 kV Transmission Project is described in Section III.C.2. The project consists of building a 125-mile 345 kV transmission line from the Pawnee Substation in northeastern Colorado to the Daniels Park Substation, south of the Denver-Metro area. The project also will result in constructing a new Harvest Mile 345 kV Substation, near Smoky Hill Substation, and a new Harvest Mile-Daniels Park 345 kV line. The project also will interconnect with the Missile Site 345 kV Substation. This project was planned in accordance with Senate Bill 07-100, in that it will accommodate generation in designated Energy Resource ERZs 1 and 2. The project was placed in-service in December 2019, at an estimated cost of $169.4 million.

2. *Projects that are Planned or Conceptual*

The projected in-service dates of these conceptual projects identified in Table 13 above can be affected by CPCN approval, revisions to load forecasts, resource plans, siting and land permitting, coordination of construction outages, and material delivery times. Because all of these projects are presently in the conceptual stage, assessments will continue on whether the stated factors will cause any modifications to these projects, in terms of configuration, timing, or otherwise.

Lamar-Front Range 345 kV (ERZs 2 and 3)

This project is described in Section III.C.2 and was planned as a high voltage project that covered vast portions of eastern Colorado to accommodate resources in ERZs 2 and 3. The original Lamar-Front Range project was estimated to cost approximately $900 million. Recently, Tri-State and Public Service have been planning and implementing projects that align with the original Lamar-Front Range plan. These include the Tri-State Burlington-Lamar 230 kV line and the Public Service Missile Site – Cheyenne Ridge 345 kV line.

Also, since 2019, the CCPG LFRTF has been re-evaluating how the Lamar – Front Range plan might be modified, based on recent changes and plans to the transmission system in Colorado. As mentioned in the Public Service 10-Year Plan Overview, a plan evaluated by the LFRTF that shows technical merit and could meet Public Service SB07-100 and SB19-236 Clean Energy Plan objectives includes the following components:

- Networking the Missile Site – Cheyenne Ridge 345 kV line to Burlington
- New 345 kV transmission from Burlington – Lamar – Comanche
- New 345 kV transmission from Burlington – Missile Site
- New 345 kV transmission from Burlington - Pawnee

Lamar-Vilas 230/345 kV (ERZ-3)

The Lamar-Vilas project has been associated with the Lamar-Front Range Plan. The Lamar-Vilas line could consist of approximately 60 miles of high-voltage transmission from Lamar Substation to the existing Vilas Substation to provide access to additional resources in ERZ-3 and Baca County.

Weld County Transmission Expansion (ERZ-1)

This plan is described in Section III.B.2 as a means to accommodate additional generation resources in ERZ-1. As a result of the potential for load growth and the Public Service plan to replace aging 44 kV infrastructure in the area, other projects have been planned and are being developed in the area that align with, and may ultimately replace the Weld County Expansion Project. Public Service is implementing the Ault-Cloverly 230/115kV Project and Tri-State is implementing the planned SWEP, which may connect transmission from the Denver-Metro area to the south of Greeley system. The CCPG NECO Subcommittee has been working to develop a comprehensive transmission plan for Northeast Colorado to serve a variety of needs. Studies indicate that a Weld-Rosedale 230 kV line and a Rosedale Box Elder - Ennis 115 kV

Transmission Lines would be a prudent next step to meet the objectives. The Weld County Expansion could be a combination of the planned Ault-Cloverly Project, and SWEP and conceptual Weld-Rosedale-Box Elder - Ennis 230 & 115 kV lines, or the Weld County Expansion may be a new project that could be considered as a third or eastern phase of the planning efforts in the area.

When specific projects have been recommended, Public Service will inform stakeholders and develop plans for implementation.

San Luis Valley (ERZs 4 and 5)

This plan has been described in Section III.B.2 and has been planned as a means to accommodate potential generation from ERZs 4 and 5, in addition to improving the reliability of the transmission system in the San Luis Valley area of Colorado. Studies were performed in the CCPG San Luis Valley Subcommittee, which identified that additional 230 kV transmission from San Luis Valley to Poncha to the Front Range would enable additional resource accommodation. As specific projects are planned and recommended, Public Service will inform stakeholders and develop plans for implementation.

VI. Stakeholder Outreach Efforts

Per Rule 3627(g), "Government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process." "Government agencies include affected federal, state, municipal and county agencies. Other stakeholders include organizations and individuals representing various interests that have indicated a desire to participate in the planning process." *See* Rule 3627(g)(I). The following sections summarize each Company's approach to government agency and stakeholder outreach and participation pertaining to Rule 3627. Processes specific to the stakeholder input directives of FERC Order No. 890 are discussed in Section VII.D.

A. Black Hills Outreach Summary

Black Hills recognizes the importance of stakeholder involvement throughout the transmission planning process and considers a stakeholder to be any person, group or entity that has an expressed interest in participating in the planning process, is affected by the transmission plan, or can provide meaningful input to the process that may affect the development of the final plan.

Stakeholders are encouraged to participate in Black Hills' transmission planning through the regular meetings held by the TCPC as part of the annual study process under FERC Order No. 890. The TCPC is an advisory committee consisting of individuals or entities who are interested in providing input to Black Hills' Transmission Plan. The TCPC study process consists of a comprehensive evaluation of the Black Hills and surrounding transmission systems for critical scenarios throughout the 10-year planning horizon. Stakeholders are notified of the initial meeting at the start of the study cycle and invited to participate. An opportunity is provided to comment on the scope of the study at this point in the process. Relevant system modeling data is requested from the stakeholders, as well as any economic study or alternative scenario requests. Once the study cases are compiled, another open stakeholder meeting is held to review and

finalize the data and study scope. A third stakeholder meeting is held to review preliminary study results and discuss potential solutions to any identified problems. This process allows the TCPC to develop a comprehensive transmission plan to meet the needs of all interested parties. A final stakeholder meeting is held to approve the study report and Local Transmission Plan ("LTP"). Following each meeting, contact information for the transmission planner performing the study is provided to allow for ongoing questions or comments regarding the study process. Updates on the progress of the TCPC study efforts also are provided to regional planning groups, such as the CCPG, to promote involvement from a larger stakeholder body.

A list of potential stakeholders was created during the initial TCPC study cycle and has continued to evolve through active invitations, recommendations from existing participants, and outreach at CCPG meetings. Black Hills is continually modifying its stakeholder list in order to invite a more comprehensive group of participants into the transmission planning process.

Two quarterly meeting invites were sent in 2019 as part of Black Hills' annual TCPC process. The primary kick-off taking place on April 23, 2019, and a second invite on October 10, 2019. Meeting notifications were sent to the stakeholder contact list, announced at the CCPG meetings and posted on Black Hills' OASIS web page.

Black Hills' Q1 stakeholder meeting is typically more educational in nature and was held via web/phone conference on April 23, 2019. It served the purpose of presenting the transmission planning process to stakeholders, describing the scope of the 2019 assessment, reviewing the current 10-Year Transmission Plan and soliciting feedback on the study scope, the stakeholder outreach process, and potential alternatives to the projects within the 10-Year Plan.

Black Hills' Q3 stakeholder meetings were sent out via e-mail on October 10, 2019. This meeting served the purpose of an update and solicitation for feedback regarding the progress of the study and conclusions. Although there were no updates made since

the kick-off meeting, this invite was to allow any part to request a meeting if it was deemed necessary. No interest was shown to pursue an official meeting after the invite was sent.

Black Hills' Q4 stakeholder meeting was not held, as cases from CCPG were not received until the week of December 20, 2019. At that time, an e-mail was sent to stakeholders presenting our updated study scope and list of scenarios included for stakeholder question and comment. The study work has been started and results will be presented at the 2020 Q1 stakeholder meeting.

A limited number of external stakeholders attended the quarterly meetings. The stakeholder meetings produced some dialog on specific projects, but substantive feedback regarding the planning process and future projects was not received. Black Hills relied heavily on coordination with affected utilities and internal review of alternatives to ensure that the projects selected and presented in the Rule 3627 Transmission Plan were optimal and adequate for the needs of its network transmission system and Colorado's goals of fostering beneficial energy resources to meet load growth.

For more information regarding the stakeholder process utilized in the 2019 or earlier Black Hills TCPC planning processes, including meeting notices, notes, presentations and contact information, refer to the Black Hills' Transmission Planning page; https://www.blackhillsenergy.com/our-company/transmission-rates-and-planning
Stakeholder outreach information also is available in the Transmission Planning folder on the Black Hills OASIS at: http://www.oatioasis.com/bhct

B. Tri-State Outreach Summary

Tri-State performs transmission planning-related stakeholder outreach as a standard part of its day-to-day business consistent with its policy of planning in an open, coordinated, transparent and participatory manner. This outreach encompasses

various efforts including: Rule 3627 specific meetings and stakeholder communications; FERC Order No. 890 specific meetings and communications; project-specific meetings and communications; and CCPG participation.

As described in Rule 3627(g)(I), stakeholders include federal, state, county, and municipal government agencies as well as other non-governmental organizations and individuals having an interest in the transmission planning process. Tri-State identifies potential governmental stakeholders based generally on a five-mile area surrounding proposed transmission facilities. Federal agencies in the areas of the transmission projects included in Tri-State's 2020 10-Year Transmission Plans typically include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Department of Defense. Potentially interested state agencies include the Colorado State Land Board and associated Stewardship Trust Lands, and the Colorado Division of Parks and Wildlife. Outreach to county and local governments typically includes communications to relevant elected officials as well as administrators, managers, and land planning, economic development, and legal staffs. In some instances, Tri-State's governmental outreach also included agencies such as parks and school districts.

Contact lists for non-governmental stakeholders were developed through various transmission planning forums such as CCPG and other WestConnect planning groups, as well as individuals and organizations that have participated in previous Tri-State stakeholder meetings. When known, Tri-State also included stakeholders identified as being interested in specific proposed projects. The resulting non-governmental stakeholders included other utilities, Tri-State Member Systems, energy and transmission project developers, environmental groups, economic development organizations, various advocacy groups, and elected officials not already included in the governmental outreach communications.

In 2019, Tri-State hosted one transmission planning-related stakeholder outreach meeting in connection with development of the 2020 10-Year Transmission Plan. The meeting was on August 21, 2019, and provided a summary of new information related

to Tri-State's ongoing transmission planning activities as well as updates on current projects and coordination with CCPG's long range transmission planning efforts. This meeting also constituted Tri-State's FERC Order No. 890 stakeholder meeting and provided an opportunity for stakeholders to provide input in connection with all of Tri-State's long-range transmission plans. All such input and relevant alternatives were considered and included in the appropriate biennial transmission plans submitted to the Colorado Public Utilities Commission pursuant to Rule 3627. No alternatives were proposed at this meeting.

In addition to this larger stakeholder meeting addressing system-wide and Colorado-specific transmission projects, Tri-State also conducted a number of meetings related to individual proposed transmission projects. These meetings and other project-related communications included relevant government agencies, economic development entities, and other interested organizations and persons to inform them of the proposed project and provide an opportunity for feedback and consideration of potential alternatives. The nature and timing of outreach efforts related to specific projects was generally dependent on the development status of the project.

Details of Tri-State's meetings, including a list of attendees and a meeting presentation video which includes questions and comments received together with Tri-State's responses thereto, and relevant presentations can be found at:
http://www.tristategt.org/stakeholder-outreach

Tri-State also participates in the CCPG's transmission planning efforts. As discussed in Section VI.D. of this Plan, the CCPG planning process includes additional stakeholder outreach and a further opportunity for stakeholder participation in and input into the overall Colorado coordinated transmission planning process, which includes Tri-State's proposed projects. Additional information concerning CCPG stakeholder opportunities is available at the WestConnect website.

Tri-State confirms that, as required by Commission Rule 3627(g)(V), this 2020 10-Year Transmission Plan is available to all government agencies and other stakeholders through Tri-State's Transmission Planning website at:
*http://*www.tristate.coop/transmission-planning

Tri-State has informed all stakeholders of the availability of the 2020 10-Year Transmission Plan.

C. Public Service Outreach Summary

Rule 3627 requires a summary of stakeholder participation and input and how this input was incorporated in the transmission plan. The rule states that government agencies and other stakeholders shall have an opportunity for meaningful participation in the planning process. The government agencies include affected federal, state, municipal and county agencies. In addition, Rule 3627 provides that other stakeholders, including organizations and individuals representing various interests that have indicated a desire to participate in the planning process, must also have an opportunity for meaningful participation. Under Rule 3627, Public Service is required to actively solicit input from the appropriate government agencies and stakeholders to identify alternative solutions. In addition to the Public Service outreach efforts listed below, the Company actively participates in numerous CCPG groups, where it also engages with and responds to comments presented by stakeholders. The following is a synopsis of the outreach that the Company performed relevant to this rule. Also, Appendix K lists some responses to comments received from two stakeholders.

Rule 3627 Webinars

The Company developed an informational PowerPoint presentation that included information on the long-range plans developed as part of Rule 3627. Two, two-hour-long webinars were held – the first on Friday, August 16, 2019, and the second on Wednesday, September 11, 2019 - to give stakeholders opportunity to participate and comment on transmission plans, either in person (at the Xcel Energy offices in

downtown Denver) or via the Internet. E-mail invitations with exact verbiage will be provided at the request of the Commission.

More than 500 individuals representing the following stakeholder groups—including all state legislators in both the House and Senate—received invitations to the webinars:

- Elected officials
- Federal, state and local government officials
- Environmental groups
- Energy developers
- Chambers of commerce
- Business and industry
- Planning and economic development agencies
- Large energy users
- Citizens and advocacy groups
- Intervenors on past PSCo filings
- Organizations involved in transmission planning (*e.g.*, CCPG members)

Invitations also were sent to the CCPG's distribution list, which includes representatives from other utilities including Black Hills, WAPA and Tri-State, as well as stakeholders representing environmental interests, consulting firms, law firms, and other individuals and groups. Local government elected officials, including county commissioners in counties that could be impacted by projects in the Public Service's portion of the 2020 Plan, were also invited along with local planning office representatives and other staff officials from local governments and agencies. Because routing had not been started on some of these projects, which were still in the planning phase, individual landowners who might be impacted were not identified.

Information on Xcel Energy's transmission projects in Colorado was provided to all invitees via a link in the e-mail, but since then, the web address was redirected to the following: http://www.transmission.xcelenergy.com/Projects/Colorado

Attendance at the August 16, 2019, session included eight in-person attendees external to PSCo and approximately 60 webinar attendees, although an actual count was difficult to gauge, as participant count decreased and increased during the course of the presentation. Since self-identification was optional, it was not possible to determine whether additional participants entered the webinar or participants already in attendance reconnected after becoming disconnected from the webinar. Attendance at the September 11, 2019, session included five in-person attendees external to Public Service and approximately 20 webinar attendees.

The PowerPoint presentation discussed at the session consisted of three basics parts. Because the level of knowledge surrounding transmission and transmission planning of the attendees was not known, part one provided an overview of electric transmission to acquaint attendees with basic information about how the system works and what constitutes the transmission system. Part two covered the transmission planning process, provided an overview of how and why planning is done, and outlined the many factors that are considered when developing plans. Part three reviewed all projects included in Public Service's portion of the 2020 Plan. Public comment from the webinar covered a wide range of topics. Written comments were received from the Office of Consumer Council and Western Resource Advocates. The written comments and Public Service responses to these comments are included in Appendix K.

FERC Order 890 Stakeholder Meetings

The Company facilitates two open stakeholder meetings per year to meet the requirements of FERC Order 890. The meetings are held in the first and fourth quarters every year at the Xcel Energy office in Denver, and the content is very similar to that presented in the Rule 3627 webinars. In the last two years, FERC Order 890 meetings were held on March 15, 2018, December 5, 2018, March 20, 2019, and December 4, 2019. Public Service has taken a similar approach to Tri-State, where the Rule 3627 and FERC Order 890 meetings are referred to as open stakeholder meetings that will

meet the objectives of both rules. Meeting agendas, presentations (referred to as "Transmission Plans", and notes are available at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

PROJECT-SPECIFIC OUTREACH

Pawnee-Daniels Park Project

The Pawnee-Daniels Park Project was energized on December 26, 2019. Final site restoration and revegetation work will continue throughout spring and summer 2020. Public Service will continue to work with landowners and impacted communities throughout the remainder of restoration activities.

Avery Substation Project

Public Service is proposing to construct the Avery Substation and Transmission Line project. The new Avery Substation will enable the company to serve existing and new load in the vicinity of Timnath, Severance and Windsor along the eastern side of the Interstate 25 corridor. Avery Substation will assist in providing back up to the existing Cobb Lake and Windsor Substations, which are reaching their capacity. It also will provide reliability to our existing and future customer load. The project consists of a new electric distribution substation, an associated overhead double-circuit 230 kV electric transmission line and overhead distribution feeder lines near the towns of Windsor, Severance and Timnath, Colorado. Power for the proposed 1.4-mile 230 kV transmission line will be provided by interconnecting the existing PRPA Timberline-Ault 230 kV transmission line. Public Service is currently evaluating in the land use permitting process with the Town of Windsor for the substation and a portion of the transmission line. Land use permits for other portions of the transmission line have been approved. This connection will supply the proposed Avery Substation with the electrical supply needed to power the distribution feeders serving the immediate communities.

Land use permitting for portions of the transmission line in unincorporated Weld County was completed in September 2018. A Conditional Use Grant application for the substation and the last half-mile of line was submitted to the Town of Windsor in December 2018. Hearings were held at the Windsor Planning Commission and Town Board in February 2019. The Town Board continued the hearing due to questions about the location and information needed from the landowner. Based on landowner feedback, Public Service decided to withdraw the application and attempt to resolve the primary concerns from the public and the town. This resulted in a new site alternative that was presented to the public at an open house on July 9, 2019.

Based on feedback at the open house, the new site was chosen as the preferred location and a new application was submitted on August 27, 2019, with this proposed site.

The Conditional Use Grant was recommended for approval by the Planning Commission on November 6 and was approved by the Town Board on November 25, 2019. It is anticipated that construction on the substation will commence at the end of Q1 or beginning of Q2 2020. Public Service staff will conduct public outreach as needed to support construction.

Ault-Cloverly 230/115 kV Transmission Project

The Ault-Cloverly 230/115 kV Transmission Project will increase electric reliability and load-serving capability of the Xcel Energy electric transmission system in and around the Greeley area, and will provide accommodation for new generation resources in the region while aligning with other transmission planning efforts in the area. The company filed a CPCN application with the CPUC on March 9, 2017, to construct the Northern Colorado Area Plan; Proceeding Number 17A-0146E.

The company held three open house meetings for the Northern Colorado Area Plan in 2018, and submitted a 1041 permit application in November 2018. Following several public comments voicing opposition to the southwestern portion of the preferred route,

the company amended its application to include the WAPA/Ault to Husky to Graham Creek portion of the line, with the intention of applying for a separate permit for the Graham Creek to Cloverly portion of the line. On June 18, 2019, the Weld County Planning Commission unanimously recommended denial to the Board of County Commissioners. Following this denial, the company determined the best course of action would be to withdraw the 1041 permit application. The company is now starting over with a new siting and community engagement effort. In the coming months, we will be hosting a Community Working Group, consisting of 12 to 20 community members and leaders to participate in the routing effort. Additionally, the second of four planned open house meetings (the first meeting was held in November 2019) will be hosted in late January in the town of Eaton. The 1041 Areas and Activities of State Interest land use permit application will be submitted in late spring/summer 2020, with Planning Commission and Board of County Commissioner hearings taking place in summer/fall 2020.

Greenwood - Denver Terminal

The Company is proposing the upgrade of approximately 15.4 miles of existing transmission facilities to 230 kV by rebuilding and/or reconductoring existing transmission facilities from the Greenwood Substation to the Denver Terminal Substation within existing right-of-way (ROW). The CPCN submittal for the project is targeted for early 2020. The project is located in six different jurisdictional boundaries: Centennial, Greenwood Village, Littleton, Englewood, Sheridan and Denver.

Outreach activities completed to date have been with elected officials and planning staff. The list below summarizes meetings that have taken place to date:

- September 16, 2019 – City of Englewood City Manager
- September 23, 2019 – City of Centennial Councilmembers
- September 25, 2019 – City of Greenwood Village Mayor and City Manager
- September 27, 2019 – City of Littleton staff
- October 3, 2019 – City of Sheridan City Manager and staff

- October 4, 2019 – City of Greenwood Village staff
- October 9, 2019 – City of Centennial Mayor and City Manager
- The City of Denver Council members were notified informally by the Company Area Manager
- November 4, 2019 – City of Littleton School District
- November 6, 2019 – City of Centennial City Planner and Public Works
- November 11, 2019 – City of Englewood City Planner and Public Works
- January 7, 2020 – Pre-Submittal Application submitted to City of Denver Planning and Development
- February 11, 2020 – Scheduled informal presentation at City of Littleton City Council public hearing.

Future meetings with the City of Englewood elected officials and the staff of the remaining cities are being scheduled. Public meetings, including open houses and neighborhood associations, will be held in February 2020.

Barker Substation

The Company is proposing the installation of equipment in the currently empty Barker Substation site and a new double circuit buried transmission line from the Barker Substation to the existing LaCombe Substation. The project is located within the City of Denver and outreach to the city is anticipated to begin in January 2020.

Glenwood-Rifle Transmission Line

In 2019, Public Service staff met with Glenwood Springs city management to discuss the Glenwood to Mitchell Creek Transmission Line Rebuild project. The Project consists of rebuilding approximately two miles of 69kV transmission line to 115kV transmission line, which will be initially operated at 69kV. Currently, the team is evaluating alternatives that include rebuilding outside of the existing alignment due to vegetation and ROW constraints in the current alignment. Public outreach is planned to begin in 2020, with a public open house and communications with elected officials tentatively planned in the first quarter of 2020.

Cheyenne Ridge Wind Farm and 345 kV Transmission Line Project

The Cheyenne Ridge 500 MW wind farm and 73-mile 345 kV transmission line is one of the projects that makes up a portion of the company's Colorado Energy Plan. The project is located in Lincoln, Kit Carson and Cheyenne counties, and, when complete, will generate enough renewable energy to power 270,000 homes. The company completed its purchase of the project asset from Tradewind Energy, who developed and permitted the project, in June 2019.

During the development phase of the project, Tradewind Energy engaged with many stakeholders, including county planning staff, landowners, Colorado Division of Wildlife, Colorado Department of Public Health and Environment, the Nature Conservancy, United States Fish and Wildlife Service, Colorado Department of Transportation, and the Colorado State Historic Preservation Office. After the company's purchase of the project, engagement with these stakeholders has continued.

The project commenced construction in July 2019 and is expected to reach commercial operations in December 2020. Since taking ownership of the project in June 2019, the company has sent a brochure on project updates to stakeholders and landowners. The brochure contains an update of the construction activities that have occurred to date and a high-level project schedule. The company also is hosting a project website that provides project updates, project photos, and contact information for questions and concerns. The website can be found at the following URL: https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power/cheyenne_ridge_wind_project

The Company plans to continue stakeholder engagement in 2020 with the issuance of future project brochures, updates to the project website, landowner liaison efforts, and coordination with Lincoln, Kit Carson and Lincoln counties, and the Colorado Department of Transportation.

D. CCPG Outreach Summary

To ensure stakeholders in Colorado have multiple opportunities to provide input and receive a broader perspective on the evolution of Colorado's transmission system, TPs also leverage the CCPG stakeholder input process in developing the 10-Year transmission plan. CCPG has a subgroup called the 3627 Subcommittee. The Subcommittee serves as a forum for coordination among the Colorado electric utilities that are required to comply with PUC Rule 3627, and for receipt and consideration of stakeholder proposals submitted in connection with 10-Year transmission plans. Since the 2012 filing, TPs have worked with CCPG to formalize and document processes for receiving, evaluating, and providing feedback on stakeholder submitted alternatives. Stakeholders are provided opportunities for meaningful participation through multiple channels, including an online form that can be emailed, by participating in open meetings via teleconference, or by actively attending quarterly meetings. Full documentation of the process by which stakeholder input, suggestions, and alternatives are to be categorized, evaluated, and recorded is included in Appendix J as well as on the CCPG website at:
http://regplanning.westconnect.com/ccpg_stakeholder_opportunities.htm

Generally, the process is initiated by the stakeholder filling out a form and supplying it to the CCPG chair. The form requests the following information:

- Study or project name
- New study or alternative
- Narrative description
- Study horizon date
- Geographic footprint of interest
- Load and resource parameters
- Transmission modeling
- Suggested participants
- Policy issues to address

- Type of study
- Other factors

Once the CCPG chair receives the request, a determination will be made as to whether adequate information has been provided. The chair may contact the requester to ask for additional details. The chair will facilitate an ad-hoc review group ("Review Group") to review and categorize the request. The Review Group will determine:

- If the request is reasonable from a reliability planning perspective.
- Who should be responsible? (CCPG or a smaller sub-group of CCPG; or should the study be forwarded to a larger group such as WestConnect or WECC)?
- The likely schedule for completing the analysis requested.

The Review Group may consider the following questions to determine the response to the request:

- Which portion(s) of the CCPG transmission system shall be under consideration in the study?
- Would the request be of interest to multiple parties?
- Does the request raise policy issues of national, regional, or state interest?
- Can the objectives of the study be met by existing or planned studies?
- Would the study provide information of broad value to customers, regulators, transmission providers and other interested Stakeholders?
- Does the request require an economic (production cost) simulation or can it be addressed through technical studies, (power flow and stability analysis)?

Once the Review Group has determined that the request is reasonable and has verified the purpose and intent of the request, a written response will be developed and provided to the requester and CCPG.

If the Review Group determines that the request cannot be accommodated by CCPG or any TP, an explanation will be provided. If the Review Group determines that the request can be accommodated, then the response will provide information as to the recommended logistics for how the request will be handled, including the responsible parties and a schedule for completion. CCPG maintains a record of all comments and requests received, as well as their disposition. These records also will be posted on the CCPG section of the WestConnect website.

CCPG Northeast Colorado Subcommittee Stakeholder Input Process

The CCPG NECO Subcommittee is the forum for coordinated planning of the transmission system that generally covers Weld, Morgan, Adams, Washington, Logan, Sedgwick, Phillips and Yuma counties and also extends to portions of Boulder and Larimer counties. The objective of the NECO Subcommittee consists of developing transmission plans that will support and facilitate load growth, allow for future generation injection, coordinate with reliability improvements in the Greeley area, and complement other longer-term transmission plans in northeast Colorado. In 2017, the group recommended the Ault – Cloverly 230/115 kV project as the Northern Greeley Area Plan (NGAP).

Public Service filed for a CPCN for the Northern Greeley Area Transmission Plan Project in 2017 and the NECO Study Report was included in the testimony. On March 1, 2018, a CPCN was granted in the Recommended Decision by the Public Utilities Commission for the Proceeding No. 17A-0146E.

In 2017-2019, the NECO Subcommittee changed its focus to the transmission system south of Greeley. The objectives are similar to the north of Greeley studies, which are to reliably replace the existing 44 kV system, increase the ability to accommodate future load growth, allow for beneficial resource development and align with other transmission projects in the area.

In 2018-2019, the NECO Subcommittee met on:

- May 2, 2018
- June 6, 2018
- July 17, 2019

The subcommittee has performed studies to evaluate the present load-serving and generation interconnection capabilities. At least 11 alternatives were evaluated. Presently, the alternative that meets not only the NECO objective, but also can assist with the Public Service 80x30 objectives appears to be a new 230 kV line from Weld – Rosedale, and a 115 kV line from Rosedale – Box Elder – Ennis.

Colorado Energy Plan Task Force

The Colorado Energy Plan Task Force (CEPTF) was formed to inform stakeholders of the studies being performed to evaluate the Company's 2016 ERP and 2017 CEP. Public Service chaired and performed the study work for the CEPTF.

The following stakeholders participated in the CEPTF:

- Basin Electric Power Company
- Black Hills Corporation
- Bright Energy Storage
- Buckyball Systems
- Colorado Public Utilities Commission
- Colorado Springs Utilities
- Dietze & Davis
- Intermountain Rural Electric Association
- Lucky Corridor
- Tormoen Hickey LLC
- Colorado Office of Consumer Council
- Western Area Power Administration
- Western Resource Advocates

- Tri-State
- TradeWind Energy

Meetings were held on:

- November 1, 2017
- November 27, 2017
- March 8, 2018
- October 18, 2018
- March 1, 2019
- July 17, 2019

The CEPTF provided a forum to inform stakeholders of key findings and recommendations related to the transmission issues associated with implementation of the CEP Portfolio, which include:

- There are no significant transmission deficiencies caused directly by the retirement of Comanche Units 1 & 2. The system will remain reliable and there are no transient stability issues.
- Implementation of the CEP Portfolio requires additional voltage control facilities and a network upgrade in the Denver metro area.
- The voltage control facilities include a mix of static and dynamic devices that are needed to maintain adequate voltage performance.
- The recommended network upgrade consists of a new Greenwood Denver Terminal 230 kV line. At least eight transmission alternatives were evaluated based on stakeholder input.

CCPG Lamar Front Range Stakeholder Input Process

In 2019, the Lamar-Front Range Task Force (LFRTF), which was facilitated by Tri-State, revisited the Lamar-Front Range studies completed in 2013. In 2013, the Lamar-Front Range plan was identified through extensive transmission analysis to facilitate

addition of new resources in eastern Colorado, improve transmission system reliability, and increase operational flexibility. The 2013 plan was conceived as a joint project between Public Service and Tri-State. A primary driver for Public Service was to meet an SB07-100 objective to plan transmission from the ERZ-3. The overall plan included the following transmission components:

- Two 345 kV transmission circuits between Lamar and Avondale
- Two 345 kV transmission circuits between Lamar and Burlington
- Two 345 kV transmission circuits between Burlington and Big Sandy
- One 345 kV transmission line between Big Sandy and Missile Site
- One 345 kV transmission line between Big Sandy and Story
- One 345 kV transmission line between Story and Pawnee
- A new Avondale Substation
- Two 230 kV transmission circuits between Lamar and Vilas

Since completion of the 2013 Lamar-Front Range studies, the eastern Colorado transmission system has materially changed with the addition of new resources and transmission facilities. The goal of the task force was to evaluate potential transmission alternatives to the Lamar-Front Range plan.

In April 2019, the LFRTF finalized a study scope and began evaluating transmission alternatives. The LFRTF performed technical analysis of 26 alternatives that facilitated the addition of new resources in eastern Colorado. Several other alternatives were considered, but not included in the technical analysis. The costs of the alternatives for this analysis were based on indicative (planning level) capital construction costs. The benefits of the alternatives were measured primarily in terms of how much incremental generation a particular alternative could accommodate compared to cost of the alternative. Other costs and benefits may be achieved, but were not the focus of this analysis. The LFRTF provided an open stakeholder forum to analyze the costs and benefits of alternative transmission proposals.

The LFRTF has held seven regularly scheduled meetings since February 2019 to discuss study assumptions, study methodology, potential alternatives, cost estimates, and benefits. The LFRTF Subcommittee participant list consisted of 38 stakeholders representing the following entities:

- Apex Clean Energy
- Black Hills
- Buckyball Systems
- Colorado Energy Office
- Colorado Springs Utilities
- Dietze and Davis, P.C.
- Juwi
- Independent Transmission Company
- Invenergy
- New Law Group
- Orion Renewable Energy Group
- Platte River Power Authority
- Savion Energy
- State of Colorado – Office of Consumer Counsel
- State of Colorado – Public Utilities Commission
- Tradewind Energy
- Tri-State Generation & Transmission
- Western Area Power Administration
- Xcel Energy

Meetings were held on:

- February 6, 2019
- March 7, 2019
- April 4, 2019

- June 6, 2019
- June 27, 2019
- July 30, 2019
- September 12, 2019

Prior to the March 2019 meeting, four stakeholders submitted transmission alternatives for consideration. The LFRTF addressed the stakeholder comments during the course of the study process, which was documented in meeting notes.

The LFRTF stakeholders evaluated numerous alternative proposals and agreed to perform technical analysis of the following 14 standalone alternatives:

1A. New 345 kV line from Burlington to Shortgrass to Big Sandy to Story to Pawnee Substation
1B. Alt 1A without Big Sandy Substation interconnection
2. New 345 kV line from Cheyenne Ridge to Burlington to Big Sandy to Missile Site Substation
3A. New 345 kV line from Missile Site to Cheyenne Ridge to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to Burlington Substation
3B. Alt 3A without Wray Substation interconnection
4A. New 345 kV line from Missile Site to Burlington to Wray to Story to Pawnee Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Burlington to Lamar Substation
4B. Alt 4A without Wray Substation interconnection
5. New 345 kV line from Lamar to Midway Substation
6. New 345 kV line from Lamar to Comanche Substation
7A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Replace Burlington-Lamar 230 kV Project with New 345 kV line from Cheyenne Ridge to Lamar Substation; New 230 kV line from Cheyenne Ridge to

Burlington Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

7B. Alt 7A without New 345 kV line from Lamar to Boone 345 kV

8A. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation

8B. Alt 8A without New 345 kV line from Lamar to Boone 345 kV

9. New 345 kV line from Badger Hills to Lamar to Boone Substation; Sectionalize Comanche to Daniels Park 345 kV line #1 or # 2 at Badger Hills Substation; New 345 kV line from Lamar to Cheyenne Ridge Substation

The LFRTF stakeholders evaluated the standalone alternative results and agreed to perform technical analysis of the following twelve combined alternatives:

Alt 3A + 5
Alt 3B + 5
Alt 3A + 7A
Alt 3A + 7B
Alt 3B + 7A
Alt 3B + 7B
Alt 4A + 5
Alt 4B + 5
Alt 4A + 7A
Alt 4A + 7B
Alt 4B + 7A
Alt 4B + 7B

Meetings to review and approve a draft study report are forthcoming. All supporting documentation including meeting agendas, presentations, and notes are accessible from the CCPG – Lamar Front Range Task Force website located at:

http://regplanning.westconnect.com/ccpg_lamar_tf.htm

Energy Storage and Non-wires Alternatives Working Group

As the Companies' strive to reduce carbon emissions, it is recognized that future challenges will require leveraging a portfolio of innovative technologies to support the Companies' goals of a cleaner and more reliable bulk electric system. As a part of this effort, Public Service has initiated and established the Energy Storage Work Group (ESWG) within the Colorado Coordinated Planning Group (CCPG). ESWG will analyze the performance and integration of such systems to identify benefits and challenges for energy storage and other non-wire alternative technologies. The ESWG will evaluate these technologies and develop recommendations for consideration of CCPG and stakeholders. Recommendations will focus on the integration of energy storage resources into the bulk electric system as well as non-wire alternative technologies to address capacity needs and reliability constraints as they relate to the bulk electric system. The ESWG aims to accomplish these goals by assembling resources from the various members of the CCPG as well as external subject matter experts as needed.

The ESWG held its first meeting on January 23, 2020. Several meetings will be scheduled through the remainder of the year as need.

VII. 10-Year Transmission Plan Compliance Requirements

A. Efficient Utilization on a Best-Cost Basis: Rule 3627(b)(I)

Each Company endeavors to conduct transmission planning with the goal of achieving best-cost solutions that balance numerous factors and result in optimal transmission projects. Rule 3627(b)(I) defines “best-cost” as “balancing cost, risk and uncertainty and includes proper consideration of societal and environmental concerns, operational and maintenance requirements, consistency with short-term and long-term planning opportunities, and initial construction cost."

The Companies recognize that a project that is financially impractical will experience difficulty in gaining support from the Commission, customers, shareholders in the case of Black Hills and Public Service, and members in the case of Tri-State. However, cost is not the only consideration when selecting and developing transmission projects. The Companies take a number of factors into consideration when planning the long-term build-out of the transmission system, including but not limited to the following:

- Load projections
- Project partnership opportunities
- Regional congestion
- Transportation corridors
- Transmission corridors
- City and county zoning
- Geographic features
- Societal and environmental impacts
- Operational and maintenance requirements
- Consistency with short-term and long-term planning opportunities
- Initial construction cost

The impact each factor has on a particular project varies based on the nature of the project. Nevertheless, each factor is considered to some extent during the planning stage.

Take the fairly broad environmental and societal concerns factor, for example. As its name implies, this factor considers how a project relates to the natural environment and the public in general – both positively and negatively. In the context of transmission planning, this usually means:

- The negative effects to the local environment from constructing a new transmission line or substation.
- The net positive impact to the environment of constructing a particular new transmission facility as an alternative to a different project over a more sensitive area.
- The positive impact to the environment of utilizing existing transmission corridors or upgrading existing facilities rather than constructing new ones.
- The positive impact to the environment and society if a project gives transmission customers access to a more diverse mix of generation resources, which can potentially reduce overall emissions and energy costs.
- The positive impacts to society by providing stable and reliable electricity. This is particularly important in rural areas where a single transmission outage has the potential to de-electrify entire regions.

For example, a planner may determine, by inspection, that a certain alternative is not practical because it would require a new transmission line over sensitive or exceptionally rugged terrain. This occurred in the CCPG San Luis Valley Subcommittee. The Subcommittee was tasked with evaluating the performance of alternatives to improve several deficiencies in the San Luis Valley transmission system, the biggest deficiency being that a single line outage can cause widespread outages to customers served by Public Service and Tri-State in Saguache, Mineral, Rio Grande, Alamosa, Costilla, and Conejos counties. One proposed alternative was to add a second 230 kV line to the

San Luis Valley from either Montrose or Pagosa Springs. Electrically speaking, a new transmission line from either of these sources would likely improve reliability in the San Luis Valley. However, the Subcommittee declined to analyze them in part because these alternatives would require the construction of new transmission lines across rugged mountainous regions. Given the potential costs, environmental impacts, and permitting and construction challenges, it was decided these alternatives did not justify the effort required to model and analyze them. More information on the work of the CCPG San Luis Valley Subcommittee can be found in the Colorado Coordinated Planning Group San Luis Valley Subcommittee report in Appendix M.

Operational and maintenance concerns also are considered in the planning process. These factors include things such as:

- Spare equipment strategies, particularly for equipment that if failed, would take longer than six months to replace.
- The ability of the system to allow maintenance outages of lines and transformers.
- The capability of the system to accommodate required and increased demands on limited transmission path transfer limits.
- The capacity of the system to allow generators to output their full energy without operating restrictions or operating procedures (congestion).
- Increasing system robustness so that the use of load shedding, special protection, and cross tripping schemes can be minimized.

For example, operational and maintenance concerns were considered by the CCPG Northeast Colorado Subcommittee in its 2017 Northern Greeley Area Transmission Plan System Impact Study Report. The study focused on improving the Greeley area 44kV transmission system, which is antiquated and operated in a mostly radial fashion. The Subcommittee proposed and evaluated several potential transmission projects to improve system reliability and maintenance of the transmission system in the Greeley area. More information on this study can be found in the Northern Greeley Area Transmission Plan System Impact Study Report included in Appendix N.

Good transmission planning requires that alternatives be evaluated in the context of short-term and long-term planning opportunities as well. In planning vernacular, this means considering:

- The relative ability of transmission alternatives to serve more loads, whether it is in the near-term or long-term planning horizon;
- The capability of new transmission alternatives to allow the injection and export of new generation resources; and
- The manner in which transmission alternatives align with longer-term transmission strategies.

The CCPG Northeast Colorado Subcommittee explicitly considered each of these factors in the 2017 Northern Greeley Area Transmission study. Voltage Stability ("P-V") analysis was performed for each studied alternative to compare its relative strength. This type of analysis is a common way to consider the relative ability of various transmission alternatives to serve future loads. The Northern Greeley Area Transmission Study considered the ability of each alternative to allow new resources out of the Greeley area and each alternative's ability to align with a longer-term area transmission plan known as the Southwest Weld Expansion Project located to the south of Greeley.

In general, a primary method of identifying and addressing many of the planning factors is through stakeholder participation in the planning process. Since planning is one of the initial stages of transmission project development, a preliminary evaluation of the aforementioned factors is typically performed as a screening process, with progressively more meaningful, in-depth evaluation occurring through the siting, permitting, and construction stages of development.

Adherence to best-cost principles is formally reflected by each Company in its internal policies. For example, Tri-State policy requires careful consideration of:

- Cost comparison of alternatives for providing capacity to serve load
- The use of existing delivery points and sub-transmission system
- Early construction of other delivery points planned by the member and/or neighboring utilities
- Alternate locations for the new delivery point
- Possible augmentation of the distribution system in lieu of transmission facility construction

The Companies perform an economic feasibility study of the best alternatives using the "single-entity concept," taking into consideration the total costs to the lead Company, as well as other affected utilities or member cooperatives. During the economic study, the following criteria are evaluated:

- Electrical performance of existing and proposed facilities, to include voltage drop, power flow, and losses
- Estimated capital and annual costs
- Wheeling costs
- Reliability
- Environmental considerations
- Coordination with other transmission providers' long-range transmission plans

In addition, the Companies incorporate "best cost" considerations through their interactions with various federal, state, and local regulatory bodies. Among other requirements, FERC has imposed planning requirements on utilities through its Order No. 890 and Order No. 1000, both of which include considerations consistent with Rule 3627's "best cost" approach. These FERC requirements are discussed further below.

All of the Companies participate in Commission dockets and initiatives, spending significant time and resources for Notices of Proposed Rulemaking, outreach efforts, meetings with Commission Staff and actively participating in initiatives in which the Commission has expressed interest. In addition, the Companies participate with Commission staff in the development of the conceptual long-range plans for Colorado's electric transmission infrastructure. The Companies individually meet with representatives of the Colorado Energy Office ("CEO") and take into consideration CEO's suggestions. The Companies also meet with local governmental officials. These meetings transcend simple permitting requests and consider factors such as the economic development aspirations of the communities, cultural concerns of communities, and the environmental aspects of transmission infrastructure expansion contemplated in various regions.

B. Reliability Criteria: Rule 3627(b)(II)

The Energy Policy Act of 2005 ("EPAct") amended the Federal Power Act ("FPA") to create mandatory electric reliability standards for the U.S. bulk power system. In compliance with these federal laws, FERC certified NERC as the electric reliability organization responsible for developing and enforcing the mandatory reliability standards authorized by the EPAct. NERC also utilizes delegation agreements with regional reliability organizations, such as WECC. Various mandatory reliability standards relating to bulk power system planning, operations, and maintenance have been implemented by NERC and WECC as a result of the EPAct with the potential for fines of up to $1 million per day for serious violations that could impact the integrity of the bulk power system.

The NERC Reliability Standards can be found at NERC's website.
www.nerc.com/pa/stand/Pages/default.aspx

The WECC TPL Standards can be found at WECC's website.
www.wecc.biz/Standards/Pages/Default.aspx

Each of the Companies take NERC and WECC compliance extremely seriously and stringently adhere to all applicable standards and criteria. Additional information concerning each Company's reliability compliance efforts is provided below.

1. *Black Hills Reliability Criteria*

On top of NERC and WECC requirements, the following additional guidelines are utilized in the planning process for determining acceptable levels of service for the Black Hills service territory:

- Transmission line loadings should not exceed 100 percent of continuous seasonal rating or the established equipment or operating limits.
- Transformer loading under system intact conditions should not exceed 100 percent of the normal rating.
- Transformer loading under contingency conditions should not exceed 100 percent of the emergency rating.
- Transmission bus voltage levels during normal conditions will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage.
- Transmission bus voltages during contingency conditions will be maintained between 0.90 p.u. and 1.1 p.u. of nominal system voltage.
- Following a disturbance, all machines in the system shall remain in synchronism as demonstrated by their relative rotor angles for all Category P1 contingencies.
- A generator that pulls out of synchronism in the simulation shall not result in the tripping of any additional transmission facilities.
- If a machines maximum relative rotor angle swing exceeds or equals 16 degrees any time two seconds after the fault has cleared, the damping shall be greater than 3% as defined by:

$$\%\,Damping = \frac{\ln\left[\frac{1st\ Cycle\ Peak - 1st\ Cycle\ Min}{Final\ Cycle\ Peak - Final\ Cycle\ Min}\right]}{Cycle\ Count * 2\pi} * 100$$

- For events where the maximum machine relative rotor angle swings are within a 16 degree window are assumed adequately damped

Additional details on the reliability criteria observed by Black Hills are provided on pages 15-18 of the Black Hills Open Access Transmission Tariff ("OATT") Attachment K Methodology, Criteria, and Process Business Practices document, available in Appendix L.

2. *Tri-State Reliability Criteria*

In addition to complying with NERC and WECC standards and criteria, Tri-State observes its own set of internal criteria for planning studies. Tri-State performs an annual assessment of its regional interconnected transmission system elements utilizing simulation modeling cases created by WECC members. This annual assessment takes into account Tri-State's members in four states, with associated projects located in Colorado included in this plan.

The modeling cases selected represent projected loads and transmission system topology for the year one through five horizon and the year six through ten horizon. These cases are selected to demonstrate system performance covering a range of forecasted demand levels and the most critical system conditions and study years. This analysis examines heavy and light loading scenarios, typically in cases modeling year one, year five, and year ten, unless other factors, such as known major system changes, dictate selection of another year. Cases created by WECC ensure that all projected firm transfers and established normal (pre-contingency) operating procedures are modeled, as well as existing and planned reactive power resources.

The transmission system is analyzed considering the planned projects for each utility in the study area. This assessment includes one or more current or past studies, which together address the entire Tri-State area of service.

Additional information concerning Tri-State's reliability criteria is available in its Engineering Standards Bulletin and is updated periodically. The most current version at the time of this filing can be found in Appendix M.

3. *Public Service Reliability Criteria*

In addition to fulfilling NERC and WECC standards and criteria, Public Service observes internal company criteria for planning studies. The most recent internal criteria can be found in Appendix N.

C. Legal and Regulatory Requirements: Rule 3627(b)(III)

Per Rule 3627(b)(III), “Each ten year transmission plan shall demonstrate compliance with…[a]ll legal and regulatory requirements, including renewable energy portfolio standards and resource adequacy requirements.” The following sections provide information concerning each Company's compliance with such legal and regulatory requirements.

1. Black Hills Legal Requirements

Black Hills’ portion of the 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements, including the Colorado RES. For information on resource planning, for both resource adequacy and RES statutory compliance, please refer to the most current Proceeding 16A-0436E as follows:

Proceeding No. 16A-0436E

- Resource Planning, ERP - Phase I 2016 and Phase II 2017

  Black Hills' 2016 ERP was docketed at the Colorado Public Utilities Commission in Proceeding No. 16A-0436E. The Company's ERP application was filed on June 3, 2016, pursuant to Commission rules and the RES codified at C.R.S. § 40-24-124.

  The ERP covered a Planning Period of 25 years from January 2016 through December 2040, and a Resource Acquisition Period of seven years from January 2016 through December 2022. The Planning Period pertains to ERP Phase I, a Commission determination of resource need. The Resource Acquisition Period pertains to ERP Phase II, a competitive solicitation for resource acquisition.

  On January 17, 2017, Recommended Decision No. R17-0039 was entered for Phase I and became a decision of the Commission by operation of law. The decision adopted a settlement agreement filed on November 10, 2016. The settlement agreement modified certain terms of the Company's ERP application. Specifically, the settlement agreement approved, in pertinent part, a resource need of up to 60 MW from RES-eligible energy resources for commercial operation in 2019. The 60 MW will enable the Company to comply with the 30% RES requirement in 2020. Standalone REC bids, to fulfill the 60 MW resource need, were not allowed under the settlement agreement. The settlement agreement approved evaluation criteria for utility-owned resource bids. Finally, the settlement agreement stipulated a timeline for Phase II to ensure that federal production tax credits can be advantaged for eligible bids.

  A Phase II competitive solicitation for 60 MW of eligible energy resources was conducted by the company on June 23, 2017. The Company received over 100 individual bids from multiple project developers for

eligible energy resources from wind, solar PV, and other resources. An independent evaluator was retained (Accion Group) to observe the Company's bid solicitation and evaluation process, and report findings. Based on the evaluation process, Bid 1117-1 was ranked the highest overall, including both economic and noneconomic evaluation criteria. Economic criteria identified Bid 1117-1 with the lowest NPVRR and the most avoided cost savings of all the bids offered in the Company's solicitation.

Bid 1117-1 is a PPA for 60 MW supplied by a wind facility located in Huerfano and Las Animas counties. The output of approximately 201,500 MWh of energy and renewable energy credits annually will enable the Company to comply with the 30% RES beginning in 2020. The awarded Bid 1117-1 will be online for commercial operation no later than December 31, 2019.

- RES Compliance Plan, 2018-2021

  The settlement agreement in ERP Proceeding No. 16A-0436E approved acquisition of on-site solar photovoltaic ("PV") and community solar garden ("CSG") resources for RES compliance.

  The PV capacity is established at 1,500 kW per year for the compliance period, 2018-2021. The settlement agreement stipulated categories for PV system sizes and incentive levels.

  The CSG program was defined in the settlement agreement to be comprised of two RFP offerings by the Company based on the type of subscribers. Each year, the Company will solicit and award up to 500 kW of CSGs for 100% low-income subscribers and up to 2,000 kW of CSGs for open subscribers. The settlement agreement stipulated 0 kW as the minimum purchase amount and 2,500 kW as the maximum purchase

amount from CSG installations each compliance year, 2018-2021. The Company expects that 15.12 MW of CSGs will operate by end of 2021.

2. Tri-State Legal Requirements

Tri-State's 2020 Plan complies with all applicable NERC and WECC reliability standards, as well as other applicable legal and regulatory requirements including Company and member compliance with the Colorado RES.

For the period 2015 through 2019, the Colorado RES requires that 6 percent of Tri-State's Member Systems' retail energy sales be served by renewable generation, growing to 20 percent in 2020 and beyond. In addition, as a qualifying wholesale utility, the Colorado RES requires Tri-State to generate or cause to be generated at least 20 percent of the energy it provides to its Colorado Member Systems at wholesale from eligible energy resources in the year 2020 and thereafter. As the wholesale power provider for its Member Systems, Tri-State's 2020 Plan is developed to ensure that the necessary transmission system capabilities will be in place to meet both its Colorado Members Systems' and its own RES requirements.

For additional information on resource adequacy requirements and resource requirements to meet the RES, please refer to Tri-State's Integrated Resource Plan/Electric Resource Plan and Electric Resource Plan Annual Progress Reports available in Appendix M.

As discussed previously, Tri-State may be subject to federal and state regulations related to carbon emission reductions from existing power plants, such as the regulations that will be promulgated pursuant to Colorado HB 19-1261. While no such regulations have been promulgated as of the date of this 10-Year Plan, Tri-State anticipates that such regulations may be promulgated within the next two years and, if so, will address them in the next 10-Year Transmission Plan. Tri-State also notes that, since it operates an interconnected, interstate transmission system,

its transmission system may be impacted as a result of federal compliance and carbon emission reduction plans enacted in other states in which Tri-State operates.

3. Public Service Legal Requirements

Public Service's 2020 Plan complies with its currently operative ERP, approved by the Commission in Proceeding 16A-0396E in its Phase II decision, C18-0761. Additional information on Public Service resource adequacy and compliance with Commission rules related to ERPs is available at:
https://www.xcelenergy.com/company/rates_and_regulations/resource_plans

Public Service's 2020 Plan additionally complies with its currently operative RES Compliance Plan approved by the Commission as modified by settlement in Decision C16-1075 in Proceeding 16A-0139E. [5] Public Service's 2020 Plan also complies with the specifications set forth in its 2020-2021 RES Compliance Plan, filed in Proceeding 19A-0369E, and currently under Commission consideration.

Information on Public Service compliance with RES requirements is available at:
https://www.xcelenergy.com/company/rates_and_regulations/filings

D. Opportunities for Meaningful Participation: FERC Order No. 890

In addition to the CCPG planning processes, each of the Companies has its own FERC Order No. 890 stakeholder process as described below. For additional information on stakeholder involvement pertinent to Rule 3627, please refer to Section VI.

[5] Public Service's 2017-2019 RES Compliance Plan was subsequently extended through the first quarter of 2020 by Decision R19-0807 in Proceeding No. 19A-0369E.

1. *Black Hills Participation Strategy*

For Black Hills, the FERC Order No. 890 Stakeholder Process is included in its Attachment K to its Open Access Transmission Tariff ("OATT"), which is included in Appendix L of this document. Additional information concerning Black Hills' FERC Order No. 890 processes can also be found in Appendix L.

2. *Tri-State Participation Strategy*

Attachment K to Tri-State's OATT demonstrates Tri-State's transmission planning processes consistency with FERC Order No. 890 planning principles. As discussed previously in this 2020 Plan, all projects included herein have been identified and developed through Tri-State's transmission planning process.

Attachment K to Tri-State's OATT can be updated periodically, and is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The most current version at the time of Attachment K is located in Appendix M.

3. *Public Service Participation Strategy*

For Public Service, the FERC Order No. 890 stakeholder process is included in the Xcel Energy Joint OATT Attachment R, available at the following website:
https://www.oasis.oati.com/woa/docs/PSCO/PSCOdocs/PSCo_Attachment_R_5-5-2020.pdf
Additional information concerning the Public Service FERC Order No. 890 processes can be found at:
http://www.oatioasis.com/psco/index.html under "FERC 890 Postings".

E. Coordination Among Transmission Providers: FERC Order No. 1000

In July 2011, FERC issued a final rule related to transmission planning and cost allocation, FERC *Order 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* ("Order 1000"). This order builds on planning principles already established in FERC Order No. 890, as previously discussed. FERC Order No. 1000 requires that transmission owning and operating public utilities:

1) Participate in a regional transmission planning process that produces a regional transmission plan.
2) Amend their OATT to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes.
3) Remove from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities.
4) Improve coordination between neighboring transmission planning regions for interregional transmission facilities.
5) Participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation.
6) Participate in a regional transmission planning process that has an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions.

WestConnect is one of four planning "regions"[6] within WECC established for regional transmission planning to comply with Order 1000. Public Service and Black Hills have designated WestConnect as their Order 1000 compliant planning regions. Tri-State has joined WestConnect as a coordinating transmission owner, which means it is not subject to all of the requirements under Order 1000 such as accepting binding cost allocation for regional transmission projects. The WestConnect planning process is described in Black Hills' and Public Service's OATTs (Attachment K and R respectively; links are provided above) as well in documentation found on the WestConnect website (http://www.westconnect.com/). The WestConnect website also houses information and announcements for many public planning meetings. WestConnect accepts stakeholder input throughout the planning process.

WestConnect develops a regionally coordinated transmission plan that begins with the determination of regional reliability, economic and public policy needs. The more cost-effective or efficient solutions to meet identified regional needs are included in the regional plan. These regional projects may be new projects in addition to the projects developed through the local or sub-regional planning processes or may replace local projects in some instances. If WestConnect determines Colorado utilities benefit from a regional project, then those Colorado utilities may be responsible for a portion of the cost of the regional project.

Additionally, WestConnect coordinates with the other western Order 1000 planning regions. This coordination also is described in Black Hills' and Public Service's planning attachments to their respective OATTs.

[6] The other three are Columbia Grid, Northern Tier Transmission Group, and the California Independent System Operator.

VIII. 10-Year Transmission Plan Supporting Documentation

A. Methodology, Criteria, & Assumptions

1. *Facility Ratings (FAC-008-3)*

NERC Reliability Standard FAC-008-3 requires that transmission and generation owners document the methodology used to develop ratings of their equipment. The standard requires that the transmission or generation owner supply its methodology to specific NERC registered entities upon request. FAC-008-3 also requires transmission and generation owners to establish facility ratings per the methodology established through FAC-008-3. Each transmission and generation owner has documented ratings for each of its facilities. The standard requires the transmission or generation owner to supply its facility ratings to specific NERC registered entities (i.e. associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s)) upon request. These documents are not publicly available and are not required to be per NERC standards. NERC Reliability Standard MOD-032-1 requires applicable entities to provide equipment characteristics, including established facility ratings, to NERC and WECC according to established reporting requirements. This is accomplished through the WECC Base Case Compilation Schedule as prescribed by the Data Preparation Procedural Manual.

a. Black Hills Ratings

Documentation of Black Hills' FAC-008-3 methodology is available in Appendix L.

b. Tri-State Ratings

Documentation of Tri-State's Facility Rating's methodology is available in its Engineering Standards Bulletin. The most current version of Tri-State's

Engineering Standard's Bulletin at the time of this filing can be found in Appendix M.

c. Public Service Ratings

Documentation of Public Service FAC-008-003 methodology can be found in Appendix N.

2. *Transmission Base Case Data: Power Flow, Stability, Short Circuit*

The Companies utilize transmission system power flow and transient dynamics modeling data prepared by WECC. Through its Annual Study Program, WECC facilitates the preparation of at least 10 models per year. The models represent a variety of system conditions out to a 10-Year planning horizon. WECC's 10-Year Regional Transmission Plan is an Interconnection-wide perspective on: 1.) expected future transmission and generation in the Western Interconnection, 2.) what transmission capacity may be needed under a variety of futures, and 3.) other related insights.

WECC members participate in the data preparation process for the models and Public Service coordinates the data for the Rocky Mountain region. Prior to being used for planning studies, the models are reviewed and adjusted to reflect the most current and accurate system elements, ratings, and operating conditions for the region to be studied. Short circuit data is coordinated between neighboring TPs as needed and periodically coordinated at the CCPG level.

Instructions for obtaining access to WECC base cases are as follows:

a. An organization requesting WECC base case(s) must either be a WECC member or they must execute the "Nonmember Confidentiality Agreement for WECC Data."

b. Non-members may obtain the confidentiality agreement from WECC by requesting the agreement from a WECC Stakeholder Services representative.

The submission must include a statement from the organization explaining why they have a legitimate business need for the WECC base case(s).

B. Load Modeling

Pursuant to each Company's OATT, network customers are required to submit 10-Year projected network loads and network resources by October 1 of each year. This information is then compiled with existing data and information to provide a basis for identification of the minimum transmission system enhancements required to ensure that a sufficiently robust transmission system is in place to meet all network customer requirements under all scenarios.

1. *Forecasts*

The Companies rely on the most recent and accurate load forecasts when developing system planning models. General load forecast assumptions are posted on each transmission provider's Company or OASIS site.

a. Black Hills Forecasts

In 2016, Black Hills filed with the Commission its latest ERP, which included details on expected customer growth based on load forecast information submitted annually by network customers. The ERP, in conjunction with the network customer forecast updates, is used in the development of Load and Resource ("L&R") reports submitted to WECC on an annual basis. Once the L&R report is developed, this forecast is disaggregated to the respective transmission system load buses. There are two types of load buses: (1) a load bus where the

load does not change over time (e.g. a single large industrial load bus); and (2) a load bus where the load changes over time (e.g. a residential load). Black Hills uses its knowledge of load characteristics along with historical loading observations to estimate the individual load bus data in time. The load bus forecasts are summed and compared to the WECC L&R report aggregate load forecast. If the two forecasts do not match, the variable bus load forecasts are adjusted until the two forecasts match. Through this procedure, the WECC L&R reports, including the assumptions in the latest ERP, are reflected in the transmission planning models used within the WECC footprint. Deviations from the ERP load forecast are commonplace in transmission studies depending on the purpose of the planning analysis being performed and the study scenario of interest. The load assumptions included in the planning model are typically specified within each planning study report for reference.

Details related to Black Hills' load forecast can be found in Black Hills' 2016 ERP in Colo. Consolidated Proceeding No. 16A-0436E; specifically, Attachment LS-1 included in Appendix L of this report.

b. Tri-State Forecasts

General load forecast information is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html
The Load Forecast Descriptive Statement available at the time of this filing is located in Appendix M.

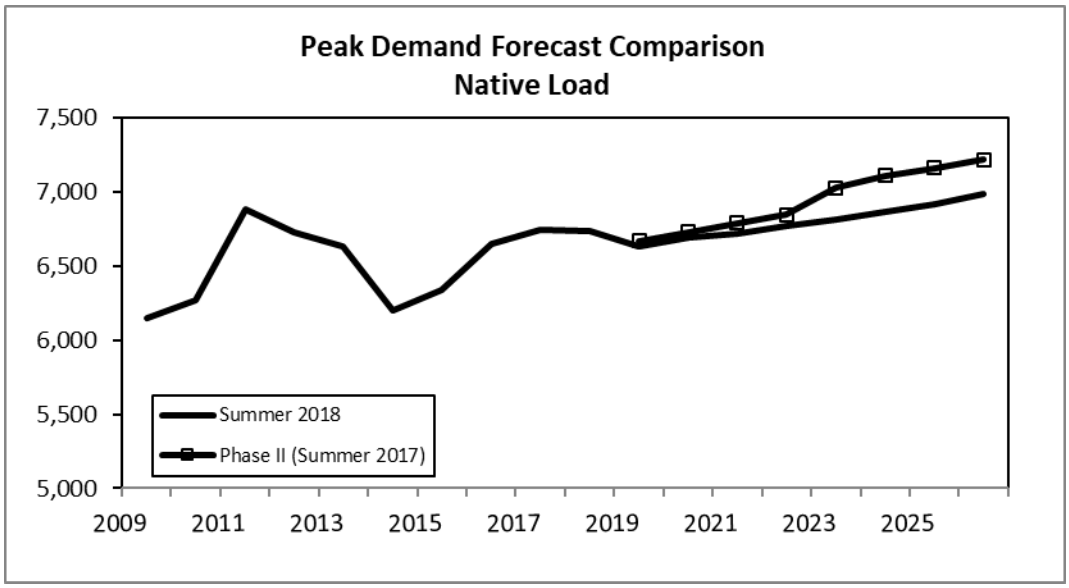
Tri-State prepares load forecasts on a system-wide and regional basis with regional forecasts used for resource planning purposes. Tri-State receives load forecasts from its network customers by October 1 of each year. These loads are modeled as required for inclusion in the planning models developed in conjunction with neighboring entities.

Tri-State's most recent transmission plans utilize 2018 load forecast data. Base forecast data for these plans is available in Appendix A of Tri-State's ERP/APR, located in Appendix M.

c. Public Service Forecasts

The load forecast used in this filing is the Summer 2018 PSCo Load Forecast, which was provided publicly in the Company's 2016 Electric Resource Plan Annual Progress Report filed dated October 31, 2018 (Proceeding No. 16A-0396E) and the PSCo Load Forecast that was provided publicly in the Company's 2016 Electric Resource Plan Modeling Assumptions Update filed in August 2017. The following figure shows a comparison between the two forecasts. The drivers of the changes in the forecast are discussed in Appendix N. The Company notes that while it has developed more recent load forecasts (e.g., as provided in the Company's 2016 Electric Resource Plan Annual Progress Report dated October 2019 filed in Proceeding No. 16A-0396E and in Proceeding No. 19A-0409E), the Summer 2018 forecast was the most current publicly available forecast at the time the Company began the analysis and preparation of this Rule 3627 Report.

Figure 8. Public Service Historic and Forecast Demand



In addition to native load forecasts, Public Service receives forecasts from its wholesale customers, which it incorporates into the overall forecast. Transmission planners allocate the loads on a substation-by-substation basis, based on historical trends. Additional information is included in Appendix N.

2. *Demand-Side Management*

The effects of Demand-Side Management ("DSM") program savings are typically taken into account within the load forecasts described previously. Within the context of power system modeling, DSM is simply reflected in the power flow model as reduced load and therefore included in planning studies.

a. Black Hills DSM

Details related to the effects of DSM savings estimates on Black Hills' load forecast can be found in the 2016 Black Hills ERP; specifically, Attachment LS-1, which is included in Appendix L of this document.

b. Tri-State DSM

Load forecasts provided for bulk electric transmission planning typically include existing DSM and other load-reducing programs, including member energy efficiency programs and local distributed generation. These programs are reflected in the power flow model as reduced load and are inherently included in studies. For transmission planning, load forecasts that contain load-reducing factors may be used for specific projects or for individual Tri-State members with DSM, local distributed generation, or other energy efficiency programs. For such cases, please refer to individual project planning studies. For Tri-State's system load forecast, these are described in Tri-State's 2018 Annual Progress Report to the 2015 ERP found at:
https://www.tristategt.org/resource-planning

c. Public Service DSM

Public Service accounts for DSM through reduction in its load forecast based, in part, on the goals established by the Commission. Additional information is included in Appendix N.

C. Generation and Dispatch Assumptions

Generator and associated equipment models are typically included in the WECC Annual Base Case Compilation Schedule base cases as required by the Data Preparation Manual. The detail of generation models utilized within planning studies can vary depending on the nature of the study. For example, a Large Generator Interconnection study for a wind facility may explicitly model each individual wind turbine and the associated collector system to properly assess the low voltage ride through capabilities of the facility. That same facility may be modeled as a single equivalent wind turbine with an equivalence collector system within a long-range planning study where the

performance of individual wind turbines is not a concern. The scope of the technical study will influence the level of detail that is modeled.

1. *Black Hills Assumptions*

At the most basic level, Black Hills dispatches existing generation to meet the demand requirements of its system, including load and losses. The objective of a particular study often drives the individual generator dispatch levels. For example, a peak demand summer baseline scenario may consist of a majority of dispatchable baseload generation online and an appropriate mix of wind and solar PV to meet the demand requirements. An off-peak demand spring or fall scenario may have the available wind generation dispatched at its nameplate capacity with the dispatchable baseload generation and solar generation reduced to capture the impacts of that particular dispatch pattern. Existing power purchase agreements and other contractual arrangements may be reflected in certain study scenarios to further stress the transmission system. Black Hills also may include speculative generation (as identified in the current version of the Black Hills Colorado Electric Generation Interconnection Request Queue, included in Appendix L) in certain transmission studies as dictated by the study objective. Additionally, existing and/or conceptual generation may be dispatched beyond the demand requirements of the study case to facilitate a net export of energy from the study area. A listing of existing and planned resources utilized in planning studies is typically included in each specific study report.

2. *Tri-State Assumptions*

Tri-State's transmission planning function receives generation assumptions from its network customers--Tri-State Power Management, Arkansas River Power Authority (“ARPA”), Municipal Electric Agency of Nebraska (“MEAN”), Raton Public Service Company (“City of Raton”), Public Service Company of Colorado (“PSCO”), Kit Carson Electric Cooperative (“KCEC”) and Public Service Company of New Mexico

("PNM")--annually by October 1. These generation assumptions are utilized to ensure a sufficiently robust transmission system to meet network customers' needs over a 10-Year planning horizon.

Generation assumptions, including dispatch assumptions, and corresponding data for other transmission plans are project-specific. Therefore, the individual transmission studies should be referenced for generation assumptions relative to each such project.

3. Public Service Assumptions

Public Service transmission planning models reflect generation dispatch based on internal procedures that take into account production costs, maintenance schedules, and other factors. Procedures include:

- Modeling of generator planned outages with outage period of 6 months or more
- In general, if not needed to meet load requirements, high production cost generation plants are modeled out of service. If resources are needed, these units may be modeled
- Public Service combustion turbine generators are typically modeled at or near full output
- Public Service large coal-fired plants are typically modeled at or near full output. These units are considered "base loaded", in that they usually operate around the clock if generation adjustments are necessary, these generators are generally adjusted last
- Hydro generation has net dependable seasonal ratings. Each seasonal rating reflects the average generation that can be continuously maintained over the duration of the daily peak period for the respective season. In winter, the daily period is approximately five hours long. All generators on-line should be

producing reactive power ("MVARs"). Generator bus voltage scheduling may be necessary if the generating unit is acting in a condensing mode (consuming MVARs)

- Pumped Hydro generators are modeled appropriately in pumping mode during off peak hours.

Renewable generation, including wind and solar are modeled based on Public Service Variable Energy Resource Dispatch Assumptions. System changes, load transfers, and other topology changes also are coordinated through CCPG.

D. Methodologies

1. *System Operating Limits (FAC-010)*

System Operating Limits ("SOL") is defined in NERC Reliability Standard FAC-010-3 as the responsibility of the Planning Authority ("PA") to ensure reliable planning of the Bulk Electric System. SOL is required to be established per FERC standards but is not required to be publicly available.

a. Black Hills SOL

Black Hills has defined both Operational Criteria, which are limits for typical every day/normal operations, and SOLs, which are limits that are of an emergency nature and must be acted upon promptly to ensure facility ratings are not exceeded. Black Hills' SOLs are communicated to the Southwest Power Pool ("SPP") Reliability Coordinator so that when an SOL is exceeded, the Reliability Coordinator will be aware of the concern and be able to provide assistance in ensuring the SOL violation is removed. Black Hills' SOLs are summarized below:

- BES Transmission Line SOLs are exceeded when the line rating is exceeded.

- BES Voltage SOLs are exceeded when the Emergency Voltage rating is exceeded. The Emergency Voltage is plus/minus 10% of the nominal voltage.
- BES transformer SOLs are exceeded when their loaded MVA is between 100% and 125% of the established FOA Rating for more than 30 minutes, OR, their loaded MVA exceeds 125% of the established FOA Rating for any period of time.

b. Tri-State SOL

Tri-State is not a PA and, therefore, uses the SOL methodology as defined by the applicable PA.

c. Public Service SOL

Public Service has one SOL for the TOT7, which is located north of the Denver metro area. SOLs are required to be established per FERC standards, but are not required to be publicly available. The TOT7 studies are conducted annually. The results of those studies are available upon request.

2. *Available Transmission System Capability Methodology (MOD-001)*

Available Transmission System Capability Methodology is available and posted per NERC Standard MOD-001 at NERC's website.

a. Black Hills TTC

Black Hills utilizes the Rated System Path Methodology for determining Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") for all Posted Paths and in all ATC time horizons. The determination of TTC is based on the maximum flow of a path while meeting all reliability criteria for single initiating event outages. In the event that the path is flow-limited and a reliability limit

cannot be reached, the transfer capability of the path is set to the thermal rating of the path. For further details on the calculation of transfer capability, refer to Black Hills' ATC Implementation Document ("ATCID") included in Appendix L.

b. Tri-State TTC

Tri-State's TTC path values for jointly owned paths that are interfaces identified and rated through WECC processes and OTC determinations are based upon the Rated System Path Methodology (NERC MOD-29-2a). Tri-State has TTC allocations on WECC rated Paths 30 (TOT1A), 31 (TOT2A), 36 (TOT3), 39 (TOT5), 47 (SNMI), and 48 (NNMI). These paths are studied by the path operator with actual flow levels at the combined path ratings under simulated N-1 scenarios to ensure that the planning reliability criteria are being met. The path participants have previously used studies and negotiations to determine the manner in which the TTC will be allocated to each of the participants.

For jointly owned paths that are not WECC-rated paths, the TPs determine the appropriate combined TTC and the allocation of it is based upon contractual capacity entitlements. This allocation is done outside of any WECC approval process since these are Tri-State TTC/ATCID minor paths that are not part of an interface and do not impact any major recognized WECC paths.

Tri-State utilizes TTC values based upon thermal facility ratings for all flow-limited paths that are owned solely by Tri-State. If the NERC MOD-029-2a requirement R2.1 simulation studies result in sufficient flow ability on a path segment to determine a reliability limit, then the TTC on the ATC path segment is set to the simulated flow corresponding to the reliability limit while at the same time satisfying all planning criteria.

In addition, Tri-State has created many extended ATC paths that are defined by a serial concatenation of rated path segments. The resulting TTC and ATC for

each extended ATC path is based upon the lowest TTC and ATC of all the serial path segments included in each path definition.

The ATCID provides for the documentation of required information as specified in the NERC MOD Standards and the NAESB OASIS Standards regarding the calculation methodology and information sharing of ATC specific to this TP. The ATCID for Tri-State is available on Tri-State's OASIS at: http://www.oasis.oati.com/tsgt/index.html

The ATCID can be updated periodically and the most recent version of the ATCID at the time of this filing can be found in Appendix M.

c. Public Service TTC

The ATCID (MOD-001) for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "ATCID Implementation Document".

The ATCID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

3. *Capacity Benefit Margin (MOD-004)*

Capacity Benefit Margin ("CBM") methodology is available and posted per NERC Standard MOD-004.

a. Black Hills Capacity Benefit Margin (MOD-004)

Black Hills does not implement CBM in the assessment of ATC. The Capacity Benefit Margin Implementation Document ("CBMID") for Black Hills is included in Appendix L.

b. Tri-State CBM

Based on FERC's allowance for TPs to not use CBM, Tri-State does not allow for the use of CBM and, as such, its value is set to zero (0) in the ATC equations for all paths posted by Tri-State. Furthermore, Tri-State's practice is to not maintain CBM. Tri-State will review its CBM practice, at least annually, and will post any changes to the OASIS as needed. The CBMID for Tri-State is available on Tri-State's OASIS, by clicking on "ATC Information" and then "Capacity Benefit Margin Statement (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix M.

c. Public Service CBM

The CBMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "CBM Implementation Document (CBMID)".

The CBMID can be updated periodically, and the most recent version at the time of this filing can be found in Appendix N.

4. *Transmission Reliability Margin Calculation Methodology (MOD-008)*

NERC Standard MOD-008-1, Transmission Reliability Margin Calculation Methodology, requires that each Transmission Operator prepare and keep current a Transmission Reliability Margin Implementation Document ("TRMID").

a. Black Hills Transmission Reliability Margin (MOD-008)

A copy of the current TRMID for Black Hills is located in Appendix L.

b. Tri-State TRM

The TRMID for Tri-State is available on Tri-State's OASIS at:
http://www.oasis.oati.com/tsgt/index.html

The TRMID can be updated periodically, and the most recent version at the time of this filing is located in Appendix M.

c. Public Service TRM

The TRMID for Public Service is available on Public Service's OASIS, by clicking on "ATC Information" and then "TRM Implementation Document (TRMID)".

The TRMID can be updated periodically and the most recent version at the time of this filing is located in Appendix N.

E. Status of Upgrades

Projects that constitute upgrades to existing transmission facilities are discussed in Section III of this Plan and the associated appendices.

F. Studies and Reports

Most of the Companies' study documentation can be found by starting at the sections of the WestConnect website that are dedicated to the CCPG:

http://www.westconnect.com/planning_ccpg.php
Additional Company-specific study and reporting resources are described below.

1. Black Hills Reporting

Public access to transmission market information, generator interconnection and transmission service requests, business practices, planning study reports and other topics related to the Black Hills transmission system is provided on Black Hills' OASIS at:

http://www.oatioasis.com/bhct

2. Tri-State Reporting

Planning studies and related reports for Tri-State transmission projects in Colorado are located at Tri-State's website at:

http://www.tristategt.org/transmission-projects

Generator interconnection, transmission service request, and other OATT study reports related to Tri-State's transmission system are provided on Tri-State's OASIS at:

http://www.oasis.oati.com/tsgt/index.html

3. Public Service Reporting

Planning studies and related reports for Public Service transmission projects in Colorado are located at the following links:

https://www.rmao.com/public/wtpp/PSCO_Studies.html
http://www.oatioasis.com/psco/index.html
http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado

G. In-Service Dates

Information concerning the expected in-service date for each utility's facilities identified in the 2020 Plan and the entities responsible for constructing and financing each facility is contained in Table 1, Section III and Appendices A-I.

H. Economic Studies

The purpose of economic planning studies is to identify significant and recurring congestion on the transmission system and/or address the integration of new resources and/or loads. Such studies may analyze any or all of the following: (i) the location and magnitude of the congestion, (ii) possible remedies for the elimination of the congestion, (iii) the associated costs of congestion, (iv) the costs associated with relieving congestion through system enhancements (or other means), and, as appropriate (v) the economic impacts of integrating new resources and/or loads. Economic studies are generally described as being either “local” or “regional” in nature.

1. *Black Hills Economic Study Policies*

Black Hills conducts economic planning studies through the procedures outlined in its OATT Attachment K, which is included in Appendix L.

Black Hills will accept requests for economic studies on an annual basis. Information on making a request is available in the Attachment K Economic Study Request Form, as shown in Appendix L. Upon receiving a valid request for an economic study, Black Hills, with input from its stakeholder committee, will classify the request as local, subregional or regional. Black Hills will engage the appropriate resources to study up to one economic study request that has been classified as local on a biannual basis. All economic study requests that have been classified as subregional or regional will be forwarded to the WECC for inclusion in the appropriate study program. Since the 2018 Rule 3627 filing, Black Hills has not received any economic study requests, nor has it performed any economic studies.

2. *Tri-State Economic Study Policies*

Western Interconnection-wide congestion and economic planning studies are conducted by WECC in an open stakeholder process that holds region-wide stakeholder meetings on a regular basis. The WECC planning process is posted on its website (see http://www.wecc.org/Pages/home.aspx). Tri-State participates in the regional planning processes, as appropriate, to ensure data and assumptions are coordinated. Tri-State did not perform any economic studies this cycle nor were any requested by Tri-State stakeholders.

3. *Public Service Economic Study Policies*

Public Service facilitates priority local economic planning studies for its transmission system, pursuant to the procedures in its OATT Attachment R. Regional economic planning studies shall be performed by WECC, pursuant to procedures posted on the WECC website. Public Service did not perform any economic studies this cycle nor were any requested by stakeholders.

2020 CPUC Rule 3627 Appendices

Appendix A: Colorado Transmission Maps

Appendix B: Denver-Metro Transmission Map

Appendix C: Black Hills Energy Transmission Map

Appendix D: Black Hills Energy Projects

Appendix E: Tri-State Generation and Transmission Association Projects

Appendix F: Public Service Company of Colorado Projects

Appendix G: Colorado Springs Utilities Projects

Appendix H: Platte River Power Authority Projects

Appendix I: Western Area Power Administration - RMR Projects

Appendix J: CCPG Stakeholder Process

Appendix K: Responses to Stakeholder Comments

Appendix L: Black Hills Supporting Documents

Appendix M: Tri-State Supporting Documents

Appendix N: Public Service Company Supporting Documents

Attachment Vol II 4-3 Tri-State Transmission Project Information

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Tri-State Generation and Transmission Association

2020-2030 Transmission Plan

Burlington - Burlington (KCEA) Rebuild

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild the existing Burlington - Burlington (KCEA) 115 kV line
Voltage Class:	115 kV
Facility Rating:	118 MVA
Point of Origin/Location:	Burlington
Point of Termination:	Burlington (KCEA)
Intermediate Points:	
Length of Line (in Miles):	2.0
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$718,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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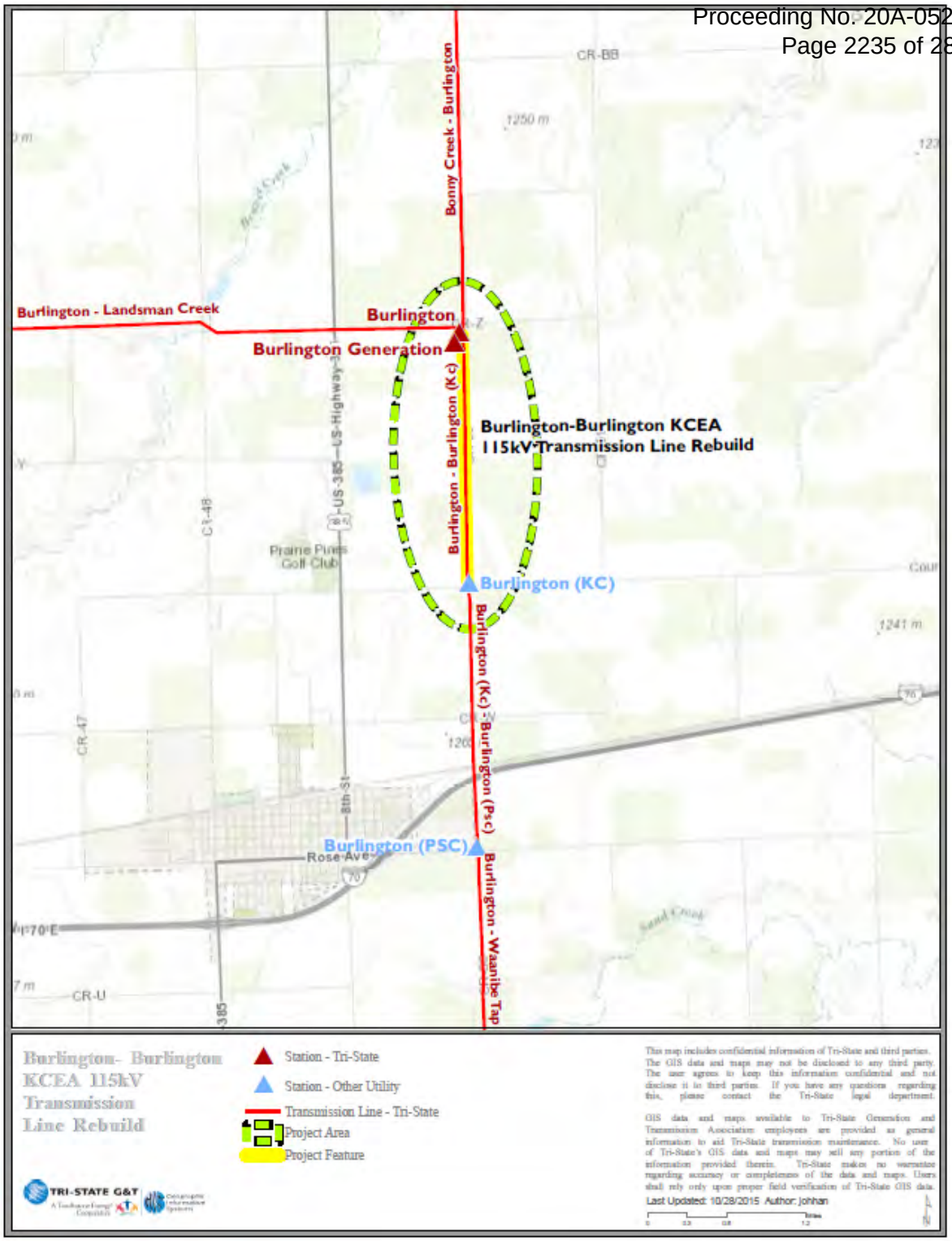
Bonny Creek - Burlington
CR-BB
1250 m
Burlington - Landsman Creek
Burlington
Burlington Generation
Burlington - Burlington (Kc)
Burlington-Burlington KCEA
115kV Transmission Line Rebuild
US-385
C1-48
Prairie Pines
Golf Club
Burlington (KC)
Burlington (Kc) Burlington (Psc)
1241 m
CR-47
8th St
Burlington (PSC)
Rose Ave
70
CR-U
385
Burlington - Waanibe Tap
Burlington- Burlington
KCEA 115kV
Transmission
Line Rebuild
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Project Area
Project Feature
TRI-STATE G&T
This map includes confidential information of Tri-State and third parties. The GIS data and maps may not be disclosed to any third party. The user agrees to keep this information confidential and not disclose it to third parties. If you have any questions regarding this, please contact the Tri-State legal department.
GIS data and maps available to Tri-State Generation and Transmission Association employees are provided as general information to aid Tri-State transmission maintenance. No user of Tri-State's GIS data and maps may sell any portion of the information provided therein. Tri-State makes no warranties regarding accuracy or completeness of the data and maps. Users shall rely only upon proper field verification of Tri-State GIS data.
Last Updated: 10/28/2015 Author: johhan
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Del Camino-Slater 115 kV Line Uprate

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Reconductor portions of the existing Del Camino-Slater 115 kV line
Voltage Class:	115 kV
Facility Rating:	131 MVA
Point of Origin/Location:	Del Camino Switch
Point of Termination:	Slater
Intermediate Points:	
Length of Line (in Miles):	3.6
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	Load Serving
Estimated Cost (in 2019 Dollars):	$1,400,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2021
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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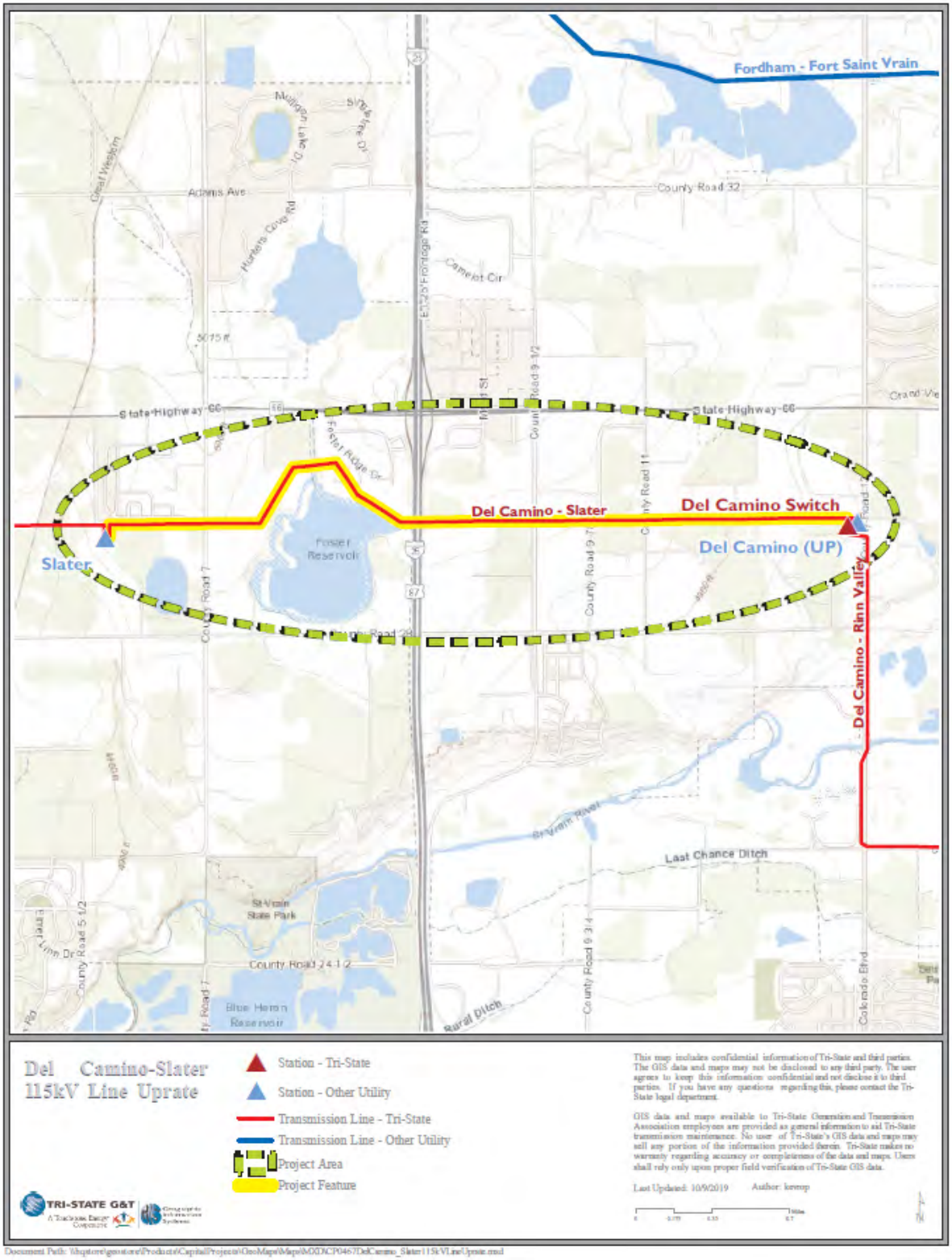
Fordham - Fort Saint Vrain
State Highway 66
Del Camino - Slater
Del Camino Switch
Del Camino (UP)
Slater
Del Camino - Rinn Valley
Last Chance Ditch
St Vrain State Park
Blue Heron Reservoir
Foster Reservoir
County Road 32
County Road 24 1/2
Del Camino-Slater
115kV Line Uprate
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Transmission Line - Other Utility
Project Area
Project Feature
TRI-STATE G&T

Falcon-Midway 115 kV Line Uprate Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Planned uprate of existing 115 kV line between Falcon and Midway.
Voltage Class:	115 kV
Facility Rating:	145 MVA
Point of Origin/Location:	Falcon
Point of Termination:	Midway
Intermediate Points:	Geesen, Lorson Ranch, Rancho
Length of Line (in Miles):	27.0
Type of Project:	Transmission Line
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$3,800,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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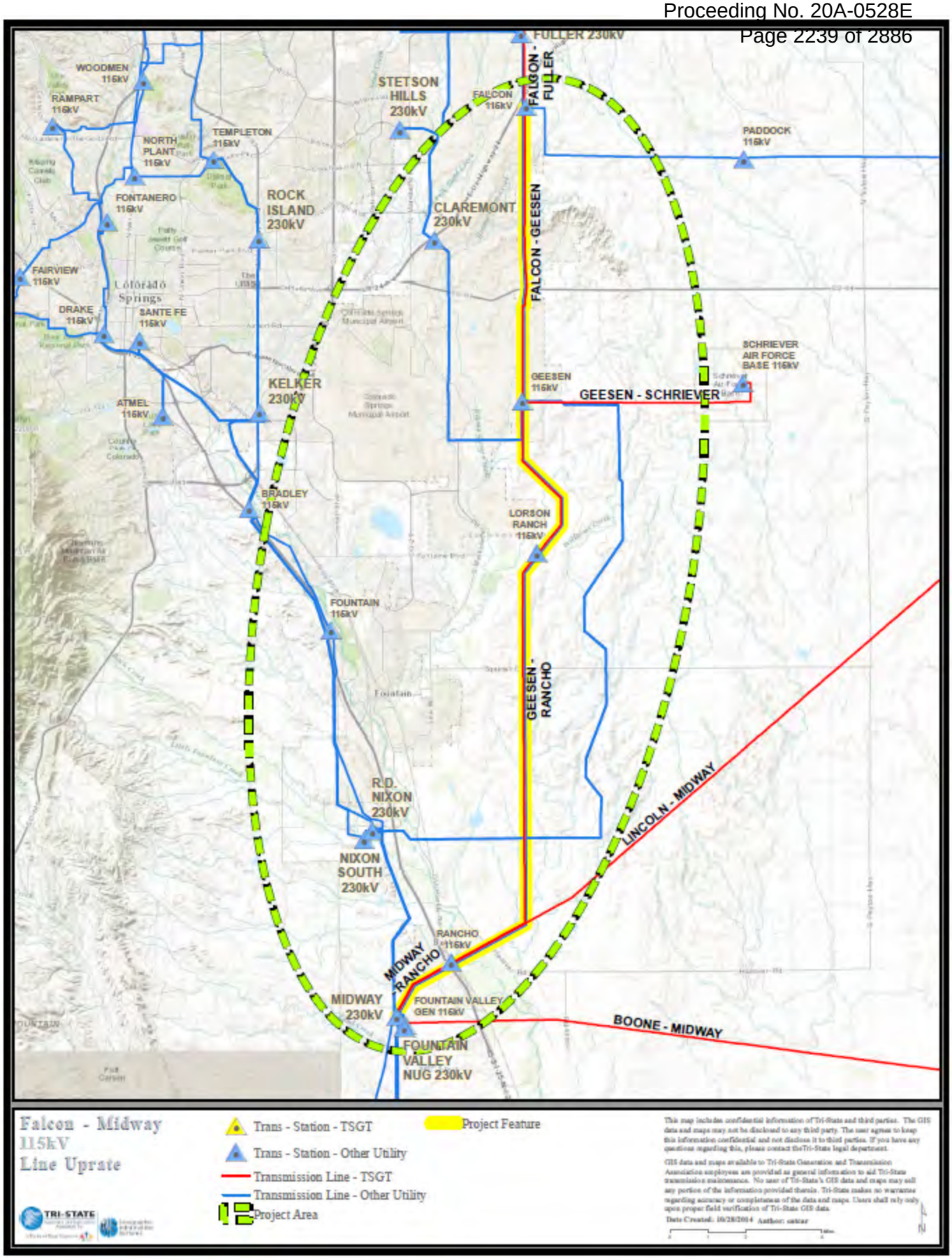
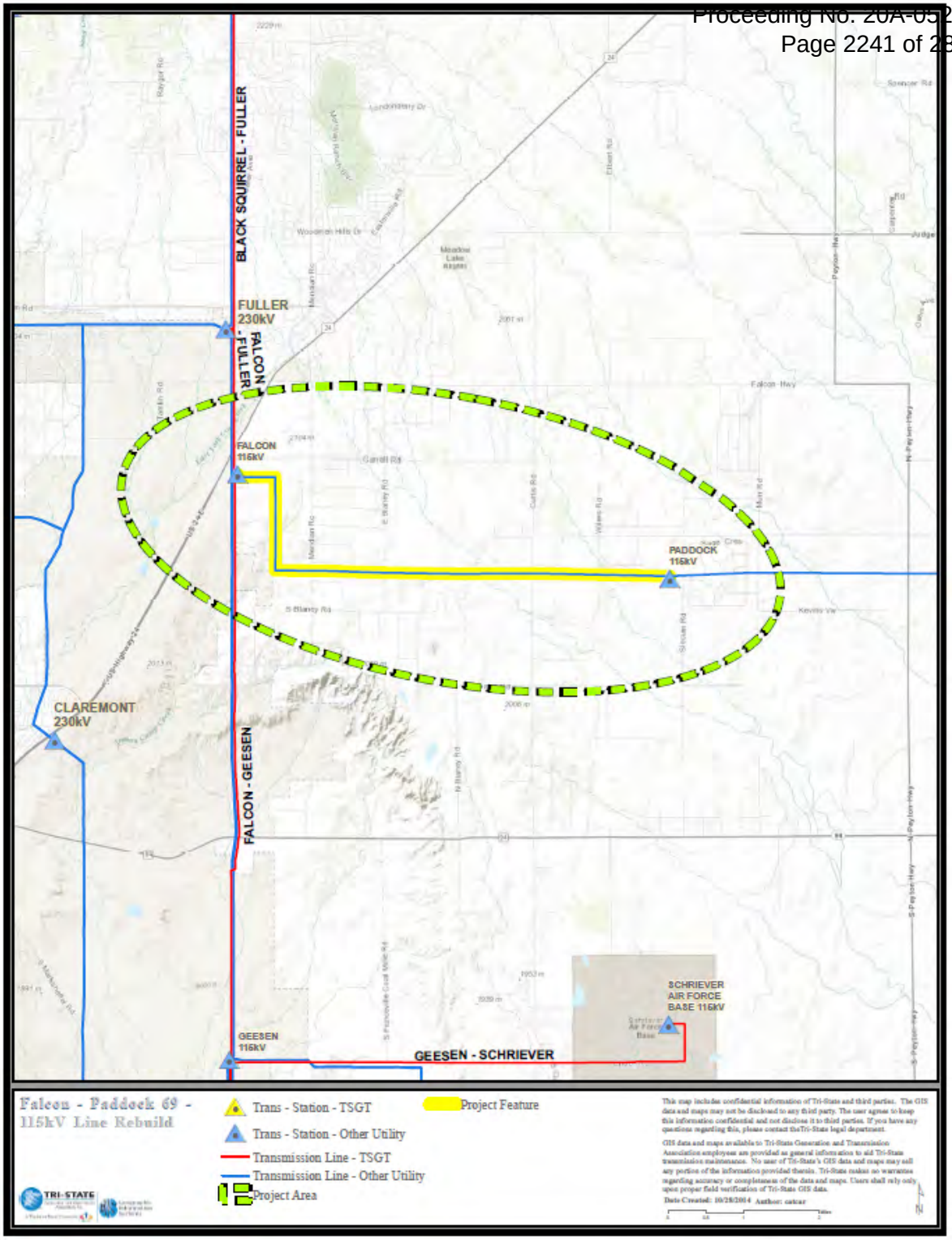
Hearing Exhibit 101
Page 13 of 45



Falcon-Paddock-Calhan 115 kV

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild of existing 69 kV line between Falcon and Calhan.
Voltage Class:	115 kV
Facility Rating:	242 MVA
Point of Origin/Location:	Falcon
Point of Termination:	Calhan
Intermediate Points:	Paddock
Length of Line (in Miles):	25.0
Type of Project:	Transmission Line and Substation
Development Status:	Conceptual
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase conductor thermal rating and create 115 kV loop.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2014 Dollars):	$33,400,000
Schedule:	
Construction Date:	
Planned In-Service Date:	TBD
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3028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FULLER
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FULLER - FALCON
FALCON
115kV
PADDOCK
115kV
CLAREMONT
230kV
FALCON - GEESEN
SCHRIEVER
AIR FORCE
BASE 115kV
GEESEN
115kV
GEESEN - SCHRIEVER
Falcon - Paddock 69 - 115kV Line Rebuild
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Transmission Line - TSGT
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Project Area
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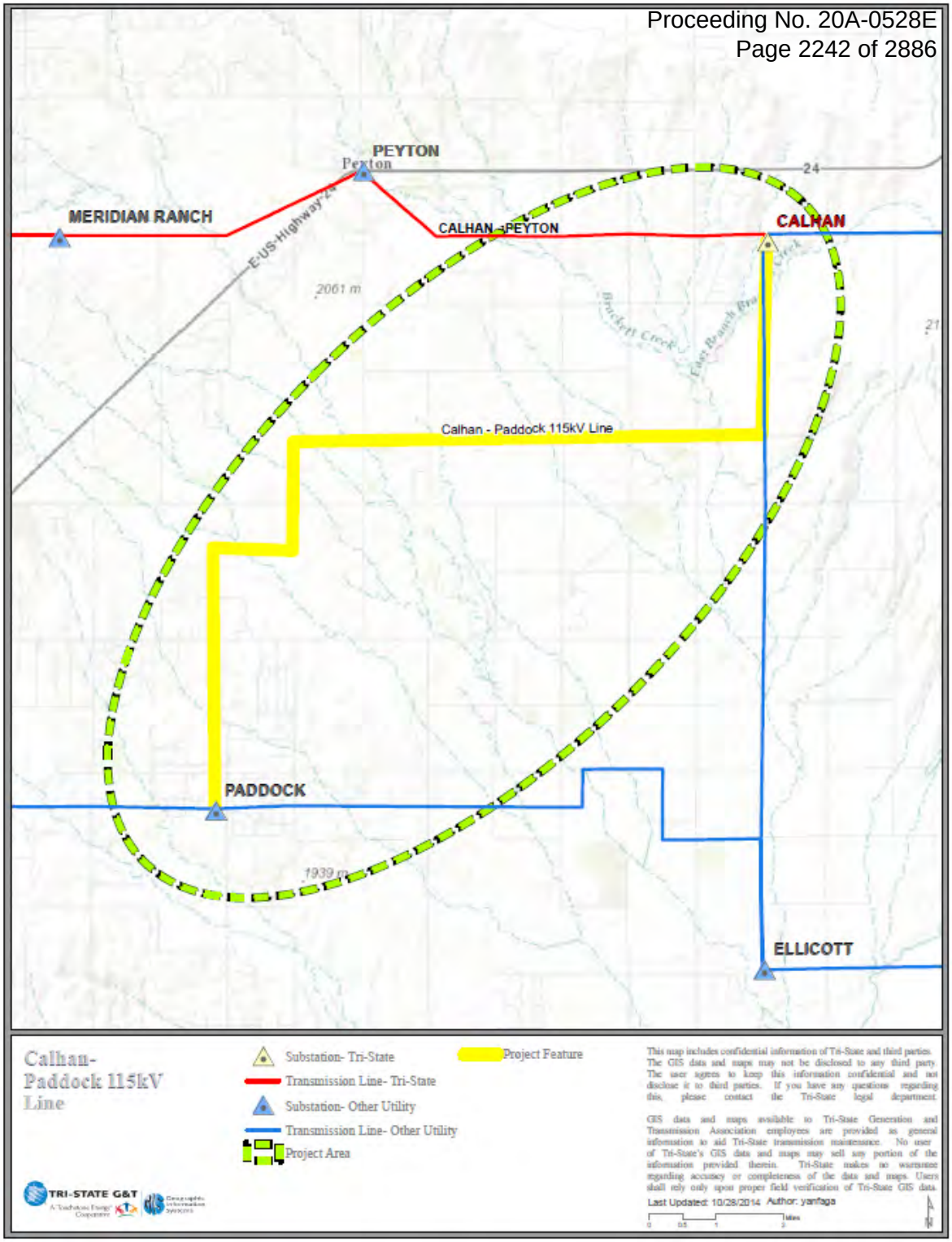
TRI-STATE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CALHAN
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Brockett Creek
East Branch Bra
Calhan - Paddock 115kV Line
PADDOCK
1939 m
ELLICOTT
Calhan-
Paddock 115kV
Line
Substation- Tri-State
Transmission Line- Tri-State
Substation- Other Utility
Transmission Line- Other Utility
Project Area
Project Feature
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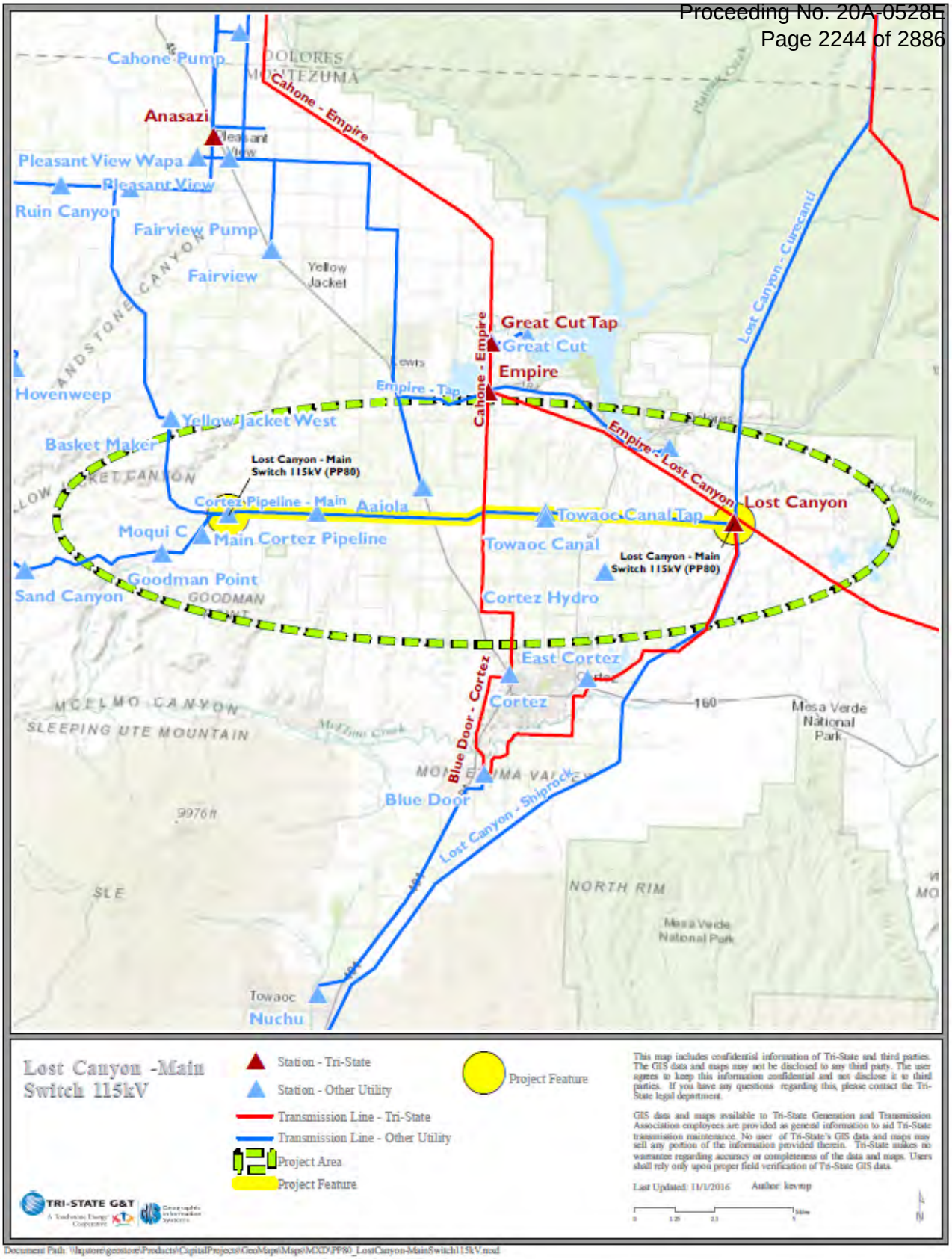
Last Updated: 10/28/2014 Author: yanfaga
TRI-STATE G&T

Lost Canyon - Main Switch 115 kV Line

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	New 115 kV transmission line between Lost Canyon and Main Switch Substations.
Voltage Class:	115 kV
Facility Rating:	238 MVA
Point of Origin/Location:	Lost Canyon
Point of Termination:	Main Switch
Intermediate Points:	
Length of Line (in Miles):	16.0
Type of Project:	Transmission Line
Development Status:	Conceptual
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load-serving capability of the CO2 Loop.
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	Reliability
Estimated Cost (in 2019 Dollars):	$22,600,000
Schedule:	
Construction Date:	
Planned In-Service Date:	TBD
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025



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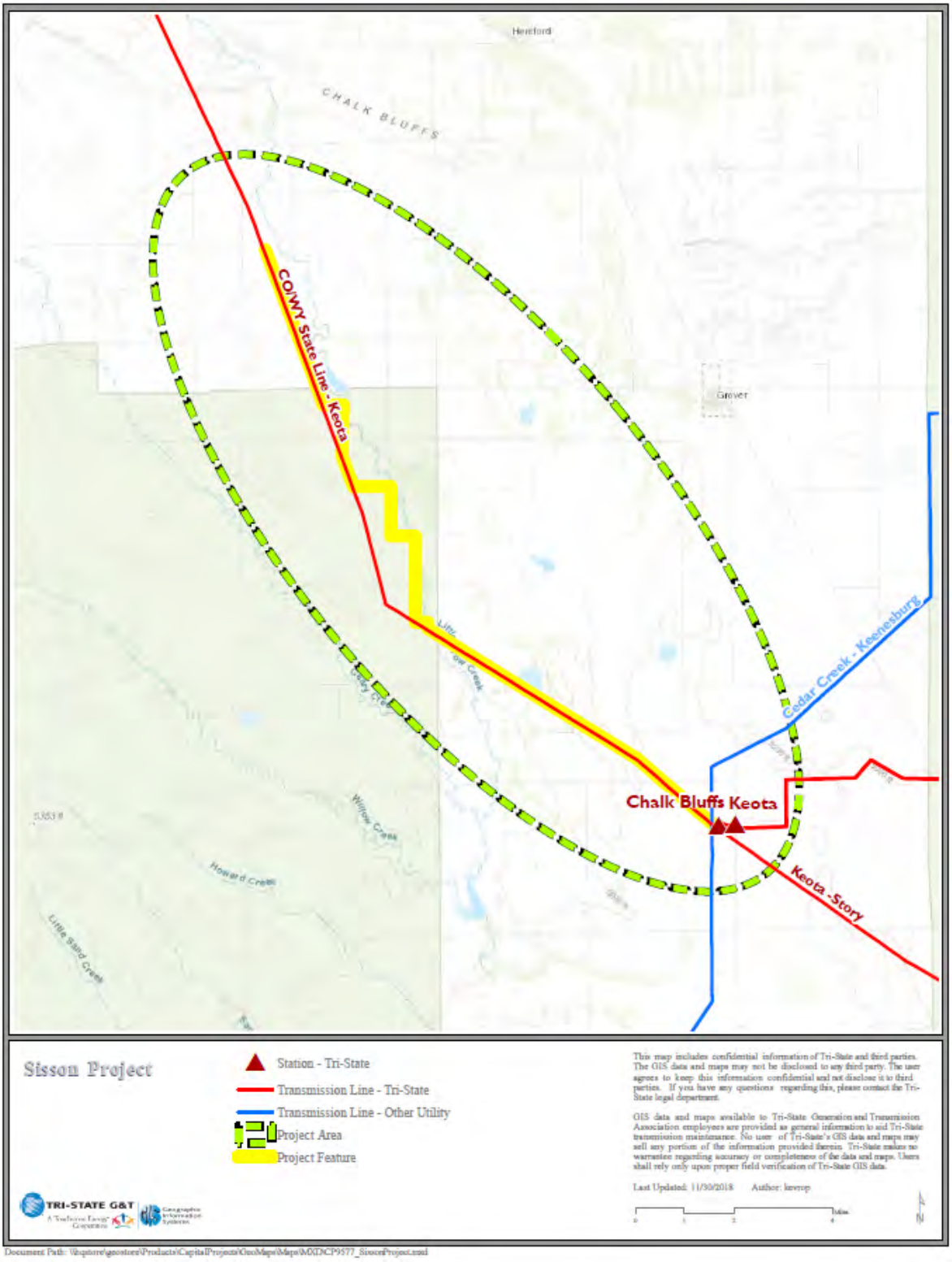
Sisson Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Substation addition radially served from Keota substation
Voltage Class:	115 kV
Facility Rating:	244 MVA
Point of Origin/Location:	Keota
Point of Termination:	Lloyd Sisson
Intermediate Points:	
Length of Line (in Miles):	24.0
Type of Project:	Transmission Line and Substation
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load serving capability.
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$18,800,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2020
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org 303-
Phone	254-3025



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Tri-State Generation and Transmission Association
2020-2030 Transmission Plan

Vollmer Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Construct approximately 2 miles of 115 kV transmission to serve the planned Vollmer substation
Voltage Class:	115 kV
Facility Rating:	143 MVA
Point of Origin/Location:	Vollmer
Point of Termination:	Jackson Fuller, Black Squirrel
Intermediate Points:	
Length of Line (in Miles):	2 miles
Type of Project:	Transmission Line and Substation
Development Status:	Planned
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Increase load-serving capability
Project Driver (Primary):	Load Serving
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$7,100,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2022
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org 303-
Phone	254-3025

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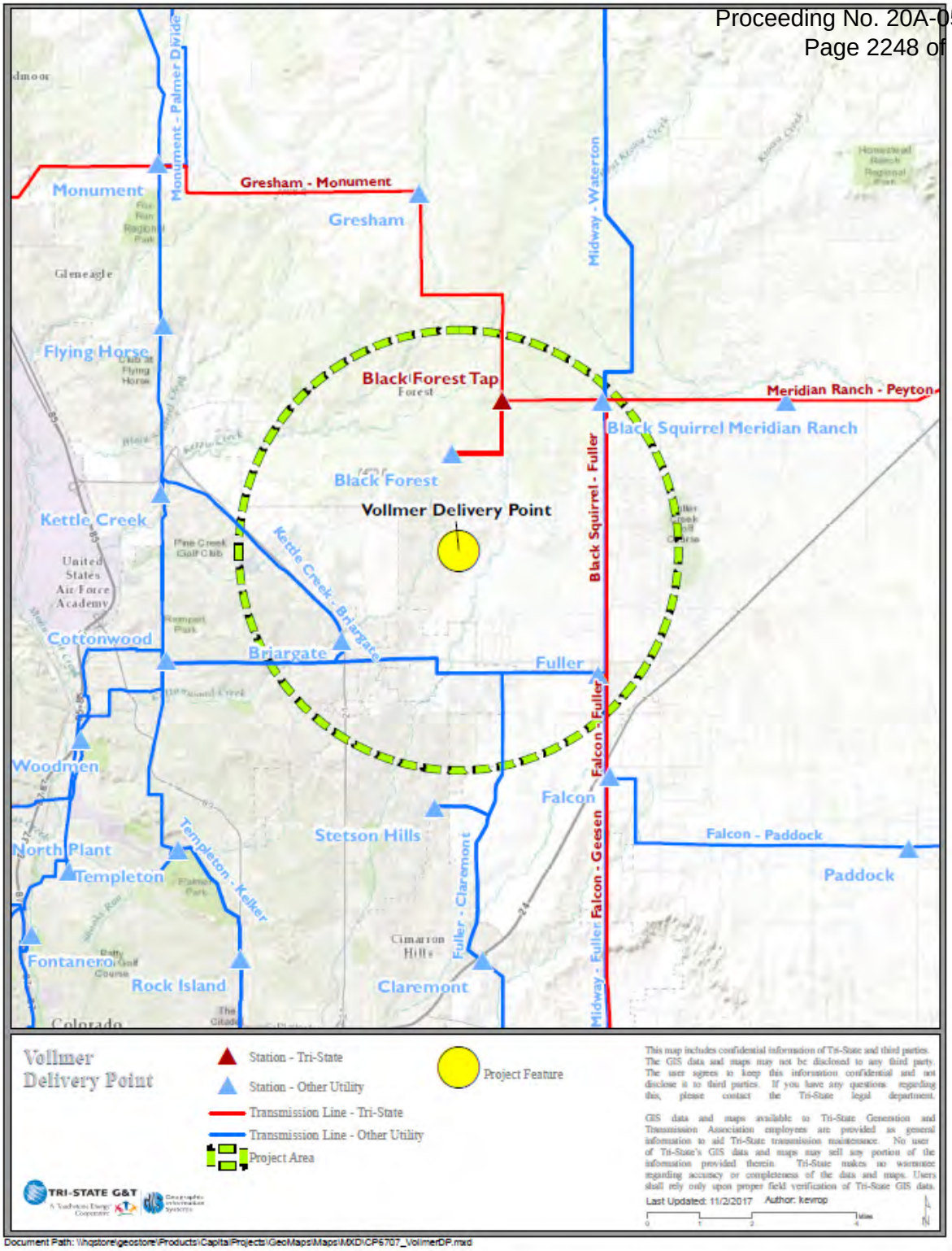
Monument
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Midway - Waterton
Gleneagle
Flying Horse
Black Forest Tap
Forest
Meridian Ranch - Peyton
Black Squirrel Meridian Ranch
Black Forest
Vollmer Delivery Point
Black Squirrel - Fuller
Kettle Creek
Kettle Creek - Briargate
United States Air Force Academy
Cottonwood
Briargate
Fuller
Falcon - Fuller
Woodmen
Falcon
Stetson Hills
Falcon - Paddock
North Plant
Templeton
Templeton - Kelker
Paddock
Fuller - Claremont
Cimarron Hills
Fontanero
Rock Island
Claremont
Midway - Fuller
Falcon - Geesen
Colorado
Vollmer Delivery Point
Station - Tri-State
Station - Other Utility
Transmission Line - Tri-State
Transmission Line - Other Utility
Project Area
Project Feature
TRI-STATE G&T
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Miles
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Western Colorado Transmission Upgrade Project

Project Sponsor:	Tri-State Generation and Transmission Association
Additional Project Participants:	
Project Description:	Rebuild existing transmission line from Montrose Substation to Cahone Substation from 115 kV to 230 kV capable. The transmission line will continue 115 kV operation and be sectionalized at the planned Maverick 115 kV substation, which will be constructed near Nucla substation. The existing Nucla - Norwood 115 kV line will sectionalize at Maverick substation.
Voltage Class:	230 kV
Facility Rating:	239 MVA
Point of Origin/Location:	Montrose
Point of Termination:	Cahone
Intermediate Points:	Maverick
Length of Line (in Miles):	80 Miles
Type of Project:	Transmission Line and Substation
Development Status:	Under Construction
Routing:	
Subregional Planning Group:	CCPG
Purpose of Project:	Reliability - eliminate need for existing Nucla Remedial Action Scheme and replace failing structures.
Project Driver (Primary):	Reliability
Project Driver (Secondary):	
Estimated Cost (in 2019 Dollars):	$57,200,000
Schedule:	
Construction Date:	
Planned In-Service Date:	2020
Regulatory Info:	
Regulatory Date:	
Permitting Info:	
Permitting Date:	
Contact Information:	Ryan Hubbard
Email	rhubbard@tristategt.org
Phone	303-254-3025

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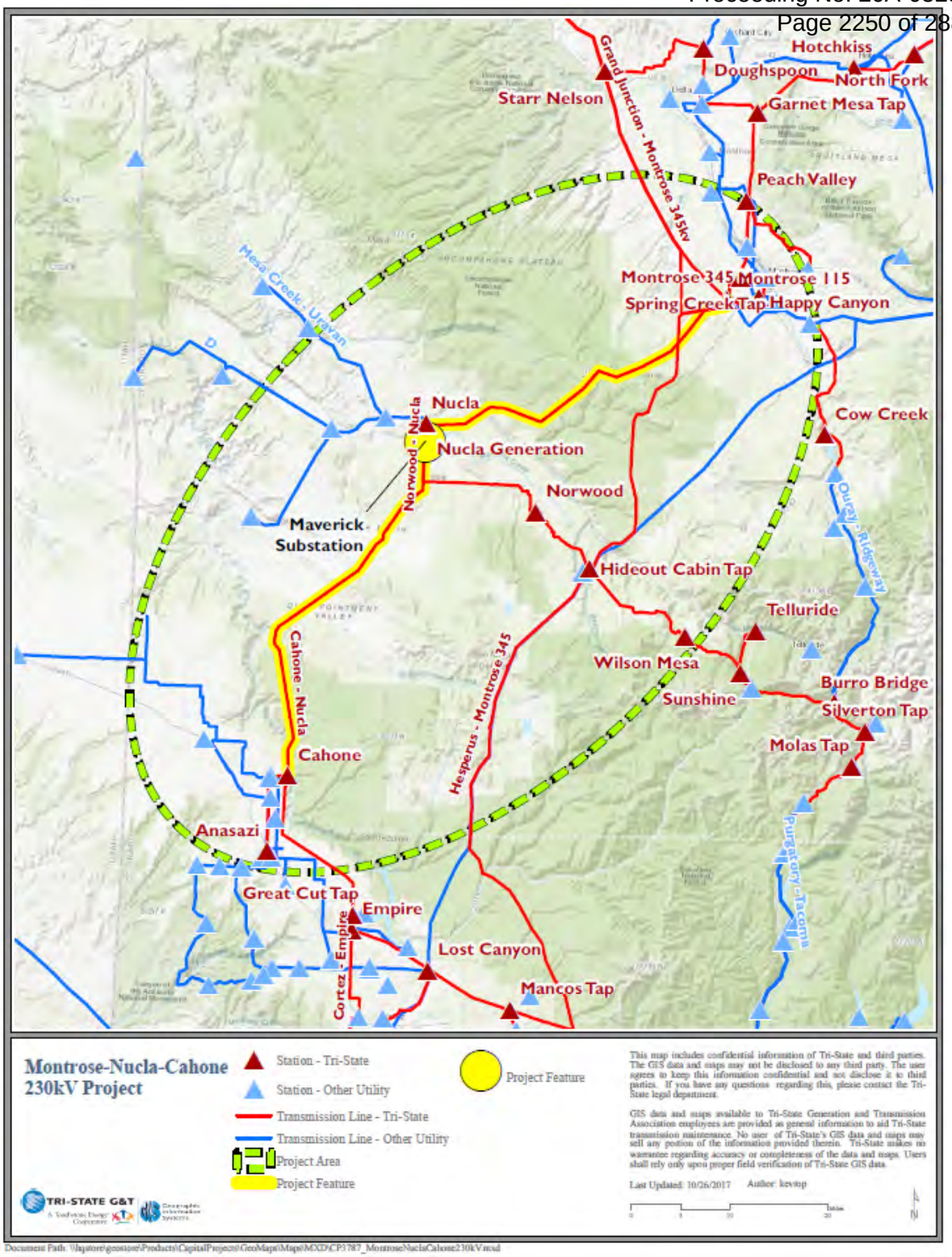

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Attachment Vol II 5-1 Demand Side Management & Energy Efficiency Potential Study

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

FOR TRI-STATE GENERATION & TRANSMISSION

MAY 8, 2020

Prepared by: Mesa Point Energy & BrightLine Group

TRI-STATE GENERGATION & TRANSMISSION DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

MAY 8, 2020

Prepared For:

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EXECUTIVE SUMMARY

Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a demand side management potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). The Mesa Point Team assessed the available technical, economic, and achievable energy and demand savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State.

The study focuses on energy efficiency, DR, and DER *achievable* potential; it is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, the study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member can choose which products and measures to offer.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report report goes into more detail on methods, savings, and findings.

A separate electronic reporting tool serves as an appendix to the report. The tool provides the ability to view findings in greater detail by sector, end-use, and region.

Results by Resource: EE, DR, DER

There are significant opportunities for cost-effective EE and DR savings in the Tri-State service territory. Behind-the-meter DER resources hold significant technical potential but realize limited cost-effective potential based on the analysis framework used for the study.

Given the uncertainty associated with customer adoption of energy-saving technologies, the Mesa Point Team developed achievable scenarios based on four different incentive and program delivery spending levels – from low to maximum levels of program funding.

These scenarios were:

1. Low – assumes incentivizing 25% of incremental cost
2. Moderate – 50% incentive level
3. Aggressive – 75% incentive level
4. Maximum – 100% of incremental cost. Note that maximum funding was assumed to be limited to 100% of the incremental cost to install a measure.

Key findings from each of the three resources assessed, EE, DR, and DER, are summarized below.

Energy Efficiency (EE) Resource

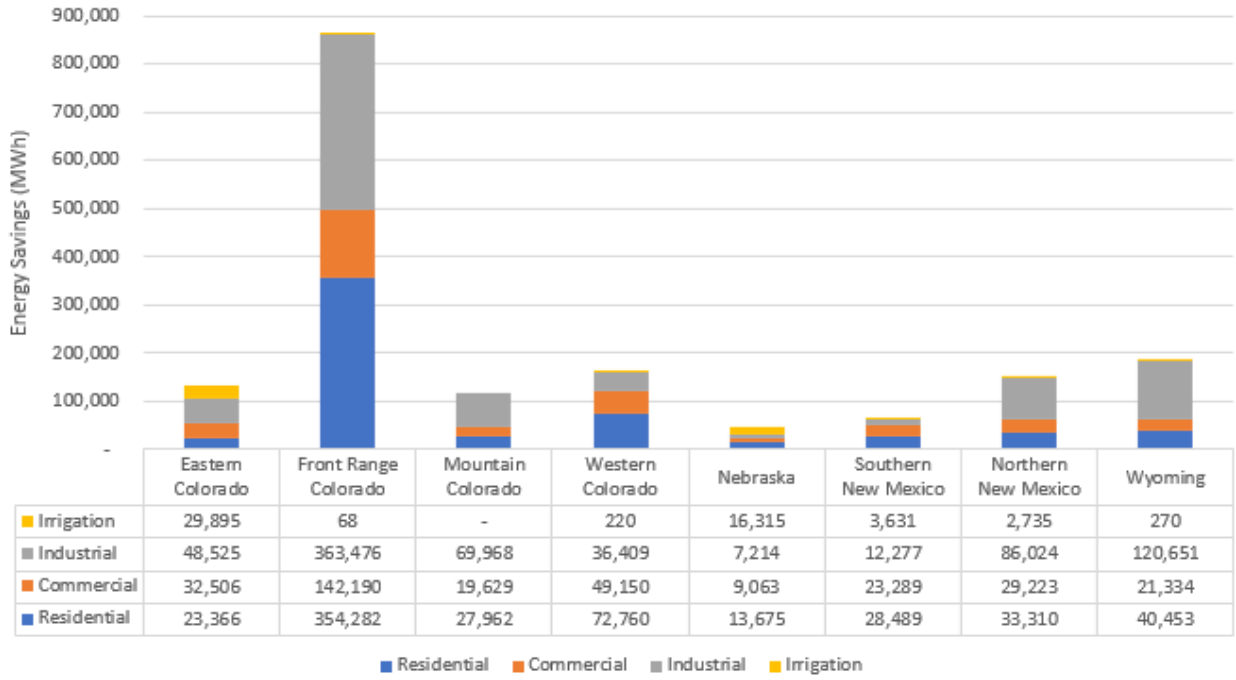
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

Table ES-1. Portfolio Cumulative Energy Efficiency Savings by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Energy Savings (MWh)						
2021 (first year)	130,384	98,221	75,523	55,330	38,083	27,043
2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109
% of Baseline Sales						
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%
2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Energy effiency savings potential breakdown shares similarities to energy load in terms of distribution by region and by sector (Figure ES-1 and Figure ES-5). Front Range Colorado has the largest cumulative energy savings potential with 860 GWh. Across all regions, the industrial customer sector has more than 744 GWh of cumulative energy savings potential, followed by the residential sector at just under 600 GWh.

Figure ES-1. 2040 Cumulative Energy Efficiency Savings Potential by Region by Customer Sector (Achievable-Moderate Scenario)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Irrigation	29,895	68	-	220	16,315	3,631	2,735	270
Industrial	48,525	363,476	69,968	36,409	7,214	12,277	86,024	120,651
Commercial	32,506	142,190	19,629	49,150	9,063	23,289	29,223	21,334
Residential	23,366	354,282	27,962	72,760	13,675	28,489	33,310	40,453

Table ES-2 summarizes the key cumulative energy efficiency cost metrics across the portfolio at four time horizons under the Achievable-Moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 114 GWh of energy savings is achievable, on average, per year at a cost of $24.3 million for an acquisition cost of $212/MWh. Over the 20 year study horizon, and on a levelized basis, the cost to acquire all energy savings under the Achievable-Moderate scenario is $21.55/MWh.

Table ES-2. Portfolio Energy Efficiency Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	SUM OF ANNUAL PROGRAM COSTS ($)[1]	SUM OF FIRST YEAR MEASURE SAVINGS (MWH)	FINAL YEAR DEMAND SAVINGS (MW)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	5.28	$182.70	$15.25
2025	1.91	$54,155,251	279,461	9.91	$193.78	$17.41
2030	1.72	$164,148,094	797,374	17.25	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	23.11	$212.54	$21.55
20-year avg.	**1.64**	**$24,339,742**	**114,520**	13.89	**$212.54**	**$21.55**

Demand Response (DR) Resource

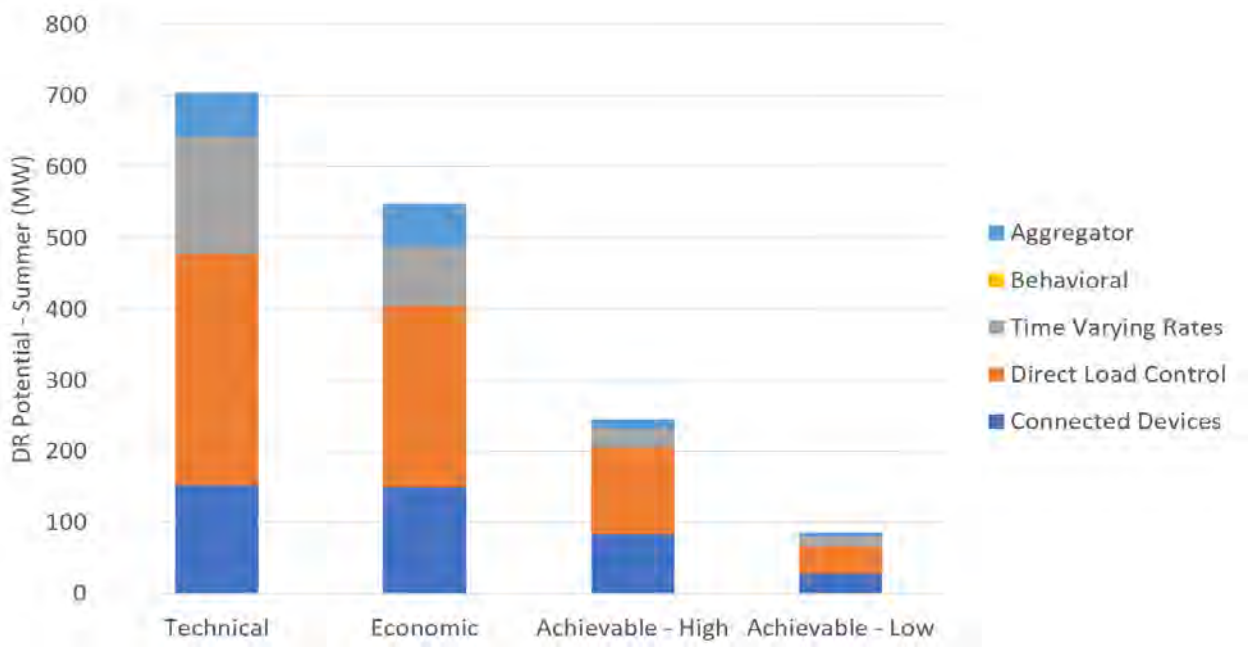
The study considered five different types of DR programs:

1. Aggregator – Capacity bidding programs managed by 3rd party aggregators
2. Behavioral – Personalized communication to customers requesting curtailed usage during peak events
3. Time varying rates – Customer retail electricity rates designed to shift usage by charging more during peak periods
4. Direct load control – Centralized remote control of customer equipment through installation of switches
5. Connected devices – Interaction with and control of internet-connected customer devices through web-based portals (e.g. Bring Your Own Thermostat programs)

Figure ES-2 shows the available DR potential across the portfolio by 2040 by program type. Connected device programs (primarily for Smart Thermostats) and Direct Load Control (DLC) (primarily for irrigation pumping) are the most significant program types.

[1] Includes administrative and incentive costs

Figure ES-2. Portfolio Demand Response Potential by Program Type (2040)



The DR analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. Because Tri-State does not control customer rates, implementing a CPP or TOU rate demand response programs would require a high level of collaboration with electric cooperatives.

Table ES-3 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cumulative total cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity until 2027.

Table ES-3. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

Distributed Energy Resource (DER)

The Team limited resources for the DER potential study to technologies that are behind-the-meter and owned by the customer; we did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040. We performed review and preliminary cost screens for other potential DER technologies such as combined heat and power and small wind but ultimately did not find these technologies applicable and/or cost effective.

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure ES-3 and Figure ES-4 below illustrate cumulative technically possible PV generation in 2040 compared to cumulative 2040 sales. It is interesting to note that in some areas of New Mexico solar power has the technical potential to produce more energy than is used. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency and relatively low consumption on average.

Figure ES-3. 2040 Technical Potential for Cumulative Residential PV Generation vs Sales by Region

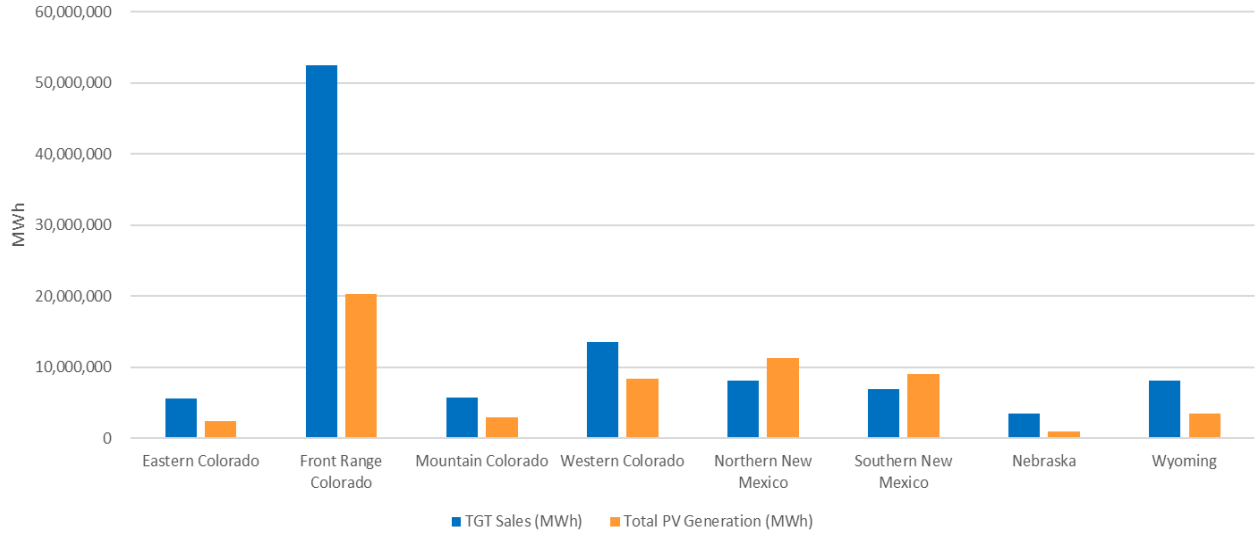
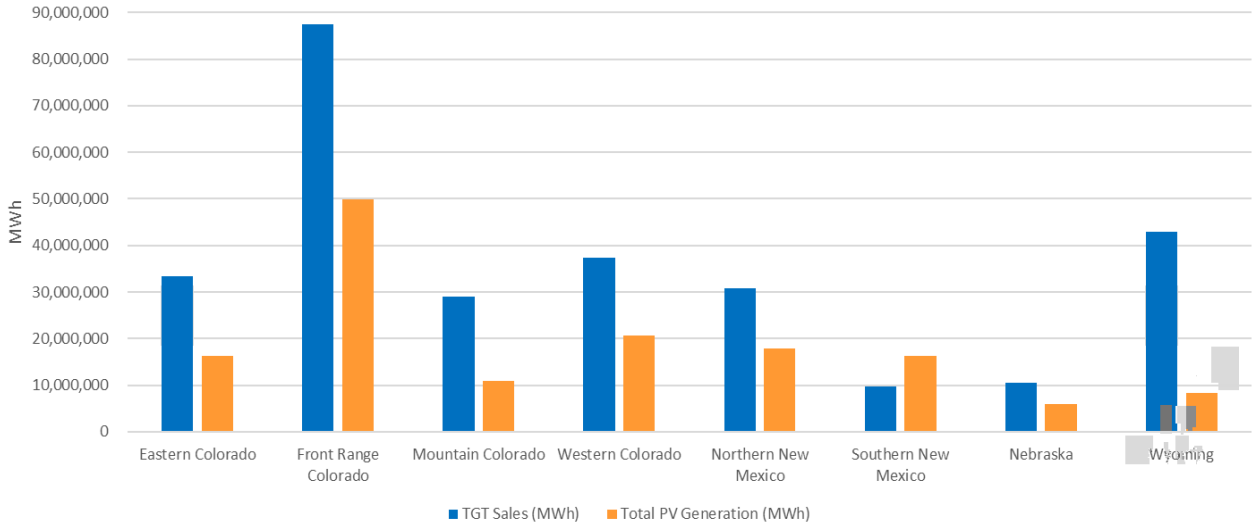
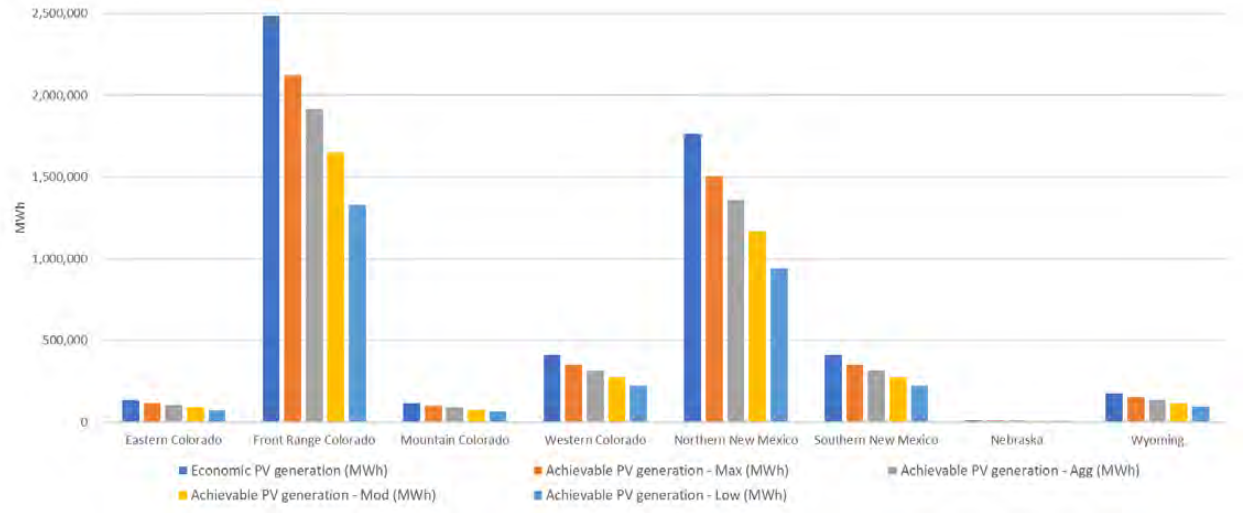


Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region



The results of the economic and achievable potential analysis are presented below in Figure ES-5. Only non-residential measures passed cost effectiveness, and those cost effective measures comprised just 9% of analyzed measure permutations. Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while this potential generation reflect the entire Tri-State territory, the cost effective scenario used in this analysis includes CO_2 emission benefits which are not applicable to regions outside of Colorado, as emissions are not a quantifiable benefit at the time of this report publication.

Figure ES-5. 2040 Cumulative Non-Residential Economic and Achievable Potential PV Energy Generation by Region



Results Summary

In summary, Tri-State and its member co-ops could save the following energy and dollars with the corresponding investment, on a levelized basis over the 20-year study period:

Table ES-7. DSM Investment Outlook through 2040 (Achievable-Moderate Scenario)

RESOURCE TYPE	RESULTS
EE	Average annual savings of 114,520 MWH/year and 14 MW at a levelized cost of $15.25/MWH (TRC = 1.64)
DR	86 MW of demand response potential by 2040 at a cumulative cost of $39M (TRC = 1.16)
DER	3,661,295 MWH and 50 MW potential by 2040 at a cumulative administrative cost of $183M (TRC = 1.04)

Market Characterization & Baseline Forecast Results

In order to develop the results presented above, the Team developed a detailed characterization of Tri-Stat's customer base. This section summarizes the market and baseline forecast characterization including Tri-State's energy usage by sector and end use (additional details about customer segment and end use breakdowns within each sector are provided in Section 3). Tri-State's forecasted 2021 electricity sales to member cooperatives is just over 15 TWh, estimated to grow to just over 20 TWh by 2040 (Figure ES-6). In the base year of the analysis industrial is the largest market sector at 44% of load, followed by the residential sector at 30% of load, commercial at 18% and finally irrigation at 8%. These sector load shares remain fairly steady during the study horizon. The distribution of energy load by customer sector varies among the eight regions modeled in this study – for example, Eastern Colorado has a large irrigation sector load share while Mountain Colorado has almost no irrigation energy load (Figure ES-7). Front Range Colorado is the largest region at 5 TWh of energy load; it also has the largest Residential load share.

Figure ES-6. Baseline Load Forecast by Sector by Milestone Year

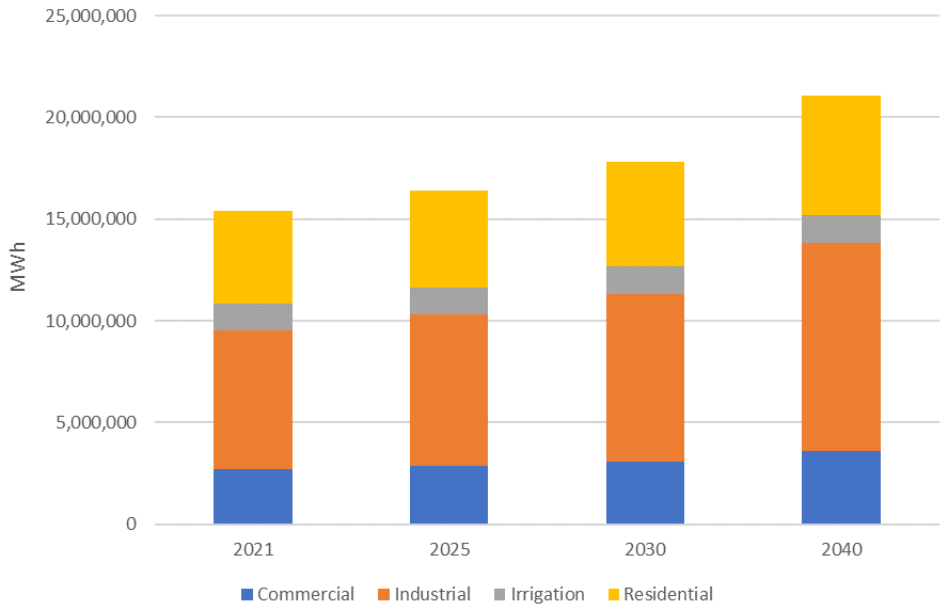
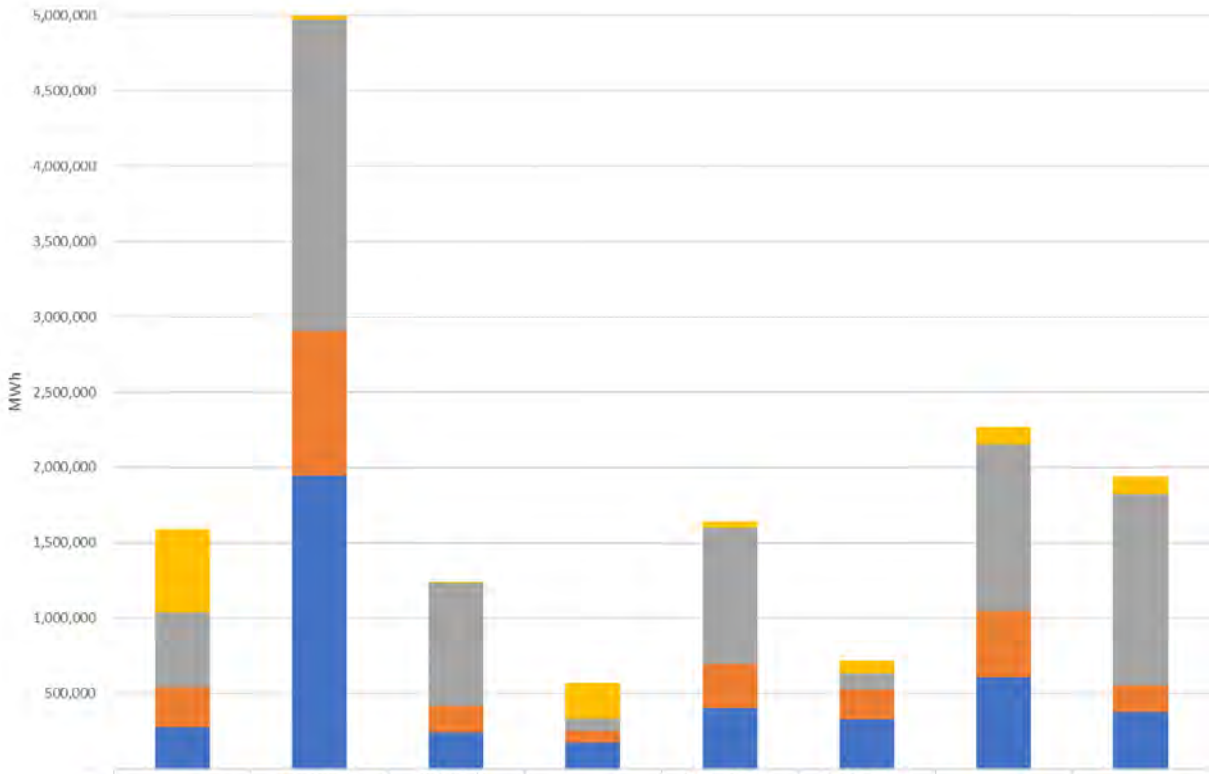


Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

Segmentation and forecast: For the market segmentation analysis, the Team collected relevant customer and forecast datasets from Tri-State to disaggregate customer energy load by region, sector, building/business type (i.e. segment), and end use for each year in the study's 20-year time horizon. This task identifies the available energy load within the various market and end use sectors available for conversion to higher efficiency or demand reduction technologies.

Measure impacts: With the market segemented and forecast disaggregated across the study horizon, the Team then characterized the universe of efficiency, demand response, and DER measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Each measure was assigned to the relevant resource, region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened for cost effectiveness according the Total Resource Cost (TRC) test with a passing threshold of 0.7 for EE measures (thus allowing some less cost-effective measures to be assessed so long as the portfolio remained above a TRC of 1.0) and a passing threshold of 1.0 for DR and DER resources.

Modeling and data analysis: The Mesa Point Team used industry-standard modeling approaches to estimate the technical, economic, and achievable potential and associated costs for EE, DR and DER resources. Specifically, a discrete model was developed for each resource and potential estimates were developed independent of one-another – for example, each resource used the same baseline disaggregated load forecast and energy efficiency improvements did not reduce the opportunity for demand response potential. The energy savings and associated costs of each resource was forecasted for a 20-year time horizon (2021 – 2040). Two to four achievable potential scenarios were developed for each resource so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from each resource model were developed at high levels of resolution, showing annual energy savings, lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon.

1. INTRODUCTION

1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a demand side management study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical, economic, and achievable energy savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State). Measures considered are limited to technologies that are behind-the-meter and owned by the end-user.

The potential study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). Tri-State will use the results of this market potential study to analyze and incorporate potential EE, DR and DER impacts at various levels of program investment over the planning horizon from 2021 to 2040.

The study focuses on energy efficiency, DR, and DER *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-specific recommendations; rather, the report focuses on identifying market opportunities and costs for EE, DR, and DER.

1.2. Achievable v. Planned Savings

This potential study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

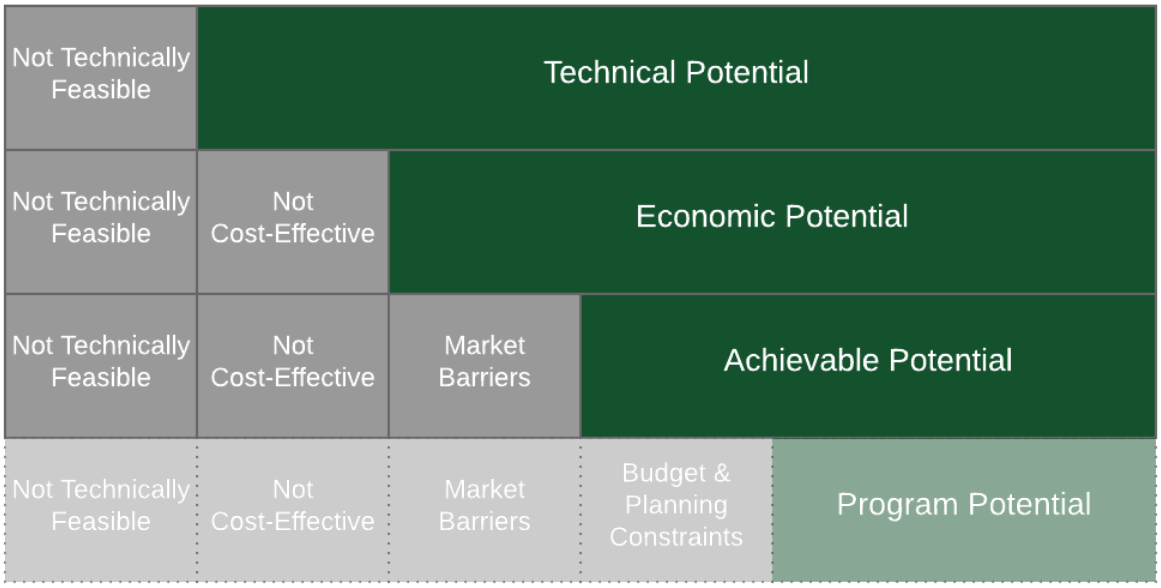
1.3. Study Approach Overview

In accordance with standard industry practice for DSM potential studies, this study considers measures from the perspective of theoretical maximum savings, and then accounts for barriers to estimate actual achievable savings.

Specifically, the study begins with *technical potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *economic potential* is assessed by estimating costs to implement measures, and then applying economic criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting DSM measure implementation. Not considered in the report are factors affecting *program potential*.

This analysis approach is based on standard perspectives of DSM resource potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE)[2] as illustrated in Figure 1.

Figure 1: Conceptual Overview of DSM Resource Potential Defintions



- **Technical Potential** is the theoretical maximum amount of energy and capacity that could be displaced by an efficient technology, regardless of cost and other barriers that may prevent the installation or adoption of a measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** is the amount of energy and capacity that could be reduced by measures that pass a cost-effectiveness test. This analysis used the Total Resource Cost (TRC) Test, which estimates the measure costs to both the utility and customer.
- **Achievable Potential** is the energy savings that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy savings the utility can realize through DSM programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to

[2] The EPA National Action Plan for Energy Efficiency: http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf

customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

1.4. Cost Effectiveness

At the core of DSM potential is the concept of cost-effectiveness. To assess cost effectiveness, the total cost of implementing measures is compared to the cost of business as usual with energy being provided to the baseline energy using equipment and behaviors. A DSM measure is considered cost effective if it is less costly than simply providing energy to baseline systems.

The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of technologies, bundles, programs, or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. "Low," Moderate ("Mod"), Aggressive ("Agg"), and Maximum ("Max") scenarios vary based on the assumptions for level of incentive, staffing, and marketing investment.

1.5. Presentation of Savings

This report represents savings in several different ways. For the most part, savings across years is presented as cumulative, but there are cases in which the savings may be presented in one of the other ways defined below. Following are the various methods for presenting savings:

- **Annual Incremental**: Energy savings acquired in the year in which measures are installed
- **Cumulative**: Total energy savings acquired over a given time horizon, accounting for measure decay (i.e. retired energy savings after an installed measure reaches the end of its useful life)
- **Sum of Annual Incremental**: Total energy savings acquired over a given time horizon, not accounting for measure decay

1.6. Organization of the Report and Related Deliverables

This report presents a summary of the analysis approach, key assumptions and study findings. Two separate electronic reporting tools serve as an appendices to the report. The tools provide the ability to view findings by sector, end-use, and region from both annual and hourly perspectives. The intent is for Tri-State and stakeholders to make use of both work products depending on the desired level of detail. Figure 2 summarizes the structure for the remainder of this report.

Figure 2. Summary of Report Structure

Section 2

- Describes the study approach and methods.

Section 3

- Discusses the team's efforts to disaggregate and analyze Tri-State's baseline forecast. That work serves as the foundation for the analysis and findings presented in the remainder of the report.

Sections 4-8

- Present sector-level findings for energy efficiency potential.

Section 9

- Presents findings for the demand response potential analysis.

Section 10

- Presents findings from the distributed energy resource (DER) potential analysis.

Section 11

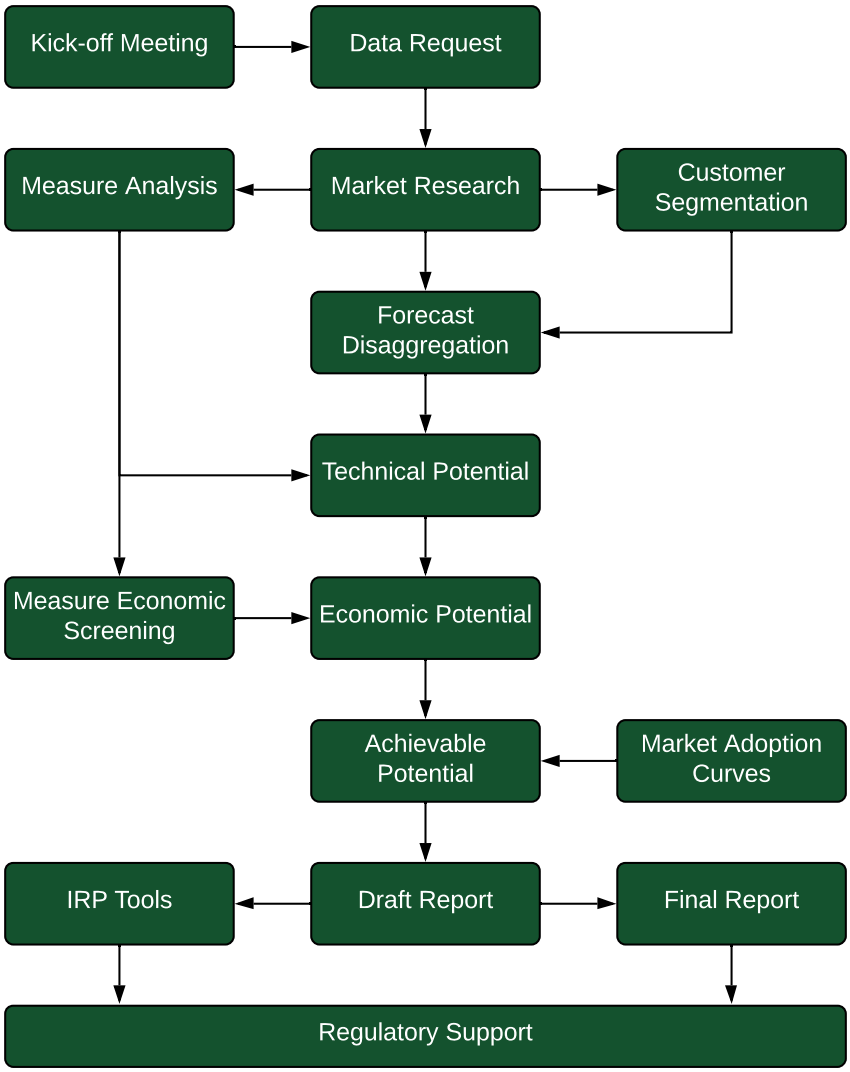
- Presents overall findings and recommendations.

2. STUDY APPROACH AND METHODS

2.1. Overview

The process shown in Figure 3 depicts the steps taken during a market potential study.

Figure 3. Approach for Demand Side Resource Potential Modeling



These steps generally apply to all three demand-side management (DSM) resources considered: energy efficiency, DR, and DER. Each step is described in detail in the sections that follow. Sections 2.2–2.4 generally apply across all three resources. Sections 2.5 and 2.6 provide additional detail for the approach and methods used for the DR and DER analyses.

2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable savings potential requires a thorough characterization of the baseline energy usage. This characterization involves the following steps:

- Determine the energy consumption per region, customer class and segment in baseline year.
- Disaggregate customer class loads into end-use loads, such as water heating.
- Analyze and calibrate data to 2018.
- Forecast the 20-year end-use energy consumption through 2040.

To complete these steps the Team relied on a large dataset consisting of:

- Information on Tri-State member cooperative customers
- Historical loads
- Market data including fuel shares, equipment saturations, and structural characteristics
- End-uses including energy use intensities and load shapes
- Measure characteristics including technologies, costs, life, and savings

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in this process follows. The findings of the market characterization is presented in Section 3.

2.2.1.Customer Segmentation

To begin, the Team analyzed the portion of Tri-State's forecasted sales attributable to DSM-ineligible accounts. This included the share of the load that is served by re-sale customer or non-premise accounts. This portion of the load was removed from the load considered eligible for energy efficiency and demand reduction measures.

Next the Team determined energy and demand loads for the appropriate regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1.
- **Customer Sectors**: Residential, commercial, irrigation, and industrial (including agricultural)
- **Market Segments:**
  - **Commercial**: Typically based on major Commercial Buildings Energy Consumption Study (CBECS) business types.
  - **Industrial**: All major industrial segments in Tri-State service territory using NAICS classification from the Form 345 information.
  - **Residential and Irrigation**: No further segment-level breakdown

- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

2.2.1.1. Primary Market Research

Primary market research guided customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. The survey yielded over 300 customer responses, with each cooperative providing a minimum confidence level of 90% with 10% precision for each surveyed technology at the cooperative level. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation. Examples of these resources include the 2010 Tri-State System-Wide Electric Energy Efficiency Potential Study , United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS)[3], the EIA Commercial Buildings Energy Consumption Survey (CBECS)[4], 2016 NorthWestern Energy End-Use and Load Profile study[5], the 2015 Platte River Power DSM Potential Study, among other references.

2.2.2.Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and energy efficiency potential by region. Eight (8) regions were defined based on geographic location of the co-ops[6]. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Energy efficiency measures more accurately match building codes in each region. For example, envelope construction requirements are different depending on climate zone.

[3] *https://www.eia.gov/consumption/residential/*

[4] https://www.eia.gov/consumption/commercial/

[5] https://www.northwesternenthinkergy.com/docs/default-source/documents/etac/2017/nexant_energy_end_use_and_load_profile_study.pdf

[6] This report and the associated Reporting Tool, described in this report, utilize the regional breakdown characterized here. The Load Shape Tool, also described in this report, utilizes an adapted breakdown to accommodate for member coops that cross certain regional boundaries. This alternative breakdown of potential savings is to allow for more accurate output data for input into Tri-State's resource planning models. The adjustment reflects where coop service territory extends across eastern and western interconnects.

- Regional segmentation captures a higher resolution of equipment end-use saturation and energy intensity. For instance, direct expansion (DX) cooling in the residential sector has a higher saturation and energy intensity in southern New Mexico as compared to northern Wyoming.
- This segmenation accommodates regional cost variances for participant energy efficiency implementation or utility avoided costs.
- Barriers to achievable potential may be regionally specific.

Based on evaluation of climatic impacts, sector segmentation and end-uses, the Team developed the regional electric cooperative groups shown in Table 1.

Table 1: Tri-State Cooperative Regional Groups

EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO
Highline	Mountain View	Gunn County	Empire
K.C.	Poudre Valley	Mountain Parks	La Plata
Morgan County	San Isabel	White River	San Luis Valley
Southeast	United		San Miguel
Y-W			Sangre De Cristo
NEBRASKA	**SOUTHERN NEW MEXICO**	**NORTHERN NEW MEXICO**	**WYOMING**
Chimney Rock	Central NM	Cont. Divide	Big Horn
Midwest	Columbus	Jemez Mtns	Carbon
Northwest	Otero County	Mor San Miguel	Garland
Panhandle	Sierra	North. Rio Arriba	High Plains
Roosevelt	Socorro	Southwestern	High West
Wheat Belt		Springer	Niobrara
			Wheatland
			Wyrulec

2.3. End-Use Load Classification

To further disaggregate the load the Team established end-use loads within each sector.[7] Table 2 presents a summary of those end-uses.

[7] The irrigation sector is solely composed of the motor end-use.

Table 2: End-Uses for Each Tri-State Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Central Air Conditioning	Cooking	Lighting
Central Heating	Cooling	HVAC
Clothes Washer	Heat Pump	Motors
Dishwasher	HVAC Aux	Pumps
Electric Cooking	Lighting	Process Heat
Electric Dryer	Plug Load	Process Cool
Freezer	Refrigeration	Pumps
Exterior Plug Load	Space Heating	
HVAC Aux	Water Heating	
Heat Pump		
Lighting		
Plug Load		
Refrigerator		
Second Refrigerator		
Room AC		
Electric Water Heater		

The primary regional inputs needed to model each end-use were the total premise count, fuel shares, end-use Unit Energy Consumption (UEC), and saturation. Expected improvements in building energy code requirements and other general trends were incorporated into the UECs based on data found in the U.S. Energy Information Administration's forecasts. In general these trends showed a decrease in all end-use UECs with the exception of plug loads, which showed an increasing trend.

2.3.1.Codes and Standards

There is uncertainty about future federal standard updates and enforcement. While the study considers current codes and standards, the analysis is not intended to predict how or when energy codes and standards will change over time. As a result, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment made in the Team's methodology impacts residential screw-in lighting. Based on the current Department of Energy final rule that did not trigger the Energy Independence and Security Act (EISA) backstop, the potential analysis does not model Tier II EISA efficiency requirements. However, the study does model the transitioning screw-based lighting market that is rapidly being

saturated with LED technology. The Team modeled this market transition by limiting the future potential for residential lighting starting in 2027. The analysis assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the latter analysis period.

Although not exhaustive, the following list outlines additional key standards the Team considered:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 15 SEER/8.8 HSPF.
- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023.
- In July 2019, the DOE makes new standards effective for more efficient furnace fan/motors. The standards are expected to improve the efficiency by approximately 45% over the current baselines. The new standard will create a shift to electronically commutated motors (ECMs).

2.4. Energy Efficiency Potential Modeling

Drawing on outcomes from of the disaggregated the Team modeled first technical, then economic, and finally achievable energy savings potential. Those steps are described in the following sections.

2.4.1. Estimate Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility of measures. The model applies the measure-level inputs to the disaggregated baseline sales forecast to estimate technical savings and demand reduction potential over the planning horizon.

As an example, the core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 1.

Equation 1. Core Equation for Residential Sector Technical Potential

Where:

Total Number of Households *= Count of customer households in the subject region.*

Base Case Equipment Energy Use Intensity *= the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case*

equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = *the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.*

Remaining Factor = *the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.*

Applicability Factor = *the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to space constraints.*

Savings Factor = *the percentage reduction in electricity consumption resulting from the application of the efficient technology*.

2.4.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical market potential is to accurately detail the universe of efficiency measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Additionally, our Team compiled all measures available from such sources as the Pacific NorthWest Regional Technical Forum (RTF), Xcel Energy's Demand Side Management Plan, and technical reference manuals (TRMs) from jurisdictions like the states of New Mexico, Pennsylvania, and Minnesota. The Team also leveraged measure data it has characterized in similar studies. From these regionally relevant databases, the Team selected measures that are commonly available, based on well-understood technology, and applicable to the buildings and end-uses in Tri-State's service territory. The Team also considered measures that show promise for future viability but have not yet gained a foothold in the market.

Energy efficiency measures are characterized in three main vintages:

- **Replace on Burnout:** As equipment replacements are made normally in the market when a piece of equipment is at the end of its effective useful life (also referred to as "turnover").
- **Retrofit:** At any time in the life of the equipment or building (referred to as "early-retirement").
- **New:** When a new home or building is constructed.

Upon finalizing the energy efficiency measure list, the Team collected data on energy savings, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

Step 1: Define market classifications for application of measures

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes savings estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Measure Type:** Equipment vs. Non-equipment
- **Vintage:**
  - **Equipment** – Turnover, Retrofit, New
  - **Non**-equipment – Existing, New

Step 2: Screen sectors, segments, and end-uses for eligibility

The Team screened market segments and end-uses for applicability of specific energy efficiency measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as offices and warehouses and therefore were analyzed only in limited market segments.

Step 3: Develop base case impacts and costs

The Team determined base case equipment and practices for each of the energy efficiency measures on the final list, and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. Base case assumptions included projected future adjustments, such as upcoming federal standards.

Step 4: Develop energy efficiency measure impacts and costs

The Team developed a description of all energy efficiency (or "change case") measure equipment and practices, including all measure energy savings assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated energy savings as a percentage of base equipment and/or end-use consumption.

In addition to energy savings, the Team collected incremental measure costs pertinent to Tri-State's service territory from appropriate TRM references and internet retailer data and researched measure life drawing on TRM documentation.

2.4.1.2. Screw-in Lighting

The Team reviewed the residential, commercial, and industrial lighting measures and lighting end-use assumptions to incorporate recent changes to the lighting market. This included reviewing and updating savings, measure cost, saturation, and expected useful life assumptions for each lighting measure. Based on federal policy projections, the Team made the assumption that the EISA "backstop" would not be enacted beginning in 2020. Additionally, the Team characterized the lighting market to transform primarily to an LED baseline for screw-in lighting by the end of the decade.

2.4.2. Estimate Economic Potential

Economic potential represents the savings possible given full adoption of all cost-effective efficiency measures. For this study, the Team utilized the Total Resource Cost (TRC), which is commonly considered the preferred test to assess measure benefits and costs from the perspective of the utility and society as a whole. Equation 2 presents the TRC ratio equation.

The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.

Equation 2. TRC Ratio

$$\textbf{TRC Ratio} = \textbf{NPV}(\textbf{Avoided Costs})/\textbf{NPV}(\textbf{Incremental Measure Costs})$$

Where*:*

$$\text{Avoided Cost} = \text{NPV}\left(\sum_{\text{year}=1}^{\text{measure life}}\left(\sum_{\text{i}=0}^{\text{i}=8760}(\text{impact}_{\text{i}} \times \text{avoided cost}_{\text{i}})\right)\right)$$

The **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Tri-State and represent their most recent forecast of avoided electric benefits. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure savings impacts and determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak definition (noon – 22nd hour in weekday summer months) was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy savings for Tri-State, the expected losses were estimated from the customers' meters to Tri-State's generation source. These losses were calculated for each climate zone, and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. In addition to line losses, a discount rate of 5% was applied to value future avoided costs.

The **costs** are the net present value of all costs to implement those measures. These costs include full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. While non-incentive costs were not included in the measure-level screening of electric energy efficiency potential, they were included in further assessments of potential at the achievable potential level described below.

Additionally the social cost of carbon at $46/ton of carbon dioxide (CO_2) was incorporated as an avoided benefit in the TRC calculations. This value was escalated annually over the study time horizon based on figures provided by Tri-State.

The measure screen from technical potential to economic potential utilized a cost-effectiveness hurdle of 0.7 in order that the sector level TRC test would be closer to 1.0. This reduction in the screening threshold permits non cost-effective measures into the portfolio so that a potential program

intervention is more well-rounded and can include a limited number of non-cost-effective measures. However, the forecasted sector portfolio must have an estimated TRC greater than 1.0 when program administrative costs are included.

2.4.3.Estimate Achievable Potential

Finally, the assessment of realistically achievable energy efficiency potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of savings expected to be achievable through DSM programs will be informed by the experience of utilities across the region and nation.
- **Customers' willingness to participate.** The likelihood that customers will participate in energy efficiency programs is a function of several factors, most notably incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of DSM programs. We prefer to think of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected savings, as well as the most likely value.

Achievable potential energy efficiency impacts were evaluated based on four incentive scenarios as a function of the incremental costs of efficiency measures:

- 25% "Low"
- 50% Moderate ("Mod")
- 75% Aggressive ("Agg")
- 100% Maximum ("Max")

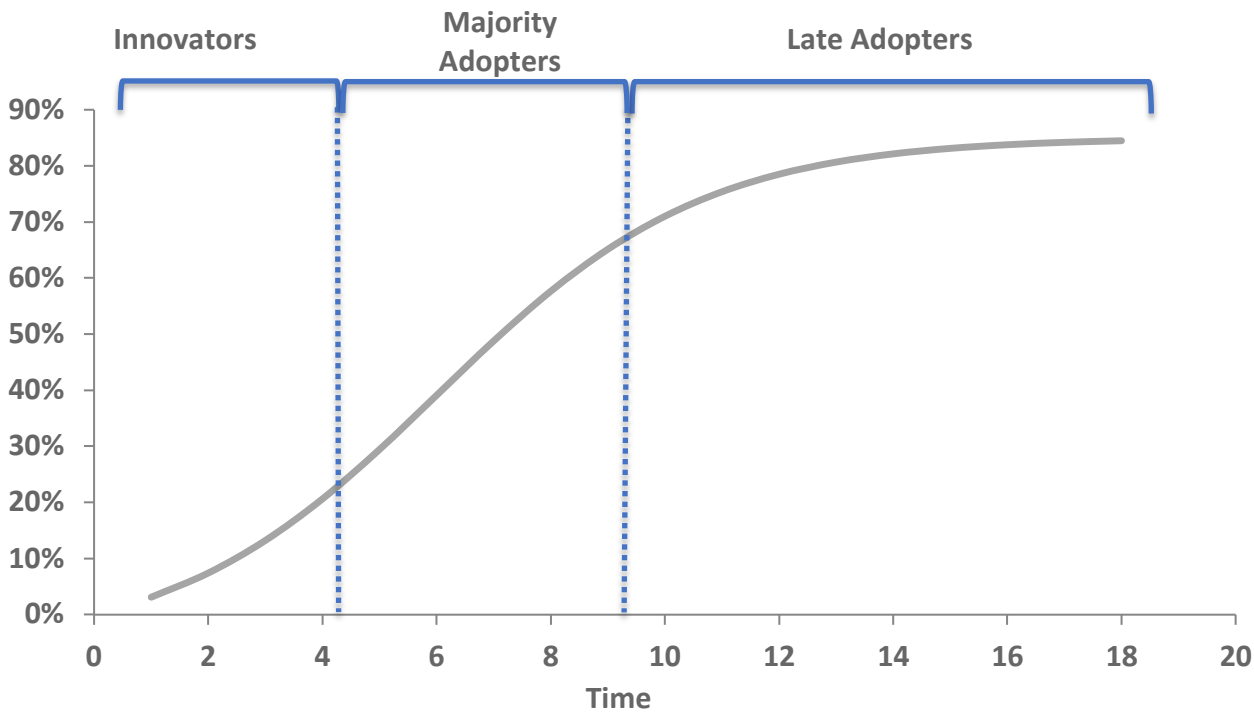
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from Tri-State's current program offerings.

2.4.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, the Team developed a quantitative approach based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State experience and other DSM programs in North America.

The Bass Diffusion Model is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

Figure 4: Typical Product Diffusion in the Marketplace



The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

- Initial Year Measure Adoption
  - First year adoption levels were informed by recent Tri-State historical performance where possible.
- Long-Term Market Adoption Rates
  - The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.
- Adoption Curve Shape
  - Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use**: Lighting, Motors, etc.
- **Incentive Level based on Achievable Scenario**: 25%, 50%, etc.

2.4.3.2. Program Costs

Finally, to capture the full cost of achievable energy efficiency potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 3.

Table 3: Summary of Non-Incentive Program Costs ($/kWh)

SECTOR	ACHIEVABLE LOW	ACHIEVABLE MOD	ACHIEVABLE AGG
Residential	$0.100	$0.115	$0.150
Commercial	$0.050	$0.058	$0.075
Industrial	$0.100	$0.115	$0.150
Irrigation	$0.050	$0.058	$0.075

2.4.4. Data Analysis and Reporting Tool

A set of dynamic analysis tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. These consist of a Reporting Tool and a Load Shape Tool specifically created for this project. The Reporting Tool summarizes and illustrates the savings potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region.

The Load Shape Tool was developed to convert the model's annual energy savings and cost outputs into 8760 hourly load profiles for direct input into Tri-State's ERP planning tool. The tool bundles and maps measures to associated 8760 hourly load profiles to illustrate at what hours during the day and year energy savings are likely to be incurred for each bundle of measures. The tool also shows the associated levelized cost of each bundle of measures on an 8760-hourly basis. The data is represented by sector, interconnect region, scenario, and load shape bundle. This tool will allow Tri-State to compare energy efficiency resource savings and levelized costs and compare them with other supply-side and demand-side resources during its ERP development process.

2.5. Demand Response Potential Assessment

Demand response refers to the reduction of electric demand by way of altering the operation of some piece of technology or equipment. Demand response programs take several forms, but most rely on

direct control of energy-using equipment via communication infrastructure like radio or WiFi or the change in customer behavior from time-based rates.

There are a few important differences between the assessment of demand response programs and other demand-side management options, such as energy efficiency. First, demand response programs require active, ongoing participation by customers. Second, unlike energy efficiency programs, demand response is designed to shift load from peak periods of energy use to non-peak periods, which can affect the availability of service to the customer. These programs use independent concepts and technologies and not 'upgrades' in the sense that energy efficiency measures are upgrades from some similar baseline option. These programs use independent concepts or technologies and are not 'upgrades' in the sense that energy efficiency measures are upgrades from similar baseline options. Thus, demand response technologies have no incremental cost. Finally, demand response depends on a customer's willingness to participate in individual events. This willingness to participate is a function of program design, which includes the number of events, incentive levels, the stipulation of mandatory or voluntary participation, and the existence of penalties for non-compliance. Hence, estimating demand response potential involves in a number of steps. The final potential number is a product of the base peak demand, eligibility rates, technical load impact rates, program participation rates, and event participation rates.

2.5.1.Estimate Peak Demand

Coincident peak demand data was available for each of the eight regions in the Tri-State system. This system-level peak demand was divided to estimate the contributions from each sector (residential, irrigation, commercial, and industrial) by using sector energy use during the peak month relative to the system energy use during the same time period. Per premise demand estimates were generated by dividing by the number of premises in each sector.

2.5.2.Apply Eligibility Rates

Eligibility rates customized to each program were applied to the base peak demand to determine the peak load eligible to participate. For example, a Direct Load Control (DLC) program capturing residential central HVAC load will require premises to have central air conditioners, while a Smart Thermostat DR program would additionally require the residence to have broadband service and a WIFI network. Irrigation load reduction is generally limited to customers with pumping power greater than 75 horsepower. Commercial and industrial customers in a capacity bidding program typically need to have a peak demand of greater than 250 kW.

2.5.3.Estimate Technical DR Potential

Technical potential for demand response is the theoretical maximum level of peak demand that could be curtailed through DR programs. This scenario disregards non-engineering constraints such as cost-effectiveness and willingness of end-users to enroll. All eligible customers are modelled as if enrolled in one or more DR programs and participating in DR events.

In the Technical Potential scenario, care must be taken to avoid double-counting participation in programs that affect the same end-uses. For example, a customer cannot be modelled as curtailing its HVAC load in both a DLC program and a rate program during the same event. We applied a hierarchy of

demand response programs for each sector based on Tri-State's unique market position, as shown in Table 4.

Table 4. Demand Response Programs Applied by Sector

RESIDENTIAL	AGRICULTURAL	COMMERCIAL	INDUSTRIAL
Smart Devices	Direct Load Control	Capacity Bidding	Capacity Bidding
Behavioral	Time Varying Rates	Smart Devices	Time Varying Rates
Direct Load Control		Direct Load Control	
Time Varying Rates		Time Varying Rates	

2.5.4. Estimate Economic DR Potential

Economic potential is a subset of technical potential that is economically cost-effective. A full cost-benefit analysis was conducted for each DR program incorporating Tri-state's avoided energy and capacity costs, program start-up costs, on-going administrative costs, equipment costs for the program and the participant, and discount rates.

Resource acquisition costs fall into one of two categories. Fixed costs include program start-up, infrastructure, maintenance, administration, and data acquisition. Variable costs include hardware costs, which vary by the number of customers, and incentive costs, which can vary by number of customers or kW reduced.

Fixed and variable costs were estimated for each program type according to comparable programs implemented by other utilities or other potential studies. In cases where published cost information could not be found, the Team used assumptions based on other comparable program data points. The Team also incorporated a multiplier of 8 into start-up costs and administration costs, to represent the complexity of managing a program with multiple co-op partners. This analysis assumes a cost of $640,000 or more to start a demand response program. Lower costs were incorporated for time-vary rates programs - $100,000 for start-up and $23,000 per year for administration. Lower costs were also assumed for some commercial programs where commercial participation could be assumed as an addition to an existing residential program. All programs were assumed to require an annual evaluation at a cost of $50,000. Average hardware, communication, and incentive levels were estimated based on published values from other utilities or studies.

Program cost assumptions are summarized in Table 5.

Table 5. Demand Response Program Cost Assumptions

SECTOR	PROGRAM	START-UP	ADMIN	EVAL	MARKETING	EQUIP
Residential	Smart Tstat	$640k	$538k/yr	$50k/yr	$50/signup	$0
	Smart Water Heater	$665k	$543k/yr	$50k/yr	$50/signup	$175
	DLC Central AC	$665k	$543k/yr	$50k/yr	$50/signup	$225
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	DLC Pool Pump	$665k	$543k/yr	$50k/yr	$20/signup	$200
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Behavioral	$640k	$7/meter	$50k/yr	$0	$0
Irrig-ation	DLC	$665k	$862k/yr	$50k/yr	$63/premise	$500
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Commer-cial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	Smart Tstat	$128k	$107k/yr	$50k/yr	$50/signup	$0
	DLC Water Heater	$128k	$107k/yr	$50k/yr	$50/signup	$175
	DLC Room AC	$665k	$543k/yr	$50k/yr	$20/signup	$50
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200
Indust-rial	Capacity Bidding	$640k	$184k/yr	$50k/yr	$50/premise	$0
	CPP no tech	$100k	$23k/yr	$50k/yr	$25/signup	$200
	Time of Use	$100k	$23k/yr	$50k/yr	$25/signup	$200

2.5.5.Estimate Achievable DR Potential

The Team applied program participation rates to economic potential to incorporate each sector's willingness to participate in demand response programs. This participation rate is expressed as a percentage of eligible customers. As it takes some time for a utility to fully implement a demand response program, program participation rates are assumed to reach a mature participation rate after 10 years.

Combining economic potential with program and event participation rates yields "achievable potential," or the load that can reasonably be reduced during any one event for a certain program. The Team modeled two achievable potential scenarios for demand response to illustrate the impacts of varying incentive levels to drive program participation. Adoption for both scenarios were selected based on achieved participation rates from similar program types in other jurisdictions.

- 'High' scenario represents best-in-class participation for programs with non-mandantory (opt-in) enrollment
- 'Low' scenario represent more typical or 'average' participation rates from the body of similar programs.

Steady-state participation rates are summarized in Table 6 for each achievable scenario.

Table 6. Demand Response Program Achievable Scenario Participation Rates

SECTOR	PROGRAM	ACHIEVABLE HIGH	ACHIEVABLE LOW
Residential	Smart Tstat	59%	20%
	Smart Water Heater	59%	20%
Irrigation	DLC	48%	15%
	CPP no tech	18%	8%
Commercial	Capacity Bidding	20%	10%
	Smart Tstat	20%	8%
	CPP no tech	18%	8%
Industrial	Capacity Bidding	20%	10%
	CPP no tech	18%	8%

The results of the approach described in this section are presented in Section 9.

2.6. Behind-the-Meter Distributed Energy Resource Potential Assessment[8]

For the purposes of this report, distributed energy resources is defined as equipment installed at customer premises behind-the-meter that generates electricity. This study reviewed the potential for end users of Tri-State's electricity to install and operate these types of resources.

The DER potential study followed the same method as energy efficiency potential in that the DER assessment reviews the opportunity for technical, economic, and achievable potential. The analysis limited resources for this potential assessment study to technologies that are behind-the-meter and owned by the customer. The analysis did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040, because it was the most probable technology to be cost effective and applicable to Tri-State's territory. We performed review and preliminary cost screens for potential DER technologies such as combined heat and power and small wind but did not find these technologies to be applicable and/or cost-effective.

2.6.1. Estimate Technical DER Potential

The technical potential of a DER is the amount of energy that can be generated at a customer's site behind the meter.

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis estimated potential for ground mounted (or covered parking) systems for a few specific business types such as municipal

[8] Actual results for DER analysis are not included in this draft report pending gathering of additional information

facilities, parking enclosures, and some manufacturing facilities. The analysis also included battery storage as an additional configuration with each solar PV system type. This study did not explore the market potential associated utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within Tri-State's territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using Equation 3.

Equation 3: Solar PV Technical Potential Calculation

$$\boldsymbol{PV\ Technical\ Potential} = \boldsymbol{\Sigma}(\boldsymbol{Suitable\ Rooftop\ Square\ Footage} \times \boldsymbol{PV\ System\ Generation\ per\ Sq.Ft.})$$

The two key parameters in Equation 3 were estimated based on multiple data sources relevant to Tri-State's territory. A discussion of methods for defining these parameters follows.

The Team estimated total rooftop square footage using the forecast disaggregation analysis to characterize the existing and new residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise EUI by region. The Team used these parameters to estimate the total rooftop square footage for each Tri-State region.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the Team relied on research completed by the National Renewable Energy Laboratory (NREL). NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of LIDAR data. NREL criteria for suitable roof area include:

- **Contiguous rooftop area size:** Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

Based on NREL's data, the Team was able to apply unique suitability factors to estimate the total square footage of suitable rooftop for residential and non-residential buildings for each Tri-State region. The Team further adjusted the total suitable rooftop square footage by accounting for existing systems. Data on existing systems was captured from Google's Project Sunroof and applied to the NREL suitability factors.

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. Additionally, the Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours during low and/or non-generation time periods.

The Team relied on NREL's PVWatts[9] (Version 6) and System Advisor Model (SAM)[10] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's LIDAR-based NSRDB to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated for various cities within each Tri-State region. The Team based assumptions for PV system azimuth on rooftop orientation data sourced from Google's Project Sunroof. For the analysis the following assumptions are summarized in Table 7.

Table 7: Key Assumptions in Solar PV Analysis

PARAMETER	ASSUMPTIONS
Residential System Sizes (Nominal DC Capacity)	3 kW, 5 kW, 7.5 kW, 10 kW, 15 kW, 20 kW
Non-Residential System Sizes (Nominal DC Capacity)	10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW
System losses	14.1%
Tilt	By region
Azimuth:	By region
DC to AC size ratio	1.2
Inverter efficiency	96% (micro-inverter)
Battery Round-Trip Efficiency	85%
Technology Useful Life	20 years

Based on the simulations and resulting capacity factors for residential and non-residential buildings for each Tri-State region, we applied the capacity factor to the system size and multiplied by 8,760 to estimate annual electricity generation. These system generation values were used to calculate total energy generation per square foot of rooftop and extrapolated based on the total suitable rooftop square footage to estimate overall all technical potential.

2.6.2. Estimate Economic DER Potential

As discussed in Section 2, economic potential represents the savings possible given full adoption of all cost-effective efficiency measures according to the Total Resource Cost (TRC) test or other commonly used tests. For the cost effectiveness analysis on solar PV, the Team set a TRC hurdle of 1.0[11]. To estimate economic potential for solar PV, we gathered pertinent data on system costs along with calculated generation benefits to use in the benefit-cost analysis which we conducted at the system measure level. The Team screened solar PV measures with an assumed program administration cost of $0.05 per kWh generated.

9 PVWatts estimates solar PV energy production and costs. Developed by the National Renewable Energy Laboratory. (NREL) *http://pvwatts.nrel.gov/*

10 SAM estimates houlry solar PV energy production and costs with more detailed inputs and outputs than PVwatts. Developed by the National Renewable Energy Laboratory. (NREL) *http:// https://sam.nrel.gov/*

11 The TRC hurdle is higher than the hurdle used for the energy efficiency study as the solar PV systems have a much more homogenous benefit-cost profile relative to the portfolio of diverse energy efficiency measures that when combined elevated the overall TRC ratio for the portfolio.

The Team relied on multiple data sources to determine the solar PV system costs for the system sizes and configurations mentioned above. We assessed system component costs based on data included in the National Renewable Energy Laboratory's (NREL) Q1 2018 Benchmarking report[12] which provided detailed cost information on modules, inverters (by technology), structural and electrical balance of system, supply chain, permitting-inspection-interconnection, marketing, overhead, and profit. We adjusted cost parameters from a national level to Tri-State region-specific values by using various market data provided by Energy Sage[13] for residential cost estimates and the Lawrence Berkeley National Laboratory Tracking the Sun[14] data for non-residential cost estimates. This analysis produced an estimated installation cost per watt installed which we applied to various system sizes to estimate total installed cost. Additionally, the Team included O&M costs that scale with system size. Finally, we assumed the impact of the federal investment tax credit (ITC) to follow the existing schedule at the time of this report which equates to a 10% tax credit for commercial systems by 2022 and a 0% tax credit for residential systems by 2022.

In addition to modeling solar PV system costs, the Team estimated cost impacts for solar PV systems coupled with battery storage. Because these systems are far less prevalent in both residential and non-residential systems at the time of reporting, fewer published data on battery costs, balance of system costs, and maintenance were available. Moreover, the battery capacity is also variable based on the service need. Ultimately, multiple data sources were used to assume an overall capital cost per kWh based on a 3- or 4-hour battery for various measure permutations. O&M costs were largely defined by a ten-year amortized battery replacement cost.

Table 8: Average Solar PV Installation Cost

SECTOR	SYSTEM COST ($/ DC W)[1]
Residential	$3.22
Residential (Battery)	$4.88
Non-Residential (<250 kW)	$2.73
Non-Residential (<250 kW w/ Battery)	$3.52
Non-Residential (≥250 kW)	$1.50
Non-Residential (≥250 kW w/ Battery)	$1.87
Operations & Maintenance	$10-$15/kw/yr
Operations & Maintenance w/Battery	$24-$76/kw/yr

[1]Costs reflect impact of federal investment tax credit and are averages across regions. Analysis uses region-specific costs.

[12] Fu, R, et. al., U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. NREL, November 2018.

[13] Energysage Solar Marketplace Intel Report, H2 2018 – H1 2019.

[14] Barbose, G. and Darghouth, N., Tracking the Sun. Lawrence Berkeley National Laboratory. October 2019.

2.6.3. Estimate Achievable DER Potential

The approach to assessing achievable potential for solar PV follows the same logic and methods as outlined in Section 0. Similar to the energy efficiency analysis, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

- Maximum estimated number of buildings suitable for solar
- Adoption rates based on customer willingness to participate

The Team estimated the first parameter based on the count of buildings suitable for solar PV measures. For example, if a 7.5 kW solar PV measure passed cost effectiveness, the total count of applicable buildings is defined as residential buildings that do not consume more than the total annual generation of the PV system and have sufficient rooftop area to support a system of that size. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed residential and non-residential customers' willingness to install solar PV on their home or facility with varying incentive levels. Residential customers were asked their willingness to install based rebate values that covered a percent of the total system cost while non-residential customers were asked their willingness to install based on number of years of payback. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on state-specific research conducted by NREL[15].

3. MARKET CHARACTERIZATION & BASELINE FORECAST FINDINGS

3.1. Overview

As outlined in Section 2, the analysis of theoretically achievable savings potential requires an accurate characterization of the baseline energy usage and customer characterization. This section summarizes the market and end-use characterization including Tri-State's energy usage by sector, region, and end-use. Tri-State's 2018 electricity sales to member cooperative customers were found to be 14,974 GWh with distribution of sales by customer sector shown in Figure 5, sales by region in Figure 6, and finally with detail conjoined by customer sector and region included in Figure 7.

[15] Sigrin, B, et. al. The Distributed Generation Market Demand Model (dGen): Documentation. National Renewable Energy Laboratory. February 2016.

Figure 5. 2018 Energy Sales by Customer Sector

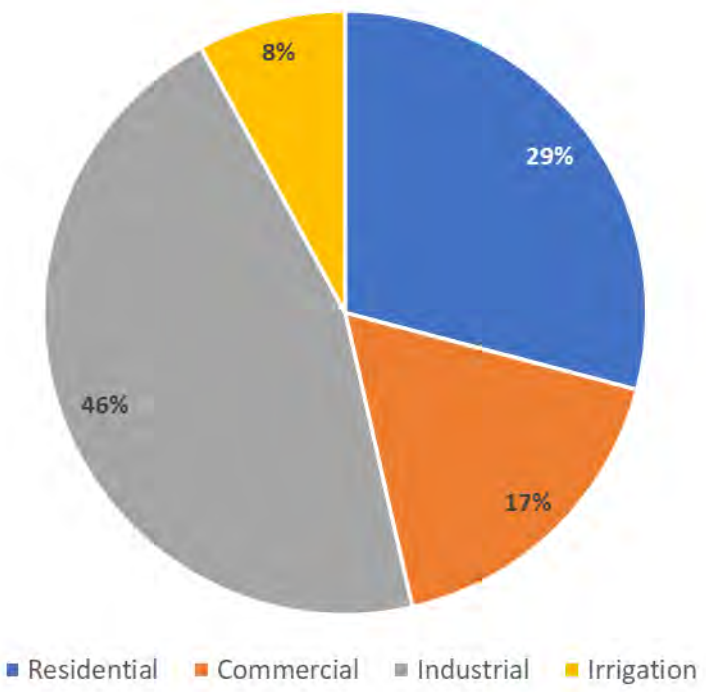


Figure 6. 2018 Energy Sales by Region

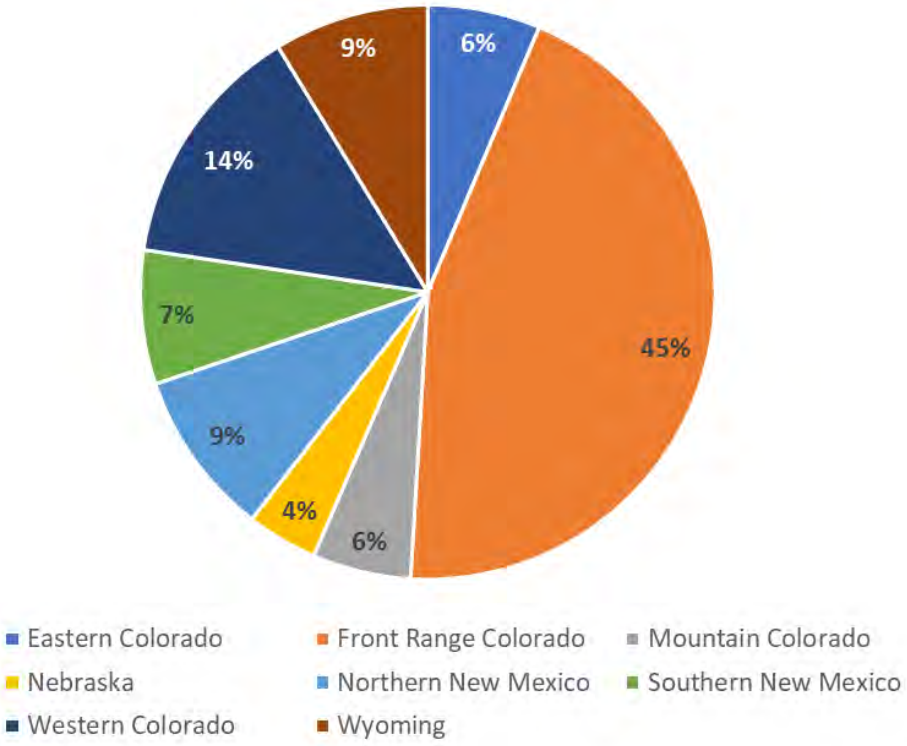
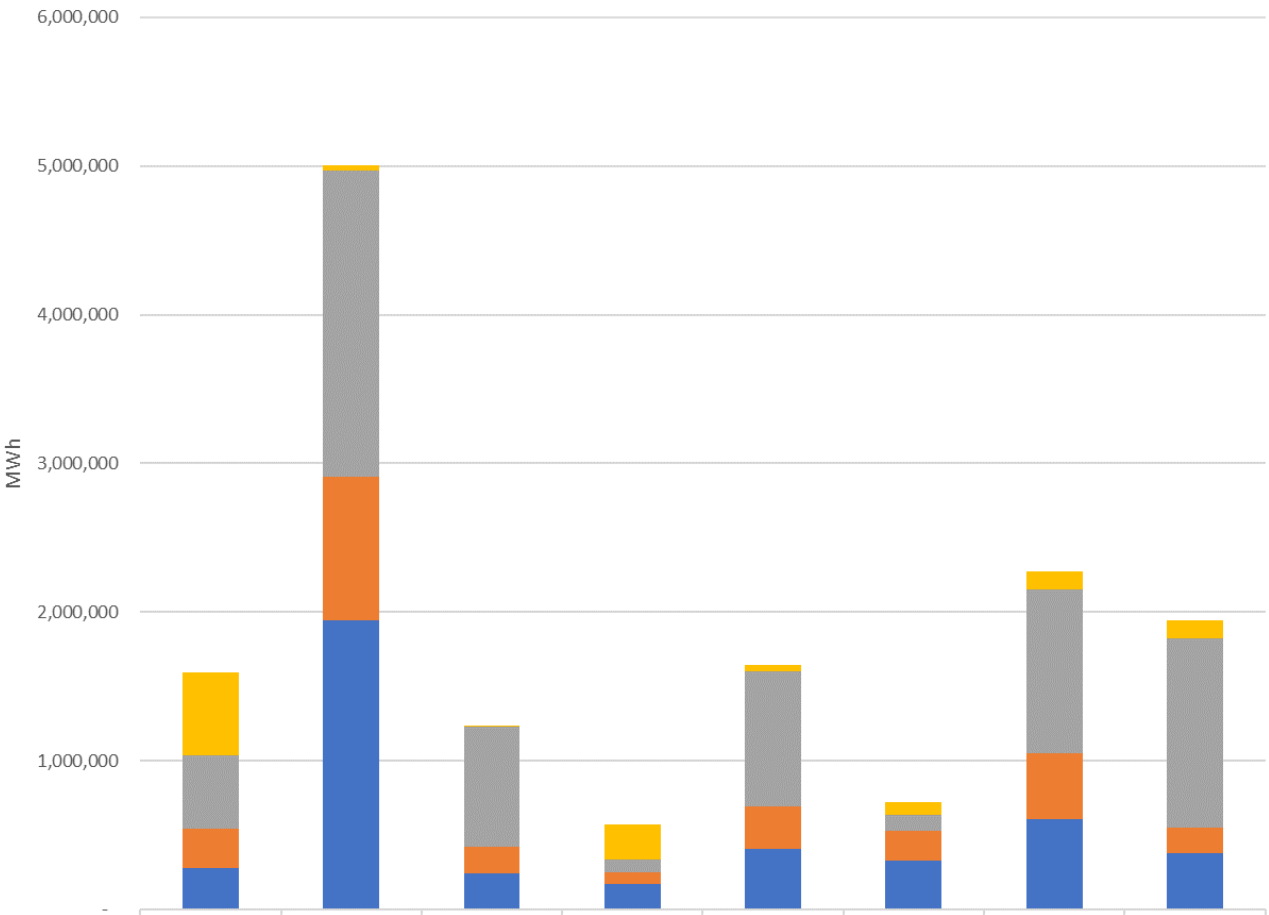


Figure 7. 2018 Energy Sales by Customer Sector and Region



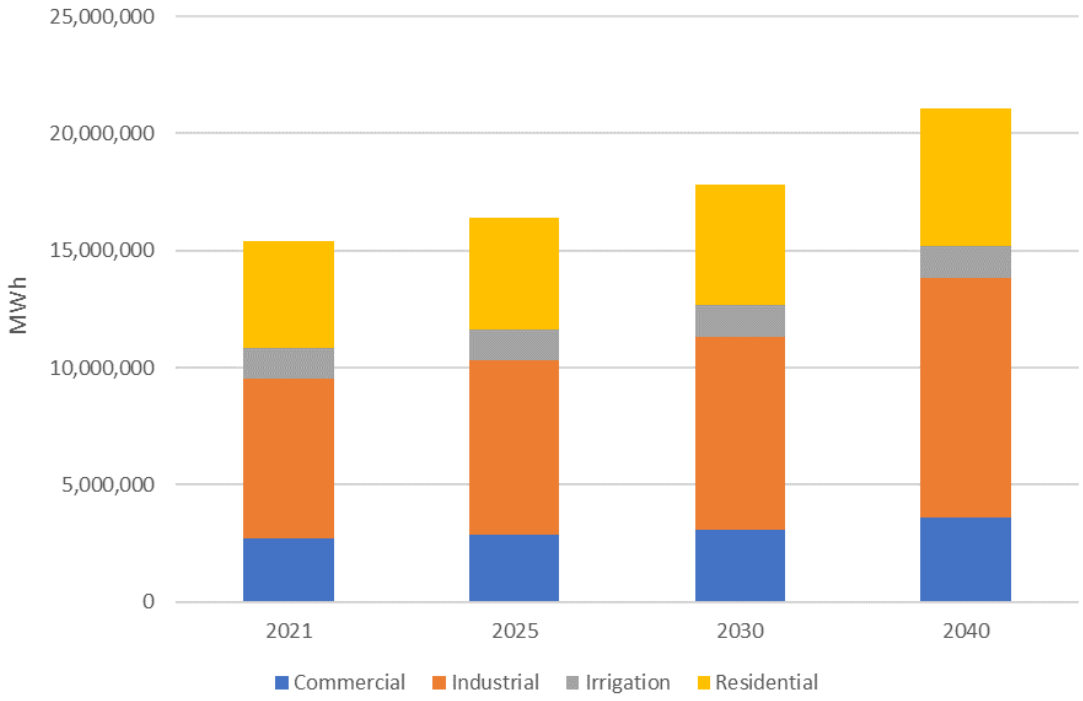
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Irrigation	554,724	31,967	861	237,972	41,763	85,091	116,352	119,890
Industrial	494,719	2,061,346	814,705	79,803	903,438	107,893	1,104,101	1,268,084
Commercial	268,177	964,547	176,453	78,733	289,986	197,934	444,417	173,590
Residential	276,257	1,944,118	241,514	173,762	406,734	328,318	606,582	380,071

The industrial sector comprises a very large share of the energy load (46%). Energy use in this sector is predominately focused around the oil, gas, and mining industries, as described further in section 4.3. Conversely, the commercial sector share, at 17%, is lower than other electric utilities that serve metropolitan communities and typically have a commercial sector share closer to 40 to 50% of all energy sales. Tri-State's relatively low commercial sector values reflect the fact that many of the member cooperatives do not serve the city and town customers within their service territories. Municipal electric utilities are common for many rural towns within western Nebraska, eastern Colorado, and most of Wyoming. Eastern Colorado and Nebraska regions have significant shares of their overall electricity sales in the irrigation sector.

Figure 8 presents the baseline load forecast at key milestone points during the analysis period. The industrial sector will see the largest amount of load growth, increasing by approximately 50% by 2040.

Commercial and residential sector load will each increase by approximately one-third. The load growth estimate for the irrigation sector is negligible.

Figure 8. Baseline Load Forecast by Sector by Milestone Year

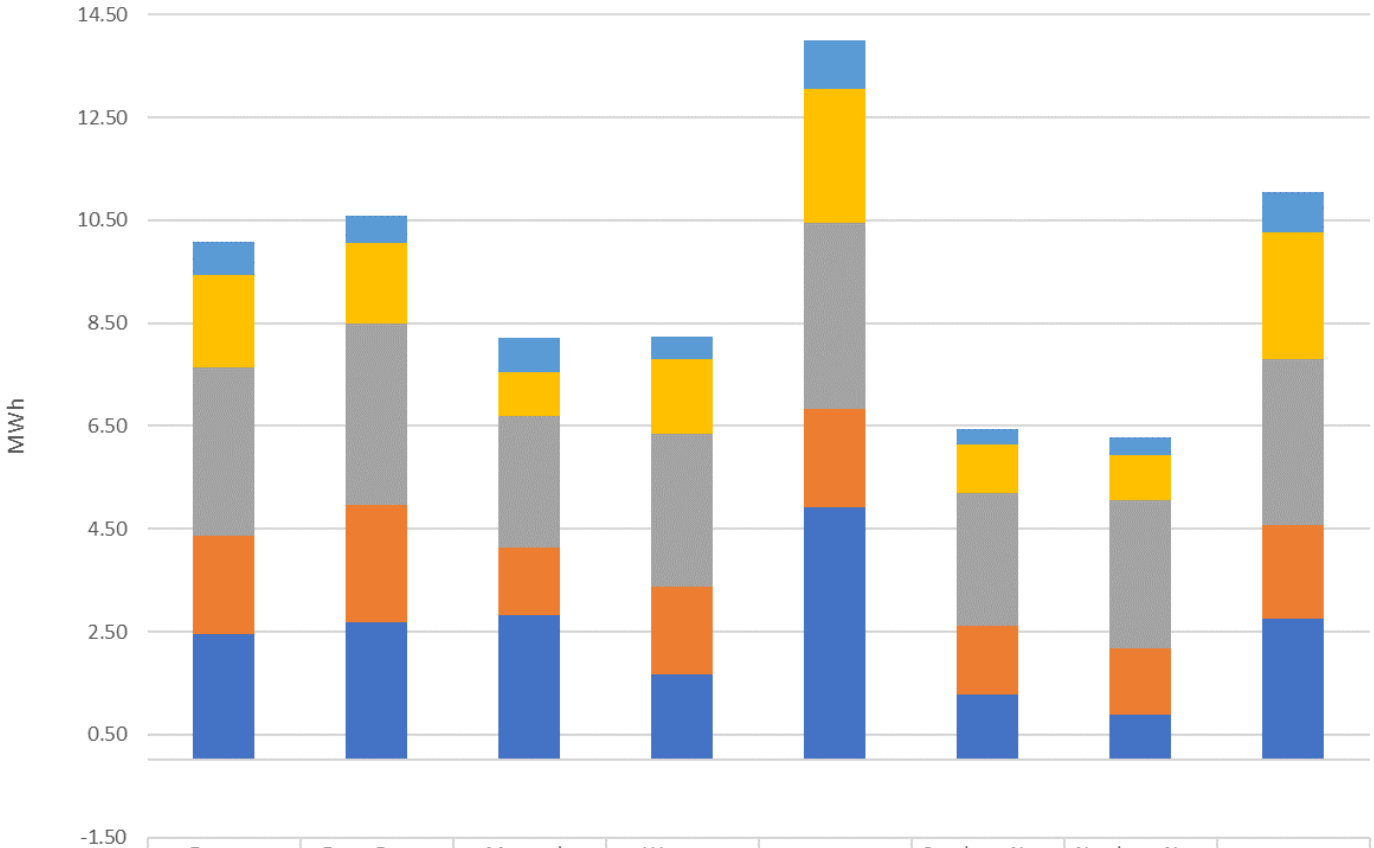


3.2. Residential End-Uses and Loads

The residential sector is responsible for 4,357 GWh of electric consumption, includes approximately 470,000 unique residential dwellings and accounts for 29% of Tri-State's total electricity sales. Average per dwelling energy usage was in line with an annual consumption of 9,260 kWh per home. Based on the limited information available to segment single-family, multi-family, and/or manufactured homes energy use or equipment saturations, it was determined that the existing residential sector should be analyzed in its entirety with no sub-sectors analyzed.

There are notable variations in average home size, average annual energy consumption, and equipment saturations across the different regions as shown in Figure 9.

Figure 9. Average Annual End-Use Consumption per Residence by Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Western Colorado	Nebraska	Southern New Mexico	Northern New Mexico	Wyoming
Water Heat	653	540	668	444	955	298	334	785
Plug Load	1,786	1,569	865	1,441	2,590	948	887	2,478
Appliances	3,279	3,527	2,557	2,972	3,621	2,564	2,868	3,225
Lighting	1,919	2,280	1,308	1,718	1,909	1,356	1,290	1,810
HVAC	2,443	2,674	2,818	1,662	4,928	1,269	890	2,757

The Team utilized the 2012 Tri-State residential end-use survey to compile end-use saturations and average residential premise square footage as in Table 9.

Table 9: Tri-State End-Use Saturations per Region

END-USE	EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO	NEBRASKA	SOUTHERN NEW MEXICO	NORTHERN NEW MEXICO	WYOMING
Central Heating	13.2%	16.0%	22.7%	15.6%	25.5%	8.4%	6.3%	15.4%
HVAC Aux	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Room AC	18.1%	6.9%	1.8%	5.8%	23.3%	11.3%	11.8%	16.1%
Evap Cooler	12.2%	10.2%	1.6%	17.3%	10.2%	33.4%	10.2%	12.2%
Central Air	44.8%	49.9%	1.4%	7.4%	44.6%	19.7%	12.5%	26.3%
Heat Pump	4.2%	3.9%	0.2%	1.2%	14.4%	2.6%	2.6%	2.0%
Interior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Exterior Lighting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Electric Cooking	56.4%	70.2%	65.8%	54.1%	71.3%	38.8%	71.0%	64.6%
Washer	81.1%	94.0%	79.8%	89.5%	89.6%	82.3%	76.8%	86.2%
Electric Dryer	75.3%	83.7%	67.5%	69.5%	85.6%	67.7%	61.3%	80.8%
Dish Washer	67.9%	91.7%	78.3%	78.6%	72.6%	57.5%	39.4%	71.8%
Electric Water Heater	29.7%	20.3%	40.9%	31.4%	53.7%	25.7%	25.8%	44.7%
Refrigerator	84.5%	96.1%	93.3%	94.3%	91.1%	90.6%	91.5%	89.1%
Second Refrig	23.4%	24.5%	14.1%	14.8%	27.5%	16.6%	14.6%	21.8%
Freezer	69.1%	62.6%	40.6%	54.3%	77.0%	53.6%	58.5%	72.0%
Exterior Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Plug Loads	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The saturations of 'plug loads' and 'lighting' are both 100% by definition. Therefore, the contribution of these end-uses to the overall energy usage is driven by the unit energy consumption (UEC) and by the prevalence of certain equipment within the end-use category.

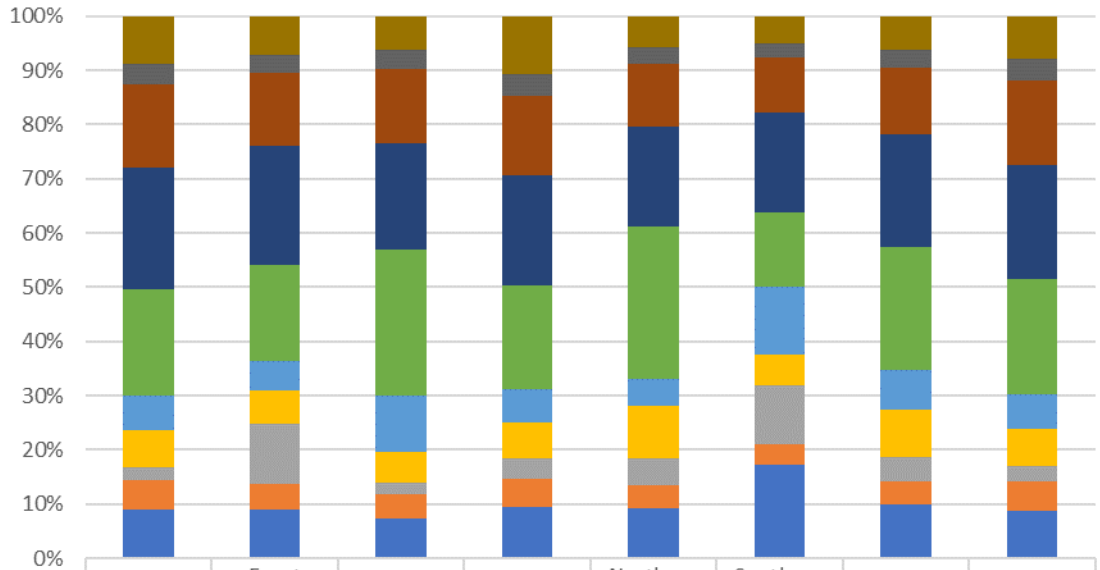
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural gas in the rural environment.

3.3. Commercial End-Uses and Loads

The commercial sector is responsible for 2,594 GWh of electric consumption, which accounts for 17% of Tri-State's total electricity sales. In general, the commercial sector covers a large spectrum of customers, usually smaller in size as compared to the remainder of the non-residential customers, with 71% having a peak demand less than 250 kW.

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct commercial business types. Assumptions largely based on secondary data used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

Figure 10. Commercial Sector Energy Shares by Business Segment and Region (2018)



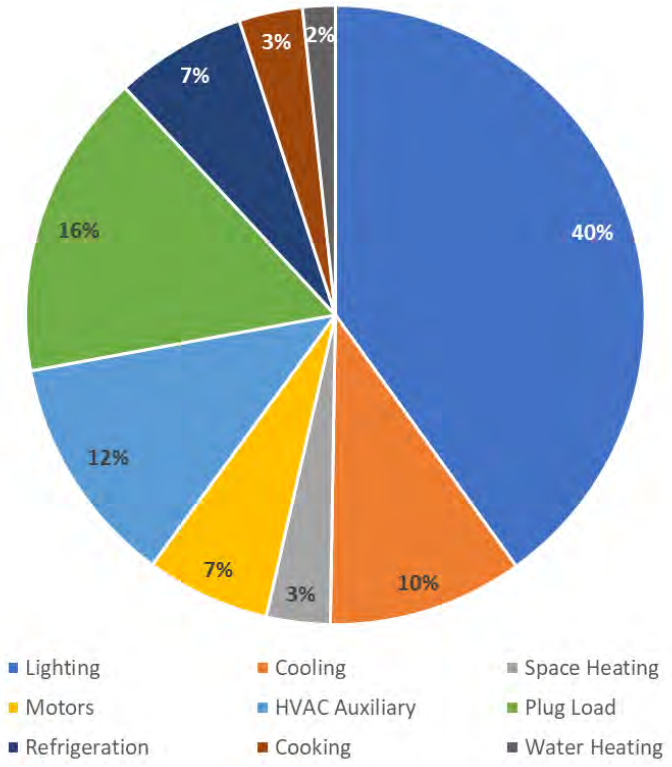
	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Warehouse	9%	7%	6%	11%	6%	5%	6%	8%
Restaurant	4%	3%	3%	4%	3%	3%	3%	4%
Office	15%	13%	14%	15%	12%	10%	12%	15%
Retail	22%	22%	20%	20%	18%	18%	21%	21%
Miscellaneous	20%	18%	27%	19%	28%	14%	23%	21%
Lodging	6%	6%	10%	6%	5%	13%	7%	6%
Health	7%	6%	6%	7%	10%	5%	9%	7%
Government	2%	11%	2%	4%	5%	11%	4%	3%
Grocery	5%	5%	5%	5%	4%	4%	4%	6%
Education	9%	9%	7%	9%	9%	17%	10%	9%

The Team next identified the appropriate energy usage intensity (EUI), or end-use energy consumption per square foot, for each end-use studied. These EUIs were calculated based on other applicable

regional commercial end-use studies, such as those found in Wyoming, Montana, Utah, Colorado, New Mexico, and Iowa. Figure 11 summarizes the energy consumption for each end-use.

Lighting makes up forty-five percent of the total electricity consumption, which is attributable to the fact that this end-use is common in all sub-sectors and does not have any seasonal operation. Lighting is followed by HVAC Auxiliary which included fans, pumps, motors, and electronics used to move or control HVAC air and water systems.

Figure 11. Commercial Energy End-Use Consumption Shares

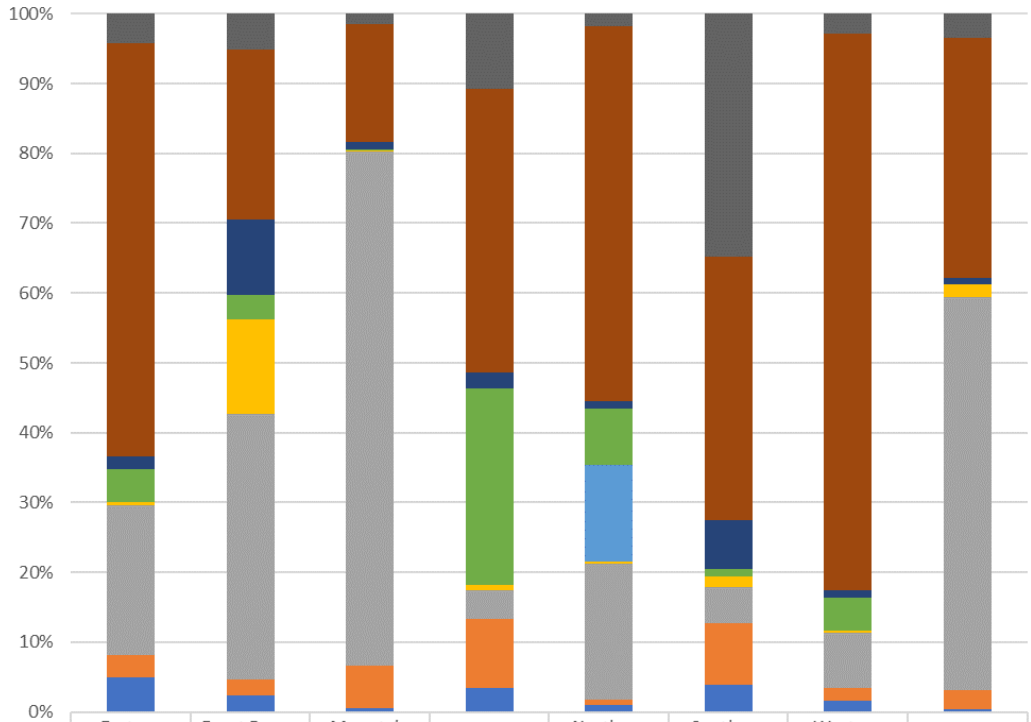


3.4. Industrial End-Uses and Loads

Industrial is the largest sector, accounting for 6,834 GWh of electric consumption and 46% of Tri-State's total electricity sales. In general, Tri-State's industrial sector is unique since approximately 77% of the sector's consumption is from the oil and gas industry and less than 15% is from manufacturing industries (Figure 12).

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct industrial business types. Assumptions used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

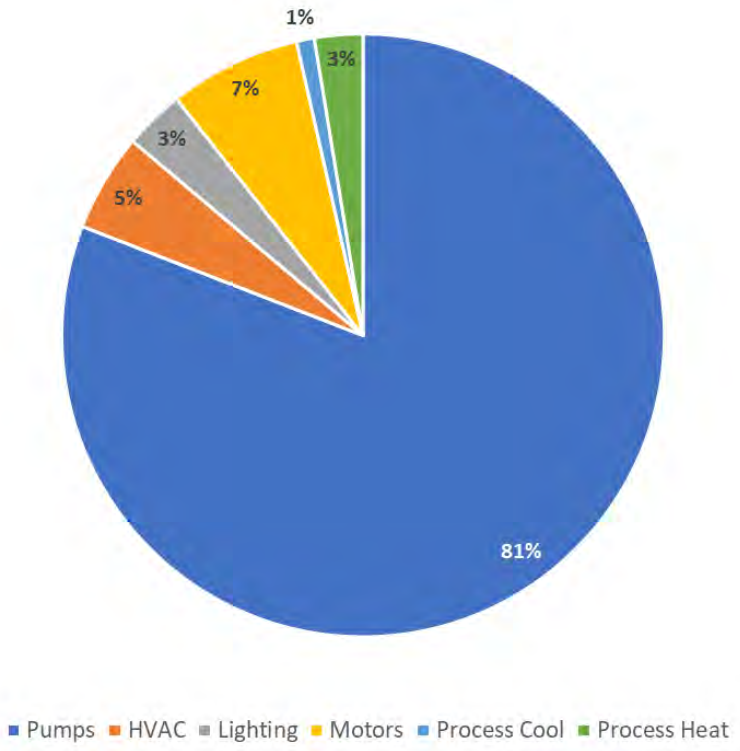
Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
TCU	4%	5%	1%	11%	2%	35%	3%	4%
Pipeline Transportation	59%	24%	17%	41%	54%	38%	80%	34%
Mfg - Misc.	2%	11%	1%	2%	1%	7%	1%	1%
Mfg - Chemical	5%	3%	0%	28%	8%	1%	5%	0%
Mfg - Paper	0%	0%	0%	0%	14%	0%	0%	0%
Mfg - Nonmetallic Mineral Product	0%	13%	0%	1%	0%	2%	0%	2%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	22%	38%	74%	4%	19%	5%	8%	56%
Mining	3%	2%	6%	10%	1%	9%	2%	3%
Agriculture	5%	2%	1%	3%	1%	4%	2%	0%

The Team identified the appropriate energy usage fraction for each industrial end-use studied. These energy end-use shares were calculated based on other applicable regional and national industrial end-use studies (Figure 13).

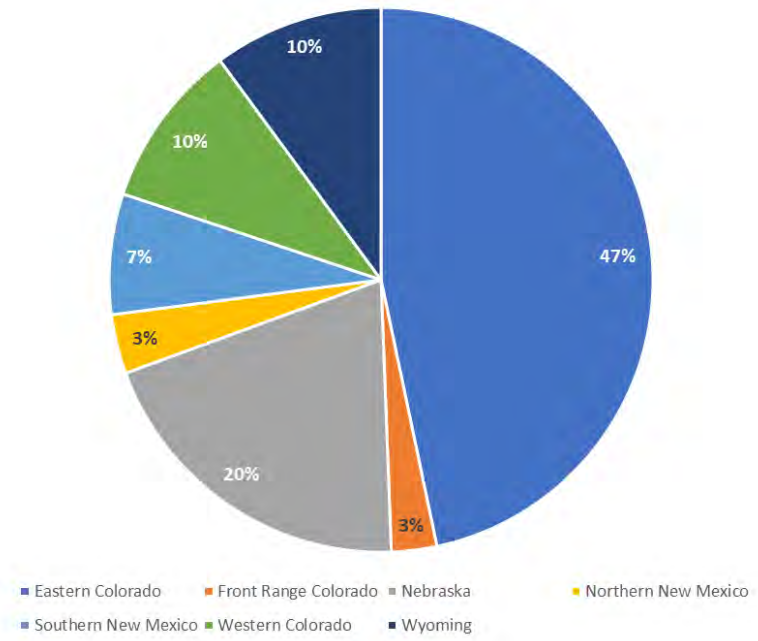
Figure 13. Industrial Sector Energy Shares by End-Use



3.5. Irrigation End-Uses and Loads

Figure 14 summarizes the irrigation energy consumption share for each region analyzed. Eastern Colorado has the largest share of irrigation energy consumption by a wide margin and is followed by the Nebraska region. The Mountain Colorado region has a negligible market share of irrigation sales and is not shown for clarity.

Figure 14: Irrigation Energy Shares by Region



Irrigation energy usage is entirely attributable to electric motors. These motors serve several different purposes, including well lift pumps, supplemental pressure boost pumps, drive motors for center pivots, and gate motors. Based on the Team's experience and research, it was determined that the major application for irrigation electricity is well lift pumps and supplemental pressure boost pumps; consequently, analyses and measures were developed for these end-uses.

3.6. Peak Demand Characterization

This section summarizes the market and end-use characterization of Tri-State's summer peak demand by sector and region. Tri-State's 2018 coincident peak demand used by member cooperatives was 2,887 MW, observed during the month of July. Figure 15 shows the distribution of the coincident peak demand by region. Energy sales by sector were used to estimate coincident peak demand allocation by sector, as described in Section 3. Figure 16 shows the results of this estimation for the Tri-State system as a whole and Figure 17 presents results by region. Notable contributors to the coincident peak demand are the residential and industrial sectors in the Front Range region, as well as the irrigation sector in Eastern Colorado and Nebraska.

Figure 15. 2018 Coincident Peak Demand by Region

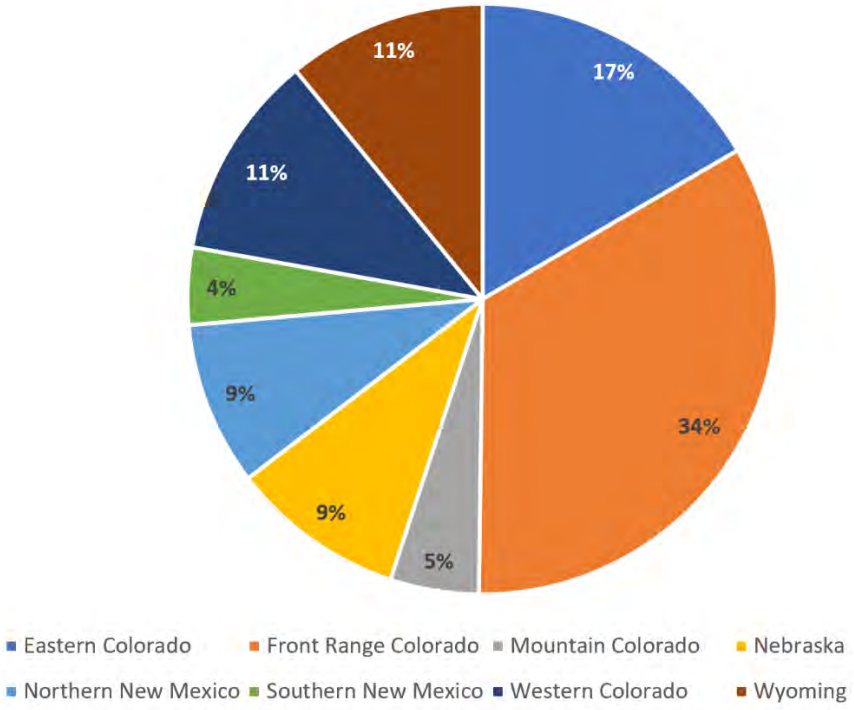


Figure 16. 2018 Coincident Peak Demand by Sector

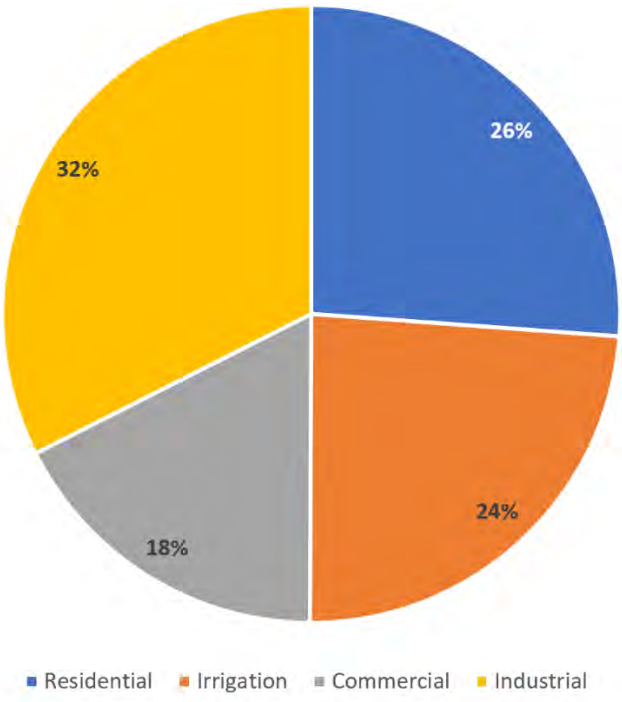
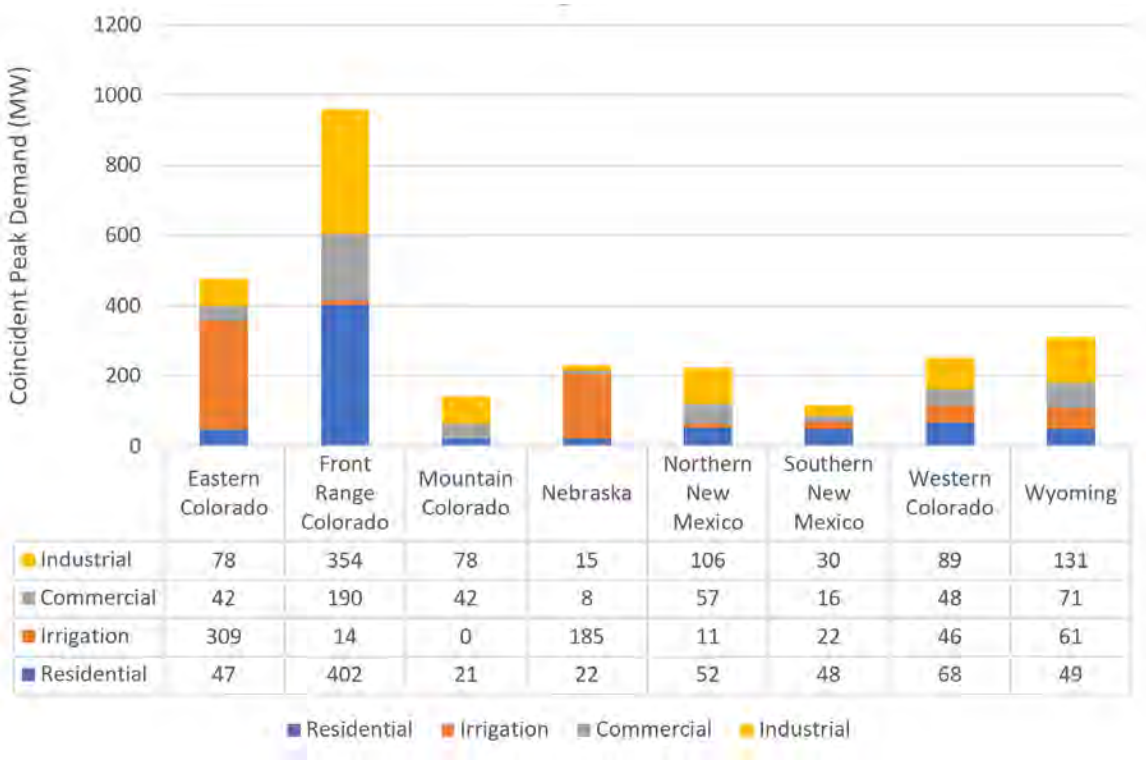


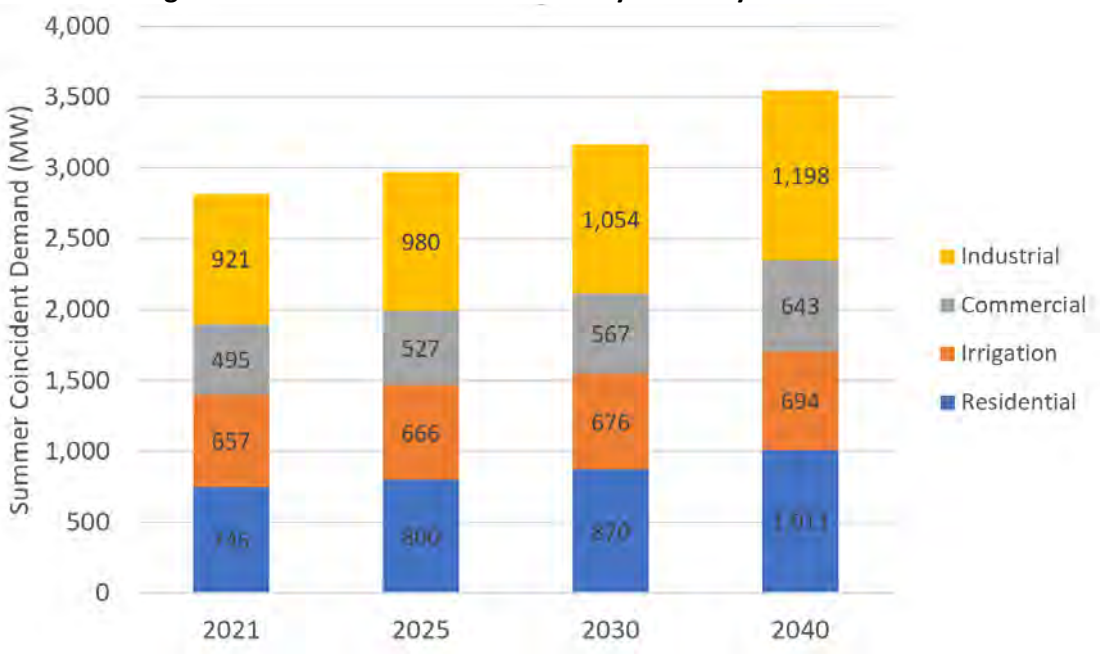
Figure 17. 2018 Coincident Peak Demand by Sector and Region



	Eastern Colorado	Front Range Colorado	Mountain Colorado	Nebraska	Northern New Mexico	Southern New Mexico	Western Colorado	Wyoming
Industrial	78	354	78	15	106	30	89	131
Commercial	42	190	42	8	57	16	48	71
Irrigation	309	14	0	185	11	22	46	61
Residential	47	402	21	22	52	48	68	49

Figure 18 presents the baseline demand forecast at key milestone points during the analysis period. Industrial, commercial, and residential sectors will increase by about 30%. The irrigation sector's coincident peak is not expected to increase significantly.

Figure 18. Baseline Demand Forecast by Sector by Milestone Year



4. PORTFOLIO LEVEL ENERGY EFFICIENCY POTENTIAL

4.1. Overview

The analysis finds that at the portfolio level Tri-State can achieve an average annual savings of 115 GWh from a collection of energy efficiency measures at an average annual cost of $24.3 million during the 20-year time horizon. This includes incentives and administrative costs and equates to an acquisition cost of $0.22/kWh which is in line with industry benchmarks.

4.2. Detailed Results

Table 10 presents portfolio-level energy efficiency savings potential by time horizon and Figure 19 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 38,083 MWh of savings potential in 2021 rising to 1,718,357 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative savings potential by approximately 40%. The maximum achievable scenario increases savings potential by approximately 25% over the aggressive scenario, resulting in cumulative savings of approximately 2,876,487 GWh. First-year savings potential for the Achievable-Moderate scenario represents an increase of approximately 19% over Tri-State's 2018 energy efficiency program performance.

Table 10 Cumulative Savings Potential (MWh) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	130,384	98,221	75,523	55,330	38,083	27,043

2025	1,293,033	928,122	539,750	393,656	266,309	179,222
2030	3,868,940	2,851,171	1,372,971	1,062,225	723,605	475,993
2040	9,081,432	6,956,507	2,876,487	2,354,365	1,718,357	1,193,109

Figure 19. Portfolio Energy Efficiency Savings Potential by Scenario by Year

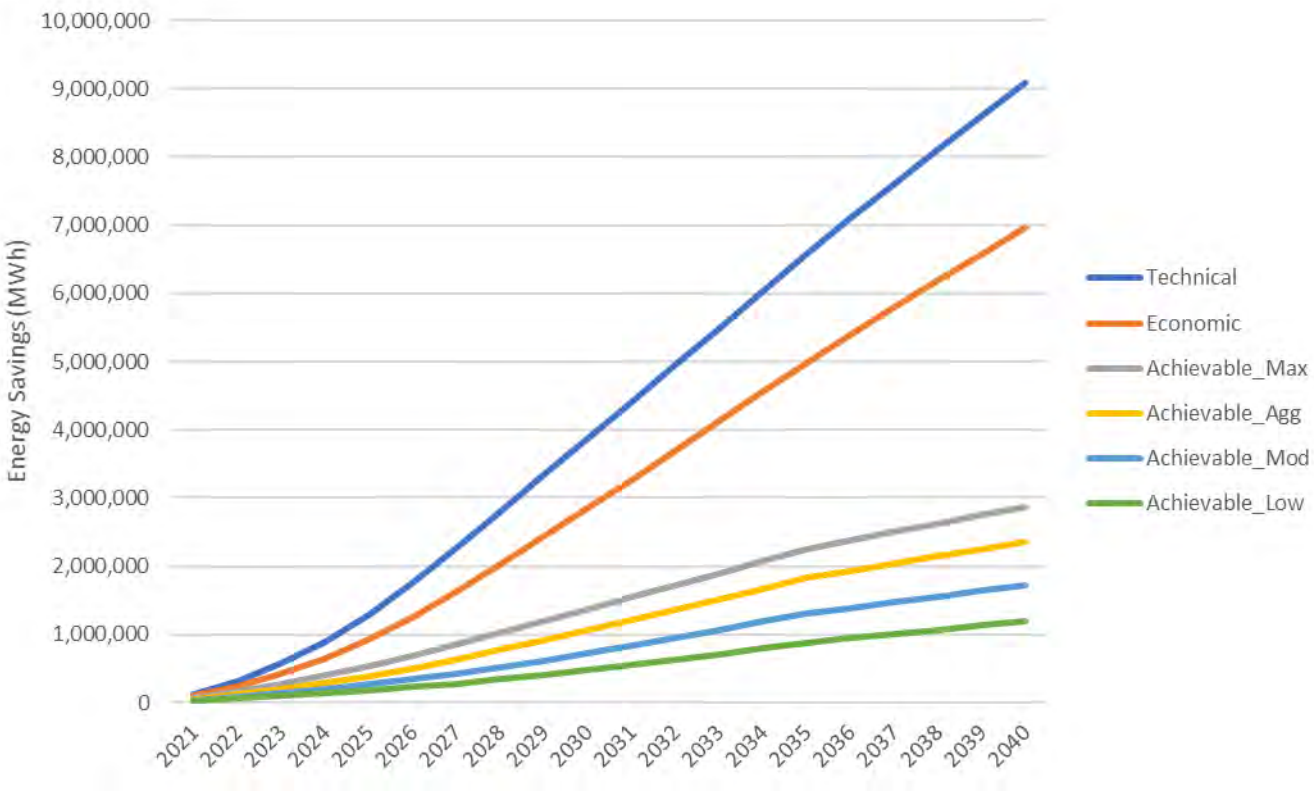


Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy consumption would grow to 1.62% by 2025 and ultimately 8% through 2040. The range of potential reduction in baseline consumption across the achievable scenarios spans from 5.7% (Achievable-Low) to 13.7% (Achievable-Max) by 2040.

Table 11. Portfolio Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.85%	0.64%	0.49%	0.36%	0.25%	0.18%
2025	7.88%	5.65%	3.29%	2.40%	1.62%	1.09%

2030	21.74%	16.02%	7.71%	5.97%	4.07%	2.67%
2040	43.14%	33.04%	13.66%	11.18%	8.16%	5.67%

Figure 20 shows the impact of the modeled scenarios on the baseline forecast. The Achievable-Max scenario would reduce Tri-State's overall load growth significantly, though Tri-State's load will continue a steady growth trajectory under all Achievable scenarios.

Figure 20. Impact of Portfolio Energy Efficiency Savings on Baseline Forecast by Scenario by Year

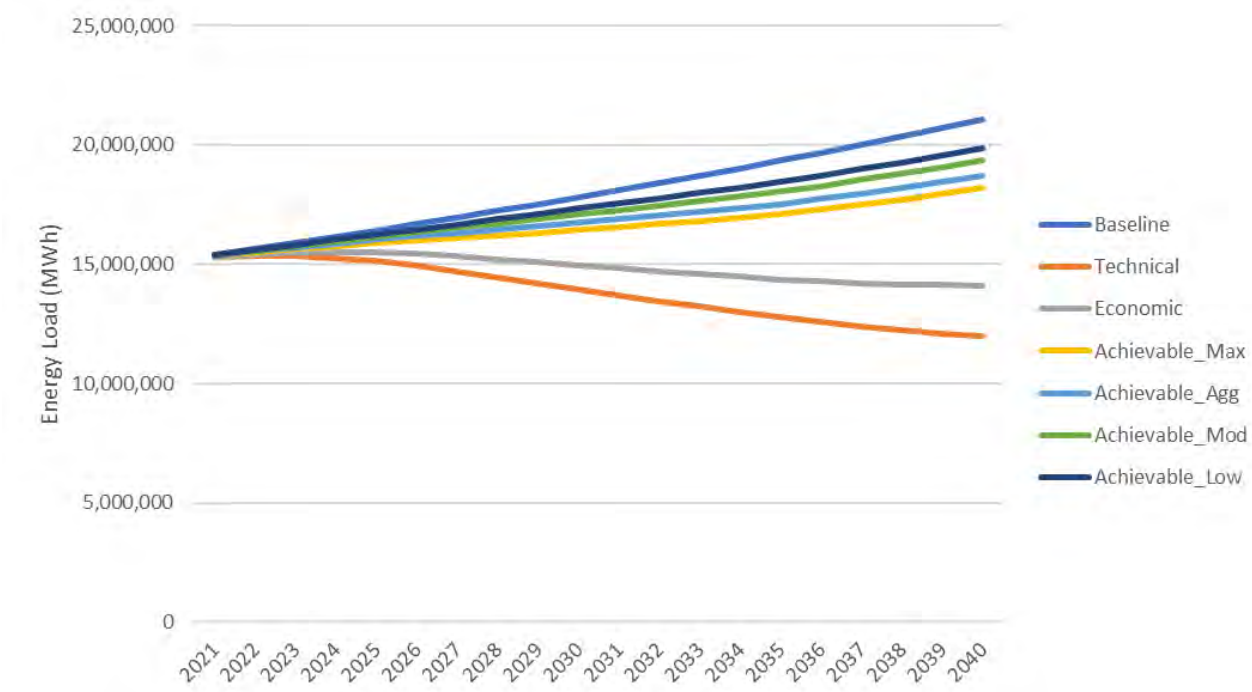
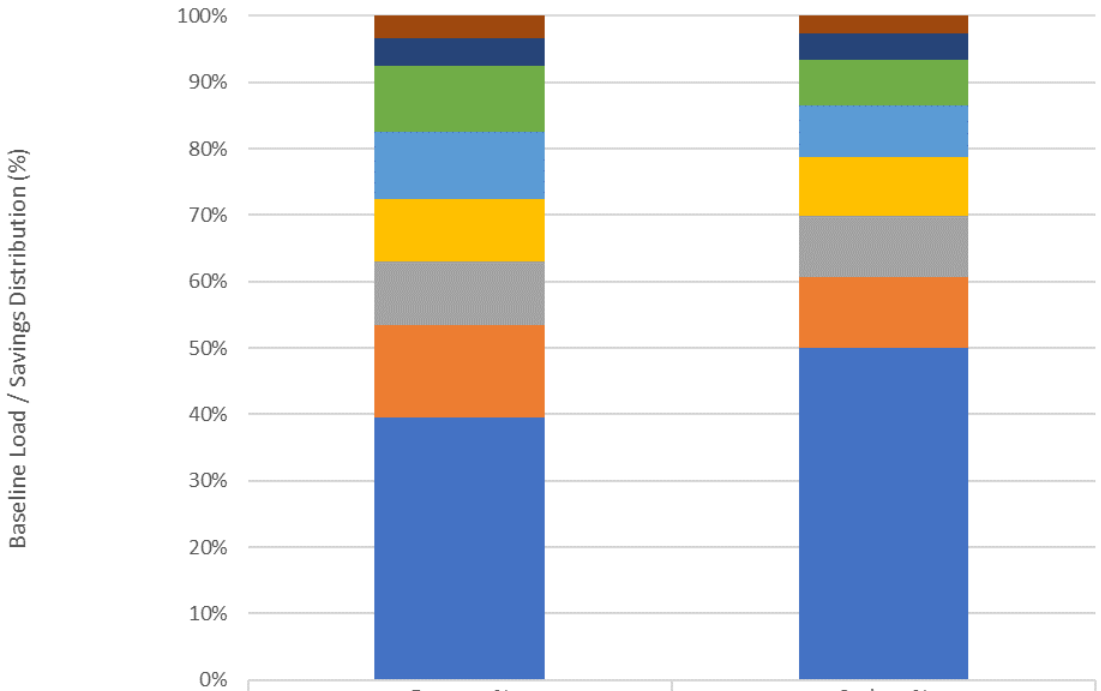


Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 13% of total savings potential, while Wyoming accounts for approximately 10% of the total. Nebraska's savings potential is much smaller at just 2.7% of the total. This savings potential is generally aligned with the distribution of forecast energy load by region. However, Front Range Colorado's share of energy savings (50%) is larger than its share of forecast baseline energy consumption (39.5%) by a notable margin.

Figure 21. Baseline Forecast and Portfolio Energy Efficiency Savings by Region



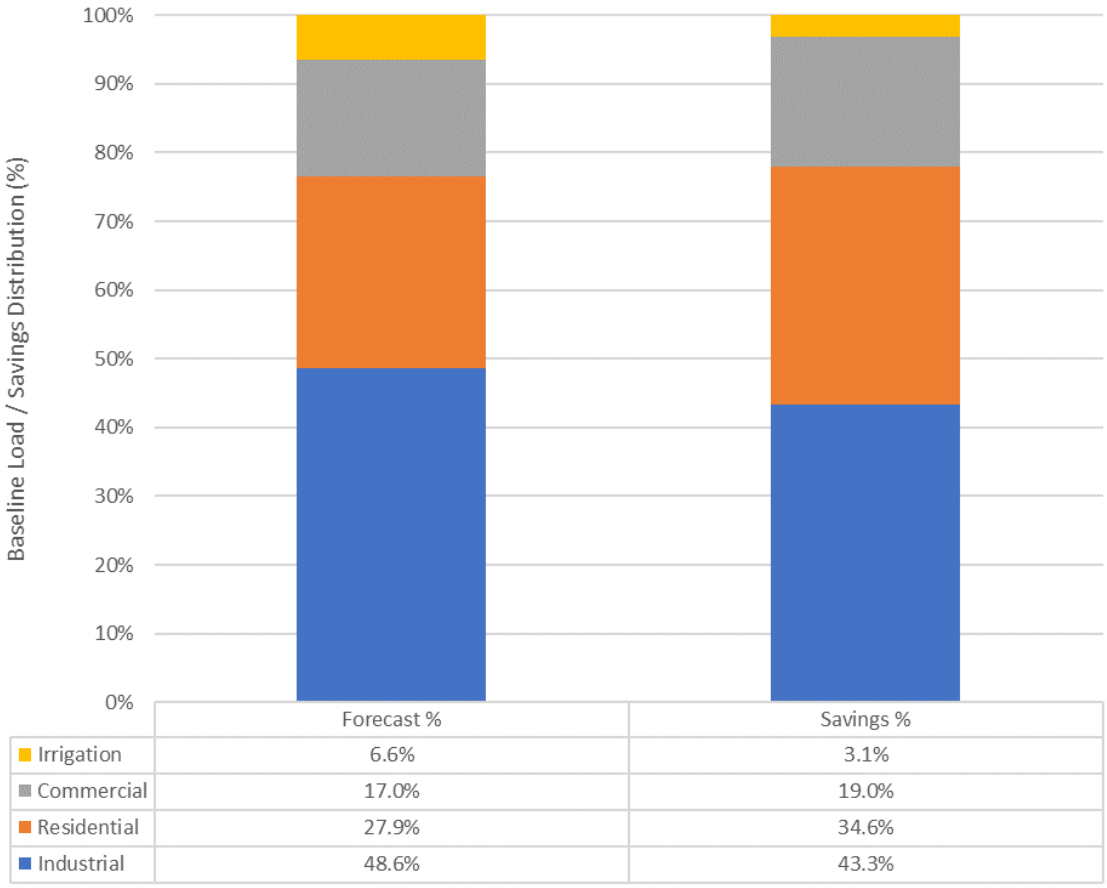
	Forecast %	Savings %
Nebraska	3.4%	2.7%
Southern New Mexico	4.1%	3.9%
Mountain Colorado	9.8%	6.8%
Eastern Colorado	10.2%	7.8%
Northern New Mexico	9.5%	8.8%
Western Colorado	9.6%	9.2%
Wyoming	13.9%	10.6%
Front Range Colorado	39.5%	50.0%

Table 12. Cumulative Savings Potential by Region, Achievable-Moderate Scenario (2040)

STATE / SUB-REGION	POTENTIAL SAVINGS (MWH)
Colorado	1,270,405
Front Range	*860,016*
Western	*158,539*
Mountain	*117,559*
Eastern	*134,292*
Wyoming	182,708
New Mexico	218,977
Northern	*151,292*
Southern	*67,685*
Nebraska	46,267
Total	**1,718,357**

As shown in Figure 22 the industrial and residential sectors represent the largest opportunity for savings. The industrial sector comprises 43% of the total savings potential and its share of the baseline forecast consumption is slightly higher at 49%. This sector's oil and gas-related energy consumption is exceptionally high, and motor-related efficiency improvements can go a long way toward reducing that load, as discussed further in Section 7. The residential sector makes up 35% of the total savings potential, and a slightly smaller portion of the baseline forecast consumption at 28%. Numerous measures are available to reduce residential energy load, with the most substantial savings coming from lighting and central heating, as discussed further in Section 5. The commercial sector also holds substantial potential energy savings at 19% of the total, which is generally in line with its share of the baseline forecast energy consumption. Heavy use of energy for lighting coupled with the availability of numerous lighting efficiency-related measures account for this sector's substantial share of savings potential. The irrigation sector contributes substantially less, both in terms of overall savings potential and in terms of its share of baseline forecast load.

Figure 22. Energy Efficiency Savings Potential by Sector (2040)



The portfolio of energy efficiency measures can achieve a cumulative demand savings of 23 MW by 2040 (Table 13.) under the Achievable-Moderate scenario. The industrial sector accounts for the largest share of demand savings, followed by the residential sector.

Table 13. Portfolio Cumulative Demand Savings Potential by Sector by Year (MW)

MILESTONE YEAR	INDUSTRIAL	RESIDENTIAL	COMMERCIAL	IRRIGATION	**TOTAL**
2021 (first year)	1.8	2.1	1.1	0.12	**5.3**
2025	3.7	3.5	2.3	0.37	**9.9**
2030	6.7	5.8	3.7	1.1	**17.2**
2040	10.3	6.2	4.5	2.1	**23.1**

Table 14 presents cumulative and average annual cost, savings and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 38,083 MWh of energy savings at a cost of approximately $7 million, or $183/MWh. As programs expand and become more established annual costs and savings increase substantially to reach a cumulative program expenditure of nearly $500 million by 2040 and savings of approximately 2,290,400 MWh. The 20-year average annual program costs are approximately $24.3 million and savings are 114,520 MWh.

Table 14. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF FIRST-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$6,957,787	38,083	$182.70	$15.25
2025	1.91	$54,155,251	279,461	$193.78	$17.41
2030	1.72	$164,148,094	797,374	$205.86	$20.18
2040	1.64	$486,794,842	2,290,399	$212.54	$21.55
20-year avg.	1.64	$24,339,742	114,520	$212.54	$21.55

5. RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

5.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, and 35% of energy savings potential. Cumulative savings potential for this sector is approximately 5,880 GWh through 2040 (Achievable-Moderate scenario) with lighting efficiency improvements making up over half the total energy savings potential. Central heating improvements comprise almost one-sixth of the residential sector savings potential.

Notable assumptions for the residential sector analysis include: 1) the speed with which lighting market transformation will occur, and 2) the timing of the roll-out and accrual of demand impacts associated with Home Energy Reports (HERs). With regard to lighting, research indicates that LED lamps will become standard technology within 10 years despite delays in implementing lighting efficiency standards under the Energy Independence and Security Act (EISA) of 2007. Lighting measures commonly account for the largest share of savings for residential energy efficiency programs. However, since residential lighting market transformation is well underway, savings from lighting measures are limited for the second half of the evaluation period.

For the home energy reports measure (HER) the analysis assumes a seven-year implementation delay in order to capture demand benefits associated with this measure. This is because Tri-State is not capacity

constrained during this period and avoided cost of capacity benefits do not apply. The addition of demand benefits along with energy savings benefits allows the HERs measure to achieve cost effectiveness for various measure permutations in varying regions.

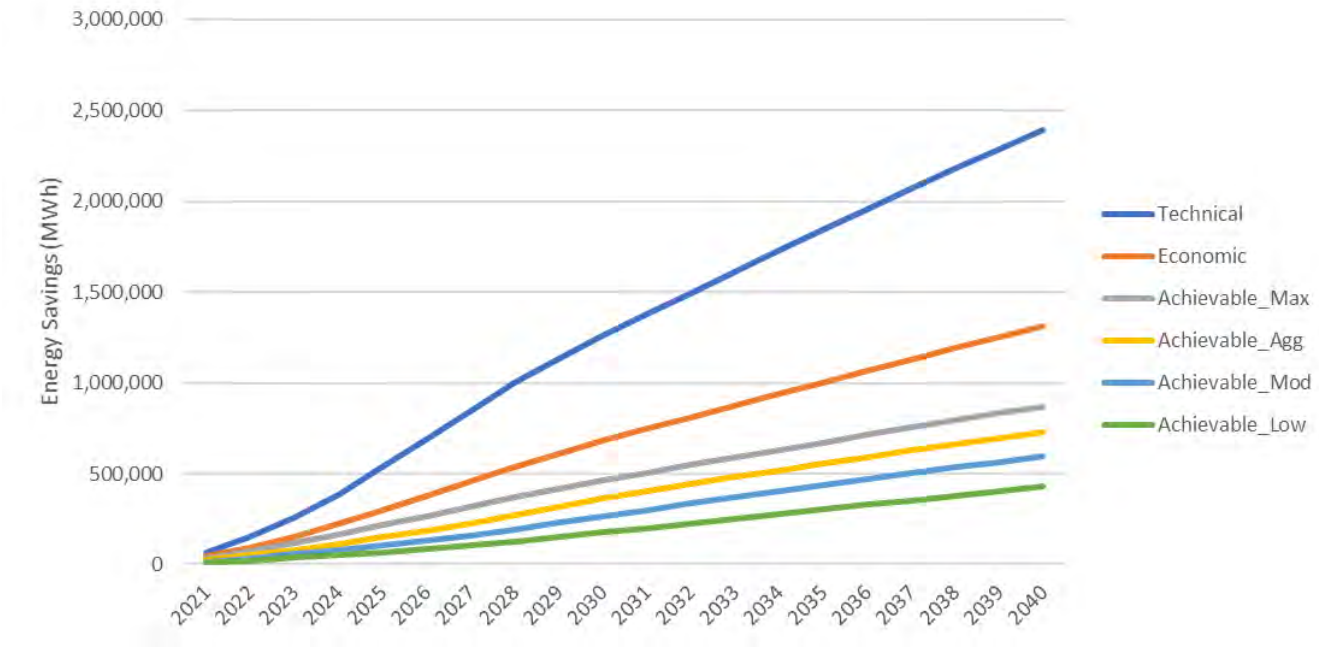
5.2. Detailed Results

Table 15 presents cumulative savings potential for the residential sector by scenario at various milestones in the analysis period and Figure 23 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14,649 MWh of savings potential in 2021 rising to 594,298 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 22%. The maximum achievable scenario estimates savings potential approximately 46% higher than the aggressive scenario, equating to cumulative savings of approximately 870,669 MWh through 2040.

Table 15. Cumulative Residential Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	63,817	42,581	34,166	22,384	14,649	9,539
2025	532,961	299,459	214,988	149,245	104,278	68,016
2030	1,257,012	679,699	461,040	361,598	263,762	175,118
2040	2,395,940	1,313,384	870,669	726,771	594,298	427,615

Figure 23. Residential Energy Efficiency Savings Potential by Scenario by Year



The cumulative residential savings potential under the Achievable-Moderate scenario equates to 9.1% of the residential baseline load forecast for 2040 (see Table 16.). The maximum achievable savings would equate to 16.2% of the forecast energy load for this sector.

Table 16. Residential Savings Potential as % of Baseline Forecast by Scenario by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 24, lighting accounts for the greatest share of energy savings potential at 55% of the total followed by central heating at approximately 15% of total savings. Plug loads, central air, HVAC auxiliary, and refrigerator/freezer end-uses combined comprise over a quarter of savings potential.

Figure 24. Residential Baseline Energy Load and Cumulative Energy Efficiency Savings Potential by End-Use (2040)

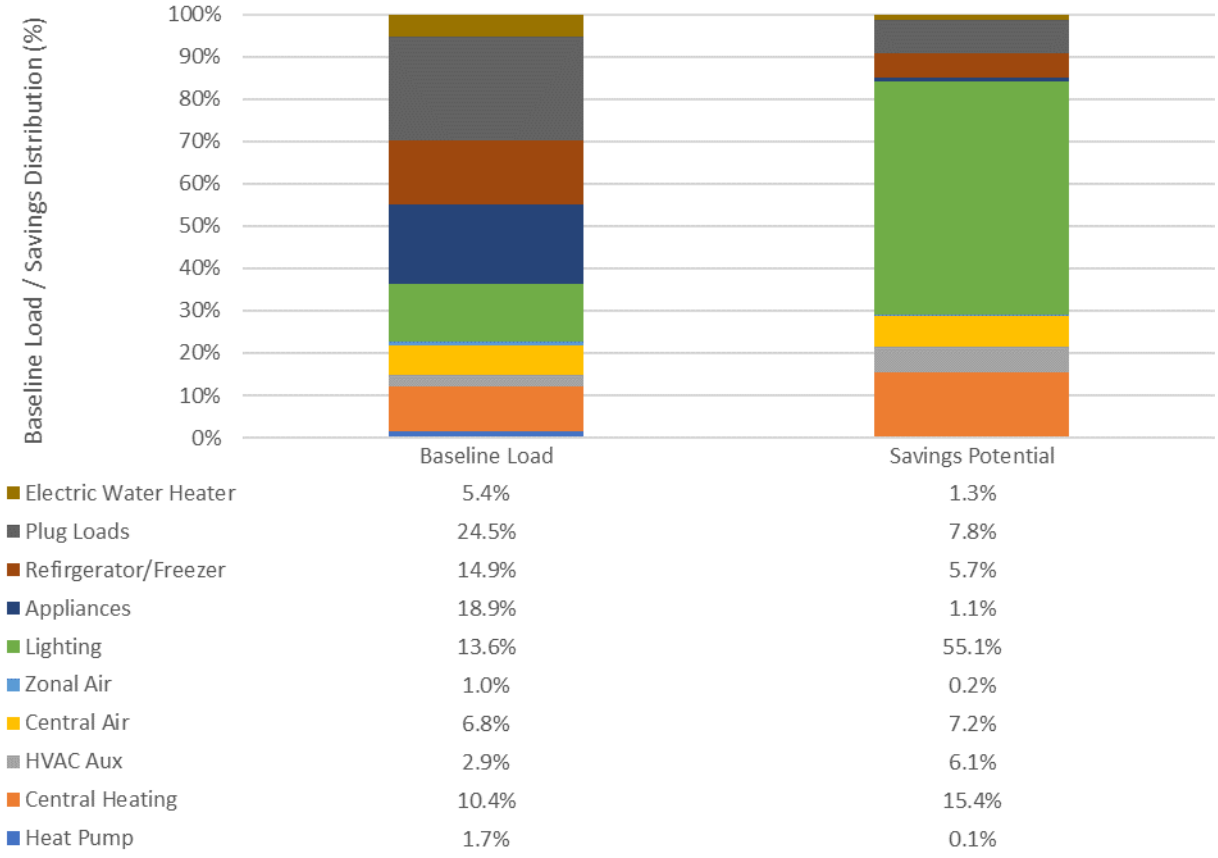


Table 17 presents cumulative residential demand savings by end-use by milestone year. High efficiency lighting is by far the greatest contributor to demand savings from residential energy efficiency measures producing 2,722 kW of cumulative demand savings through 2040. Additional measures with relatively large volumes of demand savings include plug loads and central air.

Table 17. Residential Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HEAT PUMP	CENTRAL HEATING	HVAC AUX	CENTRAL AIR	ZONAL AIR	LIGHTING	APPLIANCES	REFRIG-ERATOR / FREEZER	PLUG LOADS	ELECTRIC WH	TOTAL
2021	0.0002	0.0053	0.0122	0.0951	0.0	1.8303	0.0080	0.0605	0.1238	0.0100	**2.1454**
2025	0.0008	0.0203	0.0538	0.3813	0.0	2.4448	0.0296	0.1921	0.3284	0.0408	**3.4921**
2030	0.0031	0.0505	0.1460	1.5397	0.0806	2.9055	0.0990	0.3152	0.5296	0.1378	**5.8072**

2040	0.0037	0.0440	0.2012	1.7245	0.0829	2.7220	0.1116	0.3383	0.7502	0.1771	**6.1554**

Table 18. presents cumulative program cost metrics by milestone year. As shown, first-year program costs are approximately $3.0 million, rising to a 20-year average annual cost of approximately $8.9 millon. Acquisition costs rise from $206/MWh in 2021 to $251/MWh in 2040. A change in lighting market measures available during the analysis period drives this increase in acquisition costs, as LEDs become the market baseline within ten years. The decline in highly cost-effective lighting measures also has a downward effect on the TRC ratio, as it decreases from 2.15 in 2021 to 1.36 in 2040.

Table 18. Cumulative Residential Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.15	$ 3,013,704	14,649	$ 205.72	$ 14.90
2025	1.84	$ 23,693,929	104,884	$ 225.91	$ 18.61
2030	1.50	$ 68,913,983	280,300	$ 245.86	$ 23.95
2040	1.36	$ 177,217,648	705,466	$ 251.21	$ 26.52
20-year avg.	1.36	$ 8,860,882	35,273	$ 251.21	$ 26.52

6. COMMERCIAL ENERGY EFFICIENCY POTENTIAL

6.1. Overview

The commercial sector accounts for 17% of the total baseline forecast energy load, and 19% of cumulative energy savings potential in 2040. Cumulative savings potential for this sector is approximately 326 GWh through 2040 (Achievable-Moderate scenario) with lighting measures making up 74% of the total energy savings potential. Other end-uses comprising a notable share of savings potential include refrigeration, motors and plug load at 7.5%, 5% and 4% of savings respectively. The retail segment holds the largest opportunity for savings at roughly 27% of the cumulative savings potential in 2040.

6.2. Detailed Results

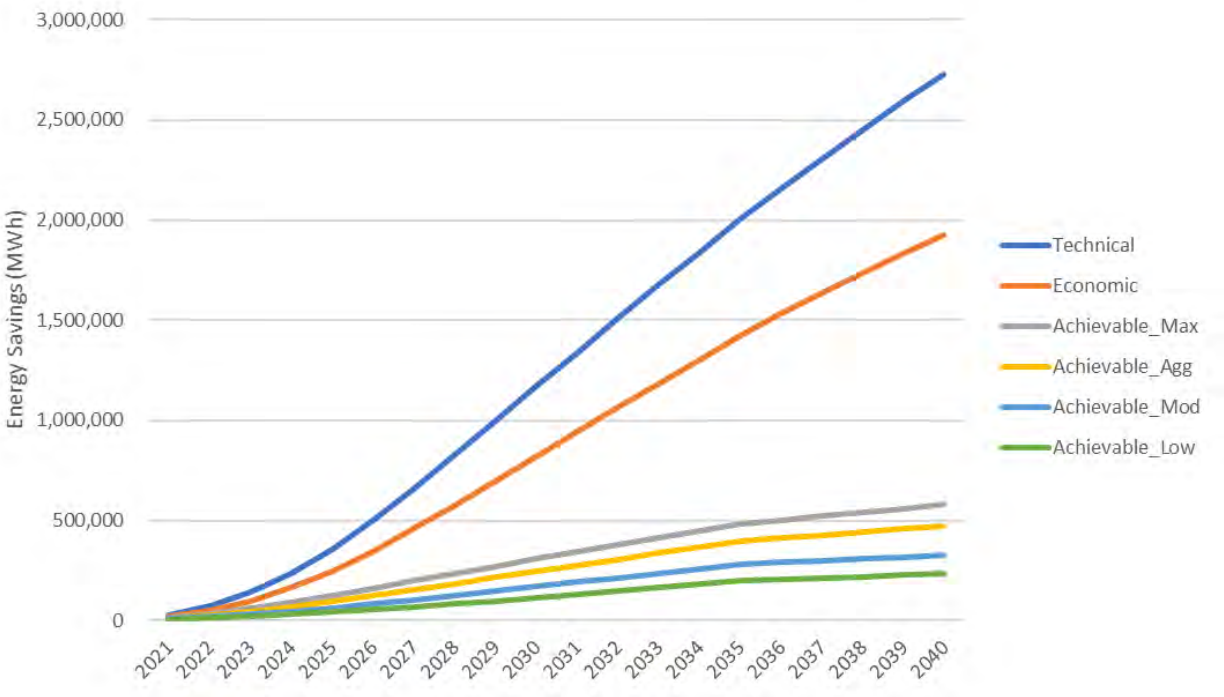
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 326 GWh of cumulative savings potential through 2040. Pursuing an aggressive program-delivery approach (Achievable-Aggressive scenario) could increase cumulative savings potential

by approximately 45% to 472 GWh. A less aggressive program delivery approach (Achievable-Low scenario) would reduce savings by approximately 30% relative to the Achievable-Moderatemoderate scenario.

Table 19. Cumulative Commercial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	29,723	20,331	15,375	12,230	8,626	6,372
2025	356,164	246,342	124,400	95,929	64,202	43,820
2030	1,167,833	819,729	307,053	245,955	169,298	114,633
2040	2,726,737	1,926,747	578,473	472,062	326,383	233,706

Figure 25. Commercial Cumulative Energy Efficiency Savings Potential by Sector by Year



The cumulative commercial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.32% of commercial baseline sales in 2021, a 2.25% reduction by 2025 and a 9.14% reduction by 2040 (see Table 20.). The Mesa Point Energy Team esimates a range in reduction of baseline energy sales for the achievable scenarios from 6.5% (Achievable-Low) to 16.2% (Achievable-Max) by 2040.

Table 20. Commercial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1.10%	0.75%	0.57%	0.45%	0.32%	0.24%
2025	12.48%	8.63%	4.36%	3.36%	2.25%	1.54%
2030	38.13%	26.76%	10.02%	8.03%	5.53%	3.74%
2040	76.33%	53.93%	16.19%	13.21%	9.14%	6.54%

As shown in Figure 26 lighting makes up a large majority of the commercial sector's energy savings potential at 74%, a significant increase in its baseline load share. Refrigeration, motors and plug loads comprise most of the remaining savings potential for this sector at 7.5%, 5.5% and 4% respectively.

Figure 26. Commercial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)

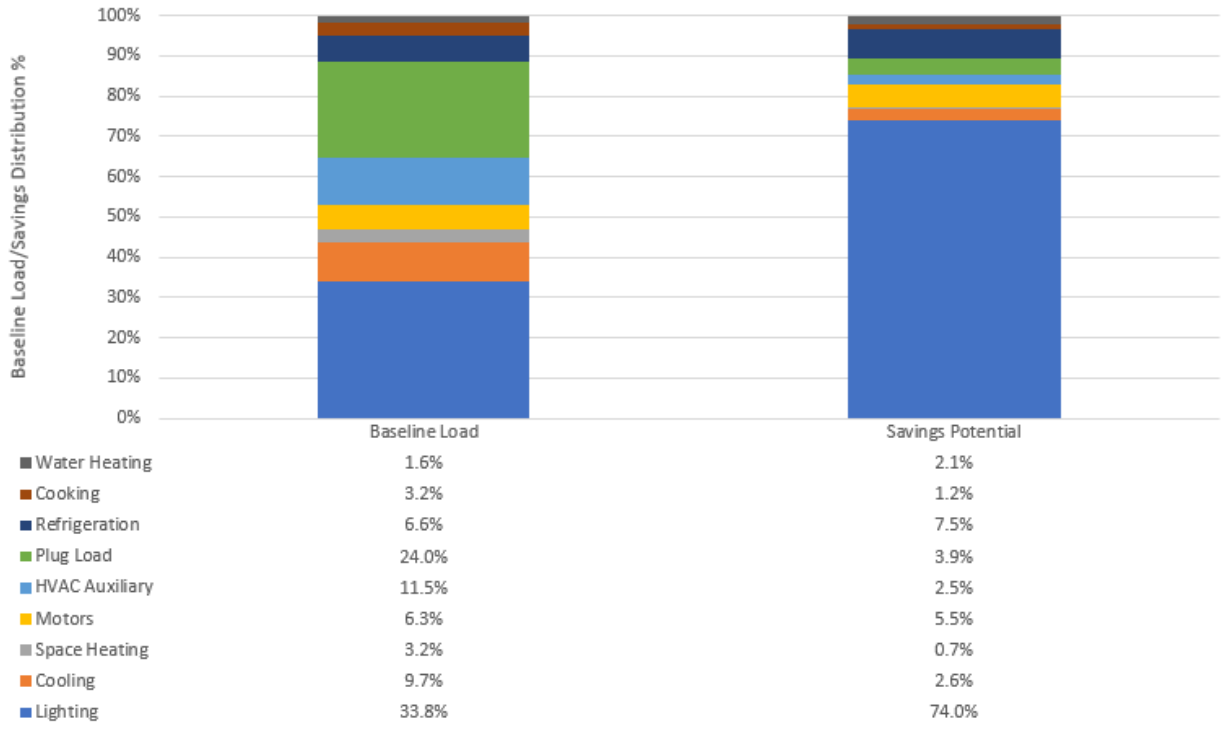


Table 21 presents cumulative commercial demand reductions by end-use by milestone year. Lighting accounts for nearly 55% of demand savings from commercial energy efficiency measures, producing almost 2,500 kW of demand reductions by 2040. Relative to their energy savings, the Cooling and HVAC Auxillary end-uses provide a large demand reduction opportunity at 430 kW and 424 kW respectively.

Table 21. Commercial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	LIGHTING	COOLING	HEATING	MOTORS	HVAC AUX	PLUG LOAD	REFRIGER-ATION	COOKING	DHW	TOTAL
2021 (first year)	0.763	O.054	0.001	0.0251	0.054	0.102	0.108	0.011	0.014	**1.133**
2025	1.526	0.147	0.002	0.0693	0.145	0.161	0.230	0.025	0.039	**2.344**
2030	2.171	0.310	0.004	O.1529	0.305	0.233	0.353	0.041	0.082	**3.653**
2040	2.476	0.430	0.006	0.2206	0.424	0.357	0.434	0.053	0.116	**4.517**

Figure 27 presents baseline energy load and cumulative savings by commercial market segment through 2040. The savings potential for each segment is generally similar to its share of total baseline energy load. The retail segment has the largest share of 2040 cumulative savings potential (27.4%), an increase of just over 7% of its baseline energy load share. This is a result of the large lighting load share in retail buildings. The Miscellaneous and Office segments comprise the next largest opportunities at 17.7% and 10.4% of cumulative savings potential respectively.

Figure 27. Commercial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)

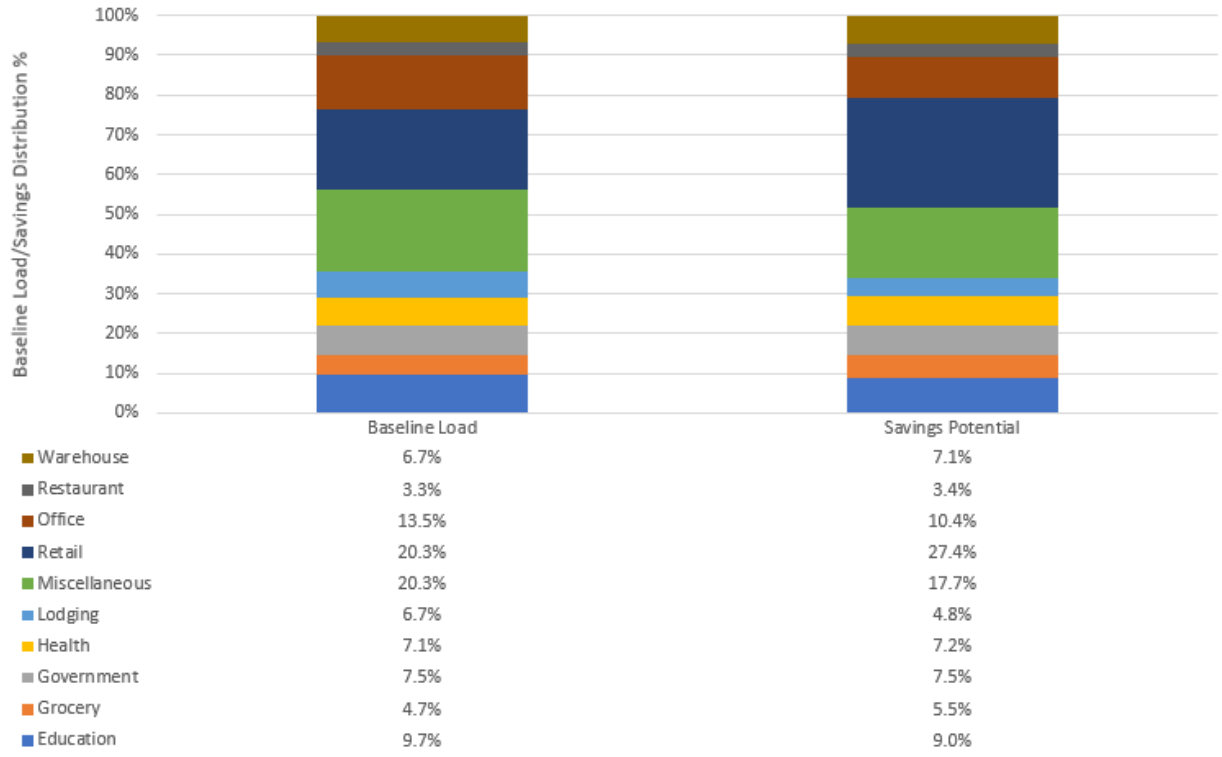


Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual increase through 2040. The TRC ratio remains solid for the commercial sector starting at 2.11 in 2021 and decreasing modestly to 1.93 in 2040.

Table 22. Commercial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.11	$ 1,367,761	8,626	$ 158.57	$ 18.87
2025	2.07	$ 10,437,397	64,743	$ 161.21	$19.27
2030	2.01	$ 30,065,223	181,191	$ 165.93	$ 20.13
2040	1.93	$ 82,522,317	481,235	$ 171.48	$ 21.24
20-year avg.	1.93	$ 4,126,116	24,062	$ 171.48	$ 21.24

7. INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

7.1. Overview

The industrial sector makes up roughly one-half of Tri-State's total baseline forecast energy load, and 43% of potential energy savings. Cumulative savings potential for this sector is approximately 745 GWh through 2040 (Achievable-Moderate scenario) with pump-related savings accounting for a majority of potential savings at 58%. Efficiency measures for the oil and gas segment of the market comprise nearly 55% of potential savings for this sector. Manufacturing-related efficiency opportunities account for most of the remaining energy savings potential.

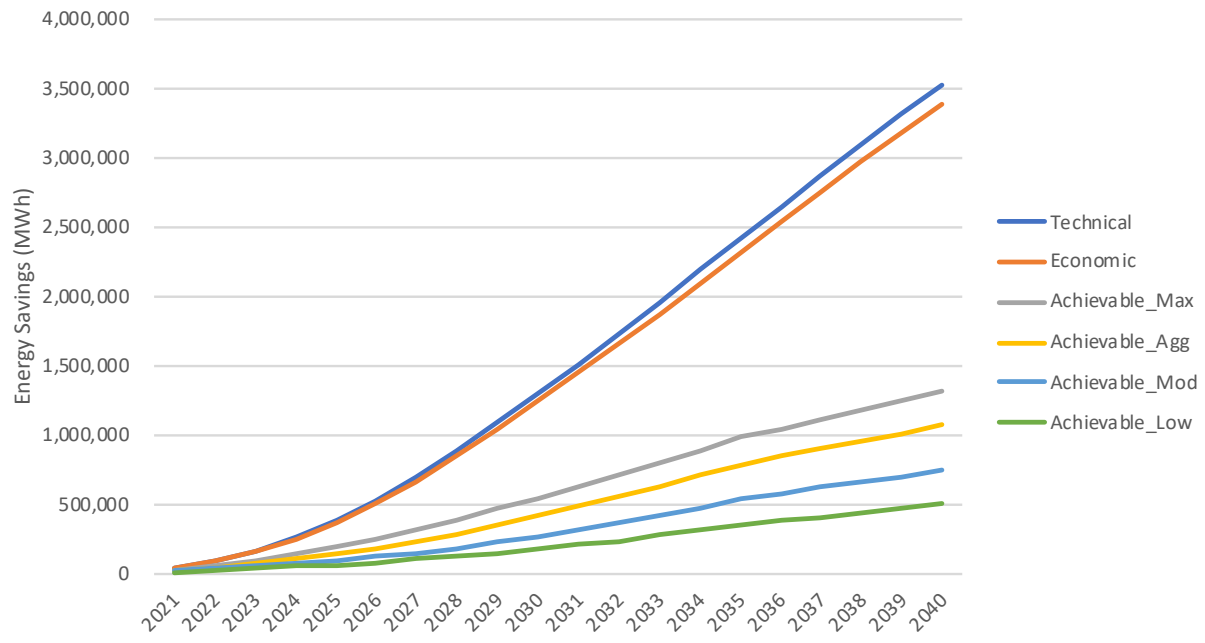
7.2. Detailed Results

Table 23 presents cumulative savings potential for the industrial sector by scenario at various milestones in the analysis period and Figure 28 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14 GWh of savings potential in 2021 rising to approximately 745 GWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 43%. Savings potential increases by an additional 22% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 1,308 GWh through 2040.

Table 23. Cumulative Industrial Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	35,303	34,181	24,956	19,902	14,224	10,678
2025	378,791	363,954	186,953	139,453	92,325	63,777
2030	1,294,201	1,240,358	544,166	414,383	268,351	173,960
2040	3,523,534	3,381,672	1,307,552	1,066,805	744,543	502,719

Figure 28. Industrial Energy Efficiency Savings Potential by Scenario by Year



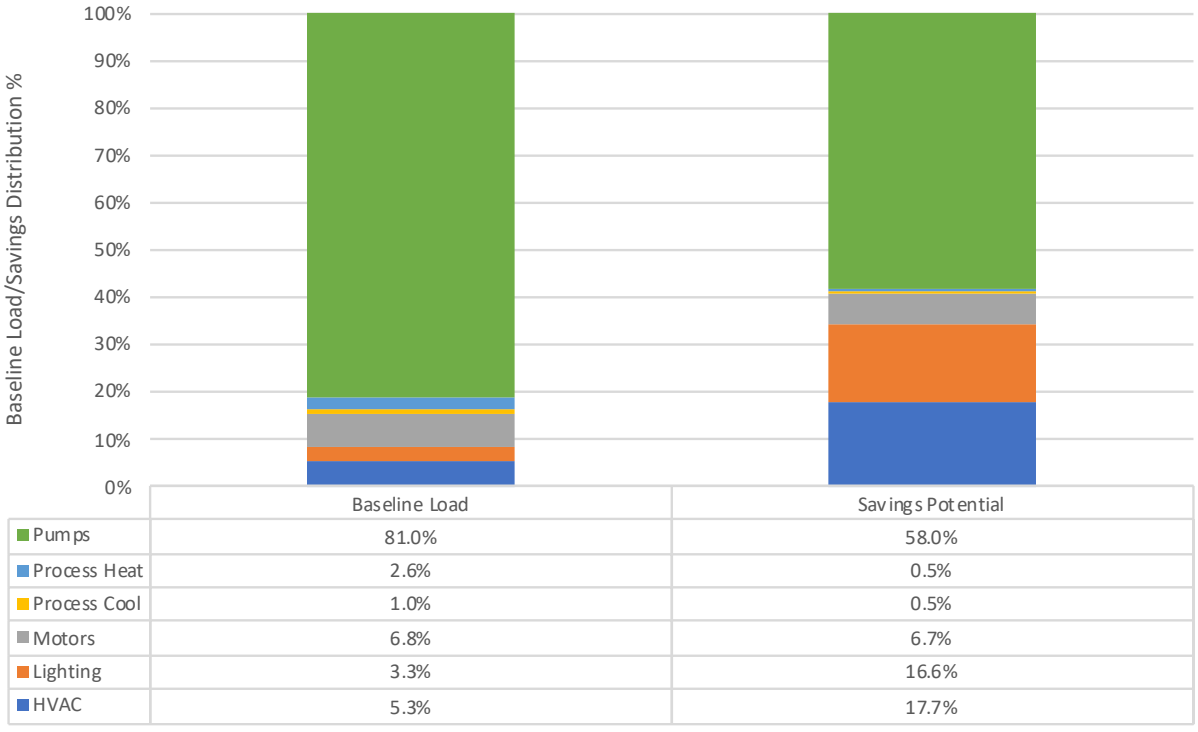
The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the achievable scenarios from 4.9% (Achievable-Low) to 12.8% (Achievable-Max) by 2040.

Table 24. Industrial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.52%	0.50%	0.36%	0.29%	0.21%	0.16%
2025	5.09%	4.89%	2.51%	1.87%	1.24%	0.86%
2030	15.66%	15.01%	6.58%	5.01%	3.25%	2.10%
2040	34.44%	33.05%	12.78%	10.43%	7.28%	4.91%

As shown in Figure 29 efficient pumps and related measures hold by far the greatest energy savings potential for the industrial sector, accounting for nearly 60% of the total. This is in part due to the fact that pumps account for such a large portion of the industrial sector's forecast baseline energy load (81%). Lighting and HVAC also hold substantial energy savings potential for this sector at 17% and 18% of the total, respectively.

Figure 29. Industrial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)



	Baseline Load	Savings Potential
Pumps	81.0%	58.0%
Process Heat	2.6%	0.5%
Process Cool	1.0%	0.5%
Motors	6.8%	6.7%
Lighting	3.3%	16.6%
HVAC	5.3%	17.7%

Table 25. presents cumulative industrial demand savings by end-use by milestone year. As with energy savings potential, pumps are also the leader in terms of demand savings potential. Pump-related

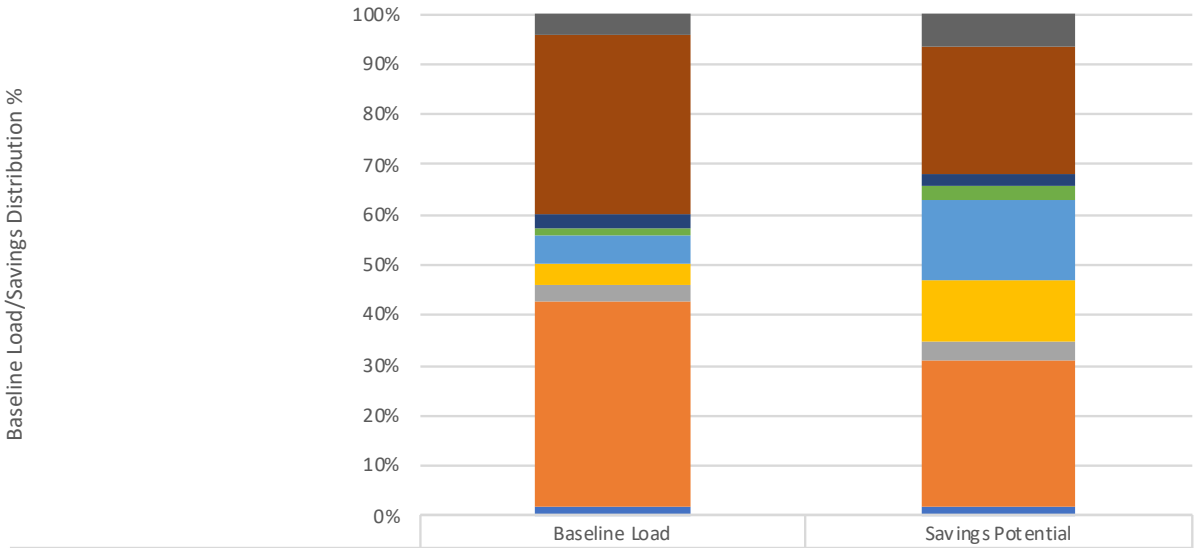
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

Table 25. Industrial Cumulative Demand Savings Potential by End-Use by Year (MW)

YEAR	HVAC	LIGHTING	MOTORS	PROCESS COOL	PROCESS HEAT	PUMPS	TOTAL
2021 (first year)	0.165	0.201	0.132	0.008	0.008	1.364	**1.878**
2025	0.469	0.496	0.242	0.022	0.020	2.456	**3.705**
2030	1.076	0.898	0.424	0.047	0.037	4.187	**6.669**
2040	1.686	1.258	0.672	0.070	0.052	6.597	**10.335**

Figure 30 shows that liquid mining and pipeline transportation are the two segments of the industrial sector that account for the most energy savings potential, at more than one-quarter of the total for each segement. Together, these two segments account for approximately 55% of the savings potential. Manufacturing-related segments (i.e., non-metallic mineral products, chemical, paper and other manufacturing segments) together make up over one-third of the total energy savings potential.

Figure 30. Industrial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)



	Baseline Load	Savings Potential
TCU	4.2%	6.6%
Pipeline Transportation (Oil, Gas, and CO2)	35.6%	25.5%
Mining	3.0%	2.0%
Mfg - Paper	1.6%	3.2%
Mfg - Nonmetallic Mineral Product	5.3%	15.9%
Mfg - Misc.	4.6%	12.1%
Mfg - Chemical	3.2%	3.9%
Liquid Mining (Oil, Gas, and Carbon Dioxide)	40.8%	29.2%
Agriculture	1.8%	1.7%

Table 26. summarizes cumulative industrial program cost metrics by milestone year. As shown, first-year program costs are approximately $2.4 million, rising to a 20-year average annual cost of roughly $9.6 millon. Acquisition costs start at $168/MWh during the first year of analysis and see only a slight increase through 2040. The TRC ratio remains solid for the industrial sector starting at 2.08 in 2021 and decreasing modestly to 1.92 in 2040.

Table 26. Industrial Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	2.08	$2,391,009	14,224	$168.09	$11.67
2025	2.02	$18,273,240	104,319	$175.17	$12.80
2030	1.96	$57,536,744	311,837	$184.51	$14.14

2040	1.92	$192,026,153	993,332	$193.32	$15.25
20-year avg.	1.92	$9,601,308	**49,667**	**$193.32**	**$15.25**

8. IRRIGATION EFFICIENCY POTENTIAL

8.1. Overview

Irrigation accounts for a small fraction of energy consumption and savings potential; it represents approximately 8% of Tri-State's total baseline energy load, and 3% of potential energy savings. Cumulative savings potential for this sector is approximately 53,134 MWh through 2040 (Achievable-Moderate scenario). Measures with notable savings potential include high efficiency motors, motor VFDs and base boot gasket improvements, making up approximately 63%, 18% and 17% of total savings potential respectively.

8.2. Detailed Results

Table 27 presents cumulative savings potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 31 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 584 MWh of savings potential in 2021 rising to approximately 53,134 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 70%. Savings potential increases by an additionad 39% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 119,793 MWh through 2040.

Table 27. Cumulative Irrigation Savings Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,541	1,128	1,026	814	584	454
2025	25,117	18,368	13,409	9,028	5,504	3,609
2030	149,894	111,385	60,712	40,289	22,193	12,282
2040	435,221	334,704	119,793	88,727	53,134	29,070

Figure 31. Irrigation Energy Efficiency Savings Potential by Scenario by Year

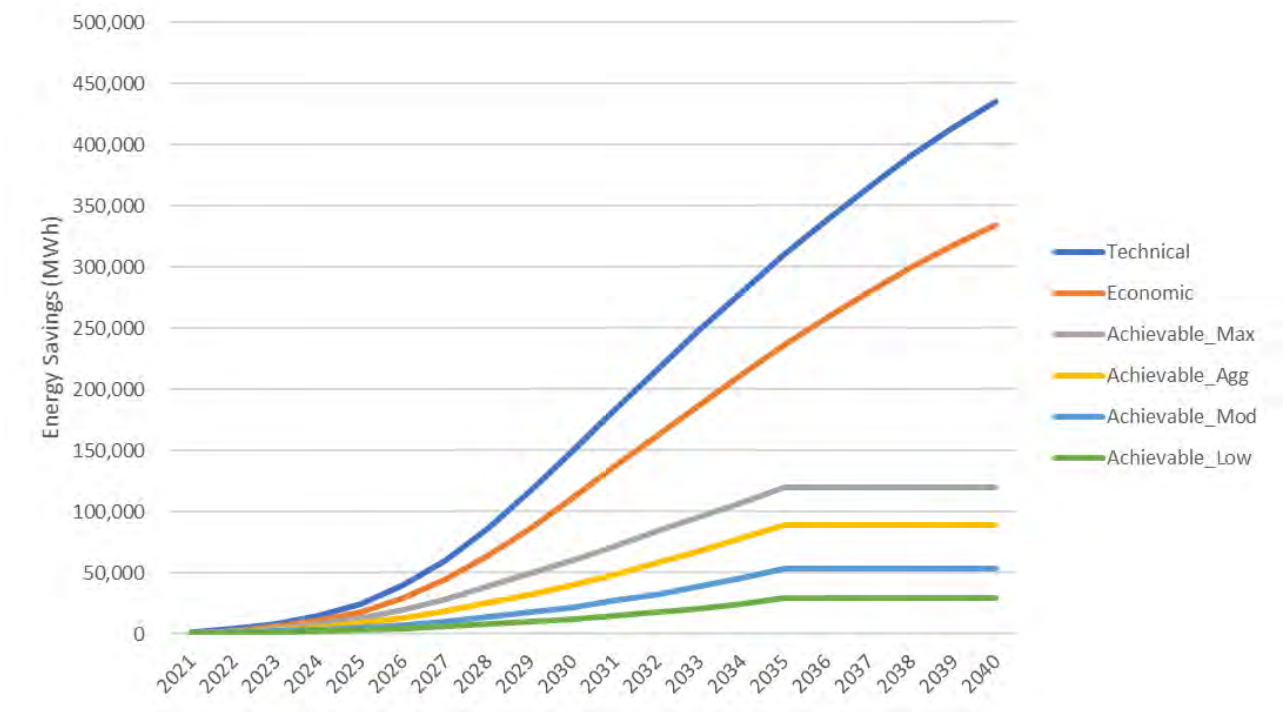


Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

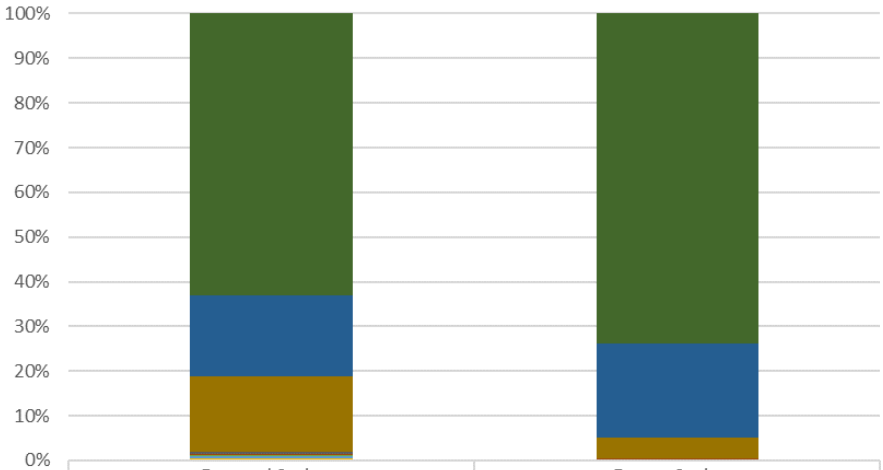
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share of total irrigation savings potential.

Table 28. Irrigation Cumulative Savings Potential as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.12%	0.09%	0.08%	0.06%	0.04%	0.03%
2025	1.90%	1.39%	1.01%	0.68%	0.42%	0.27%
2030	11.17%	8.30%	4.52%	3.00%	1.65%	0.91%
2040	31.51%	24.23%	8.67%	6.42%	3.85%	2.10%

Figure 32 shows the range of measures examined as part of the analysis, as well as the share of total demand and energy savings each measure represents. High efficiency motors comprise by far the largest share of savings at 63% of demand and approximately 74% of energy savings. Motor VFDs and base boot gaskets also represent notable savings opportunities. Other measures, like upgrades to Low Elevation Spray Application (LESA) and Low Energy Precision Application (LEPA) and scheduling-related measures may hold potential for improving customer satisfaction, as they can reduce water use and improve crop yields. However, LESA and LEPA are not found to provide substantial energy savings, and the analysis Team did not explore scheduling-related measures as part of this analysis.

Figure 32. Irrigation Cumulative Demand and Energy Savings by Measure (2040)



	Demand Savings	Energy Savings
HE Motor	63.07%	73.81%
Motor VFD	18.02%	21.18%
Base boot gasket	16.91%	4.52%
Cut and press repair	0.43%	0.12%
Hub gasket	0.25%	0.11%
Upgrade from high pressure to LESA/LEPA/MDI	0.22%	0.10%
Upgrade from high pressure to MESA	0.20%	0.09%
Sprinkler package replacement, high pressure	0.41%	0.03%
Nozzle replacement	0.24%	0.02%
Gaskets	0.15%	0.02%
Drains	0.08%	0.01%
Sprinkler package replacement, MESA	0.02%	0.00%

Table 29. presents cumulative and average annual costs, savings and TRC metrics associated with the Achievable-Moderate scenario for irrigation efficiency measures. As shown, in the first year Tri-State can achieve approximately 584 MWh of energy savings at a cost of approximately $185,313, or a levelized cost of $47.49/MWh. As programs expand and become more established annual costs and savings increase substantially. The 20-year average annual program costs are approximately $1.75 million and savings are 5,518 MWh.

Table 29. Irrigation Cumulative Cost Metrics by Time Horizon

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	SUM OF 1st-YEAR MEASURE SAVINGS (MWH)	ACQUISTION COST ($/MWH)	LEVELIZED COST ($/MWH)
2021	0.99	$185,313	584	$317.40	$47.49
2025	0.99	$1,750,685	5,516	$317.39	$47.50
2030	0.99	$7,632,143	24,046	$317.40	$47.51
2040	0.99	$35,028,723	110,365	$317.39	$47.53
20-year avg.	**0.99**	$1,751,436	5,518	$317.39	$47.53

9. DEMAND RESPONSE POTENTIAL STUDY

9.1. Overview

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year analysis time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory.

Table 30 presents portfolio-level demand response potential by time horizon. As Tri-State does not currently offer demand response programs, each scenario ramps from zero and then plateaus when the program achieves maturity. The Achievable-Low scenario estimates 86 MW of cumulative summer demand response potential in 2040. Achieving more aggressive participation rates through increased marketing and incentive costs could yield an estimated 245 MW of potential (Achievable-High scenario).

Table 30. Cumulative Demand Response Potential (MW) By Scenario By Time Horizon

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	46	30	12	5
2025	297	196	85	30
2030	647	500	222	78
2040	704	548	245	86

Figure 33. Portfolio Demand Response Potential by Scenario by Year

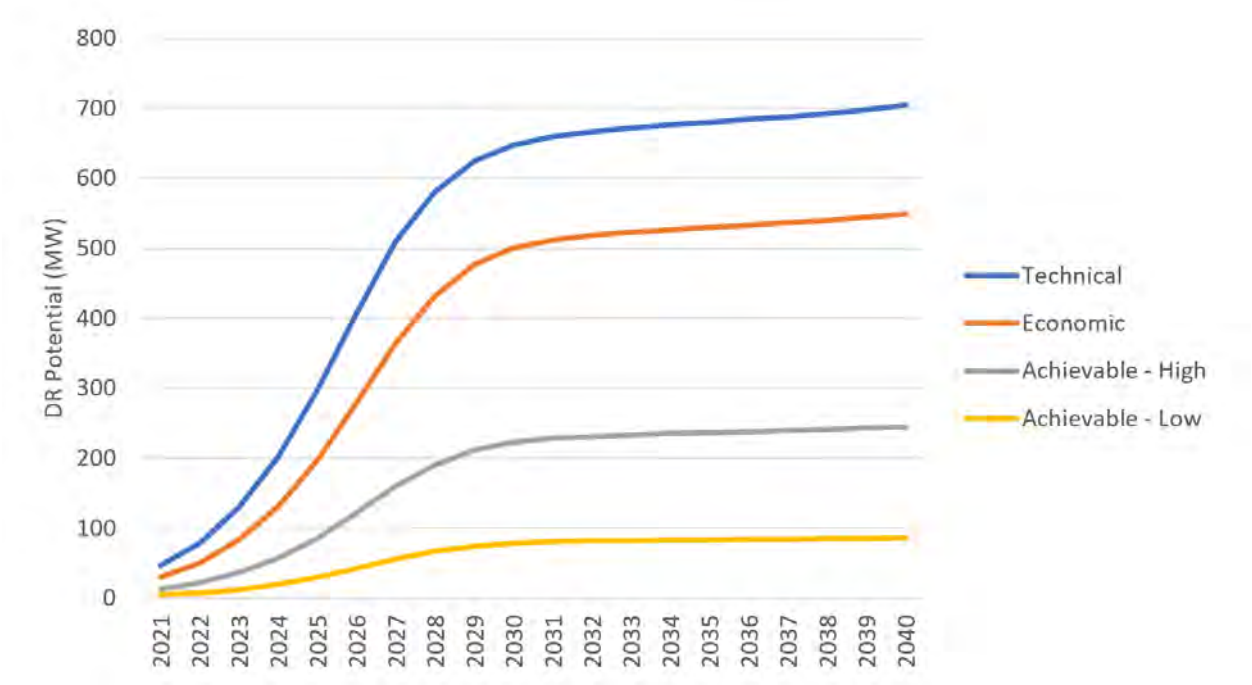


Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

Table 31. Portfolio Demand Response Potential as % of Baseline Forecast by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE HIGH	ACHIEVABLE LOW
2021	1.65%	1.07%	0.48%	0.16%
2025	9.99%	6.61%	2.87%	1.00%
2030	20.43%	15.79%	7.03%	2.47%
2040	19.85%	15.46%	6.90%	2.43%

Figure 34 and Figure 35 show contributions to the portfolio-level demand response potential by sector and by program type respectively. In each scenario, the largest contributors to the demand response potential are the residential and irrigation sectors. Connected device programs, primarily Smart Thermostat programs, and Direct Load Control (DLC), primarily for irrigation pumping, are the most significant program types.

This analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. As Tri-State does not control customer rates, implementing this type of demand response program would require a high level of collaboration with electric cooperatives.

Figure 34. Portfolio Demand Response Potential by Sector (2040)

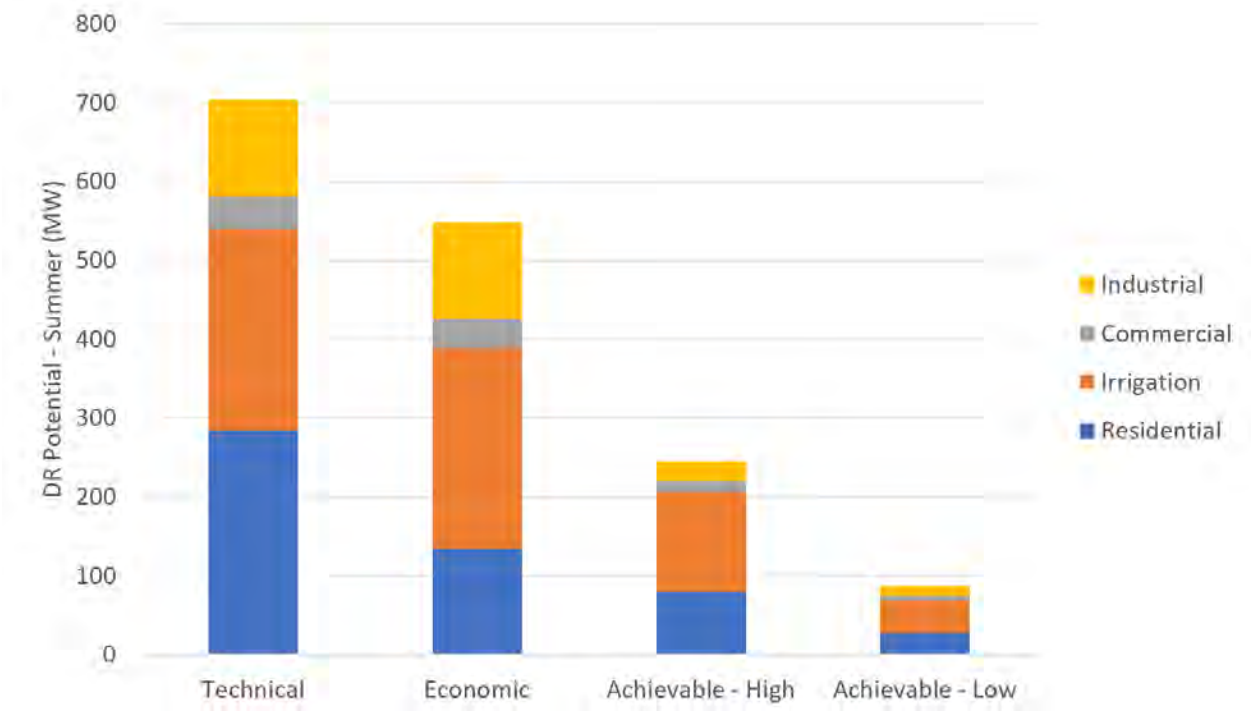
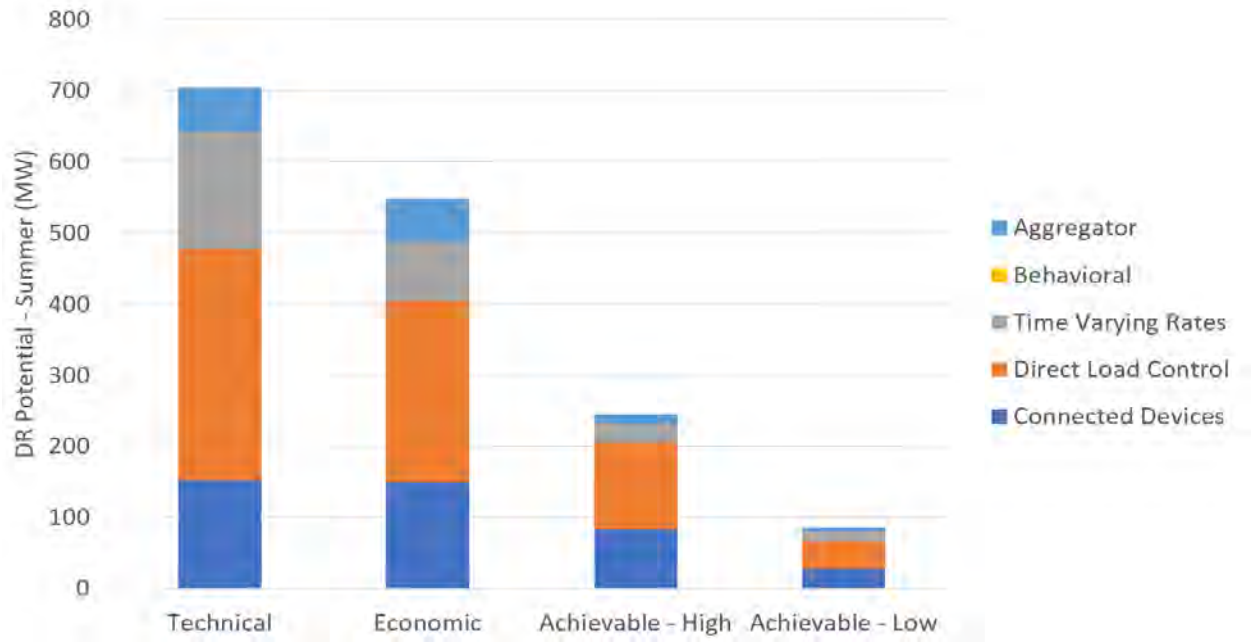


Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]



[16] Behavioral value is too small to observe.

Table 32 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity for 2021 through 2026 with an increase in 2027.

Table 32. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)

MILESTONE YEAR	TRC RATIO	CUMULATIVE PROGRAM COST ($)	DR POTENTIAL (MW)
2021	0.02	$5,440,119	5
2025	0.09	$13,818,802	30
2030	0.60	$24,286,062	78
2040	1.16	$39,068,285	86

9.2. Residential Sector Demand Response Potential

Figure 36 shows how demand response potential for residential sector programs grows over the study horizon as program participation increases. Figure 37 shows the contribution from each modeled demand response program for the four considered scenarios in 2040. Two programs were cost effective and thus included in the economic and achievable scenarios – Smart Thermostats and Smart Water Heaters. In the Achievable scenarios, Smart Thermostats achieve the largest share of the demand response potential.

Traditional DLC programs are not cost effective given their higher switch and controller hardware costs. The analysis shows that demand response for residential HVAC unit loads could be more cost effectively managed with a Bring-Your-Own-Thermostat program format utilizing customer-purchased smart thermostat devices. This finding aligns with a nationally observable trend away from the older DLC technology and pager network communications protocols towards programs that use customer-purchased devices and device internet access for communication.

Although a less mature program model, Smart Water heater programs are also increasing in popularity in many jurisdictions nationwide. Some versions of these programs similarly use internet-based communications and would be the most cost effective for Tri-State. Water heaters with built-in grid connection technology are also becoming more widely available, thus eliminating the need for installation of a separate device. As this technology matures, Tri-State could likely develop a successful demand response program to control residential water heaters during peak periods.

Figure 36. Residential Sector Demand Response Potential by Scenario by Year

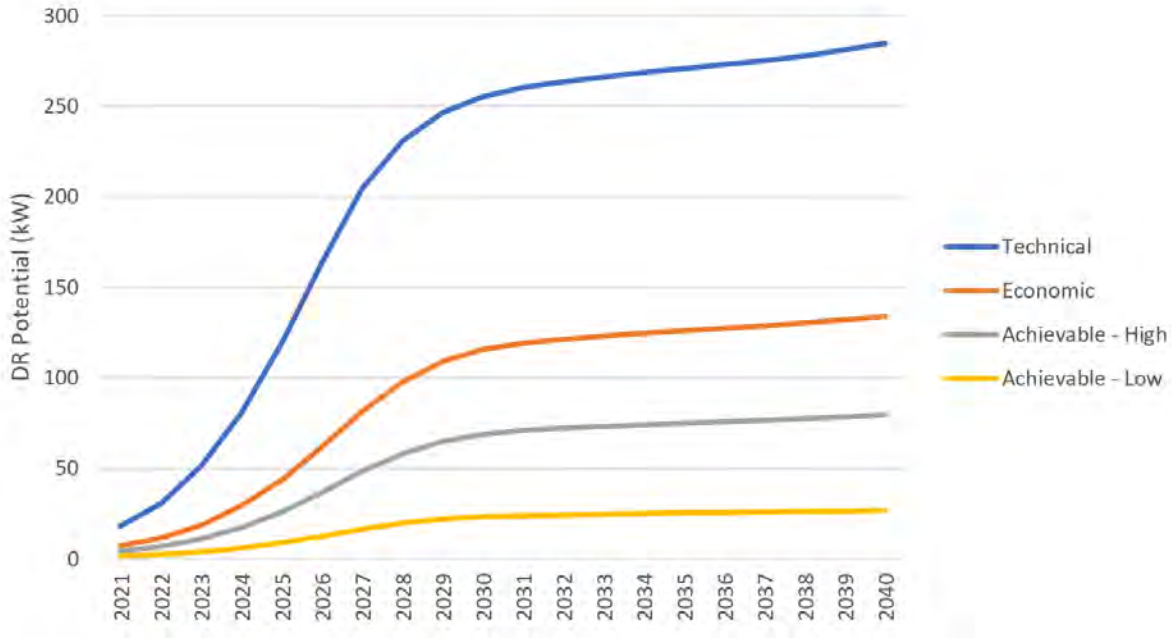
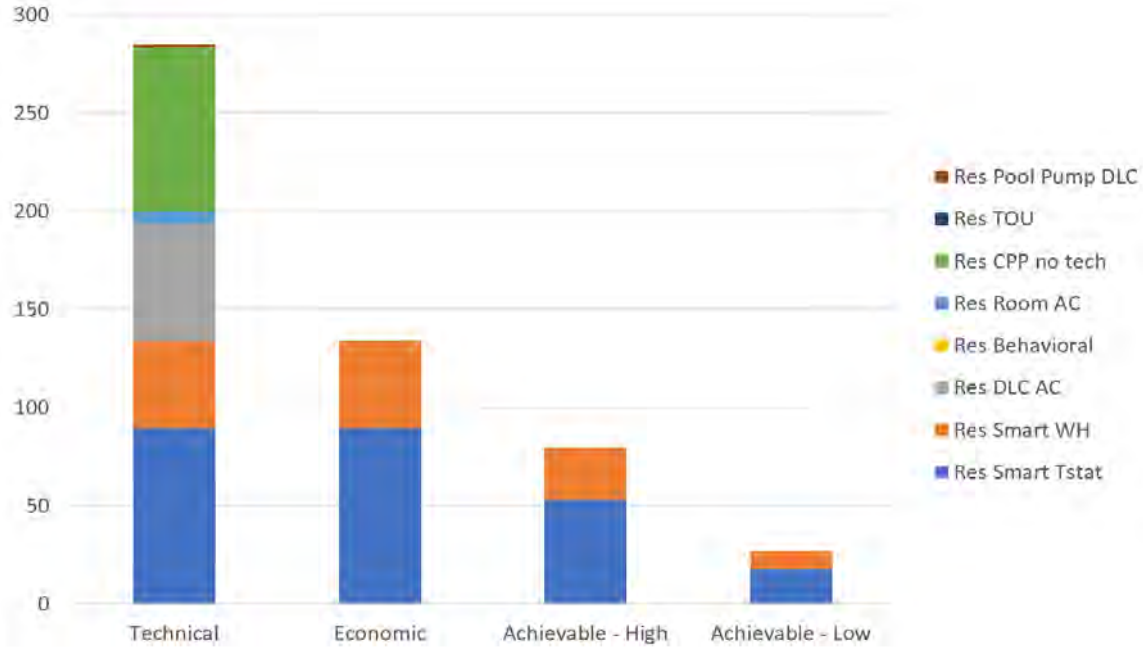


Figure 37. Residential Sector Demand Response Potential by Program (2040)



9.3. Irrigation Sector Demand Response Potential

Figure 38 shows how demand response potential for the irrigation sector programs grows over the study horizon as program participation increases. Figure 39 shows the each modeled demand response program's contribution to the four considered scenarios in 2040. Two programs were cost effective and therefore included in the economic and achievable scenarios – Direct Load Control and Critical Peak Pricing without Enabling Technology. In the Achievable scenarios, Direct Load Control achieves the largest share of the demand response potential.

Successful irrigation DLC programs are currently operational in regions similar to portions of Tri-State's territory, such as Idaho Power's Irrigation Peak Rewards program. That program is designed to target only customers with pumping demand greater than 75 horsepower, thereby focusing economic resources for maximum demand reduction. This analysis included eligibility rates for each region in Tri-State's territory to estimate the regional prevalence of large irrigation pumps. Mountain Colorado, for example, has a 0% eligibility rate because of presumed reliance on lower horsepower pumps for horizontal pumping.

Figure 38. Irrigation Sector Demand Response Potential by Scenario by Year

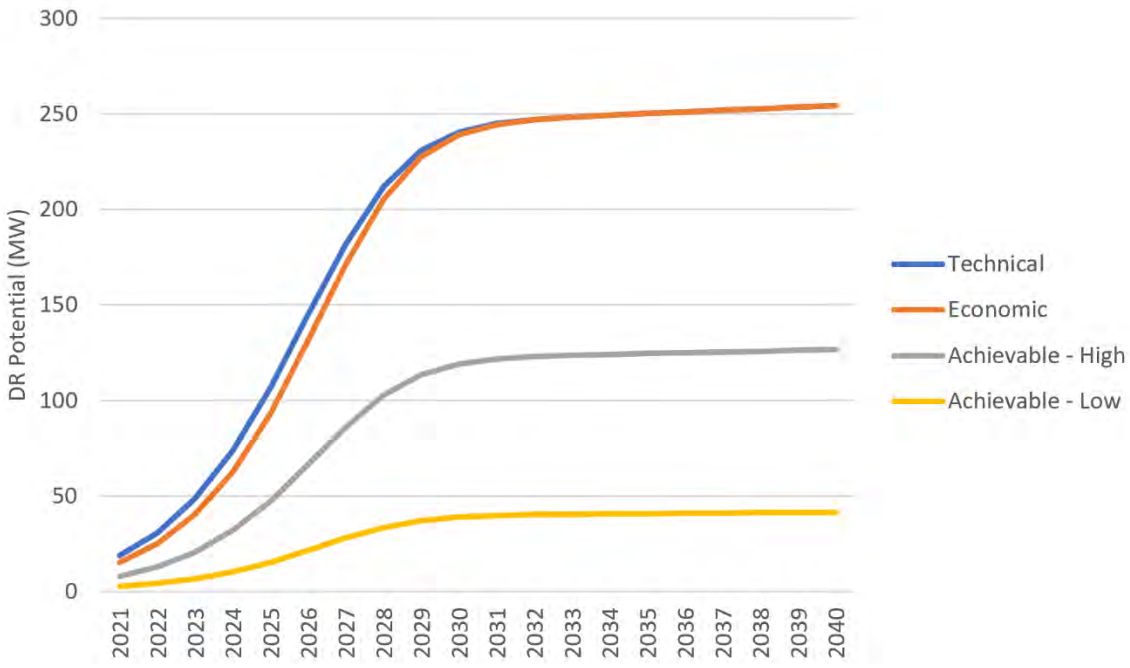
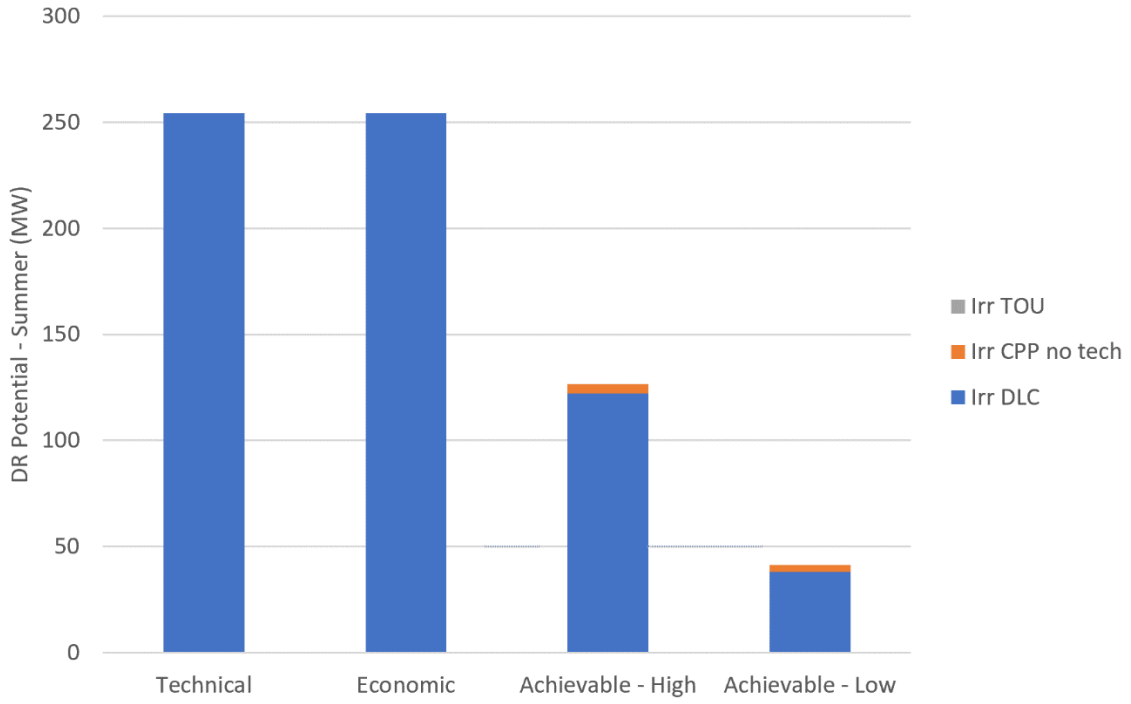


Figure 39. Irrigation Sector Demand Response Potential by Program (2040)



9.4. Commercial Sector Demand Response Potential

Figure 40 shows how demand response potential for irrigation sector programs grows over the study horizon as program participation increases. Figure 41 shows each modeled demand response program's contribution to the four considered scenarios in 2040. Three programs were cost effective and therefore included in the economic and achievable scenarios – Demand Bidding, Smart Thermostats, and Critical Peak Pricing without Enabling Technology. The Smart Thermostats program option was modelled as an extension of the residential Smart Thermostats program and assuming the residential program sector carries a majority of program set-up and administration costs.

Capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. Third-party aggregators often manage these types of programs; thefore, this could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 40. Commercial Sector Demand Response Potential by Scenario by Year

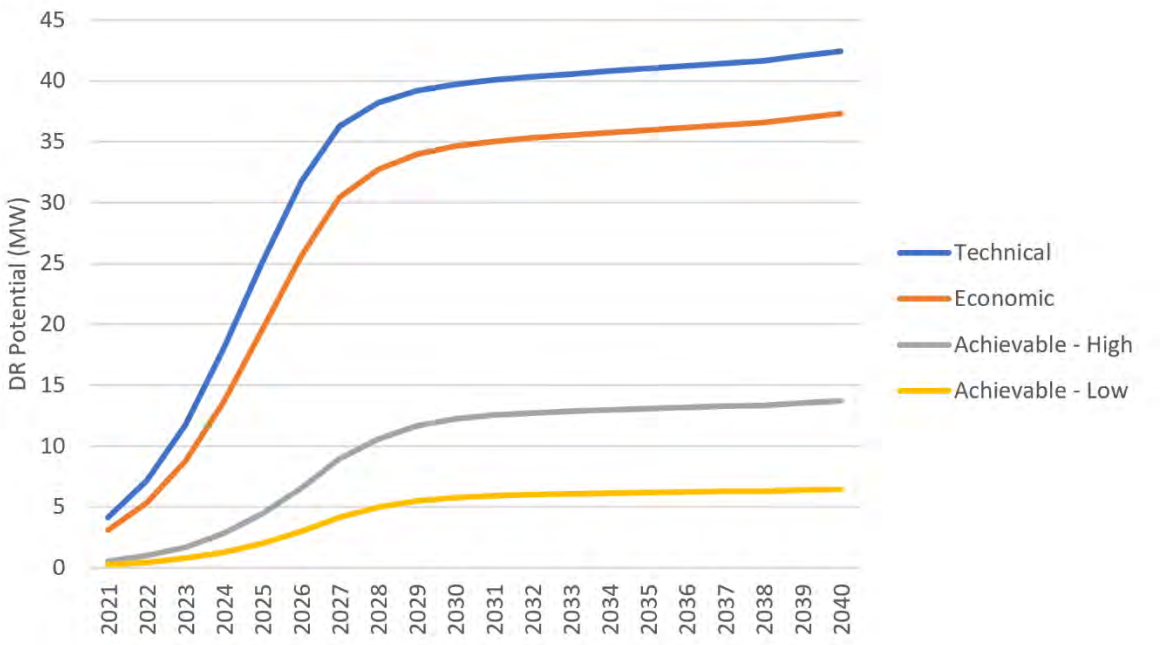
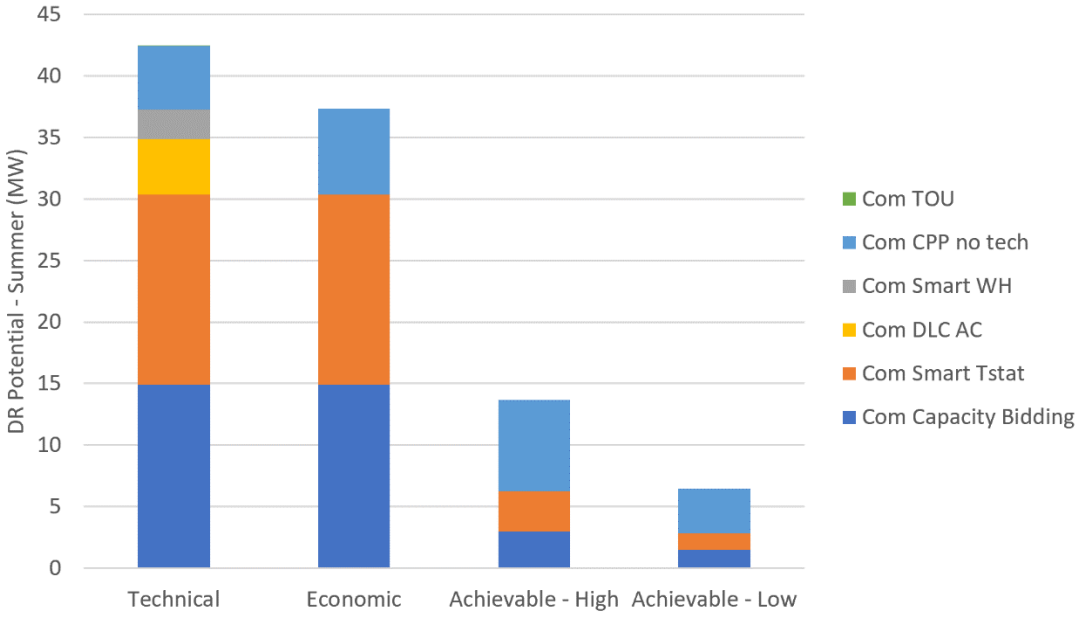


Figure 41. Commercial Sector Demand Response Potential by Program (2040)



9.5. Industrial Sector Demand Response Potential

Figure 42 shows how demand response potential for industrial sector programs grows over the study horizon as program participation increases. Figure 43 shows each modeled demand response program's

contribution to the four considered scenarios in 2040. Two programs are cost effective and therefore included in the economic and achievable scenarios – Capacity Bidding and Critical Peak Pricing without Enabling Technology.

As in the commercial sector, capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. These types of programs are often managed by third-party aggregators, and thus could be a strategy to overcome Tri-State's lack of direct access to end-users.

Figure 42. Industrial Sector Demand Response Potential by Scenario by Year

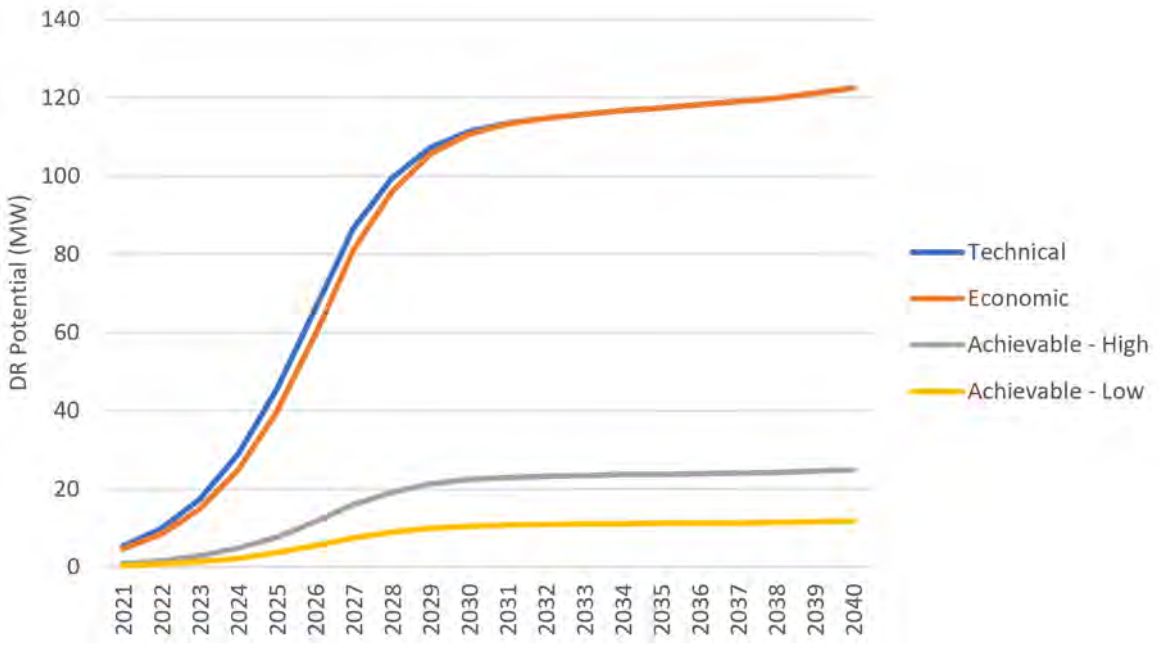
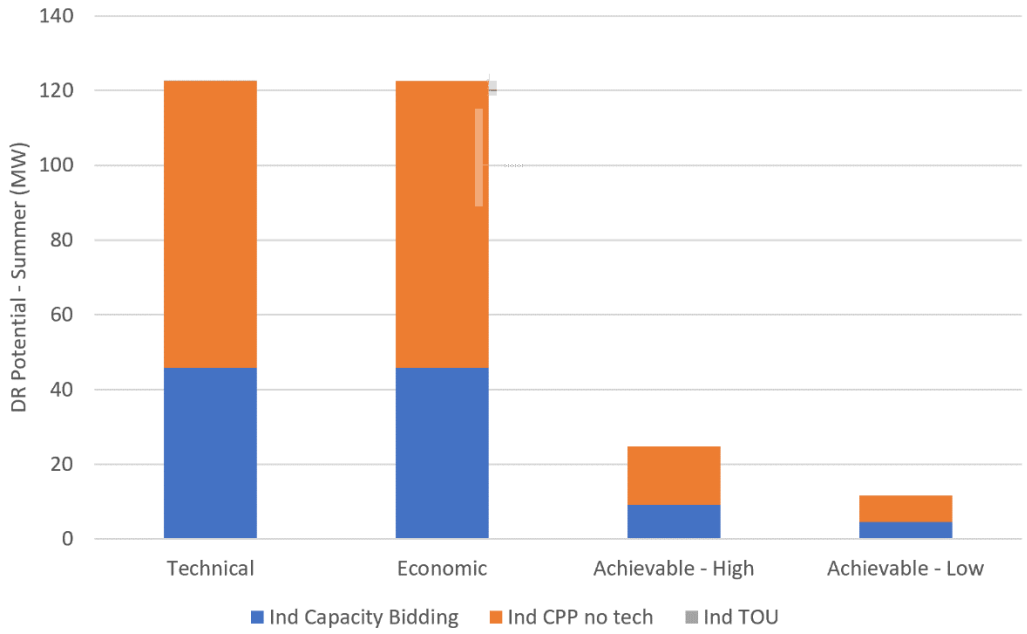


Figure 43. Industrial Sector Demand Response Potential by Program (2040)



10. BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCE POTENTIAL STUDY FINDINGS

10.1. Overview

As discussed in Section 3, the Team assessed rooftop solar PV potential for the residential and non-residential sectors. The technical potential analysis considered the total rooftop area suitable for solar PV within Tri-State's territory and extrapolated potential solar generation based on solar system power density per square foot for each Tri-State region. The Team subsequently screened systems for cost effectiveness and adjusted potential accordingly followed by further adjustments using adoption curves to represent achievable potential.

The Team found no systems to be cost effective for the residential sector under any TRC scenario analyzed. The highest TRC ratio achieved under the residential sector was 0.45 which reflects capacity and CO_2 emissions benefits.

The non-residential sector's very large PV systems are marginally cost effective for specific scenarios. Of these scenarios, the Team found the presence of CO_2 emissions benefits to be crucial as no PV system analyzed surpassed a TRC of 1.0 without inclusion of these benefits.

10.2. Detailed Results

Table 33 and Table 34 summarize the solar PV cumulative annual potential estimated generation for the residential and non-residential sectors, respectively. Electric demand impacts are presented for each sector in Table 35 and Table 36. While technical potential represents 100% adoption for each year, economic and achievable potential reflect applied adoption rates across the study time horizon.

Table 33. Cumulative Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE _MAX	ACHIEVABLE _AGG	ACHIEVABLE _MOD	ACHIEVABLE _LOW
2021 (first year)	2,548,130	0	0	0	0	0
2025	13,139,699	0	0	0	0	0
2030	27,290,122	0	0	0	0	0
2040	58,657,889	0	0	0	0	0

Table 34. Cumulative Non-Residential Generation Potential by Scenario by Time Horizon (MWh)

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	6,417,504	10,322	10,310	10,300	10,284	10,256
2025	33,037,716	141,370	139,829	138,809	137,108	134,198
2030	68,427,022	1,011,060	951,078	911,778	851,923	764,606
2040	146,160,272	5,512,777	4,705,933	4,254,001	3,661,295	2,952,911

The demand impacts presented in Table 35 and Table 36 reflect technical capacity based on operational capacity (based on installed nameplate) and coincident peak capacity. Economic and achievable scenarios reflect coincident peak capacity benefits.

Table 35. Summary of Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	1,644	400	0	0	0	0	0
2025	1,747	425	0	0	0	0	0
2030	1,878	457	0	0	0	0	0
2040	2,141	521	0	0	0	0	0

Table 36. Summary of Non-Residential Solar PV Electric Demand Market Potential (MW)

MILESTONE YEAR	TECHNICAL DC CAPACITY	TECHNICAL PEAK CAPACITY	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	4,139	1,106	2	2	2	2	2
2025	4,384	1,172	9	9	9	9	9
2030	4,686	1,252	49	45	42	37	31
2040	5,281	1,411	83	69	61	50	39

The cumulative residential generation potential under the technical scenario equates to 57% of the cumulative residential baseline load sales forecast for 2040 (see Table 37). Similarly, the non-residential cumulative generation represents 52% of the cumulative residential baseline load forecast for 2040 (see Table 38). Non-residential economic potential equates to 2.0% of the cumulative residential baseline load forecast for 2040 and ranges from 1.7% to 1.1% under the achievable potential scenarios.

Table 37. Cumulative Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	56.1%	0	0	0	0	0
2025	56.3%	0	0	0	0	0
2030	56.4%	0	0	0	0	0
2040	56.5%	0	0	0	0	0

Table 38. Cumulative Non-Residential Generation Potential as % of Baseline Forecast Sales by Year

MILESTONE YEAR	TECHNICAL	ECONOMIC	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	53.9%	0.1%	0.1%	0.1%	0.1%	0.1%
2025	53.4%	0.2%	0.2%	0.2%	0.2%	0.2%
2030	53.1%	0.8%	0.7%	0.7%	0.7%	0.6%
2040	52.0%	2.0%	1.7%	1.5%	1.3%	1.1%

10.3. Technical DER Potential Findings

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure 44 and Figure 45 below illustrate cumulative PV generation in 2040 compared to cumulative 2040 sales. For both the residential and non-residential

sectors, PV generation is well below total sales for each region with the exception of Northern New Mexico (for residential) and Southern New Mexico. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency, a relatively high number of buildings, and relatively low energy consumption on average.

Figure 44. 2040 Cumulative Residential PV Generation vs Sales by Region

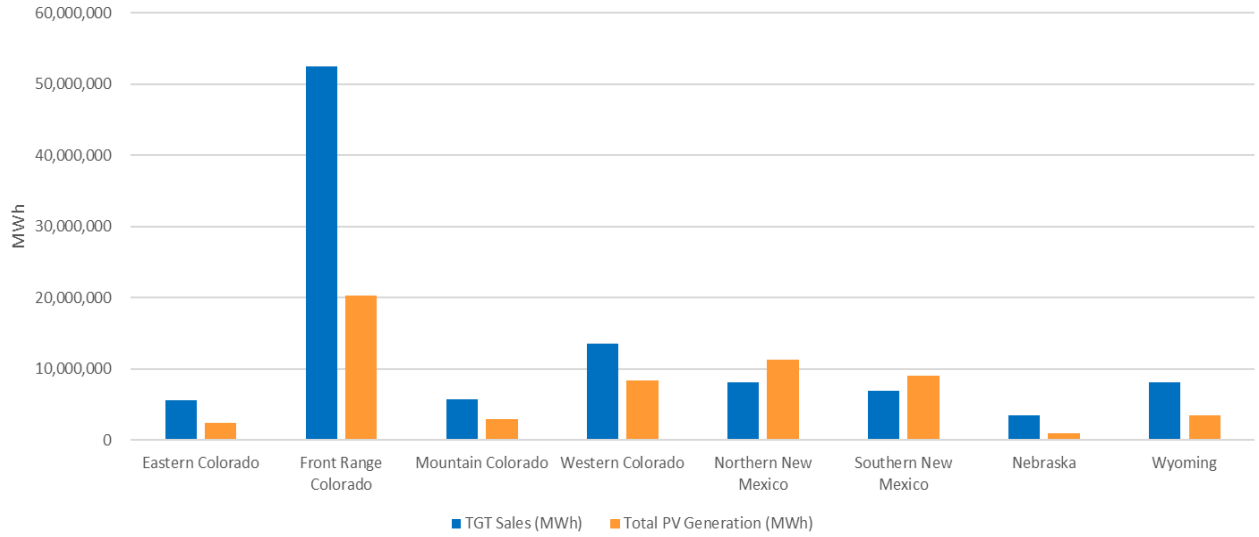
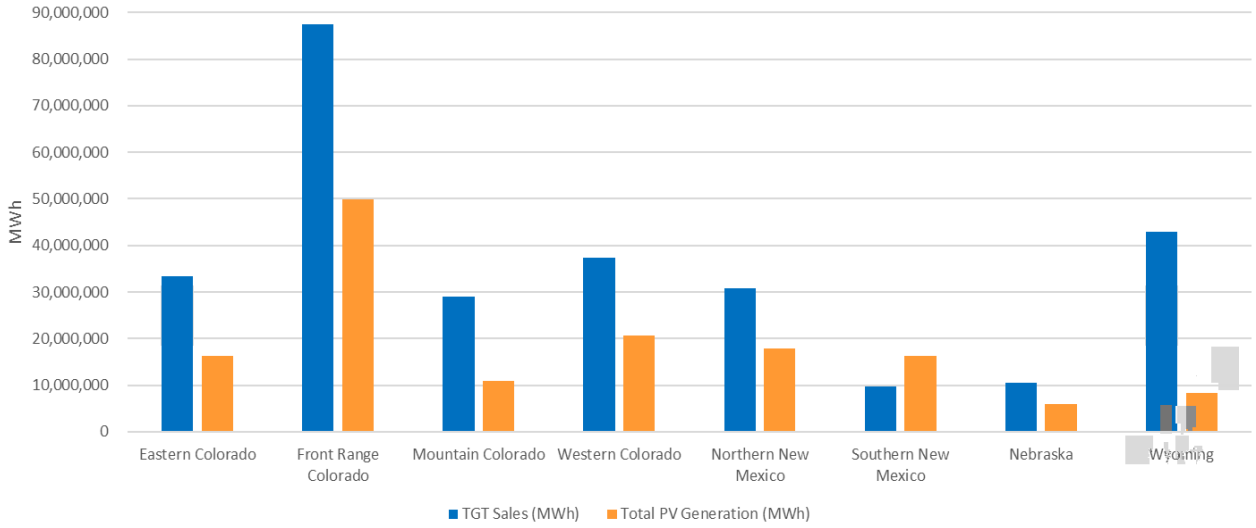


Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region



10.4. Economic and Achievable DER Potential Findings

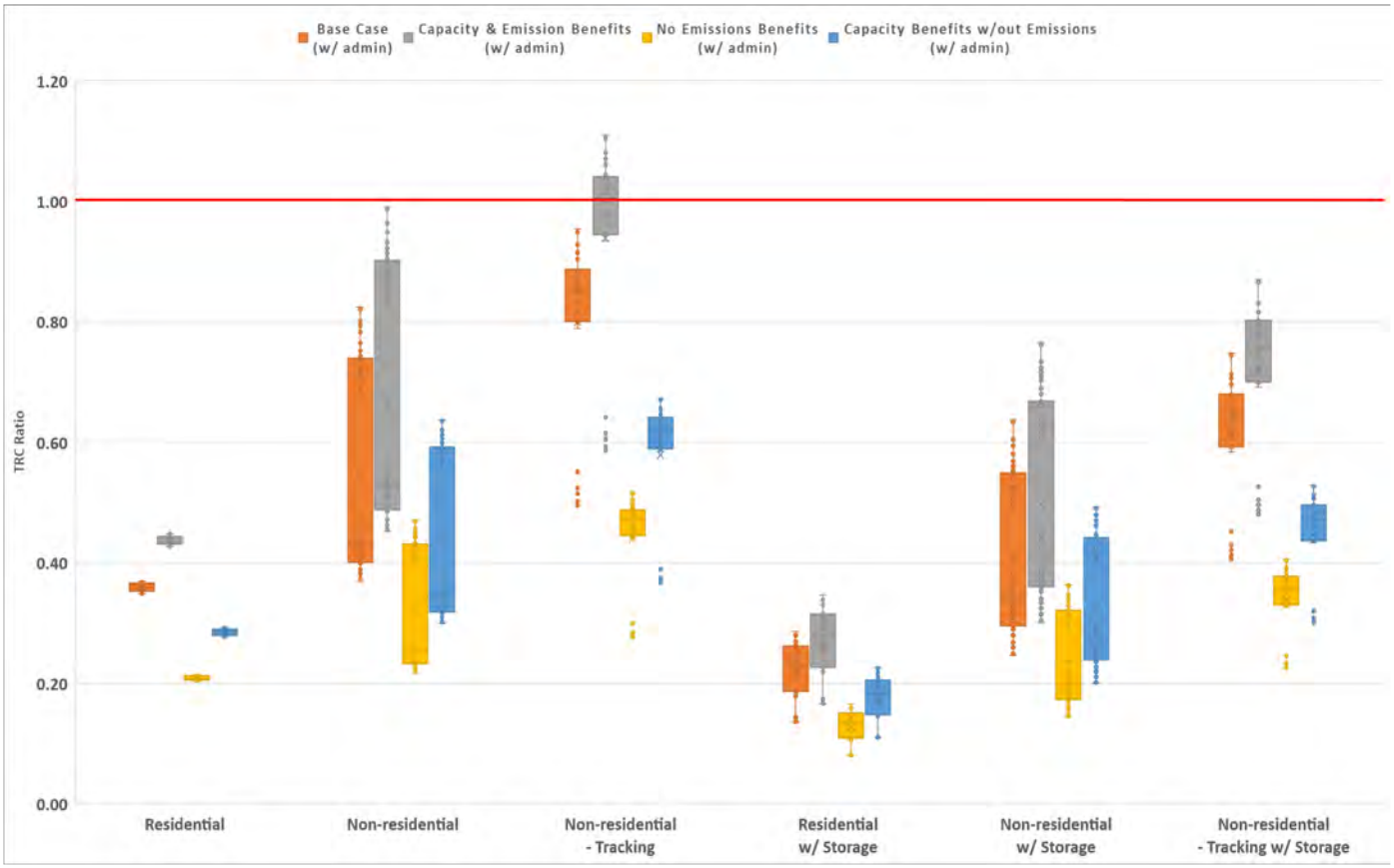
The Team screened economic potential using a TRC hurdle of 1.0 with the inclusion of CO_2 emission benefits based on the social cost of carbon of $46/ton and administrative costs of $0.05/kWh. However,

to understand the sensitivity of various benefit parameters, the team modeled cost effectiveness for multiple scenarios that included various combinations of benefits. Scenarios reviewed included:

- Base case
  - Inclusive of CO_2 emission reduction benefits
- Capacity and emission benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Inclusive of CO_2 emission reduction benefits
- No emissions benefits
  - Base case exclusive of CO_2 emission reduction benefits
- Capacity benefits without emissions benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Exclusive of CO_2 emission reduction benefits

Figure 46 illustrates the results and sensitivities of the solar PV cost effectiveness under each of these scenarios for various categories of solar PV systems included in the potential study. Only one scenario yields TRC ratios that exceed 1.0 – non-residential tracking systems assuming the presence of capacity and CO_2 emission benefits benefits. Also noted is any scenario excluding CO_2 emission benefits results in all solar system configurations analyzed to fail pass cost effectiveness.

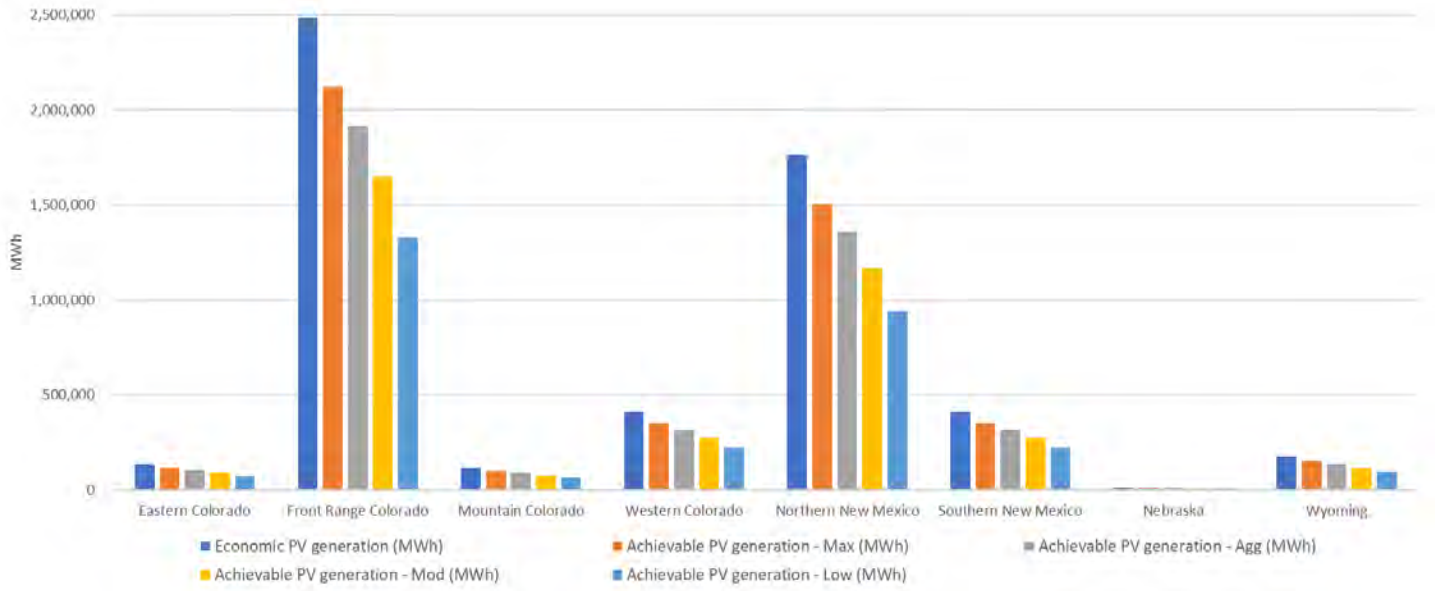
Figure 46. Solar PV TRC Ratios - Multiple Scenarios



Based on the cost effectiveness analysis, the Team modeled economic and achievable potential based on the sole cost effective scenario – non-residential tracking solar systems with capacity and emission benefits. Twenty two solar PV system configurations (9% of all tested measure permutations) passed cost effectiveness including tracking systems varying in size from 250 kW to 2000 kW system capacity. These passing measures have an average TRC of 1.04. This scenario, however, is not applicable throughout the Tri-State territory insofar as capacity constraints are not expected until 2027 (and therefore capacity benefits would not be realized until that time) and carbon benefits are only applicable to Colorado regions (at the time of report publication). Regardless, for the purposes of this report, the Team opted to model economic and achievable potential for all regions in order to inform Tri-State of how solar adoption may occur throughout its territory.

The results of the economic and achievable potential are presented below in Figure 47. Economic and achievable potential is limited due to the small number of solar systems that pass cost effectiveness and due to the physical requirements of these systems – tracking systems are considered ground-mounted for this analysis and therefore are only applicable to sites that are expected to have sufficient land space to host these systems and the system does not generate more energy than the site consumes. Based on these constraints, the team estimated 66 eligible sites across Tri-State's territory for the economic scenario. The number of eligible systems decreases for each achievable potential scenario as solar system payback time increases.

Figure 47. 2040 Cumulative Non-Residential Economic and Achievable Potential by Region



As illustrated in Figure 47, the highest concentration of eligible sites, and thereby the highest potential, are in the Front Range and Northern New Mexico regions. However, as noted earlier, carbon emission benefits at the time of this report publication are not currently a quantifiable benefit in New Mexico, Wyoming, or Nebraska and therefore this reported economic and achievable potential should be considered with that perspective.

11.KEY FINDINGS

At present Tri-State and its member cooperatives deliver some energy efficiency and DR programs, and no DER programs, to their customers. Even with low avoided energy cost benefits for DSM programs within Tri-State's service territory this study identifies significant cost-effective opportunities for energy and demand savings for energy efficiency programs. There are also opportunities for DR programs, but in some cases those program require long term operation to provide cost-effectiveness. DER programs are generally not cost-effective except for larger systems in specific regions. Key findings and observations related to each of these resources is summarized below. It should be noted that the results of this study and the findings presented here are uncertain to a degree and are sensitive customer adoption of DSM intervetions. Furthermore, the dynamic relationship between Tri-State and the member co-ops presents instrinsic challenges to the seamless implementation of DSM programs. These variables should be take into account when considering the results of this study.

11.1. Energy Efficiency

In 2018, Tri-State cooperative members acquired roughly 30 GWh of energy efficiency savings (~0.2% of baseline energy load)[17]. This suggests that Tri-State's members are currently operating programs somewhere between the Achievable-Low and Achievable-Moderate scenarios, which identified energy savings of 27 GWh and 38 GWh respectively in 2021. With coordinated efforts among cooperative members the long-term market opportunity for cost-effective energy efficiency savings in the region served by Tri-State is considerably higher; the average annual savings potential is 115 GWh over the study's 20-year time horizon for the Achievable-Moderate scenario. Additional key findings within the energy efficiency assessment include:

- 20-year average annual energy savings are just under 115 GWh (0.66% of baseline energy load) at a total program cost of $24M per year ($212/MWh acquired).
- 20-year levelized cost of energy to acquire all energy savings is $21.55/MWh.
- While the industrial sector represents the largest market opportunity (43% of 20-year potential), the residential sector represents the biggest opportunity (35% of potential) compared to its load share (28% of load).
- The commercial sector holds the most cost-effective savings opportunities with a TRC of 1.93 and average 20-year acquisition cost of $171/MWh.
- Pumps (primarily within the industrial sector) represent the largest end-use opportunity across the portfolio at 25% of 20-year cumulative energy savings – much of this opportunity resides with several large Liquid Mining and Pipeline Transportation customers.
- Even with rapid market transformation to LEDs for A-lamp bulbs, there is still considerable savings opportunities in the commercial lighting (21% of potential) and Residential lighting (19% of potential) end-uses – these end-uses are also among the most cost effective with acquisition costs of $150/MWh and $200/MWh respectively.

[17] Tri-State Generation and Transmission, Inc. 2018 Annual Report. (p. 12).

- HVAC measures account for 18% of savings potential – though are relatively expensive with an average acquisition cost of roughly $275/MWh.
- With zero capacity benefits in the first seven years, Home Energy Reports did not pass the study's TRC cost-effectiveness screen until 2028; after which the measure becomes a major opportunity contributing to almost 6% of portfolio savings potential.
- High/medium bay linear lamp and fixture conversions to LED technology represents more than 60% of cumulative energy savings potential in the commercial sector by 2040.
- Non-EISA compliant light bulbs contribute more than 45% to cumulative energy savings potential by 2040 in the residential sector.
- Upgrading existing air source heat pumps to higher efficiency models represent more than 6% of cumulative energy savings potential by 2040 in the residential sector.

11.2. Demand Response

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory. Additional key findings from the demand response potential analysis include:

- High levels of investment in marketing and incentives could yield up to 245 MW of potential (Achievable-High scenario).
- Potential reduction in portfolio-level baseline forecast demand ranges from 2.4% (Achievable-Low) to 6.9% (Achievable-High).
- The residential and irrigation sectors hold the greatest potential for demand response program savings.
- In general, the Direct Load Control program model holds the greatest potential for savings. Among the two Achievable scenarios the most promising program models within each each sector are:
    - Residential: Smart Thermostats and Smart Water Heaters
    - Commercial sector: Critical Peak Pricing and Smart Thermostats
    - Industrial: Critical Peak Pricing
    - Irrigation: Direct Load Control

11.3. Behind-The-Meter Distributed Generation

We analyzed potential for rooftop solar PV across Tri-State's territory for both the residential and non-residential sectors. Ultimately we found rooftop solar PV to not be cost effective for the residential sector. The non-residential sector is cost effective for very large ground-mounted tracking solar arrays when including key benefits of capacity and emission benefits. Additional findings from the distributed energy resource potential analysis include:

- Technical potential solar generation for both residential and non-residential sectors can equate to just over half of total sales.
- No residential solar PV measures pass cost effectiveness under any benefit-cost scenario analyzed in the study.
- The sole cost effective scenario includes both capacity benefits and CO_2 emissions benefits. Just 9% of analyzed measure permutations pass this cost effectiveness scenario and are characterized as non-residential ground-mounted tracking systems varying from 250 kW to 2000 kW system capacity. These system measures have an average TRC of 1.04.
- Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while these potential savings reflect the entire Tri-State territory, the sole cost effective scenario is not applicable to regions outside of Colorado as emissions are not a quantifiable benefit at the time of this report publication.

Attachment Vol II 5-2 B&V Loss of Load Probability Study

Report on Loss of Load Probability Analysis

BV PROJECT NO. 404347

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PREPARED IN CONSULTATION WITH

Tri-State Generation & Transmission Association

14 October 2020

BLACK & VEATCH

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1.0 Executive Summary

Black & Veatch Management Consulting LLC (Black & Veatch) was retained by Tri-State Generation & Transmission Association (Tri-State) to analyze the potential for loss of load within the Tri-State system. Black & Veatch ("we" or "us") has utilized production cost modeling software and in-house expertise to conduct a probabilistic loss of load probability (LOLP) analysis for the Tri-State system for two forecast years, 2025 and 2030, under four capacity expansion (CE) plans. The four CE plans were provided to us by Tri-State and include varying load forecast and capacity addition assumptions. The four CE plans are as follows:

1. Base: Business as usual scenario without greenhouse gas (GHG) emissions reduction requirements in Colorado using market parameters and unit conditions as of March 2020.
2. MAX: Low load scenario representing a 10 percent reduction in system demand and related energy with corresponding reductions in losses and planning reserve margin.
3. MARS: High distributed generation scenario representing an increase in distributed generation equivalent to 10 percent of system demand.
4. Carbon Reduction: GHG reduction scenario with substantial reduction in GHG emissions by 2030 from 2005 baseline.

A production cost model using PLEXOS software was configured to represent the Tri-State system under each of these alternative future CE plans. Assumptions and forecasts were provided by Tri-State including load forecasts, contract purchases and sales, hydro monthly energy constraints, and generator financial and operational characteristics. Outputs from initial runs of the PLEXOS model were then compared to outputs from Tri-State's prior simulation of the Base CE using its own production cost modeling tool.[1] This was done to confirm the accuracy of the PLEXOS model prior to conducting the LOLP analysis. For each year and each capacity expansion plan, the PLEXOS model was then run 20 times with different risk draws to simulate random forced outages within the Tri-State system. The mean and standard deviation LOLP was calculated from the 20 risk samples. We found that the LOLP for the Base CE and MARS CE plans exceeded the LOLP target of 1 day in 10 years for the year 2030 while all other CE plans met the LOLP target. To compensate for these exceedances, two (2) and three (3) 100 MW 4-hour batteries with 400 MWh of energy storage capability were added to the Base CE and MARS CE plans, respectively. The PLEXOS model was run again, and results showed that the mean LOLP target was met for both the Base and MARS capacity expansion plans.

[1] File "March Base 2020 PO Annual data Confidential.xls" (March 2020 Base)

2.0 Scope

Tri-State retained Black & Veatch to analyze the impacts of increased renewable generation and thermal power plant retirements on reliability of the Tri-State power generation system. Generation reliability is traditionally measured in a "static" fashion by observing the forecast capacity reserve margin which is the surplus of forecast generation capacity above forecast peak load measured on an annual basis. However, in high renewable scenarios a dynamic LOLP analysis is a more appropriate because both renewable energy available to serve load and net peak load (load net of renewable generation behind the meter) are highly variable resulting in a highly variable reserve margin. An LOLP analysis allows consideration of this variable margin and a more rigorous probabilistic analysis of conventional generating unit outages as opposed to forecasted capacity reserve margin alone.

The objective for this analysis was to use a production cost model (PCM) implemented in PLEXOS to replicate Tri-State's various future expansion and operation scenarios and to examine the resulting LOLP. The LOLP is a measure of the likelihood of failing to meet load which is present on the Tri-State system and being forced to curtail load in a period with higher load than generation capability. The resulting LOLP under each scenario should not exceed a rate of 1 day in 10 years which is the typical reliability threshold expected for resource portfolios such as that of Tri-State.

The scope of the LOLP analysis was limited to two forecast years (2025 and 2030) and the four CE plans (Base, MAX, MARS, Carbon Reduction) developed by Tri-State. Therefore, the LOLP was forecast for a total of eight cases using the PLEXOS PCM developed for this analysis.

3.0 Methodology

Black & Veatch used a commercial PCM software package, PLEXOS[2], for this analysis. PLEXOS is a fundamental-based PCM software package that provides an optimal solution to meet a given load with a set of generators subject to constraints such as generator operational constraints, transmission constraints, and policy constraints. PLEXOS is widely used in the industry for long-term planning, including use by the California Independent System Operator (CAISO) for integrated resource planning (IRP) in the Western Electricity Coordinating Council (WECC)[3]. Key features of PLEXOS include capacity expansion planning, unit commitment and dispatch, co-optimization of energy and ancillary service markets, and evaluation of Monte-Carlo stochastic algorithms.

Tri-State provided data relevant to their system to conduct the LOLP analysis, including load forecasts, transmission transfer limits, operating reserve requirements with the Northwest Power Pool (NWPP) and the Southwest Reserve Sharing Group (SRSG), fuel forecasts, and generator financial and operational characteristics such as capacity, minimum stable level, heat rates, variable costs, minimum up/down time, ramp rates, outage rates, hourly renewable generation profiles, and monthly hydro generation. Contract purchases and sales were also provided and included in the model. Once configured, the model was assessed in comparison to the March 2020 Base dispatch profile provided by Tri-State. The evaluation primarily consisted of verifying annual generation quantities for each generator and contract to ensure PLEXOS was properly configured.

Four Tri-State CE plans were analyzed including the Base, MAX, MARS, and Carbon Reduction plans. Each plan has unique resource additions, and the MAX plan had a lower load forecast as compared to the other scenarios as shown in Table 1.

Table 1 Summary of Installed Capacity for Each Capacity Expansion Plan

	2025				2030			
Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Peak Load (MW)	3076	2636	3076	3076	3350	2904	3350	3350
Solar Additions (MW)	0	0	0	200	800	100	500	1300
Wind Additions (MW)	0	0	0	200	0	100	200	400
Battery Additions (MW)	0	0	0	75	0	0	0	750
Thermal Additions (MW)	0	0	0	0	596	410	575	265
Total Capacity Additions (MW)	0	0	0	475	1396	1410	1275	2715
Capacity Retirements (MW)	0	0	0	0	648	648	648	648
Net Capacity Additions (MW)	0	0	0	475	748	762	627	2067

To determine the LOLP in each scenario, we used PLEXOS' Monte-Carlo stochastic algorithms to randomly generate a set of forced outages based on forced outage rate and mean time to repair

[2] https://energyexemplar.com/solutions/plexos/
[3] http://www.caiso.com/Documents/2019-01-31-Comments_ProductionCostModeling-IRPProceeding-R16-02-007.pdf

assumptions (each a “risk draw”). The “short term” module of PLEXOS was utilized. PLEXOS was configured and run to simulate 20 risk draws for each year assessed (2025 and 2030) under each CE plan. Outputs from the simulation included mean and standard deviation of the number of hours with unserved energy (USE) each year. From this, an LOLP was calculated by dividing the USE by the total number of hours in the year. If the resulting LOLP exceeded the 1 day in 10 years maximum allowed, an amount of additional battery storage capacity was added to the capacity expansion plan and the simulation rerun. This was done in an iterative fashion until the target LOLP was achieved.

4.0 Results & Discussion

An LOLP of less than 1 day in 10 years corresponds to an LOLP of less than 0.0274 percent on an annual hour basis. The results of the LOLP analysis, including the mean and standard deviation of unserved energy (USE) hours and LOLP percent for each scenario, are shown in Table 2.

Table 2 Summary of USE and LOLP Prior to Battery Additions

	2025				2030			
CE Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Mean USE (hr)	1.95	0.00	1.95	0.00	9.20	1.45	25.75	0.70
Std. Dev. USE (hr)	2.31	0.00	2.31	0.00	4.77	2.48	6.15	1.30
Mean LOLP (%)	0.02	0.00	0.02	0.00	**0.11**	0.02	**0.29**	0.01
Std. Dev. LOLP (%)	0.03	0.00	0.03	0.00	0.05	0.03	0.07	0.01

Results for the year 2025 show that each CE plan was below the LOLP target on a mean LOLP basis. Results for the MAX CE and Carbon Reduction CE plans had zero mean LOLP. This is due to the MAX CE plan having a lower load forecast as compared to the other CE plans and the Carbon Reduction CE plan having capacity additions which are not present in the other CE plans. The MARS CE plan and the Base CE plan had some unserved load and thus non-zero mean LOLPs. Their LOLPs are identical in 2025 because the CE plans are identical up to that point in time.

Results for the year 2030 show that the LOLPs increased for each CE plan, above the LOLP target for two of them (shown in bold). The Base and MARS CE plans exceeded the LOLP target with mean LOLPs of 0.11% and 0.29% respectively. For the Base CE plan, this was due to load growth and not enough firm capacity growth to maintain LOLP below the target level. For MARS, this was due to the plan having the lowest net capacity additions by 2030 as compared to the other CE plans. While the Max CE plan had a mean LOLP (0.02%) under the target LOLP, the standard deviation was high (0.03%) suggesting certain conditions where the LOLP can be exceeded. For the Carbon Reduction CE plan, the mean LOLP (0.01%) was under the LOLP target by enough that the standard deviation (0.01%) does not suggest likely conditions where the LOLP would be exceeded.

To compensate for the excess LOLP in the Base CE and MARS CE plans, additional capacity was added to the Base CE and MARS CE plans in the year 2030 and the simulations re-run. Given Tri-State's long-term goal of achieving GHG reductions, we added generic new battery storage resources instead of thermal resources. The results of the LOLP analysis for the Base and MARS CE plans following addition of the energy storage are shown in Table 3.

Table 3 Summary of USE and LOLP After Battery Additions

	2025				2030			
Plan Name	Base	MAX	MARS	Carbon Red.	Base	MAX	MARS	Carbon Red.
Mean USE (hr)	1.95	0.00	1.95	0.00	1.7	1.45	0.9	0.70
Std. Dev. USE (hr)	2.31	0.00	2.31	0.00	1.92	2.48	1.17	1.30

	2025				2030			
Mean LOLP (%)	0.02	0.00	0.02	0.00	**0.02**	0.02	**0.01**	0.01
Std. Dev. LOLP (%)	0.03	0.00	0.03	0.00	0.02	0.03	0.01	0.01

Results show that both the Base CE and the MARS CE achieve the LOLP target in 2030 with addition of batteries (shown in bold). We found that for the Base CE, two additional 100 MW 4-hour batteries with 400 MWh of storage capacity are required to achieve the LOLP target. These batteries were added in eastern Colorado and Wyoming. For the MARS CE, three additional 100 MW 4-hour batteries with 400 MWh of capacity are required to meet the LOLP target. These batteries were added in western Colorado. While the Base CE plan had a mean LOLP (0.02%) under the target LOLP, the standard deviation was high (0.02%) suggesting certain conditions where the LOLP can be exceeded. As an additional sensitivity, we added three batteries to the Base CE (one in each of eastern Colorado, western Colorado, and Wyoming) and reran the simulation. Results (not shown here) indicated that the sum of the mean LOLP plus standard deviation LOLP was below the LOLP target.

END OF REPORT

Attachment Vol II 5-3 B&V Modified Effective Load Carrying Capability Study

Report on Effective Load Carrying Capability

BV PROJECT NO. 404347

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PREPARED IN CONSULTATION WITH

Tri-State Generation & Transmission Association

14 October 2020

BLACK & VEATCH

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1.0 Executive Summary

Tri-State Generation & Transmission Association ("Tri-State") forecasts the effective load carrying capability (ELCC) of its existing and planned new solar photovoltaic (PV) and wind resources for the purposes of modeling the long-term resource adequacy of its resource plans as part of the energy resource planning process. Tri-State retained Black & Veatch ("we" or "us") to forecast ELCC Values for the overall system that includes the planned solar and wind resources of a representative expansion plan, specifically (the "Analysis"). This report presents the results of the Analysis.

Results show that the System ELCC, as a percent of installed capacity, is forecast to decline as additional planned solar and wind resources are added to the Tri-State system. Effectively, the solar resources provide capacity during peak daytime hours only. That causes the "net peak" to shift to non-solar generating hours, in effect, causing additional solar to have lower capacity value because the added solar is not reducing the net peak. In contrast, results show that the planned additional wind resources will have relatively good capacity value. The Wind Only ELCC is generally increasing over time which indicates the planned additional wind resources will be generating during the new net peak hours and therefore contribute to System ELCC. It is also worth noting that the expansion plan evaluated has a specific resource mix of expansion plan additions, and as the mix is modified from plan to plan a reiterative process to address impacts to ELCC is required.

2.0 Methodology

The basis for calculating the ELCC Values for photovoltaic and wind power is partly based on the methods published by the U.S. Department of Energy (DOE) in document number PNNL-22117 entitled Capacity Value of PV and Wind Generation in the NV Energy System (the "DOE Paper"). Determining ELCC Values is important for estimating additional load that can be served by new PV and wind installations. Variability in solar and wind generation causes wind and solar generation's contribution to resource adequacy to be determined differently from conventional generation.

Our Analysis used the capacity value method described in Chapter 5 of the DOE Paper (the "Capacity Value Method"). The Capacity Value Method defines capacity value as the equivalent perfectly reliable generation capacity that, when used to replace intermittent renewable generation, the system has the same loss of load expectation (LOLE). The Capacity Value Method is a reasonable approximation to a full ELCC method which relies on calculation of loss of load probability (LOLP) and LOLE in every hour. When demand is very low compared to installed capacity, as it is in most systems, the LOLP in low demand hours is negligible. Since the LOLP in low demand hours is very small, the contribution to the annual LOLE is very small. The LOLE result will probably not be affected much if the LOLP in those low demand hours is ignored; and determination of the ELCC can be reasonably accurate using the top 2.5% Net Peak Load hours by determining the average contribution of the renewable generation to meet load during the top 2.5% Net Peak Load hours, as is done under the Capacity Value Method. The Capacity Value Method approximates the ELCC method and eliminates the need for conventional generation data and the calculation of the system LOLP. The Capacity Value Method yields results that are nearly as accurate as the full ELCC method and the analysis can be performed very quickly. The Capacity Value Method is also an improvement over the Peak Period Capacity Factor (PPCF) method mentioned in the DOE Paper.

3.0 Scope and Assumptions

A working model of the Capacity Value Method was developed for the Tri-State system. The ELCC was determined for the renewable generators defined in Table 1 below and for the hourly demand summarized in Table 2 for the Colorado, New Mexico, and Wyoming regions of the Tri-State system (excludes Nebraska). The aggregated system results assume no transmission constraints on flow between locations.

Table 1 – Summary of Renewable Generation Characteristics

ENTITY	CAPACITY (MW) AC	INSTALLATION DATE	RETIREMENT DATE	LOCATION
Alta Luna Solar	25	1/1/2019	1/31/2042	New Mexico
Carousel Wind	150	1/1/2019	7/31/2041	East Colorado
Colorado Highlands Wind	91	1/1/2019	12/31/2032	East Colorado
Crossing Trails Wind	104	12/1/2020	12/1/2035	East Colorado
Cimarron Solar	30	1/1/2019	11/24/2035	New Mexico
Kit Carson Wind	51	1/1/2019	11/30/2030	East Colorado
San Isabel Solar	30	1/1/2019	12/31/2041	East Colorado
Spanish Peaks Solar	100	11/1/2023	11/30/2038	East Colorado
Twin Buttes Wind	76	1/1/2019	12/31/2042	East Colorado
Axial Basin Solar	145	12/31/2023	12/31/2038	West Colorado
Coyote Gulch Solar	120	12/31/2023	12/31/2038	West Colorado
Dolores Canyon Solar	110	12/31/2023	12/31/2038	West Colorado
Niyol Wind	200	12/31/2021	12/31/2041	East Colorado
Spanish Peaks II Solar	40	12/31/2023	12/31/2038	New Mexico
Escalante Solar	200	11/30/2023	11/30/2040	New Mexico
WCO Tracking Solar Simulated	200	1/1/2028		West Colorado
WCO Tracking Solar Simulated	200	1/1/2029		West Colorado
WCO Tracking Solar Simulated	100	1/1/2032		West Colorado
WCO Tracking Solar Simulated	100	1/1/2034		West Colorado
WCO Tracking Solar Simulated	100	1/1/2035		West Colorado
WCO Tracking Solar Simulated	100	1/1/2036		West Colorado
WCO Tracking Solar Simulated	100	1/1/2037		West Colorado
ECO Tracking Solar Simulated	200	1/1/2030		East Colorado
ECO Tracking Solar Simulated	100	1/1/2036		East Colorado
NM Tracking Solar Simulated	50	1/1/2029		New Mexico
NM Tracking Solar Simulated	50	1/1/2030		New Mexico

NM Fixed Solar Simulated	50	1/1/2029		New Mexico
NM Fixed Solar Simulated	50	1/1/2030		New Mexico
NM Wind Simulated	100	1/1/2039		New Mexico
NM Wind Simulated	200	1/1/2040		New Mexico
WY Wind Simulated	100	1/1/2028		Wyoming
WY Wind Simulated	100	1/1/2029		Wyoming
WY Wind Simulated	100	1/1/2030		Wyoming
ECO Wind Simulated	200	1/1/2040		East Colorado

Table 2 - Summary of Model System Annual Energy and Peak Demands

YEAR	ANNUAL ENERGY DEMAND (GWH)	ANNUAL PEAK DEMAND (MW)	YEAR	ANNUAL ENERGY DEMAND (GWH)	ANNUAL PEAK DEMAND (MW)
2020	16,271	2,643			
2021	16,432	2,751	**2031**	19,406	3,230
2022	16,744	2,773	**2032**	19,725	3,264
2023	17,058	2,817	**2033**	20,036	3,296
2024	17,378	2,919	**2034**	20,357	3,336
2025	17,591	2,930	**2035**	20,681	3,403
2026	17,813	2,959	**2036**	21,012	3,481
2027	18,131	3,016	**2037**	21,330	3,504
2028	18,458	3,039	**2038**	21,654	3,563
2029	18,774	3,103	**2039**	21,977	3,600
2030	19,091	3,191	**2040**	22,300	3,656

4.0 Results & Discussion

Table 3 contains the results of the Analysis for each of the years 2020 through 2040. The Peak MW is the coincident peak demand for each year for the defined system analyzed. The Installed Solar Capacity, Installed Wind Capacity, and Installed Renewable Capacity columns show each year's installed solar, wind, and total wind and solar capacity based on existing and proposed renewable capacity additions.

Table 1 ELCC for Wind, Solar, and Combined Wind and Solar in Tri-State System (exclusive of the Nebraska area)

	Peak	Installed Solar Capacity	Installed Wind Capacity	Installed Renewable Capacity	Solar Only ELCC	Wind Only ELCC	Combined Solar and Wind (System) ELCC	Solar Only ELCC	Wind Only ELCC	System ELCC	Incremental Solar Only ELCC	Incremental Wind Only ELCC
Year	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**% of Installed Capacity**				
2020	2,643	85	368	453	36	120	156	42.5%	32.7%	34.5%	43.7%	27.9%
2021	2,751	85	472	557	37	194	231	43.5%	41.1%	41.4%	41.5%	37.5%
2022	2,773	85	672	757	39	257	296	45.4%	38.3%	39.1%	45.1%	31.8%
2023	2,817	85	672	757	39	260	299	46.2%	38.7%	39.6%	44.1%	30.4%
2024	2,919	800	672	1,472	226	246	473	28.3%	36.6%	32.1%	13.3%	32.8%
2025	2,930	800	672	1,472	226	236	462	28.3%	35.2%	31.4%	15.0%	31.6%
2026	2,959	800	672	1,472	223	252	475	27.9%	37.5%	32.3%	14.5%	34.1%
2027	3,016	800	672	1,472	224	270	494	28.0%	40.2%	33.6%	14.0%	35.1%
2028	3,039	1,000	772	1,772	264	292	557	26.4%	37.8%	31.4%	11.4%	35.3%
2029	3,103	1,300	872	2,172	281	314	595	21.6%	36.0%	27.4%	7.4%	34.8%
2030	3,191	1,600	972	2,572	317	328	646	19.8%	33.8%	25.1%	5.1%	32.2%
2031	3,230	1,600	921	2,521	310	330	640	19.4%	35.8%	25.4%	5.8%	32.9%
2032	3,264	1,700	921	2,621	314	318	632	18.5%	34.5%	24.1%	5.2%	31.8%
2033	3,296	1,700	830	2,530	301	347	649	17.7%	41.8%	25.6%	5.3%	36.6%
2034	3,336	1,800	830	2,630	303	337	641	16.9%	40.7%	24.4%	4.7%	34.8%
2035	3,403	1,900	830	2,730	324	323	646	17.0%	38.9%	23.7%	5.2%	36.7%
2036	3,481	2,070	726	2,796	358	276	634	17.3%	38.1%	22.7%	5.1%	40.6%
2037	3,504	2,170	726	2,896	361	281	642	16.6%	38.7%	22.2%	4.5%	39.0%
2038	3,563	2,170	726	2,896	357	270	627	16.4%	37.2%	21.6%	4.5%	39.3%
2039	3,600	1,655	826	2,481	313	313	626	18.9%	37.9%	25.2%	4.2%	38.1%
2040	3,656	1,655	1,226	2,881	328	433	761	19.8%	35.3%	26.4%	3.6%	34.0%

Although wind and solar ELCCs are not separable per sei, in that for example, not only is the Solar ELCC a function of the amount of solar generation in the system, but also a function of how much wind is in the system; one could remove the wind generation and determine the Solar ELCC in the absence of wind; or conversely, leave the wind in and remove the solar and then determine how much the solar generation was contributing to the total system ELCC by subtracting the wind's contribution from the system ELCC assuming the difference is the solar contribution.

Calculations were performed to determine the ELCC with each of the following three configurations: solar only generation (Solar Only ELCC), wind only generation (Wind Only ELCC), and combined solar and wind generation (System ELCC). The Solar Only ELCC was calculated by removing the wind generation from the system. The Wind Only ELCC was calculated by removing the solar generation from the system. The System ELCC is based on the ELCC calculated with both the wind and solar installed as configured. The Solar Only ELCC MW column shows (in megawatts) the average of the Solar Only ELCC and the difference of the System ELCC and the Wind Only ELCC. The Wind Only ELCC MW column shows the average of the Wind Only ELCC and the difference of the System ELCC and the Solar Only ELCC.

The Solar Only ELCC, Wind Only ELCC and System ELCC are also shown as a percent of installed capacity. The System ELCC as a percent of installed capacity is determined by dividing the System ELCC by the total installed solar and wind capacity. The Wind Only ELCC as a percent of installed capacity is determined by dividing the Wind Only ELCC by the total installed wind capacity. A similar calculation was performed to determine the Solar Only ELCC as a percent of installed capacity.

The last two columns in Table 3, labeled Incremental Solar Only ELCC and Incremental Wind Only ELCC as a percent of installed capacity report the incremental ELCC associated with additional wind and solar capacity additions. The incremental Solar Only ELCC was calculated by increasing the Solar generation by five percent. The increase in the system ELCC divided by the increase in solar installed capacity is the Incremental Solar Only ELCC. The five percent increase is based on increasing the output of all installed solar by five percent. A similar method was used to calculate the Incremental Wind Only ELCC.

END OF REPORT

Attachment Vol II 5-4 B&V Report on Review of Existing Resources

August 3, 2020 Revision

Report on Review of Existing Resources

Executive Summary

As part of the energy resource planning process, Tri-State Generation & Transmission Association ("Tri-State") must establish assumptions concerning the future performance and cost of its existing resources for the purposes of modeling the long-term performance and cost of the resource plan ("Modeled Values"). Tri-State retained Black & Veatch ("we" or "us") to review the Modeled Values and as necessary recommend changes to the Modeled Values to better represent future resource performance and cost (the "Review"). The Modeled Values included capacity, heat rate, availability rate, forced outage rate, emissions, renewable production profiles, variable O&M costs and fixed O&M costs. The existing resources included eighteen (18) coal, gas and oil fired resources) two (2) long-term purchase agreements with Basin Electric and seven (7) renewable (solar and wind) facilities located across the Tri-State system. This Report summarizes the scope, methodology and results of our Review.

Our approach was to compare the Modeled Values against actual performance and cost data provided to us by Tri-State, data collected by federal regulatory agencies and national reliability coordinators, and data reported by other generators for resources of similar technology, size, age and location. In cases where a Modeled Value was significantly different from the values shown in the data sources, and if the data was determined to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (each a "Recommended Modeled Value").

Our review revealed that some of the Modeled Values were significantly different than those shown in one or more of the data sources. Differences included heat rates for the Burlington resources, fixed O&M costs for the Rifle resource, and NOx emission rates for the Burlington and Rifle resources. They also included SO2 emission rates for the Rifle and Shafer resources, availability factors for the Burlington, Limon, Rifle and Shafer resources, and forced outage factors for the Burlington, Knutson, Limon, Rifle and Shafer plants. For each of these we provided a Recommended Modeled Value for consideration by Tri-State. The Recommended Modeled Values are summarized in the Results section of this Report.

Scope

The scope of our Review was defined by Tri-State and included the resources shown in Table 1 below.

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) of the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, the Limon Units 1 and 2 and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State.

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output from these resources is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

Table 1 – Summary of Resources to be Reviewed

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	Owned	wco	427	102	1980
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	Owned	wco	410	98	1979
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	Owned	wco	448	448	1984
4	GC-LRS 2-WY	Steam Turbine - Coal	Owned	wyo	570	231	1981
5	GC-LRS 3-WY	Steam Turbine - Coal	Owned	wyo	570	230	1982
6	GC-SV 3-SPV	Steam Turbine - Coal	Owned	arz	417	317	2006
7	GG-Burlington 1-E_CO	Frame CT - Oil	Owned	eco	55	55	1977

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
8	GG-Burlington 2-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
9	GG-Knutson 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
10	GG-Knutson 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
11	GG-Limon 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
12	GG-Limon 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
17	GG-Rifle-NW_CO	Combined Cycle - Gas	Owned	wco	81	81	1987
18	GG-Shafer-E_CO	Combined Cycle - Gas	Owned	eco	272	272	1994
19	CP-AltaLuna-S_NM	Tracking Array Solar	PPA	nm	25	25	2017
20	CP-SanIsabel-E_CO	Tracking Array Solar	PPA	eco	30	30	2016
21	CP-FirstSolar-N_NM	Fixed Solar	PPA	nm	30	30	2010
22	CP-ColoHighlands-E_CO	Wind	PPA	eco	91	91	2012
23	CP-KitCarson-E_CO	Wind	PPA	eco	51	51	2010
24	CP-TwinButtes-E_CO	Wind	PPA	eco	76	76	2017
25	CP-Carousel-E_CO	Wind	PPA	eco	150	150	2015
26	CP-Basin_West	Basin System	PPA	eco	268	268	2017
27	CP-Basin_East	Basin System	PPA	eco	317	317[1]	2017

The scope of parameters to review for each of these resources was also specified by Tri-State. The parameters included heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate, SO2 emission rate, availability rate, forced outage rate, and capacity factor for the renewable resources only (each a "Parameter").

Methodology

Our methodology for the Review was to compare the Modeled Values against historical Parameters from three (3) data sources and base our Recommended Modeled Values on the results of that comparison. The Modeled Values were provided to us by Tri-State and consisted of Parameters for each of the existing resources. The first data source was historical data provided to us by Tri-State for heat rate, availability rate and forced outage rate for the thermal resources ("Tri-State Data"). The second data source was historical data gathered from federal regulators by the S&P Global Market Intelligence

[1] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

service ("S&P")[2] for heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate and SO2 emission rate for the thermal resources and capacity factor for the renewable resources ("S&P Data"). The third data source was a compilation of Parameters from S&P and from historical data reported by the North American Reliability Corporation ("NERC") for resources of similar technology, size, age and location to the Tri-State resources but that are owned or controlled by others ("Peer Group Data"). Comparing the Modeled Values against data from these three sources allowed us to evaluate the extent to which the Modeled Values were consistent with the actual historical Parameters of the resource and other similar resources in the market.

A summary of the key features of the Peer Group Data is provided in the table below.

Table 2- Summary of Key Features of the Peer Group Data

-	Plant/Unit	Peer Group	NERC Regions	Capacity	COD	# of Units in GADS	GADS Data	# of Units in S&P	S&P Data
1	GC-Craig 1-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26	2015-2018 Forced Outage Factor (FOF) and Availability Factor (AF)	41	2015-2018 Heat Rate, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo), CO2 Emissions (lb/MMBtu), NOx Emissions (lb/MMBtu), SO Emissions (lb/MMBtu)
2	GC-Craig 2-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
3	GC-Craig 3-NW_CO	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
4	GC-LRS 2-WY	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
5	GC-LRS 3-WY	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
6	GC-SV 3-SPV	Large Coal ST	MRO, WECC and SPP	300 to 500 MW	1980 to 2010	26		41	
7	GG-Burlington 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
8	GG-Burlington 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
9	GG-Knutson 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
10	GG-Knutson 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
11	GG-Limon 1-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
12	GG-Limon 2-E_CO	Frame CT	MRO, WECC and SPP	60 MW to 80 MW	1970 to 2010	125		49	
13	GG-Pyramid 1-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	

[2] https://www.spglobal.com/marketintelligence/en/solutions/market-intelligence-platform

	Plant/Unit	Peer Group	NERC Regions	Capacity	COD	# of Units in GADS	GADS Data	# of Units in S&P	S&P Data
14	GG-Pyramid 2-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
15	GG-Pyramid 3-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
16	GG-Pyramid 4-S_NM	Aeroderivative CT	MRO, WECC and SPP	40 MW to 60 MW	1998 to 2008	122		95	
17	GG-Rifle-NW_CO	Small CC	All	50 MW to 100 MW	1980 to 1995	21		88	
18	GG-Shafer-E_CO	Large CC	MRO, WECC and SPP	250 MW to 350 MW	1985 to 2005	17		14	
19	CP-AltaLuna-S_NM	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	2015-2018 Capacity Factor, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo)
20	CP-SanIsabel-E_CO	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	
21	CP-FirstSolar-N_NM	Small Solar CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	12	
22	CP-ColoHighlands-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
23	CP-KitCarson-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
24	CP-TwinButtes-E_CO	Small Wind CO NM WY	WECC	20 to 100 MW	All	n/a	n/a	26	
25	CP-Carousel-E_CO	Large Wind CO NM WY	WECC	100 MW +	All	n/a	n/a	25	
26	CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27	CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

For each peer group, the NERC region, capacity range and age range were selected such that the existing resource(s) and a reasonable number of third party resources would fall into the group. The total capacity of the existing resource rather than just the Tri-State share was considered in developing each peer group.

Once the peer groups were established, the associated Tri-State Data, S&P Data and Peer Group Data was acquired. Modeled Values and data were limited for the solar and wind resources. Tri-State has

Modeled Values for only capacity factor and none of the other Parameters (variable O&M, fixed O&M, etc.) since the existing wind and solar resources are not owned by Tri-State. Also, NERC has only recently begun requiring owners of renewable energy resources to submit performance and reliability data and NERC has not yet made the data available. Therefore, capacity factor was the only Parameter considered in Review of the wind and solar resources.

Modeled Values and data were also limited for the Basin Contracts because they are not resource specific. Modeled Values for the Basin Contracts included only CO2, SO2 and NOx emission rates. These Modeled Values were calculated by Tri-State based on historical emission rates for Laramie River Station (LRS2, LRS 3) for Basin West and egrid subregion MRO-W emissions were used for the Basin East. This approach reflects the fact that historically some of the energy from Basin West has likely been generated from coal fired power plants on the Basin system and that Basin East is served by the Southwest Power Pool. Modeled Values for the other Parameters (variable O&M, fixed O&M, etc.) were not available. No Parameters were available in the S&P Data and Peer Group Data because S&P and NERC do not record data for non-resource specific system sales. Therefore CO2, SO2 and NOx emission rates were the only Parameters considered in review of the Basin Contracts. It is also important to note that none of the Parameters reviewed in this report including emissions are specified in the Basin Contracts.

Data analysis began with comparison of each Modeled Value against a four year (2015 – 2018 inclusive) average of the associated Parameter from the Tri-State Data, the S&P Data and the Peer Group Data. Data for the years 2019 and 2020 was excluded because it was either unavailable or incomplete at the time the Review was performed (Spring 2020). Each Modeled Value was then also compared against an average of the three averages (the “Grand Average”). In cases where the Modeled Value was more than 10% greater or less than the Grand Average (5% for the availability factor and forced outage factor Grand Averages), the difference was considered significant and we further examined the data to determine the cause of the difference including whether or not the Grand Average was skewed high or low by the presence of high or low outliers in the underlying data or the underlying data was of poor quality for some other reason. If the Grand Average proved to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (a "Recommended Modeled Value").

The threshold for significance was only 5% for the availability factor and forced outage factor Grand Averages because the data ranged from only 70% to 100% and therefore, we felt that using a 10% threshold would mask too many significant differences.

Results

Results of the data analysis are summarized in the following tables. Each table summarizes the analysis for one of the Parameters including the relevant Modeled Value, the Tri-State Data value, the S&P Data value, the Peer Group Data value and the Grand Average for each of the existing resources. Grand Averages highlighted in yellow indicate the Grand Average is significantly (+\- 10% or +/- 5%) different than the Modeled Value. Recommended Values highlighted in green indicate Recommended Values different than the Modeled Value.

Heat rate results show that the Grand Average was significantly different than the Modeled Value for several of the resources. However, review of the Grand Average revealed that the underlying Tri-State data and Peer Group data was skewed in most of these cases. For these resources, no change was recommended. The exception are the Burlington combustion turbine Units 1 and 2. A Recommended Modeled Value was therefore provided based on the Grand Average. A heat rate comparison was not applicable to the renewable resources and the Basin Contracts.

Variable O&M cost results show that the Grand Average was significantly different than the Modeled Value for nearly all of the resources. However, review of these Grand Averages revealed that the underlying S&P Data was not actual data (but rather calculated) for the coal-fired units and was skewed by extreme outliers for the combustion turbine units and for the Shafer combined cycle plant. As a result, the Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A variable O&M Cost comparison was not applicable to the renewable resources and the Basin Contracts.

Fixed O&M cost results show that the Grand Average was significantly different than the Modeled Values for nearly all of the resources. However, the underlying S&P data and Peer Group data was judged to be of poor quality and therefore no changes to the Modeled Values were recommended. The exception was for the Rifle combined cycle plant, where a lower Recommended Modeled Value was provided. The Recommended Modeled Value was also expressed in $000s for convenience since Tri-State models fixed O&M on a dollar basis instead of $/kw-yr. A fixed O&M cost comparison was not applicable to the renewable resources and the Basin Contracts.

CO2 emission rate results show only a few significant differences between the Grand Averages and the Modeled Values. Further investigation into these differences revealed that the S&P Data and Peer Group Data was not actual but rather calculated. As a result, our Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A CO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

NOx emission rate results show that the Grand Average is significantly different than the Modeled Values for nearly all resources. However, no changes were recommended in most cases due to poor S&P Data and Peer Group Data quality. For Craig 2, no change was recommended because the significant difference is due to NOx emission controls that have been added to the unit. This causes the rate to be much less than Craig 1 as well as the S&P Data and Peer Group Data. Changes were recommended for Burlington Units 1 and 2 and the Rifle combined cycle plant. The Modeled Values are relatively high for these resources. It is possible that the Modeled Values reflect actual emission rates which are relatively high due to use of fuel oil at Burlington or lack of modern emission controls at Rifle. If this is the case, then no change should be made to the Modeled Value. A NOx emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

SO2 emission rate results show that the Grand Average is significantly different than the Modeled Values for all the resources. However, no changes were recommended in most cases due to poor S&P Data quality. The exception is the Rifle and Shafer resources. The Modeled Values are relatively low for these resources and so a higher Recommended Modeled Value is provided. An SO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

Availability factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 1, Craig Unit 3, Springerville Unit 3, Knutson Unit 2 and Limon Unit 2) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in maintenance outage hours (MOH) for convenience since Tri-State models maintenance outages on an hourly basis instead of a percentage basis. An availability factor comparison was not applicable to the renewable resources and the Basin Contracts.

Forced outage factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 2, LRS Unit 2) no change was recommended since the Grand Average if rounded would equal the Modeled Value and therefore the Modeled Value was judged to be in a reasonable range. In other cases (Craig Unit 3, Springerville Unit 3) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016, 2017 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in forced outage hours (FOH) for convenience since Tri-State models forced outages on an hourly basis instead of a percentage basis. A forced outage factor comparison was not applicable to the renewable resources and the Basin Contracts.

Renewable capacity factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (San Isabel, Twin Buttes and Carousel) no change was recommended since the Tri-State and S&P data were skewed low due to outlier low values in 2015, 2016 or 2017. In the other cases (Colorado Highlands and Kit Carson) no changes were recommended due to the Peer Group Data being relatively low. A capacity factor comparison was not applicable to the thermal resources and the Basin Contracts.

Table 3 – Results of Review – Heat Rate (Btu/kwh)

	Heat Rate (Btu/kwh)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	10,316	10,176	10,213	10,582	10,324	No change	Within reasonable range	10,316
2 GC-Craig 2-NW_CO	10,219	10,075	10,117	10,582	10,258	No change	Within reasonable range	10,219
3 GC-Craig 3-NW_CO	10,135	10,156	10,227	10,582	10,322	No change	Within reasonable range	10,135
4 GC-LRS 2-WY	9,926	10,035	10,099	10,582	10,239	No change	Within reasonable range	9,926
5 GC-LRS 3-WY	10,286	9,917	10,117	10,582	10,206	No change	Within reasonable range	10,286
6 GC-SV 3-SPV	9,945	13,205	10,183	10,582	11,323	No change	Tri-State data skewed by high 2015 and 2018 values	9,945
7 GG-Burlington 1-E_CO	11,924	14,358	12,999	15,337	14,231	14,000	Tri-State data not skewed, use average.	14,000
8 GG-Burlington 2-E_CO	11,924	13,610	12,999	15,337	13,982	14,000	Tri-State data not skewed, use average.	14,000
9 GG-Knutson 1-E_CO	11,646	16,295	12,270	15,337	14,634	No change	Tri-State and Peer Group data skewed	11,646
10 GG-Knutson 2-E_CO	11,646	15,553	12,515	15,337	14,469	No change	Tri-State and Peer Group data skewed	11,646
11 GG-Limon 1-E_CO	11,646	10,984	12,106	15,337	12,809	No change	Peer group data skewed	11,646
12 GG-Limon 2-E_CO	11,646	11,655	12,504	15,337	13,165	No change	Peer group data skewed	11,646
13 GG-Pyramid 1-S_NM	9,742	9,688	9,908	10,898	10,164	No change	Within reasonable range	9,742
14 GG-Pyramid 2-S_NM	9,742	9,699	10,026	10,898	10,207	No change	Within reasonable range	9,742
15 GG-Pyramid 3-S_NM	9,742	10,069	10,394	10,898	10,453	No change	Within reasonable range	9,742
16 GG-Pyramid 4-S_NM	9,742	9,972	10,230	10,898	10,366	No change	Within reasonable range	9,742
17 GG-Rifle-NW_CO	10,658	6,925	7,672	7,934	7,510	No change	Low Tri-State data from 2015 only, actuals higher due to duct burners.	10,658
18 GG-Shafer-E_CO	9,322	9,021	9,562	7,434	8,672	No change	Within reasonable range	9,322
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 4 – Results of Review – Variable O&M Cost ($/MWh)

	Non-Fuel Variable O&M Costs per MWh							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	[redacted]	None	3.37	3.62	3.49	No change	S&P data not actual	[redacted]
2 GC-Craig 2-NW_CO		None	3.37	3.62	3.49	No change	S&P data not actual	
3 GC-Craig 3-NW_CO		None	3.37	3.62	3.49	No change	S&P data not actual	
4 GC-LRS 2-WY		None	2.58	3.62	3.10	No change	S&P data not actual	
5 GC-LRS 3-WY		None	2.58	3.62	3.10	No change	S&P data not actual	
6 GC-SV 3-SPV		None	5.89	3.62	4.75	No change	S&P data not actual	
7 GG-Burlington 1-E_CO		None	88.57	14.97	51.77	No change	S&P data reflects extreme year	
8 GG-Burlington 2-E_CO		None	88.57	14.97	51.77	No change	S&P data reflects extreme year	
9 GG-Knutson 1-E_CO		None	15.26	14.97	15.11	No change	S&P data reflects extreme year	
10 GG-Knutson 2-E_CO		None	15.26	14.97	15.11	No change	S&P data reflects extreme year	
11 GG-Limon 1-E_CO		None	5.67	14.97	10.32	No change	S&P data reflects extreme year	
12 GG-Limon 2-E_CO		None	5.67	14.97	10.32	No change	S&P data reflects extreme year	
13 GG-Pyramid 1-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
14 GG-Pyramid 2-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
15 GG-Pyramid 3-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
16 GG-Pyramid 4-S_NM		None	6.49	8.69	7.59	No change	S&P data not actual	
17 GG-Rifle-NW_CO		None	8.32	3.23	5.77	No change	Within reasonable range	
18 GG-Shafer-E_CO		None	3.75	1.63	2.69	No change	S&P data skewed by 2017 value	
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 5 – Results of Review – Fixed O&M Costs ($/kw-yr)

	Fixed O&M Costs per kW-Year									
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Max Capacity (MW)	Recommended Modeled	Recommended Modeled ($000s)
1 GC-Craig 1-NW_CO	[redacted]	None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	102	[redacted]	[redacted]
2 GC-Craig 2-NW_CO		None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	98		
3 GC-Craig 3-NW_CO		None	42.62	27.77	35.19	No change	S&P data poor quality (duplicative, missing)	448		
4 GC-LRS 2-WY		None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	231		
5 GC-LRS 3-WY		None	28.01	27.77	27.89	No change	S&P data poor quality (duplicative, missing)	230		
6 GC-SV 3-SPV		None	49.73	27.77	38.75	No change	S&P data poor quality (duplicative, missing)	417		
7 GG-Burlington 1-E_CO		None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55		
8 GG-Burlington 2-E_CO		None	4.68	3.55	4.12	No change	S&P data poor quality (duplicative, missing)	55		
9 GG-Knutson 1-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
10 GG-Knutson 2-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
11 GG-Limon 1-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
12 GG-Limon 2-E_CO		None	3.62	3.55	3.58	No change	S&P data poor quality (duplicative, missing)	70		
13 GG-Pyramid 1-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55		
14 GG-Pyramid 2-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	55		
15 GG-Pyramid 3-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70		
16 GG-Pyramid 4-S_NM		None	3.51	6.34	4.92	No change	S&P data poor quality (duplicative, missing)	70		
17 GG-Rifle-NW_CO		None	26.68	14.44	20.56	25.00	Current modeled very high	52		
18 GG-Shafer-E_CO		None	14.64	11.08	12.86	No change	Within reasonable range	14		
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 6 – Results of Review – CO2 Emission Rate (lb/MMBtu)

		CO2 Emission Rate (lb/MMBtu)							
	Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1	GC-Craig 1-NW_CO	224.80	None	209.76	208.80	209.28	No change	Within reasonable range	224.80
2	GC-Craig 2-NW_CO	229.96	None	209.76	208.80	209.28	No change	Within reasonable range	229.96
3	GC-Craig 3-NW_CO	206.21	None	209.76	208.80	209.28	No change	Within reasonable range	206.21
4	GC-LRS 2-WY	221.94	None	209.76	208.80	209.28	No change	Within reasonable range	221.94
5	GC-LRS 3-WY	234.01	None	209.76	208.80	209.28	No change	S&P data not actual	234.01
6	GC-SV 3-SPV	215.08	None	209.66	208.80	209.23	No change	Within reasonable range	215.08
7	GG-Burlington 1-E_CO	185.51	None	162.22	122.03	142.13	No change	S&P data not actual	185.51
8	GG-Burlington 2-E_CO	174.94	None	162.22	122.03	142.13	No change	S&P data not actual	174.94
9	GG-Knutson 1-E_CO	129.15	None	119.08	122.03	120.56	No change	S&P data not actual	129.15
10	GG-Knutson 2-E_CO	128.80	None	119.07	122.03	120.55	No change	S&P data not actual	128.80
11	GG-Limon 1-E_CO	128.63	None	120.09	122.03	121.06	No change	S&P data not actual	128.63
12	GG-Limon 2-E_CO	128.12	None	119.16	122.03	120.60	No change	S&P data not actual	128.12
13	GG-Pyramid 1-S_NM	127.28	None	120.20	118.98	119.59	No change	Within reasonable range	127.28
14	GG-Pyramid 2-S_NM	126.46	None	121.06	118.98	120.02	No change	Within reasonable range	126.46
15	GG-Pyramid 3-S_NM	128.31	None	122.74	118.98	120.86	No change	Within reasonable range	128.31
16	GG-Pyramid 4-S_NM	127.08	None	120.04	118.98	119.51	No change	Within reasonable range	127.08
17	GG-Rifle-NW_CO	113.15	None	118.40	116.81	117.61	No change	Within reasonable range	113.15
18	GG-Shafer-E_CO	105.24	None	118.86	118.67	118.77	No change	S&P data not actual	105.24
19	CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	CP-Basin_West	168.32	n/a	n/a	n/a	n/a	n/a	n/a	168.323
27	CP-Basin_East	123.81	n/a	n/a	n/a	n/a	n/a	n/a	123.805

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 7 – Results of Review – NOx Emission Rate (lb/MMBtu)

	NOx Emission Rate (lb/MMBtu)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	0.269	None	0.249	0.139	0.194	No change	S&P peer group data suspect	0.27
2 GC-Craig 2-NW_CO	0.066	None	0.197	0.139	0.168	No change	Lower than Craig 1 due to NOx controls	0.07
3 GC-Craig 3-NW_CO	0.222	None	0.275	0.139	0.207	No change	S&P peer group data suspect	0.22
4 GC-LRS 2-WY	0.235	None	0.153	0.139	0.146	No change	S&P peer group data suspect	0.23
5 GC-LRS 3-WY	0.234	None	0.150	0.139	0.145	No change	S&P data, peer group data suspect	0.23
6 GC-SV 3-SPV	0.079	None	0.077	0.139	0.108	No change	S&P peer group data suspect	0.08
7 GG-Burlington 1-E_CO	1.047	None	0.301	0.202	0.252	0.300	Current modeled very high	0.30
8 GG-Burlington 2-E_CO	1.030	None	0.301	0.202	0.252	0.300	Current modeled very high	0.30
9 GG-Knutson 1-E_CO	0.030	None	0.029	0.202	0.115	No change	S&P peer group data suspect	0.03
10 GG-Knutson 2-E_CO	0.029	None	0.030	0.202	0.116	No change	S&P peer group data suspect	0.03
11 GG-Limon 1-E_CO	0.037	None	0.029	0.202	0.116	No change	S&P peer group data suspect	0.04
12 GG-Limon 2-E_CO	0.028	None	0.029	0.202	0.116	No change	S&P peer group data suspect	0.03
13 GG-Pyramid 1-S_NM	0.129	None	0.127	0.057	0.092	No change	S&P peer group data suspect	0.13
14 GG-Pyramid 2-S_NM	0.120	None	0.118	0.057	0.087	No change	S&P peer group data suspect	0.12
15 GG-Pyramid 3-S_NM	0.129	None	0.122	0.057	0.089	No change	S&P peer group data suspect	0.13
16 GG-Pyramid 4-S_NM	0.125	None	0.125	0.057	0.091	No change	S&P peer group data suspect	0.13
17 GG-Rifle-NW_CO	0.245	None	0.020	0.048	0.034	0.030	Current modeled very high	0.03
18 GG-Shafer-E_CO	0.080	None	0.089	0.010	0.050	No change	S&P peer group data suspect	0.08
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	0.173	n/a	n/a	n/a	n/a	n/a	n/a	0.173
27 CP-Basin_East	0.099	n/a	n/a	n/a	n/a	n/a	n/a	0.099

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 8 – Results of Review – SO2 Emission Rate (lb/MMBtu)

	SO2 Emission Rate (lb/MMBtu)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, S&P, Peer Group Data	Recommendation	Notes	Recommended Modeled
GC-Craig 1-NW_CO	0.0366	None	0.042	0.187	0.1148	No change	S&P peer group data suspect	0.0366
GC-Craig 2-NW_CO	0.0338	None	0.043	0.187	0.1151	No change	S&P peer group data suspect	0.0338
GC-Craig 3-NW_CO	0.1291	None	0.131	0.187	0.1592	No change	S&P peer group data suspect	0.1291
GC-LRS 2-WY	0.1109	None	0.098	0.187	0.1427	No change	S&P peer group data suspect	0.1109
GC-LRS 3-WY	0.1772	None	0.112	0.187	0.1496	No change	Modeled rate based on permit. S&P peer group data suspect	0.1772
GC-SV 3-SPV	0.0843	None	0.073	0.187	0.1298	No change	S&P peer group data suspect	0.0843
GG-Burlington 1-E_CO	0.0173	None	0.075	0.014	0.0443	No change	S&P data suspect	0.0173
GG-Burlington 2-E_CO	0.0153	None	0.075	0.014	0.0443	No change	S&P data suspect	0.0153
GG-Knutson 1-E_CO	0.0007	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0007
GG-Knutson 2-E_CO	0.0008	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0008
GG-Limon 1-E_CO	0.0007	None	0.001	0.014	0.0072	No change	S&P peer group data suspect	0.0007
GG-Limon 2-E_CO	0.0007	None	0.001	0.014	0.0071	No change	S&P peer group data suspect	0.0007
GG-Pyramid 1-S_NM	0.0013	None	0.001	0.001	0.0011	No change	S&P peer group data suspect	0.0013
GG-Pyramid 2-S_NM	0.0017	None	0.002	0.001	0.0014	No change	S&P peer group data suspect	0.0017
GG-Pyramid 3-S_NM	0.0012	None	0.003	0.001	0.0017	No change	S&P peer group data suspect	0.0012
GG-Pyramid 4-S_NM	0.0006	None	0.001	0.001	0.0011	No change	S&P peer group data suspect	0.0006
GG-Rifle-NW_CO	0.0001	None	0.001	0.004	0.0026	0.0010	Current modeled data very low	0.0010
GG-Shafer-E_CO	0.0008	None	0.001	0.001	0.0006	0.0010	Current modeled data very low	0.0010
CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CP-Basin_West	0.107	n/a	n/a	n/a	n/a	n/a	n/a	0.107
CP-Basin_East	0.139	n/a	n/a	n/a	n/a	n/a	n/a	0.139

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 9 – Results of Review – Annual Availability Factor (%)

	Availability Factor (%)								
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (NERC)	Avg. Tri-State, Peer Group Data (5% Sig.)	Recommendation	Notes	Recommended Modeled	Resulting Modeled MOH
1 GC-Craig 1-NW_CO	95.81	91.63	None	88.83	90.23	No change	Tri-State data skewed by low 2016 value	95.81	367
2 GC-Craig 2-NW_CO	93.70	90.37	None	88.83	89.60	No change	Within reasonable range	93.70	552
3 GC-Craig 3-NW_CO	92.88	78.77	None	88.83	83.80	No change	Tri-State data skewed by low 2016 value	92.88	624
4 GC-LRS 2-WY	91.66	91.28	None	88.83	90.05	No change	Within reasonable range	91.66	731
5 GC-LRS 3-WY	91.93	91.96	None	88.83	90.39	No change	Within reasonable range	91.93	707
6 GC-SV 3-SPV	93.70	87.31	None	88.83	88.07	No change	Tri-State data skewed by low 2016 value	93.70	552
7 GG-Burlington 1-E_CO	99.27	97.74	None	90.23	93.99	98	Current modeled too high	98.00	175
8 GG-Burlington 2-E_CO	99.78	98.65	None	90.23	94.44	99	Current modeled too high	99.00	88
9 GG-Knutson 1-E_CO	99.56	96.46	None	90.23	93.34	96	Current modeled too high	96.00	350
10 GG-Knutson 2-E_CO	99.56	95.32	None	90.23	92.78	No change	Tri-State data skewed by low 2018 value	99.56	38
11 GG-Limon 1-E_CO	99.56	96.39	None	90.23	93.31	96	Current modeled too high	96.00	350
12 GG-Limon 2-E_CO	99.56	91.59	None	90.23	90.91	No change	Tri-State data skewed by low 2018 value	99.56	38
13 GG-Pyramid 1-S_NM	98.55	98.61	None	90.23	94.42	No change	Within reasonable range	98.55	127
14 GG-Pyramid 2-S_NM	98.42	98.69	None	90.23	94.46	No change	Within reasonable range	98.42	139
15 GG-Pyramid 3-S_NM	98.42	98.90	None	90.23	94.57	No change	Within reasonable range	98.42	139
16 GG-Pyramid 4-S_NM	98.55	99.07	None	90.23	94.65	No change	Within reasonable range	98.55	127
17 GG-Rifle-NW_CO	99.74	89.98	None	87.91	88.95	90	Current modeled too high	90.00	876
18 GG-Shafer-E_CO	99.91	89.89	None	86.31	88.10	90	Current modeled too high	90.00	876
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 10 – Results of Review – Annual Forced Outage Factor (%)

	Forced Outage Factor (%)								
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (NERC)	Avg. Tri-State, Peer Group Data (5% Sig.)	Recommendation	Notes	Recommended Modeled	Resulting Modeled FOH
1 GC-Craig 1-NW_CO	4.00	3.52	None	4.53	4.03	No Change	Within reasonable range	4.00	350
2 GC-Craig 2-NW_CO	4.00	2.70	None	4.53	3.62	No Change	Within reasonable range	4.00	350
3 GC-Craig 3-NW_CO	4.00	15.93	None	4.53	10.23	No Change	Tri-State data skewed by 2018 45%	4.00	350
4 GC-LRS 2-WY	4.00	3.01	None	4.53	3.77	No Change	Within reasonable range	4.00	350
5 GC-LRS 3-WY	4.00	3.53	None	4.53	4.03	No Change	Within reasonable range	4.00	350
6 GC-SV 3-SPV	4.00	10.21	None	4.53	7.37	No Change	Tri-State data skewed by 2016, 2017 15%	4.00	350
7 GG-Burlington 1-E_CO	0.00	1.23	None	3.85	2.54	1.00	Modeled too low. Use Tri-State data.	1.00	88
8 GG-Burlington 2-E_CO	0.22	0.92	None	3.85	2.38	1.00	Modeled too low. Use Tri-State data.	1.00	88
9 GG-Knutson 1-E_CO	0.44	0.51	None	3.85	2.18	1.00	Modeled too low. Use Tri-State data.	1.00	88
10 GG-Knutson 2-E_CO	0.44	0.52	None	3.85	2.18	1.00	Modeled too low. Use Tri-State data.	1.00	88
11 GG-Limon 1-E_CO	0.44	1.00	None	3.85	2.43	1.00	Modeled too low. Use Tri-State data.	1.00	88
12 GG-Limon 2-E_CO	0.44	0.70	None	3.85	2.27	1.00	Modeled too low. Use Tri-State data.	1.00	88
13 GG-Pyramid 1-S_NM	0.44	0.24	None	3.85	2.05	1.00	Modeled too low. Use Tri-State data.	1.00	88
14 GG-Pyramid 2-S_NM	0.44	0.88	None	3.85	2.36	1.00	Modeled too low. Use Tri-State data.	1.00	88
15 GG-Pyramid 3-S_NM	0.44	0.31	None	3.85	2.08	1.00	Modeled too low. Use Tri-State data.	1.00	88
16 GG-Pyramid 4-S_NM	0.44	0.19	None	3.85	2.02	1.00	Modeled too low. Use Tri-State data.	1.00	88
17 GG-Rifle-NW_CO	0.26	3.27	None	4.50	3.89	3.00	Modeled too low. Use Tri-State data.	3.00	263
18 GG-Shafer-E_CO	0.09	2.93	None	3.93	3.43	3.00	Modeled too low. Use Tri-State data.	3.00	263
19 CP-AltaLuna-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20 CP-SanIsabel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21 CP-FirstSolar-N_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22 CP-ColoHighlands-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23 CP-KitCarson-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24 CP-TwinButtes-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25 CP-Carousel-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

Table 11 – Results of Review – Annual Renewable Capacity Factor

	Renewable Capacity Factor (%)							
Resource	Current Modeled	Tri-State Data	S&P Data	Peer Group Data (S&P)	Avg. Tri-State, Peer Group Data	Recommendation	Notes	Recommended Modeled
1 GC-Craig 1-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2 GC-Craig 2-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3 GC-Craig 3-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4 GC-LRS 2-WY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5 GC-LRS 3-WY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6 GC-SV 3-SPV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7 GG-Burlington 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8 GG-Burlington 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9 GG-Knutson 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10 GG-Knutson 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11 GG-Limon 1-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12 GG-Limon 2-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13 GG-Pyramid 1-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14 GG-Pyramid 2-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15 GG-Pyramid 3-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16 GG-Pyramid 4-S_NM	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
17 GG-Rifle-NW_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18 GG-Shafer-E_CO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19 CP-AltaLuna-S_NM	35	33	31	23	29	No Change	Peer group data suspect, very low	35
20 CP-SanIsabel-E_CO	29	19	19	35	29	No Change	Within reasonable range	29
21 CP-FirstSolar-N_NM	22	24	24	29	29	No Change	Peer group data suspect, very high	22
22 CP-ColoHighlands-E_CO	46	45	44	32	41	No Change	Peer group data suspect, very low	46
23 CP-KitCarson-E_CO	42	40	40	32	37	No Change	Peer group data suspect, very low	42
24 CP-TwinButtes-E_CO	45	28	23	32	28	No Change	Tri-State, S&P data skewed by low 2017	45
25 CP-Carousel-E_CO	51	37	37	32	35	No Change	Tri-State, S&P data skewed by low 2015	51
26 CP-Basin_West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
27 CP-Basin_East	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

END OF REPORT

Attachment Vol II 5-5 B&V Benchmarking Study

August 3, 2020 Revision

Report on Benchmarking of Existing Resources

Executive Summary

As part of its responsibilities under a recent Energy Resource Planning decision by the Colorado Public Utilities Commission[1], Tri-State Generation & Transmission Association ("Tri-State") must file in support of its Energy Resource Plan (ERP) an assessment of its existing resources including a comparison of the costs and performance of each of its existing resources (utility owned and contracted) to the costs and performance of the generic resources (a "Benchmarking")[2]. Tri-State retained Black & Veatch ("we" or "us") to perform the Benchmarking for the purposes of supporting a filing by Tri-State. Tri-State defined the existing resources to include eighteen (18) of its coal, gas and oil fired resources, two (2) long-term purchase agreements with Basin Electric, and seven (7) of its renewable (solar and wind) facilities totaling twenty seven (27) existing resources ("Existing Resources"). Tri-State did not include its renewable facilities that are under contract but not yet in commercial operation. The generic resources included future potential gas-fired, solar, wind, battery storage, solar plus battery, wind plus battery, and hydroelectric resources located in Colorado, Wyoming and New Mexico totaling sixty one (61) generic resources ("Generic Resources"). This Report summarizes the scope, methodology and results of the Benchmarking.

Our approach was to first identify for each Existing Resource a Generic Resource for comparison based on the type of Existing Resource (thermal or renewable), the location of the Existing Resource, the generating capacity of the Existing Resource, and the annual capacity factor typically expected for a resource of that type. We then forecast the annual energy production and costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming each operated at the same capacity factor in isolation from all other resources and under common assumptions for the Colorado social cost of carbon ("Social Cost of Carbon"), fuel costs, interest rates and escalation. Assumptions for heat rate, fixed O&M, variable O&M, capital basis, depreciation, and book life were specific to each resource and were provided by Tri-State. We developed assumptions for a limited number of the Generic Resources where necessary. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource operated for the same years in the study period at the same capacity factor. We then discounted the annual capacity, energy production and annual cost streams to net present values and expressed them as a levelized cost of energy in $/MWh (LCOE) for cases where the capacity factor was relatively high or a levelized cost of capacity in $/kw-yr (LCOC) where the capacity factor was relatively low.

[1] Colorado Public Utilities Decision No. C20-0155 issued March 10, 2020 adopting amendments to the provisions in the rules governing Electric Resource Planning (ERP Rules).

[2] Colorado Department of Regulatory Agencies, Public Utilities Commission, Code of Colorado Regulations (CCR) 723-3, Part 3 Rules Regulating Electric Utilities, Electric Resource Planning, Section 3605 (c)(II).

Results of the Benchmarking show that each coal-fired Existing Resource is more costly than its associated Generic Resource counterpart due primarily to higher Social Cost of Carbon and higher FOM costs. Each oil and gas fired combustion turbine Existing Resource is less costly than its Generic Resource counterpart due primarily to a lower (highly depreciated) capital basis and therefore lower depreciation and interest costs. Each renewable Existing Resource is more costly than its associated Generic Resource counterpart likely due to the fact that the Existing Resources were built in prior years when the cost of solar and wind technology was higher than today and much higher than costs expected in future years (a declining capital cost curve). The Basin West Contract is more costly than its Generic Resources due to an applied social cost of carbon rate, whereas conversely the Basin East Contract is less costly than its Generic Resources due to the need to include a gas-fired peaking resource in the Generic Resources to account for renewable intermittency. Results are shown in the Results section of this Report.

We also performed a supplemental analysis concerning the Existing Resources not located in Colorado to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied ("Non-Colorado Benchmarking"). Results of the Non-Colorado Benchmarking revealed that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking. Results also revealed that although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent.

Scope

The scope of the resources to be Benchmarked was defined by Tri-State and included the Existing Resources shown in Table 1 and the Generic Resources shown in Table 2 below.

Existing Resources

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned, and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, and the Limon Units 1 and 2and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) Existing Resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

Table 1 – Summary of Existing Resources to be Benchmarked

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	Owned	wco	427	102	1980
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	Owned	wco	410	98	1979
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	Owned	wco	448	448	1984
4	GC-LRS 2-WY	Steam Turbine - Coal	Owned	wyo	570	231	1981
5	GC-LRS 3-WY	Steam Turbine - Coal	Owned	wyo	570	230	1982
6	GC-SV 3-SPV	Steam Turbine - Coal	Owned	arz	417	317	2006
7	GG-Burlington 1-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
8	GG-Burlington 2-E_CO	Frame CT - Oil	Owned	eco	55	55	1977
9	GG-Knutson 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
10	GG-Knutson 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2002
11	GG-Limon 1-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
12	GG-Limon 2-E_CO	Frame CT - Gas	Owned	eco	70	70	2003
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003

	Plant/Unit	Technology	Type	Location	Nominal Capacity (MW)	Tri-State Modeled Capacity (MW)	Year In Service
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	Owned	snm	40	40	2003
17	GG-Rifle-NW_CO	Combined Cycle - Gas	Owned	wco	81	81	1987
18	GG-Shafer-E_CO	Combined Cycle - Gas	Owned	eco	272	272	1994
19	CP-AltaLuna-S_NM	Tracking Array Solar	PPA	nm	25	25	2017
20	CP-SanIsabel-E_CO	Tracking Array Solar	PPA	eco	30	30	2016
21	CP-FirstSolar-N_NM	Fixed Solar	PPA	nm	30	30	2010
22	CP-ColoHighlands-E_CO	Wind	PPA	eco	91	91	2012
23	CP-KitCarson-E_CO	Wind	PPA	eco	51	51	2010
24	CP-TwinButtes-E_CO	Wind	PPA	eco	76	76	2017
25	CP-Carousel-E_CO	Wind	PPA	eco	150	150	2015
26	CP-Basin_West	Basin System	PPA	eco	268	268	2017
27	CP-Basin_East	Basin System	PPA	eco	317	317[3]	2017

Generic Resources

Twenty-eight (28) of the Generic Resources were gas-fired including reciprocating engine ("Recip_Engine"), aeroderivative combustion turbine ("Aeroderivative_CT"), industrial combustion turbine ("Frame_CT") and industrial combined cycle ("Frame_CCCT") technologies that would be located in western Colorado ("wco"), southwestern Colorado ("swco"), northwestern Colorado ("nwco"), northern New Mexico ("nnm") and Wyoming ("wyo"). All of these would be wholly owned by Tri-State with the capacity shown as the "Tri-State Modeled Capacity".

The remaining Generic Resources included:

- Solar PV ("Solar_PV") technologies of various sizes (40, 100, 120, 230 MW) and wind ("Wind") technologies of various sizes (40, 100, 165, 280 MW) to be located in eco, swco, nnm, and wyo either under third party ownership ("PPA") or Tri-State ownership ("Build-Transfer");
- Standalone lithium ion battery storage technology ("Li-Ion Battery") in various combinations of size (25, 100, 500 MW) and duration (4 hour or 8 hour) to be located in eco, swco, wco, nnm, and wyo to be owned ("Owned") by Tri-State;
- 300 MW pumped storage technology located in nnm to be owned by Tri-State;
- 100 MW combined solar PV plus storage ("Solar+Battery") and wind plus storage ("Wind+Battery") technologies to be located in eco, nnm, wyo and swco either under third party ownership or Tri-State ownership

[3] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

Table 2 – Summary of Generic Resources to be Considered in the Benchmarking

	Name	Technology	Type	Location	Modeled Tri-State Capacity (MW)
1	112_18x6RICE_eco	Recip_Engine	Owned	eco	112
2	112_18x6RICE_nnm	Recip_Engine	Owned	nnm	112
3	46_9x5RICE_eco	Recip_Engine	Owned	eco	46
4	46_9x5RICE_nnm	Recip_Engine	Owned	nnm	46
5	46_9x5RICE_swco	Recip_Engine	Owned	swco	46
6	Upd-93_10x9_3ICE_eco	Recip_Engine	Owned	eco	93
7	Upd-93_10x9_3ICE_nnm	Recip_Engine	Owned	nnm	93
8	Upd-93_10x9_3ICE_swco	Recip_Engine	Owned	swco	93
9	Upd-93_10x9_3ICE_wyo	Recip_Engine	Owned	wyo	93
10	40_1x40LM6000_eco	Aeroderivative_CT	Owned	eco	40
11	40_1x40LM6000_nnm	Aeroderivative_CT	Owned	nnm	40
12	40_1x40LM6000_swco	Aeroderivative_CT	Owned	swco	40
13	81_2x40LM6000_eco	Aeroderivative_CT	Owned	eco	81
14	81_2x40LM6000_wyo	Aeroderivative_CT	Owned	wyo	81
15	93_1x100_LMS100_nnm	Aeroderivative_CT	Owned	nnm	93
16	300_1x1_7FA05_eco	Frame_CCCT	Owned	eco	300
17	300_1x1_7FA05_nnm	Frame_CCCT	Owned	nnm	300
18	300_1x1_7FA05_swco	Frame_CCCT	Owned	swco	300
19	300_1x1_7FA05_wyo	Frame_CCCT	Owned	wyo	300
20	287_1x1_M501G_nwco	Frame_CCCT	Owned	nwco	350
21	331_1x1_STG-8000H_nwco	Frame_CCCT	Owned	nwco	375
22	357_1x1_7HA01_nwco	Frame_CCCT	Owned	nwco	357
23	545_1x1_7HA03_nwco	Frame_CCCT	Owned	nwco	545
24	200_1x235_7FA05_eco	Frame_CT	Owned	eco	200
25	200_1x235_7FA05_nnm	Frame_CT	Owned	nnm	200
26	200_1x235_7FA05_swco	Frame_CT	Owned	swco	200
27	CP-1x100PV_eco	Solar_PV	PPA	eco	100
28	CP-1x100PV_nnm	Solar_PV	PPA	nnm	100
29	CP-1x100PV_swco	Solar_PV	PPA	swco	100
30	CP-1x100PV_eco Build-Transfer	Solar_PV	Owned	eco	100
31	CP-1x100PVBatt_eco	Solar+Battery	PPA	eco	100
32	CP-1x100PVBatt_nnm	Solar+Battery	PPA	nnm	100
33	CP-1x100PVBatt_swco	Solar+Battery	PPA	swco	100
34	CP-1x100PVBatt_eco Build-Transfer	Solar+Battery	Owned	eco	100
35	CP-1x100Wind_eco	Wind	PPA	eco	100
36	CP-1x100Wind_nnm	Wind	PPA	nnm	100
37	CP-1x100Wind_wyo	Wind	PPA	wyo	100
38	CP-1x100Wind_eco Build-Transfer	Wind	Owned	eco	100
39	CP-1x100WindBatt_eco	Wind+Battery	PPA	eco	100
40	CP-1x100WindBatt_nnm	Wind+Battery	PPA	nnm	100
41	CP-1x100WindBatt_wyo	Wind+Battery	PPA	wyo	100
42	100MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	100
43	100MW Li-Ion Battery_wco	Li-Ion_Battery	Owned	wco	100
44	100MW Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	100

	Name	Technology	Type	Location	Modeled Tri-State Capacity (MW)
45	25MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	25
46	25MW Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	25
47	25MW Li-Ion Battery_wco	Li-Ion_Battery	Owned	wco	25
48	25MW Li-Ion Battery_wyo	Li-Ion_Battery	Owned	wyo	25
49	50MW 8Hr Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	50
50	50MW 8Hr Li-Ion Battery_nnm	Li-Ion_Battery	Owned	nnm	50
51	50MW 8Hr Li-Ion Battery_swco	Li-Ion_Battery	Owned	swco	50
52	Pumped Storage - nnm	Hydro	Owned	nnm	300
53	CP-1x130PV-eco	Solar_PV	PPA	eco	130
54	CP-1x165Wind-eco	Wind	PPA	eco	165
55	270_18x6RICE_eco	Recip_Engine	Owned	eco	270
56	CP-1x230PV-eco	Solar_PV	PPA	eco	230
57	CP-1x280Wind-eco	Wind	PPA	eco	280
58	500MW Li-Ion Battery_eco	Li-Ion_Battery	Owned	eco	500
59	CP-1x40PV-eco	Solar_PV	PPA	eco	40
60	CP-1x40Wind-eco	Wind	PPA	eco	40
61	306_18x6RICE_eco	Recip_Engine	Owned	eco	306

Overall Methodology

Our overall methodology for the Benchmarking was to first select for each Existing Resource a Generic Resource for comparison. We identified certain criteria to guide and constrain the selection of the Generic Resource for comparison (the "Selection Criteria"). The Selection Criteria included 1) that the Generic Resource must be of similar technology to the Existing Resource (e.g. a thermal resource could not be compared with a renewable resource), 2) that the Generic Resource must have a similar location as the Existing Resource, 3) that the Generic Resource must have a capacity similar to the Existing Resource and 4) that the Generic Resource must be capable of operating at or above the annual capacity factor typically expected for a resource of that type. Each combination of Existing Resource and its associated Generic Resource for comparison was known as a "Pairing".

The total capacity of the Existing Resource rather than just the Tri-State Modeled Capacity was considered in selecting the Generic Resource for comparison. This was done because the performance and cost of Tri-State's share of the Existing Resource benefits from the economies of scale of the entire Existing Resource (for example, entire resource heat rate, variable O&M cost rate, fixed O&M cost rate) and therefore a Generic Resource of similar size to the entire Existing Resource should be selected for a fair comparison.

Once the Pairings had been made, we then forecast the annual capacity, energy production and annual operating and ownership costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming they would operate in isolation from each other and all other resources. Both the Existing Resource and the Generic resource were forecast to operate at a capacity factor consistent with resources of their types and with historical or expected capacity factors for the Existing Resources as reported by Tri-State (the "Common Capacity Factor"). Energy for each Existing Resource was forecast based on the Common Capacity Factor and its Tri-State Modeled Capacity. Energy for each Generic

Resource was forecast to operate based on the Common Capacity Factor but only a portion of the Plant Capacity equal to their Tri-State Modeled Capacity for the Existing Resource (the "Tri-State Share"). This was done so that the forecast energy production for the Existing Resource and the Generic resource were the same, as if Tri-State was to own just a share of the Generic Resource.

Assumptions for fuel cost, heat rate, carbon emission rates, fixed O&M, variable O&M, capital expenditures, capital basis, depreciation, book life and PPA price (for the third party owned renewable resources) were specific to each Existing Resource and Generic Resource. Assumptions for the Existing Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Existing Resource Review work. Similarly, assumptions for the Generic Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Generic Resource Review work. Assumptions for a limited number of the Generic Resources were developed by us. Please see the Results section of this report for a more detailed description of these assumptions and the forecasting methodology. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource were modeled to operate for the same years in the study period. Assumptions provided by Tri-State were aligned with those used in their resource capacity expansion modeling software and were not representative of inputs specific to their financial modeling.

We then discounted the annual capacity, energy production and annual cost streams to net present values and used them to calculate a levelized cost in 2020 dollars for both the Existing Resource and Generic Resource. In cases where the Common Capacity Factor was relatively high, we calculated a levelized cost of energy (LCOE) in $/MWh. In cases where the Common Capacity Factor was relatively low, we calculated a levelized cost of capacity (LCOC) in $/kw-yr. We then compared the LCOE or LCOC results for the Existing Resource and the Generic Resource and commented on why they differed.

Expanded Methodology for the Basin Contracts

For the Basin Contracts, a special methodology was necessary because no specific generating resource is associated with either Basin Contract. For the purposes of benchmarking this type of unspecified energy with varying profiles, we expanded the methodology to allow comparison of each Basin Contract against a group of three (3) Generic Resources (a "Generic Composite") instead of just a single Generic Resource. Use of three resources of differing types was judged a reasonable proxy for a system resource for the purposes of benchmarking.

Generic Resources were selected for each Generic Composite based on three general criteria; 1) to maximize the use of renewable resources; 2) to match the forecast delivery profile of the associated Basin Contract as best possible and 3) minimize the overall cost of the Generic Composite. We began the selection process by examining the hourly Basin Contract forecast energy profile for a typical year (8760 hours). We then attempted to replicate the Basin Contract profile with the hourly forecast energy profiles of the various sized solar and wind Generic Resources. Invariably, there were hours in which the combined forecast solar and wind profiles were insufficient to replicate the Basin Contract profile. In these cases, we introduced a forecast hourly profile for a dispatchable resource to fill the gap. The dispatchable resource was either Recip_Engine, Aeroderivative_CT, Frame_CT, Frame_CCCT or Li-Ion

Battery based. For a battery resource, it was assumed to store energy from the selected solar and wind resources only with a certain efficiency "round-trip" loss.

Although specific generating resources are not associated with the Basin Contracts, Tri-State did provide us with carbon emission rates based on how the Basin Contracts primarily have been historically served to apply to the Basin Contracts.

Results

This section includes results of the resource Pairing, a detailed description of the forecasting and costing methodology with detailed results for one of the Pairings, and a summary of the LCOE and LCOC results for all of the Pairings.

Pairings

Table 3 summarizes results of the resource Pairing.

The coal-fired Existing Resources have plant capacities ranging from 410 to 570 MW with relatively high historical capacity factors reported by Tri-State. Therefore, each of these Existing Resources was paired with the large gas-fired combined cycle combustion turbine (545_1x1_7HA03_nwco) Generic Resource. This Pairing satisfies the Selection Criteria except in the case of the Springerville 3 (SV 3) resource and the Laramie River Station (LRS2, LRS 3) resources. With respect to SV 3, the Generic Resource has a northwest Colorado location instead of an Arizona location. However, we judged the pairing as reasonable since no other CCCT Generic Resource is located in Arizona. With respect to LRS 2 and LRS 3, the Generic Resource has a capacity (545 MW) that is smaller than LRS 2 and LRS 3 (570 MW). However, we judged the Pairings as reasonable because no Frame_CCCT Generic Resource has a capacity greater than LRS. The 545_1x1_7HA03_nwco Generic Resource is the largest Frame_CCCT Generic Resource. We also judged the other coal-fired resource Pairings reasonable even though the capacity (545 MW) is much greater than that of the other coal-fired resources (410-448 MW). This is because no other Frame_CCCT Generic Resource has a capacity greater than 375 MW and therefore would not have satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to eighty (80) percent which is representative for large coal fired resources and large gas-fired combined cycle resources. This capacity factor is also representative of air quality permit limitations for Craig 1 which limits its capacity factor to 80%.

The combustion turbine Existing Resources have plant capacities ranging from 40 to 70 MW and relatively low historical and expected capacity factors reported by Tri-State. Therefore, each of these resources was paired with a small simple cycle combustion turbine (781_2x40LM6000_eco) Generic Resource. This Pairing satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Rifle Existing Resource is relatively small (81 MW) combined cycle plant. Although a combined cycle plant, Rifle has a historical and expected capacity factor reported by Tri-State that is much lower than typical for combined cycle resource and more typical of a combustion turbine resource. Therefore, the Rifle resource was paired with the same small simple cycle combustion turbine (81_2x40LM6000_eco) Generic Resource used for the combustion turbine Existing Resources. This Pairing satisfied the

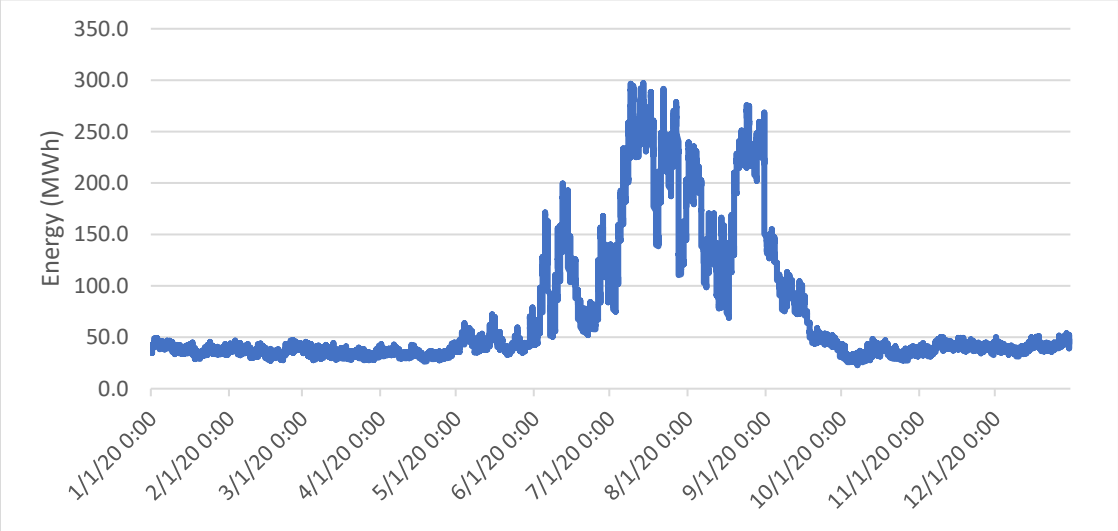
Selection Criteria. We set the Common Capacity Factor for the Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Shafer combined cycle Existing Resource is relatively large (272 MW) with a historical and expected capacity factor reported by Tri-State of approximately thirty five (35) percent. This is relatively low with respect to typical combined cycle resources yet relatively high compared with combustion turbine resources. We decided to pair the Shafer resource with the small gas-fired combined cycle combustion turbine (300_1x1_7FA05_eco) Generic Resource. We felt this was more representative than pairing it with a combustion turbine resource. This Pairing satisfies the Selection Criteria. We set the Common Capacity Factor for the Pairing equal to thirty five (35) percent.

The solar PV Existing Resources were paired with the 100 MW solar PV (CP-1x100PV_eco) Generic Resource. The wind Existing Resources were paired with the 100 MW wind (CP-1x100Wind_eco) Generic Resource. These Pairings satisfy the Selection Criteria, with the exception of the Carousel wind resource. The wind Generic resource has a capacity (100 MW) that is less than the Carousel capacity (150 MW). However, we judged this Pairing reasonable because there is no wind Generic Resource with a capacity greater than 100 MW. We set the Common Capacity Factor for the Pairings equal to the historical capacity factors reported by Tri-State for the Existing Resources.

The Basin West Contract was paired with a Generic Composite consisting of a 230 MW Solar PV resource PPA in eco (CP-1x130PV-eco), a 280 MW Wind resource PPA in eco (CP-1x280Wind-eco) and a 500 MW Li-Ion Battery resource Owned in eco (500MW Li-Ion Battery_eco). The Basin East Contract was paired with a 40 MW Solar PV resource PPA in eco (CP-1x40PV-eco), a 40 MW wind resource PPA in eco (CP-1x40Wind-eco) and a 306 MW RICE resource Owned in eco (306_18x6RICE_eco). It's important to note that a gas-fired dispatchable resource was selected for the Basin East Generic Composite rather than a Li-Ion Battery resource. This was due to the fact that the Basin East Contract energy demand is driven by irrigation loads which are consistently high in the summer and consistently low in the winter (see Figure 1 below). It was judged that a Li-Ion Battery resource with just 4 hours of duration and a relatively high capital cost would have very little utilization over the year and therefore would be less cost-effective than a RICE generating resource with a relatively low capital cost.

Figure 1 – Hourly Energy Profile for the Basin East Contract



Forecasting Methodology and Craig 1 Results

This section provides a detailed description of the methodology used for the forecasting and LCOE and LCOC calculations for Benchmarking of Existing Resources other than the Basin Contracts. As a guide, detailed results for the Craig 1 Pairing are shown below (Table 4 for the Existing Resource and Table 5 for the Generic Resource). Assumptions and results are shown in the upper left portion of the results with the annual cost forecast shown below that. A summary of LCOE and LCOC results for all the Pairings are provided in the subsequent LCOE and LCOC Results section.

Generation for the Existing Resource was forecast to be constant every year based on the Tri-State Modeled Capacity and the Common Capacity Factor for the Existing Resource, and the Tri-State Share and the Common Capacity Factor for the Generic Resource.

For Existing Resources and Generic Resources to be owned by Tri-State, fuel cost was forecast based on the heat rate multiplied by the generation and the first year fuel price (Fuel Cost 2021). For costs in subsequent years the fuel price was escalated at the fuel cost escalation rate which was set equal to the compound annual growth rate of prices observed in the fuel price forecasts provided by Tri-State. Carbon costs were forecast similarly, based on the generation, the carbon emission rate of the resource and the first year Social Cost of Carbon (Social Cost of Carbon 2021) and an escalation rate based on the compound annual growth rate of the Social Cost of Carbon forecast provided by Tri-State. Variable O&M (VOM) was forecast based on generation and the first year variable O&M cost (VOM Cost 2021) and an assumed VOM cost escalation rate. Fuel, carbon and VOM forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, fixed operations and maintenance cost (FOM) and capital expenditures (Capex) were forecast similarly to VOM except in the case of the Existing Resources for which resource-specific forecasts were provided by Tri-State. In order

to ensure equal service lives between the Existing Resource and the Generic Resource, we requested for the purposes of the Benchmarking that Tri-State develop the Existing Resource forecasts assuming that the Existing Resources would operate for the entire study period (through 2040). This ran counter to planned retirement decisions for the Existing Resources, in particular the Craig 1 resource which will be retired by 2025 and Craig 2 and Craig 3 resources which will be retired by 2030, but was necessary to the integrity of the comparison. In addition, Tri-State indicated they would not be expending capex in the final five years of the resource life for the Existing Resources and the Generic Resources. Therefore, the capex costs for the years 2035 through 2040 were assumed to be zero for both the Existing Resources and the Generic Resources. FOM and Capex forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, interest and depreciation were forecast based on the undepreciated capital cost of the resource at the beginning of each year (Capex Balance) multiplied by an assumed debt interest rate and an assumed depreciation rate. The resulting interest and depreciation were deducted from the subsequent year Capex Balance. For the Existing Resources the assumed interest and depreciation rates were provided by Tri-State. For the Generic Resources we assumed the same debt interest rate but a depreciation rate equal to straight line depreciation over a 30 year life. Interest and depreciation forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, we also forecast the liability that Tri-State would incur at the time an Existing Resource owned by Tri-State would reach the end of its depreciation life (the "Accounting Retirement Year"). This liability would occur if and to the extent that the resource is not fully depreciated at the end of the Accounting Retirement Year. We characterized this liability as the "Stranded Cost" of the resource which we set equal to the beginning Capex Balance plus the Capex amount in the year equal to the Accounting Year. The Accounting Year assumption was provided by Tri-State.

For Existing Resources and Generic Resources that are (or would be) owned by third parties, PPA Cost was forecast based on Generation multiplied by a PPA price forecast. For Existing Resources, the PPA price forecast was provided by Tri-State. For Generic Resources, the PPA price forecast was developed by us as part of our Generic Resource Review work.

For calculation of LCOE and LCOC, we first calculated the net present value (NPV) of total costs (Total), fixed costs (Fixed Only), Generation and Capacity by discounting the annual cost values to the year 2020 using a discount rate equal to the debt interest rate. The debt interest rate represents the weighted average cost of capital of Tri-State since Tri-State does not have equity in its capital structure. LCOE was then calculated as the ratio of Total NPV to Generation NPV expressed as $/MWh. LCOC was calculated as the ratio of Fixed Only NPV to Capacity NPV expressed as $/kw-year.

LCOE and LCOC Results

A summary of LCOE and LCOC results for all the Pairings is shown in Table 6. Results broken down by cost component are shown on Figure 2, Figure 3 and Figure 4.

For the coal-fired plant pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources due primarily to higher Social Cost of Carbon and higher FOM costs. The difference is greatest for Springerville 3 due to its relatively high interest cost in addition to the Social Cost of carbon and FOM cost differences.

For the Frame CT pairings, only LCOC results are relevant. Results show that the Existing Resources are less costly than the Generic Resources due to lower depreciation, interest, capex and FOM costs. The Existing Resources benefit from very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs.

For the Shafer Pairing, both the LCOE and LCOC results are relevant. The Common Capacity Factor of 35% is relatively low for a resource that is intended to provide energy (such as a CCCT) and relatively high for a resource that is intended to provide capacity (such as a CT). LCOE results show that Shafer is less costly than the Generic Resource due primarily to very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs. LCOC results also show Shafer less costly, with the difference due to the same reasons.

For the renewable plant Pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources for nearly all the Pairings. This is likely because the Existing Resources were built in prior years when the cost of solar and wind technology was high relative to the costs expected in future years (a declining capital cost curve). The exception is the Twin Buttes wind resource. Its LCOE is less than the Generic Resource. Review of the Twin Buttes PPA price forecast reveals that it has a low price with no escalation which compares favorably to the Generic resource that has a similar first year price but is assumed to escalate at 2% annually thereafter.

For the Basin Contracts, only LCOE results are relevant. Results show that the Basin West Contract is more costly than its Generic Composite. This is primarily because the Basin West Contract has a carbon emission rate and therefore incurs a Social Cost of Carbon whereas the Generic Composite does not (all renewables and battery storage). The impact of the Social Cost of Carbon becomes evident when examining the case where there is no Social Cost of Carbon as described in the Non-Colorado Benchmarking section below. Conversely to the Basin West results, the Basin East Contract results show that the Basin East Contract is less costly than its Generic Composite. The Basin East Contract incurs a Social Cost of Carbon, but so does its Generic Composite along with the relatively high cost of installing and operating a new RICE resource. The net effect is a higher cost for the Generic Composite.

Non-Colorado Benchmarking

In addition to the Benchmarking described above, we also performed a supplemental analysis concerning only the Existing Resources not located in Colorado ("Non-Colorado Resources") to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied ("Non-Colorado Benchmarking"). The overall methodology, pairing and forecast methodology was identical to the Benchmarking, except that the Social Cost of Carbon was set to zero for both the Existing Resources and the Generic Resources.

A summary of LCOE and LCOC results for the Non-Colorado Benchmarking is shown in Table 7 below.

LCOE results show that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking above. For the thermal resources, although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent. LCOE results for the renewable resources are unchanged from the Benchmarking results above since the Social Cost of Carbon does not apply to renewable resources. LCOE results for the Basin Contracts show that each contract is less expensive than its Generic Composite if the Social Cost of Carbon is not applied.

LCOC results are identical to those under the Benchmarking above. This is because the Social Cost of Carbon is a variable cost and therefore is not a component of LCOC which considers fixed costs only.

Table 3 – Results of the Pairings of Existing Resources with Generic Resources for Comparison

	Pairings															
	Existing Resource				Generic Resource 1				Generic Resource 2				Generic Resource 3			
	Name	Type	Plant Capacity (MW)	Tri-State Modeled Capacity (MW)	Name	Type	Capacity	Capacity Factor for Comparison	Name	Type	Capacity	Capacity Factor for Comparison	Name	Type	Capacity	Capacity Factor for Comparison
1	GC-Craig 1-NW_CO	Steam Turbine - Coal	427	102	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	GC-Craig 2-NW_CO	Steam Turbine - Coal	410	98	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
3	GC-Craig 3-NW_CO	Steam Turbine - Coal	448	448	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
4	GC-LRS 2-WY	Steam Turbine - Coal	570	231	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	GC-LRS 3-WY	Steam Turbine - Coal	570	230	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
6	GC-SV 3-SPV	Steam Turbine - Coal	417	317	545_1x1_7HA03_nwco	Frame_CCCT	545	80%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
7	GG-Burlington 1-E_CO	Frame CT - Oil	55	55	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
8	GG-Burlington 2-E_CO	Frame CT - Oil	55	55	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
9	GG-Knutson 1-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	GG-Knutson 2-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
11	GG-Limon 1-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	GG-Limon 2-E_CO	Frame CT - Gas	70	70	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	GG-Pyramid 1-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
14	GG-Pyramid 2-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15	GG-Pyramid 3-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	GG-Pyramid 4-S_NM	Aeroderivative CT - Gas	40	40	40_1x40LM6000_nnm	Aeroderivative_CT	40	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
17	GG-Rifle-NW_CO	Combined Cycle - Gas	81	81	81_2x40LM6000_eco	Aeroderivative_CT	81	15%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
18	GG-Shafer-E_CO	Combined Cycle - Gas	272	272	300_1x1_7FA05_eco	Frame_CCCT	300	35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
19	CP-AltaLuna-S_NM	Tracking Array Solar	25	25	CP-1x100PV_nnm	Solar_PV	100	35%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	CP-SanIsabel-E_CO	Tracking Array Solar	30	30	CP-1x100PV_eco	Solar_PV	100	29%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	CP-FirstSolar-N_NM	Fixed Solar	30	30	CP-1x100PV_nnm	Solar_PV	100	22%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	CP-ColoHighlands-E_CO	Wind	91	91	CP-1x100Wind_eco	Wind	100	46%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	CP-KitCarson-E_CO	Wind	51	51	CP-1x100Wind_eco	Wind	100	42%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	CP-TwinButtes-E_CO	Wind	76	76	CP-1x100Wind_eco	Wind	100	45%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	CP-Carousel-E_CO	Wind	150	150	CP-1x100Wind_eco	Wind	100	51%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	CP-Basin_West	Basin System	268	268	CP-1x230PV-eco	Solar_PV	230	30%	CP-1x280Wind-eco	Wind	280	43%	500MW Li-Ion Battery_eco	Li-Ion_Battery	500	9%
27	CP-Basin_East	Basin System	317	317	CP-1x40PV-eco	Solar_PV	40	30%	CP-1x40Wind-eco	Wind	40	43%	306_18x6RICE_eco	Recip_Engine	306	16%

Table 4 LCOE and LCOC Calculations for an Existing Resource

LCOE and LCOC (values in 2020 $ million unless stated otherwise)																	
Existing Resource	GC-Craig 1-NW_CO					Calculate LCOE and											
Technology	Steam Turbine - Coal																
Type	Owned																
Basin Contract?	No																
Assumptions	Base	Escalation															
Plant Capacity (MW)	427																
Tri-State Share (MW)	102																
Capacity Factor	80%																
Heat Rate (Btu/kwh)	10,316																
Fuel Cost 2021 ($/MMBtu)	[redacted]	0.2%															
VOM Cost 2021 ($/MWh)		0.0%															
Social Cost of Carbon 2021 ($/MWh)	$46.00	1.8%															
FOM Cost 2021 ($/kw-yr)	See Detail	0.0%															
Capex Cost 2021 Tri-State Share ($ million/yr)	$0.8	3.0%															
Capex Balance 2021 BOY ($ million)	$86																
Debt Interest Rate	2.21%																
Debt Term (Years)	30																
Depreciation Rate	4%																
Accounting Retirement Year	2025																
PPA First Year Energy Price ($/MWh)	n/a	n/a															
PPA First Year Capacity Price ($/kw-mo)	n/a	n/a															
PPA Start Year	n/a																
PPA Term	n/a																
Discount Rate	2.21%																
Results																	
Levelized Cost of Energy (2020 $/MWh)	**$101**																
Levelized Cost of Capacity (2020 $/kw-yr)	**$154**																
Detail							Book										
	Generation (GWh)	Fuel	VOM	Social Cost of Carbon	FOM	Capex Balance	Capex	Interest	Depreciation	Stranded Cost	PPA Cost	Total	Total ($/MWh)	Capacity (MW)	Fixed Only	Total Fixed Only ($/kw-yr)	
NPV	11,455	[redacted]			[redacted]							$1,160.4		1,635	[redacted]		
2021	715			$38.1		$86.3	$0.8	$1.9	$3.7	$0.0	$0.0	$65.7	$92	102			
2022	715			$38.8		$83.5	$1.0	$1.9	$3.6	$0.0	$0.0	$66.4	$93	102			
2023	715			$39.5		$80.9	$1.1	$1.8	$3.5	$0.0	$0.0	$67.1	$94	102			
2024	715			$40.2		$78.6	$1.4	$1.8	$3.4	$0.0	$0.0	$67.9	$95	102			
2025	715			$40.9		$76.6	$1.6	$1.7	$3.3	$78.2	$0.0	$147.0	$206	102			
2026	715			$41.7		$74.9	$2.5	$0.0	$0.0	$0.0	$0.0	$63.6	$89	102			
2027	715			$42.4		$77.4	$2.8	$0.0	$0.0	$0.0	$0.0	$64.6	$90	102			
2028	715			$43.2		$80.2	$3.0	$0.0	$0.0	$0.0	$0.0	$65.6	$92	102			
2029	715			$44.0		$83.2	$3.3	$0.0	$0.0	$0.0	$0.0	$66.6	$93	102			
2030	715			$44.8		$86.5	$2.9	$0.0	$0.0	$0.0	$0.0	$67.1	$94	102			
2031	715			$45.6		$89.3	$3.0	$0.0	$0.0	$0.0	$0.0	$68.0	$95	102			
2032	715			$46.4		$92.3	$3.1	$0.0	$0.0	$0.0	$0.0	$68.9	$96	102			
2033	715			$47.2		$95.4	$3.1	$0.0	$0.0	$0.0	$0.0	$69.9	$98	102			
2034	715			$48.1		$98.5	$3.2	$0.0	$0.0	$0.0	$0.0	$70.8	$99	102			
2035	715			$48.9		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$68.5	$96	102			
2036	715			$49.8		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$69.4	$97	102			
2037	715			$50.7		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$70.3	$98	102			
2038	715			$51.6		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$71.2	$100	102			
2039	715			$52.6		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$72.2	$101	102			
2040	715			$53.5		$101.7	$0.0	$0.0	$0.0	$0.0	$0.0	$73.2	$102	102			

Table 5 – LCOE and LCOC Calculations for a Generic Resource

LCOE and LCOC (values in 2020 $ million unless stated otherwise)																	
Generic Resource	1																
Resource	545_1x1_7HA03_nwco																
Technology	Frame_CCCT																
Type	Owned																
Assumptions	Base	Escalation															
Plant Capacity (MW)	545																
Tri-State Share (MW)	102																
Capacity Factor	80%																
Heat Rate (Btu/kwh)	6,170																
Fuel Cost 2021 ($/MMBtu)	$1.79	4.5%															
VOM Cost 2021 ($/MWh)	$3.67	0.0%															
Social Cost of Carbon 2021 ($/MWh)	$46.00	1.8%															
FOM Cost 2021 ($/kw-yr)	$10.83	0.0%															
Capex Cost 2021 Tri-State Share ($ million/yr)	$0.5	3.0%															
Installed Cost Tri-State Share ($ million)	$121																
Debt Interest Rate	2.21%																
Debt Term (Years)	30																
Depreciation Rate	3%																
Accounting Retirement Year	2051																
PPA First Year Price ($/MWh)	#N/A	n/a															
PPA Start Year	n/a																
PPA Term	n/a																
Discount Rate	2.21%																
Results																	
Levelized Cost of Energy (2020 $/MWh)	**$52**																
Levelized Cost of Capacity (2020 $/kw-yr)	**$67**																
Detail							Book										
	Generation (GWh)	Fuel	VOM	Social Cost of Carbon	FOM	Capex Balance	Capex	Interest	Depreciation	Stranded Cost	PPA Cost	Total	Total ($/MWh)	Capacity (MW)	Fixed Only	Total Fixed Only ($/kw-yr)	
NPV	11,455											$590.7		1,635	$109.0		
2021	715	$7.9	$2.6	$13.1	$1.1	$121.1	$0.5	$2.7	$4.1	$0.0	$0.0	$31.9	$45	102	$8.3	$81	
2022	715	$8.2	$2.6	$13.4	$1.1	$117.5	$0.5	$2.6	$3.9	$0.0	$0.0	$32.3	$45	102	$8.1	$79	
2023	715	$8.6	$2.6	$13.6	$1.1	$114.1	$0.5	$2.5	$3.8	$0.0	$0.0	$32.8	$46	102	$7.9	$78	
2024	715	$9.0	$2.6	$13.9	$1.1	$110.7	$0.5	$2.5	$3.7	$0.0	$0.0	$33.2	$47	102	$7.8	$76	
2025	715	$9.4	$2.6	$14.1	$1.1	$107.5	$0.5	$2.4	$3.6	$0.0	$0.0	$33.7	$47	102	$7.6	$75	
2026	715	$9.8	$2.6	$14.4	$1.1	$104.4	$0.5	$2.3	$3.5	$0.0	$0.0	$34.3	$48	102	$7.4	$73	
2027	715	$10.3	$2.6	$14.6	$1.1	$101.5	$0.5	$2.2	$3.4	$0.0	$0.0	$34.8	$49	102	$7.3	$72	
2028	715	$10.7	$2.6	$14.9	$1.1	$98.6	$0.6	$2.2	$3.3	$0.0	$0.0	$35.4	$50	102	$7.2	$70	
2029	715	$11.2	$2.6	$15.2	$1.1	$95.8	$0.6	$2.1	$3.2	$0.0	$0.0	$36.0	$50	102	$7.0	$69	
2030	715	$11.7	$2.6	$15.4	$1.1	$93.2	$0.6	$2.1	$3.1	$0.0	$0.0	$36.7	$51	102	$6.9	$68	
2031	715	$12.2	$2.6	$15.7	$1.1	$90.7	$0.6	$2.0	$3.0	$0.0	$0.0	$37.3	$52	102	$6.8	$66	
2032	715	$12.8	$2.6	$16.0	$1.1	$88.2	$0.6	$2.0	$3.0	$0.0	$0.0	$38.1	$53	102	$6.7	$65	
2033	715	$13.4	$2.6	$16.3	$1.1	$85.9	$0.6	$1.9	$2.9	$0.0	$0.0	$38.8	$54	102	$6.5	$64	
2034	715	$14.0	$2.6	$16.6	$1.1	$83.7	$0.7	$1.9	$2.8	$0.0	$0.0	$39.6	$55	102	$6.4	$63	
2035	715	$14.6	$2.6	$16.9	$1.1	$81.5	$0.0	$1.8	$2.7	$0.0	$0.0	$39.7	$56	102	$5.6	$55	
2036	715	$15.3	$2.6	$17.2	$1.1	$78.8	$0.0	$1.7	$2.6	$0.0	$0.0	$40.5	$57	102	$5.5	$54	
2037	715	$16.0	$2.6	$17.5	$1.1	$76.2	$0.0	$1.7	$2.5	$0.0	$0.0	$41.4	$58	102	$5.3	$52	
2038	715	$16.7	$2.6	$17.8	$1.1	$73.6	$0.0	$1.6	$2.5	$0.0	$0.0	$42.3	$59	102	$5.2	$51	
2039	715	$17.4	$2.6	$18.1	$1.1	$71.2	$0.0	$1.6	$2.4	$0.0	$0.0	$43.2	$60	102	$5.0	$49	
2040	715	$18.2	$2.6	$18.4	$1.1	$68.8	$0.0	$1.5	$2.3	$0.0	$0.0	$44.2	$62	102	$4.9	$48	

Table 6 – Summary of LCOE and LCOC Results

	Pairings				Results			
	Existing Resource	Generic Resource 1	Generic Resource 2	Generic Resource 3	LCOE (2020 $/MWh)		LCOC (2020 $/kw-yr)	
	Name	Name	Name	Name	Existing	Generic	Existing	Generic
1	GC-Craig 1-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$101	$52		
2	GC-Craig 2-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$109	$52		
3	GC-Craig 3-NW_CO	545_1x1_7HA03_nwco	n/a	n/a	$93	$55		
4	GC-LRS 2-WY	545_1x1_7HA03_nwco	n/a	n/a	$92	$53		
5	GC-LRS 3-WY	545_1x1_7HA03_nwco	n/a	n/a	$98	$53		
6	GC-SV 3-SPV	545_1x1_7HA03_nwco	n/a	n/a	$123	$53		
7	GG-Burlington 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$48	$149
8	GG-Burlington 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$48	$149
9	GG-Knutson 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$42	$159
10	GG-Knutson 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$42	$159
11	GG-Limon 1-E_CO	81_2x40LM6000_eco	n/a	n/a			$54	$159
12	GG-Limon 2-E_CO	81_2x40LM6000_eco	n/a	n/a			$54	$159
13	GG-Pyramid 1-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
14	GG-Pyramid 2-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
15	GG-Pyramid 3-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
16	GG-Pyramid 4-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
17	GG-Rifle-NW_CO	81_2x40LM6000_eco	n/a	n/a			$63	$167
18	GG-Shafer-E_CO	300_1x1_7FA05_eco	n/a	n/a	[redacted]	$104	$50	$158
19	CP-AltaLuna-S_NM	CP-1x100PV_nnm	n/a	n/a		$33		
20	CP-SanIsabel-E_CO	CP-1x100PV_eco	n/a	n/a		$28		
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a		$33		
22	CP-ColoHighlands-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
23	CP-KitCarson-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
24	CP-TwinButtes-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
25	CP-Carousel-E_CO	CP-1x100Wind_eco	n/a	n/a		$30		
26	CP-Basin_West	CP-1x230PV-eco	CP-1x280Wind-eco	500MW Li-Ion Battery_eco		$39		
27	CP-Basin_East	CP-1x40PV-eco	CP-1x40Wind-eco	306_18x6RICE_eco		$112		

Figure 2 – Comparison of LCOE for Thermal Resource Pairings

Figure 3 – Comparison of LCOC for Thermal Resource Pairings

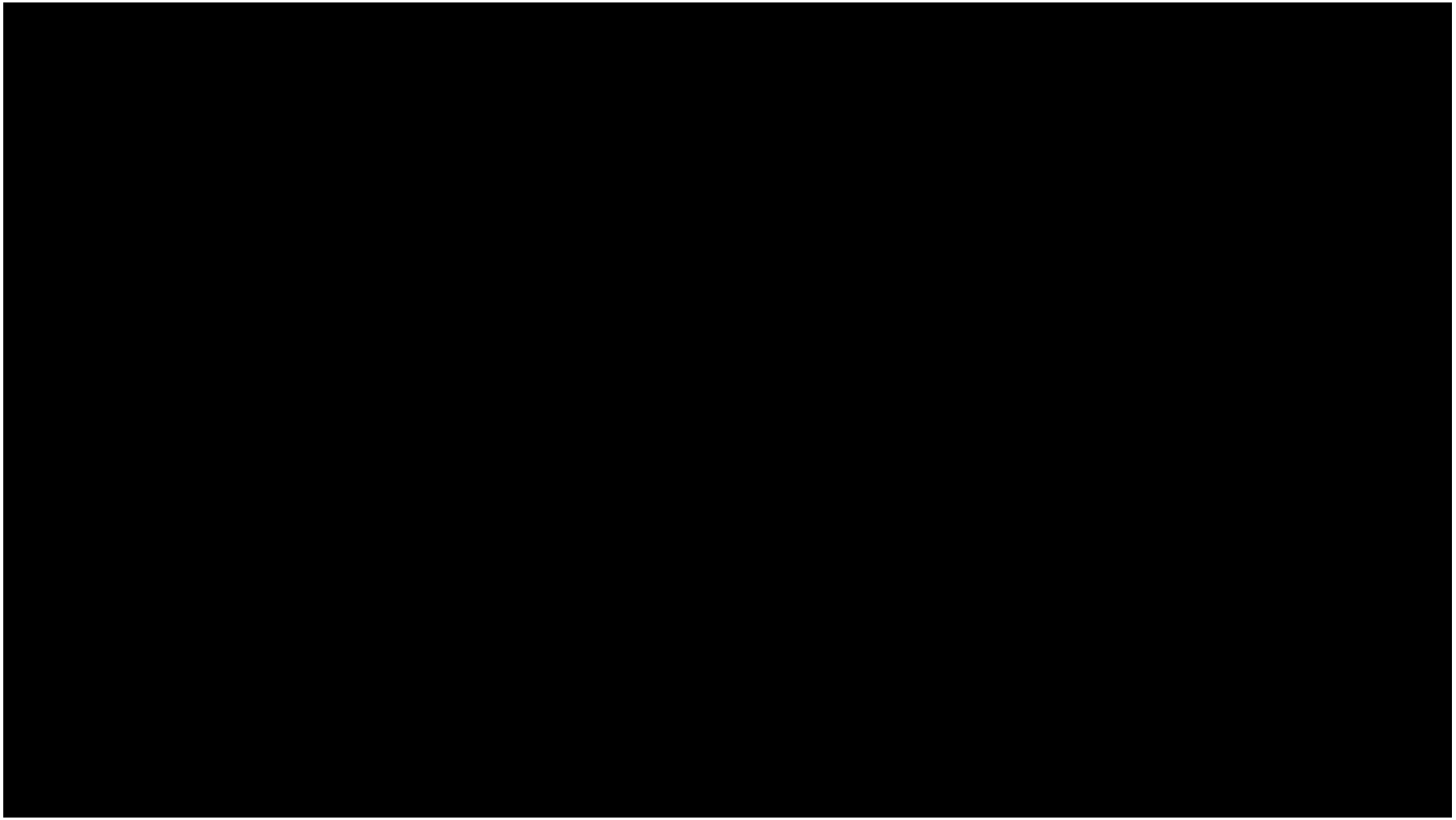


Figure 4 – LCOE Comparison for the Renewable Resource Pairings

Table 7 - Summary of LCOE and LCOC Results for the Non-Colorado Benchmarking

	Pairings				Results - Non-Colorado Benchmarking			
	Existing Resource	Generic Resource 1	Generic Resource 2	Generic Resource 3	LCOE (2020 $/MWh)		LCOC (2020 $/kw-yr)	
	Name	Name	Name	Name	Existing	Generic	Existing	Generic
1	GC-Craig 1-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
2	GC-Craig 2-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
3	GC-Craig 3-NW_CO	545_1x1_7HA03_nwco	n/a	n/a				
4	GC-LRS 2-WY	545_1x1_7HA03_nwco	n/a	n/a	$32	$31		
5	GC-LRS 3-WY	545_1x1_7HA03_nwco	n/a	n/a	$33	$31		
6	GC-SV 3-SPV	545_1x1_7HA03_nwco	n/a	n/a	$65	$32		
7	GG-Burlington 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
8	GG-Burlington 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
9	GG-Knutson 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
10	GG-Knutson 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
11	GG-Limon 1-E_CO	81_2x40LM6000_eco	n/a	n/a				
12	GG-Limon 2-E_CO	81_2x40LM6000_eco	n/a	n/a				
13	GG-Pyramid 1-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
14	GG-Pyramid 2-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
15	GG-Pyramid 3-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
16	GG-Pyramid 4-S_NM	40_1x40LM6000_nnm	n/a	n/a			$43	$158
17	GG-Rifle-NW_CO	81_2x40LM6000_eco	n/a	n/a				
18	GG-Shafer-E_CO	300_1x1_7FA05_eco	n/a	n/a				
19	CP-AltaLuna-S_NM	CP-1x100PV_nnm	n/a	n/a	[redacted]	$33		
20	CP-SanIsabel-E_CO	CP-1x100PV_eco	n/a	n/a				
21	CP-FirstSolar-N_NM	CP-1x100PV_nnm	n/a	n/a		$33		
22	CP-ColoHighlands-E_CO	CP-1x100Wind_eco	n/a	n/a				
23	CP-KitCarson-E_CO	CP-1x100Wind_eco	n/a	n/a				
24	CP-TwinButtes-E_CO	CP-1x100Wind_eco	n/a	n/a				
25	CP-Carousel-E_CO	CP-1x100Wind_eco	n/a	n/a				
26	CP-Basin_West	CP-1x230PV-eco	CP-1x280Wind-eco	500MW Li-Ion Battery_eco	[redacted]	$39		
27	CP-Basin_East	CP-1x40PV-eco	CP-1x40Wind-eco	306_18x6RICE_eco		$91		

END OF REPORT

Attachment Vol II 5-6 Ascend Analytics Renewables & Ramping Analysis

Tri-State Generation and Transmission Colorado Energy and Resource Plan Renewables and Ramping Analysis

Summary of work delivered by Ascend Analytics

Overview

Ascend Analytics (Ascend) is pleased to support Tri-State G&T (Tri-State) as it prepares for the 2020 Energy Resource Plan filing with the Colorado Public Utility Commission. Ascend was retained by Tri-State to supplement their in-house modeling capabilities by generating hourly simulation data for renewables and load that capture new market dynamics in the western grid driven by large scale renewable resource deployment. A key limitation of traditional production cost models is the inability to capture weather-driven variability in load and renewable output. A typical approach is to use weather-normalized (e.g. smooth, averaged) input curves for load and renewables. This was not generally a problem when most resources were dispatchable thermal resources. With Tri-State's goal to dramatically increase the amount of variable renewable resources in its portfolio, it becomes critical to capture the inherent variability in loads and resources, because increased volatility drives the need for different types of resources, particularly flexible resources that can provide integration services for system reliability.

Tri-State hired Ascend to use its power system simulation tool PowerSimm to help Tri-State's modeling team better capture the new energy system dynamics with increasing renewable related volatility. This was achieved by providing two deliverables:

1. Simulations of Tri-State member co-op loads and generation of various wind and solar resources between 2021-2030, and
2. An analysis of the effects these variable resources would have on the ramping of system-wide net load.

Tri-State provided historical data on all existing loads and resources for use in training PowerSimm's load and renewable energy simulation modules. Tri-State also provided forecasts of expected future gross load and renewable generation. PowerSimm uses NCDC weather data to generate time-series models that characterize the relationship between weather -> load and weather -> renewable resource behavior. The simulations are internally correlated and consistent within each "sim-rep" or each simulation run of 8760 hours per year over the course of the 10-year study horizon. Ascend delivered 20 such simulated future states. Some or all of these simulated forecasts of Tri-State load and each renewable resource will be input into Tri-State's internal modeling software to solve for resource and portfolio values consistent with an increasingly variable resource portfolio.

Results

Renewable Simulation

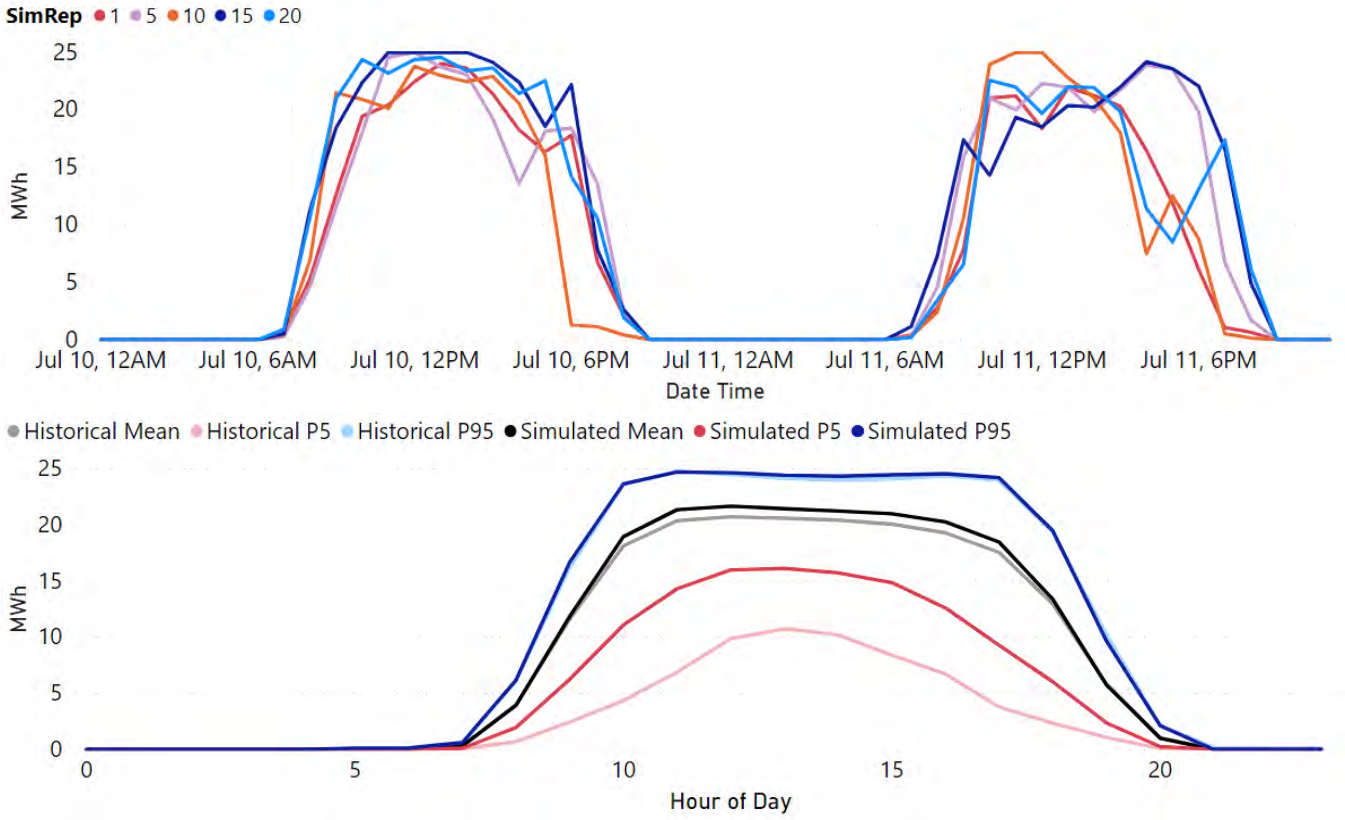
Tri-State provided the following renewable resources to be modeled in PowerSimm:

Resource	Unit Type	Location	State
Alta Luna	Solar	Deming, NM	Existing
Axial	Solar	Moffat County, CO	Under Contract
Carousel	Wind	Burlington, CO	Existing
Cimarron	Solar	Cimarron, NM	Existing
CO Highlands	Wind	Fleming, CO	Existing
Coyote Gulch	Solar	La Plata, CO	Under Contract
Crossing Trails	Wind	Seibert, CO	Under Contract
Dolores	Solar	Dolores County, CO	Under Contract
Kit Carson Wind	Wind	Burlington, CO	Existing
Niyol	Wind	Logan and Washington County, CO	Under Contract
San Isabel Solar	Solar	Trinidad, CO	Existing
Spanish Peaks	Solar	Trinidad, CO	Under Contract
Spanish Peaks Two	Solar	Trinidad, CO	Under Contract
TPE (Escalante)	Solar	McKinley County, NM	Under Contract
Twin Buttes II	Wind	Lamar, CO	Existing

PowerSimm uses historical hourly generation from a resource and correlates that generation against historic weather data to ensure that all behaviors of the resource are captured in the simulation: generation during various meteorological conditions, seasonality, behavior during low-probability weather patterns, etc. Rather than simply repeating historical hourly generation patterns or weather normalized shapes, PowerSimm simulates hourly weather over the modeling time period and uses the historically derived correlations between weather and generation to simulate future hourly generation.

PowerSimm models were set up using historical generation data and expected monthly forecasts provided by Tri-State. The resulting hourly simulations provide statistically robust data on renewable generation across both typical and low-probability conditions, as exemplified in Figure 1 (below) of a sample of five sim-reps (out of 20 simulated) for the Alta Luna solar project.

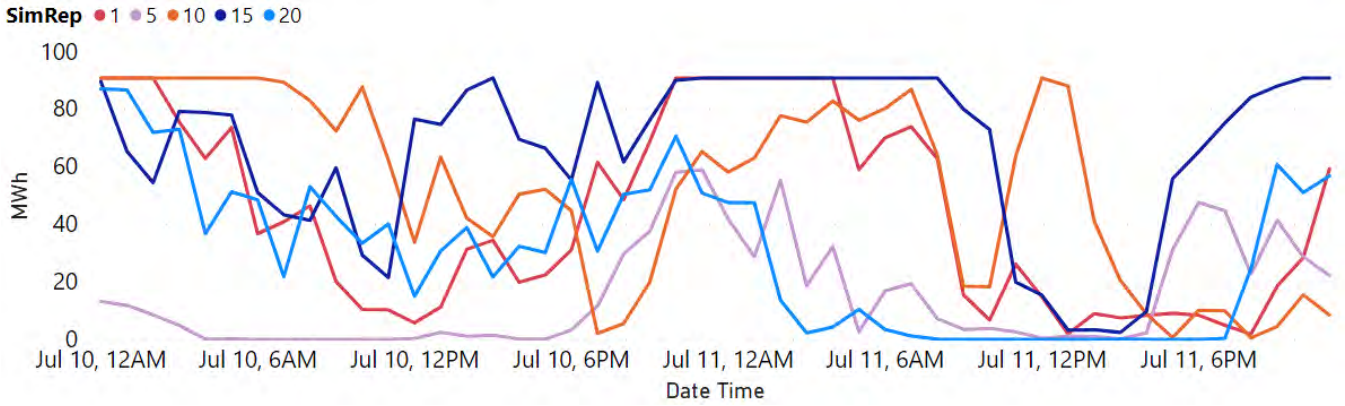
Figure 1: Sample Solar Generation and Validation – Alta Luna

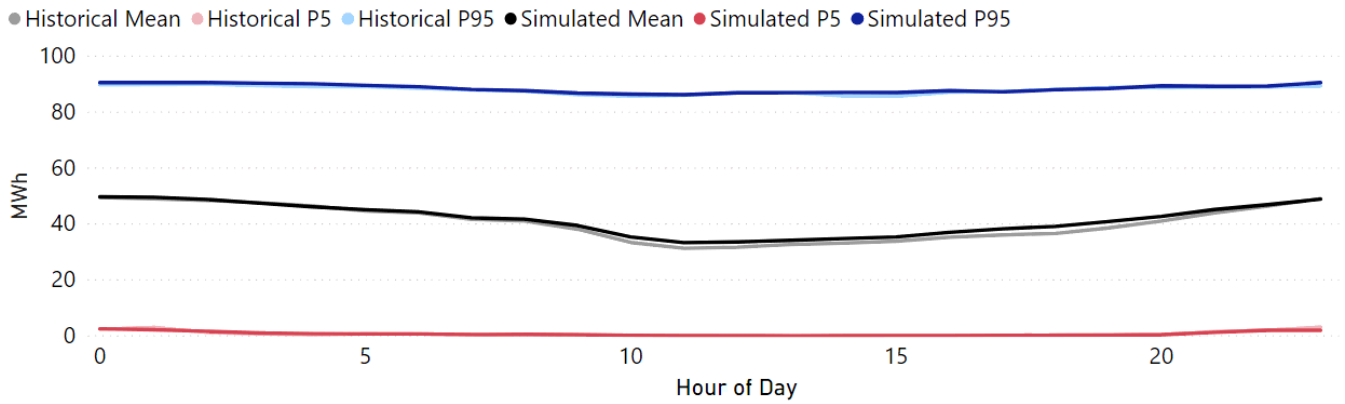


The sim-reps capture a range of variability in the unit's generation. One sim-rep may have max output on one day, while cloud cover on the next day inhibits the unit from outputting at its total capacity as seen in sim-rep 15. For validations (bottom of figure 1) we ensure that the model accurately captures historically observed variations by meeting the mean, P5, and P95 historical observations in the simulations. This approach allows Tri-State to fully understand renewable resource behavior (e.g. wind bursts or droughts, cloudiness, etc.) and risk profiles (e.g. availability during peak load events).

Similarly, Figure 2 shows example generation for five of twenty sim-reps for Tri-States CO Highlands wind unit (top of figure 2).

Figure 2: Sample Wind Generation and Validation – CO Highlands





The sim-reps capture a range of possible variability in the unit's generation. Sim-rep 15 shows generation at max capacity for several hours as the wind resources are plentiful, then a sudden drop off as the wind dies down. Sim-rep 5 demonstrates a different possible weather future where this entire stretch of time shown has relatively low generation. For validations (bottom of figure 2) we ensure that we accurately capture historically present variations by meeting the mean, P5, and P95 historical observations in our simulations.

Load Simulation

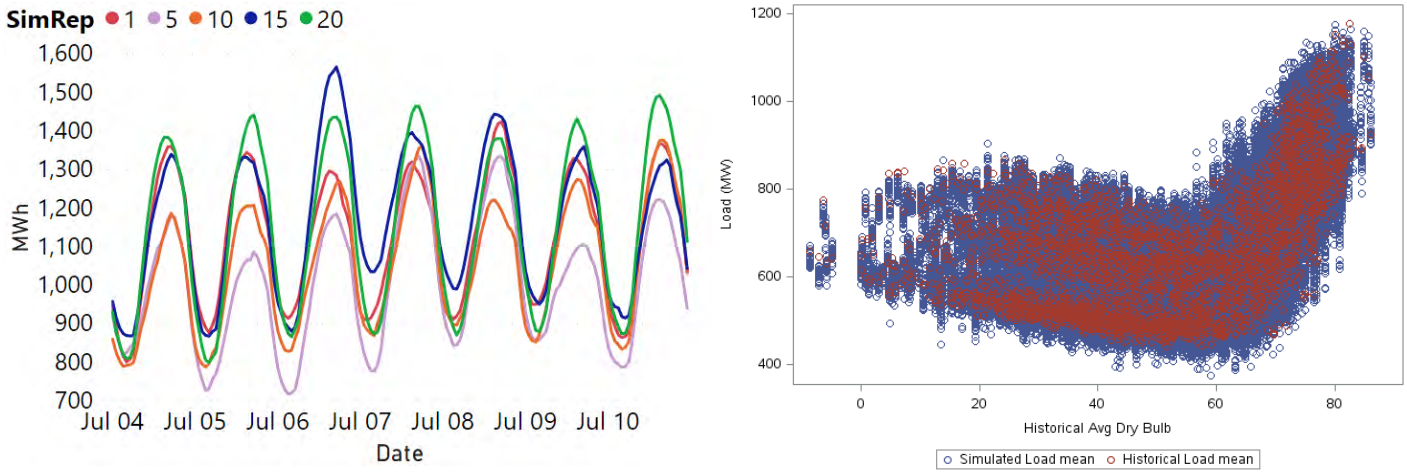
Tri-State provided the following load zones to be modeled in PowerSimm:

Load Zone
East Colorado
Nebraska
New Mexico
West Colorado
Wyoming

The load simulation follows a similar methodology as the renewable simulation. Inputs to the model include hourly historical load volumes as well as a load forecast of expected aggregate growth in demand. The model develops a complex set of correlations based on historical data that considers load, temperature, hour of day, day of week, and time of year. Temporal autocorrelations in the model are also important as each hourly load observation in the simulation is not independent, rather its highly correlated with the observation that came before it.

Figure 3 shows example electric load for five of twenty sim-reps for a week in July (left), showing a variety of possible demand futures. The temporal autocorrelation effects of the model come through, as sim-rep 5 consistently has lower demand than other sim-reps while sim-rep 20 shows consistently higher demand. Weather driven impacts are also visible, as seen in the spike in demand on July 6th for sim-rep 15 indicating a particularly hot day. For load simulations we ensure that we meet the historically present variations by meeting the mean, P5, and P95 historical observations in our simulations. We also ensure that we preserve historically observed temperature-load correlations as shown in the boomerang validation plot to the right. As temperature veers into extreme cold or warm territories we expect load to increase, and we expect our simulations (in blue) to mirror the behavior and cover the full range of historical observations (in red).

Figure 3: Sample Load Simulation and Validation - East Colorado

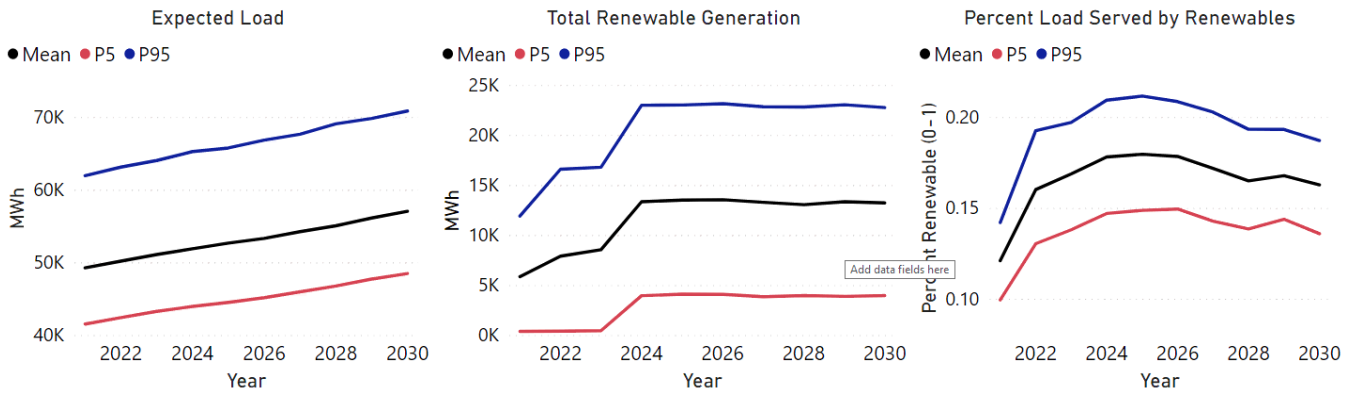


Analysis

Co-simulating Tri-State's load and renewables provides insight on the dynamics in net load, the difference between load and renewable generation, which represents the remaining load to be served by dispatchable resources. Simulating across 20 different possible weather futures, including weather that is considered both "normal" and "extreme," the model captures the interactions of weather, load, and renewable generation and statistically envelopes the most likely future scenario (the mean simulation) while also planning for more extreme possibilities (the P5 and P95 cases).

Figure 4 shows annual trends in load and renewables:

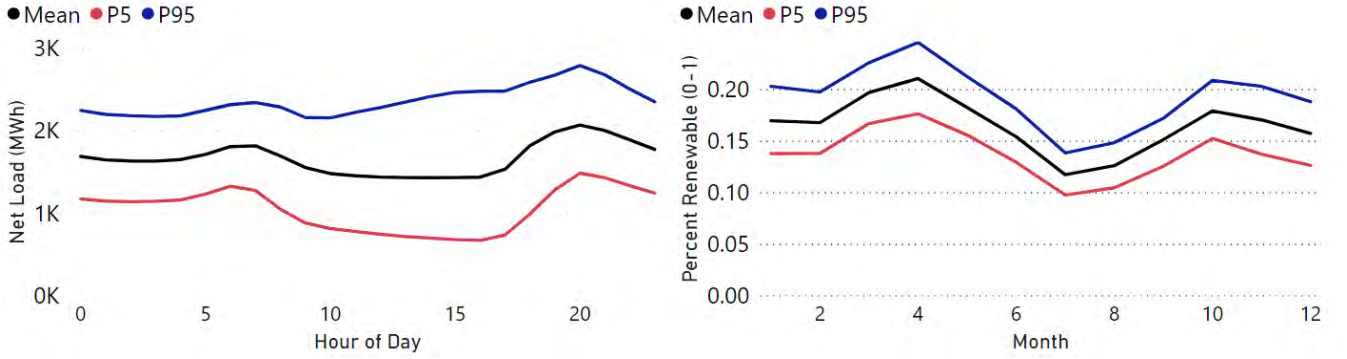
Figure 4: Annual Trends in Load and Renewables



Tri-State's Load (left) across its five load zones grows steadily through time. Renewable generation (middle) grows slowly in the beginning years of the analysis with a big jump in generation in 2024 as new resources come online followed by a leveling out. The resulting percent of load served by renewables (right) grows until 2024 as renewables generation increases followed by a steady decline as the growth in load surpasses the growth in renewable generation.

Figure 5 is a sample of load and renewable generation interaction in 2026.

Figure 5: Net Load (left) and Percent of Load Served by Renewables (right) in 2026



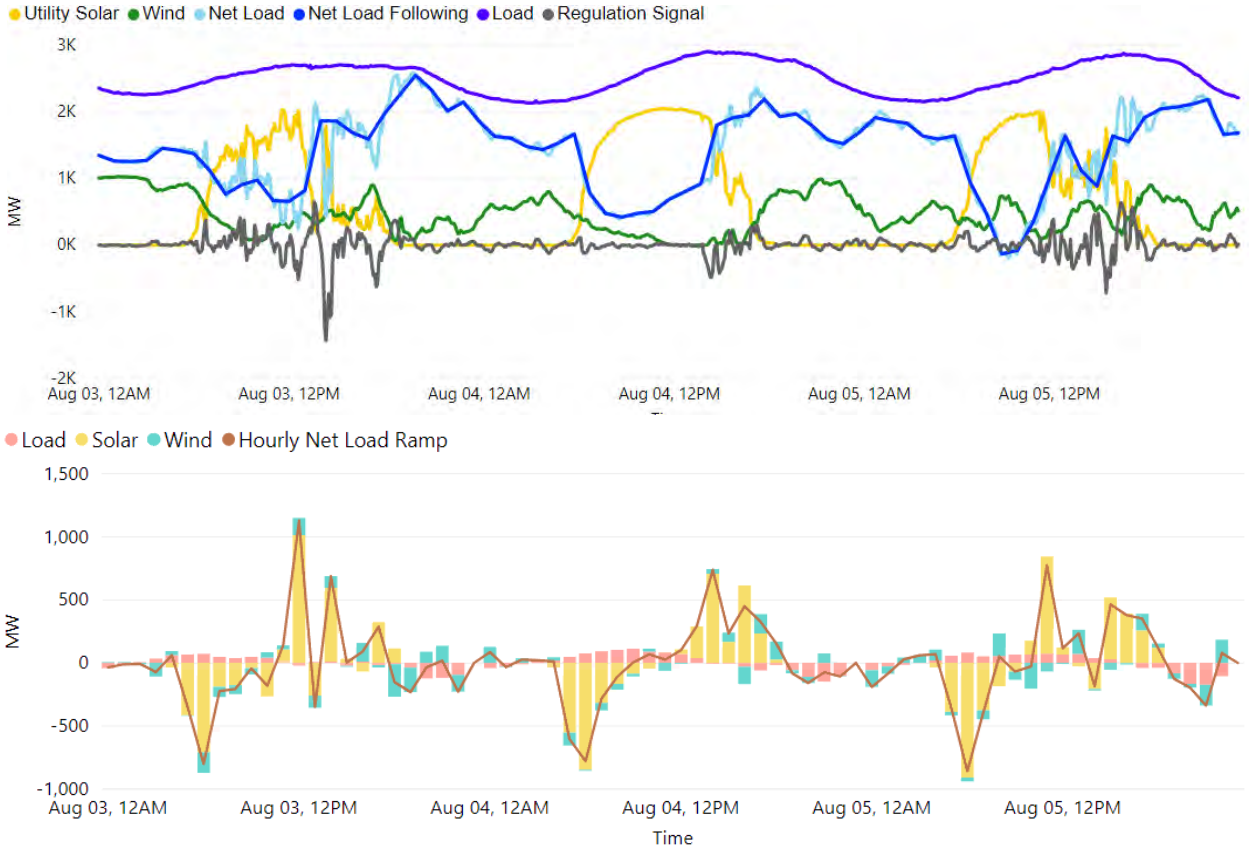
The percent of load served by renewables (right) shows the greatest renewable load share occurs in April and October when loads are low due to moderate temperatures and renewable output tends to peak. Tri-State's solar assets have their peak generation in May, but wind assets have a dual peak in April and October with the April peak being significantly larger. Although there is more solar capacity on the system in 2026 than wind capacity, the wind has a higher capacity factor, more generation, and therefore a stronger influence on total monthly renewable penetration. The hourly weekday Net Load figure (left) shows that Tri-State's net load takes on the "duck" shape, peaking in the morning hours between 6AM and 7AM with a larger peak in the evening at 8PM. Notably, the evening ramp intensity scales inversely with total load with the steepest ramps occurring (on average) during the days with lowest average loads and vice versa.

Ramping Analysis

Ramping analysis was carried out using PowerFlex, an Ascend software tool that analyzes renewable and load behavior on a minute-by-minute timescale to understand the ramping risk of a portfolio on multiple timescales as well as the value of flexible resources and ancillary services required to maintain load balance.

For this study all load and renewable items were input into PowerFlex on a 5-minutely timescale and were scaled up on a yearly basis to match forecasted quantities/capacities. PowerFlex calculated rolling statistics on Net Load (= Load – Total Renewable Generation) to find the largest ramp up and ramp down events in any 5-minute, 15-minute, 30-minute, and 60-minute time period in each month from 2021-2030. Figure 6 below shows a snapshot of the results of this analysis.

Figure 6: Sample PowerFlex Results and Ramping Contributions



The snapshots above shows a sample three-day period of representative load and renewable generation scaled to meet 2030 forecasts; the bottom figure shows the relative ramping contributions of load and renewables. While load takes on a relatively smooth shape, wind and solar profiles have more variability, particularly solar (as seen in the large yellow bars of solar contributions to both positive and negative ramping in the bottom figure). August 3rd shows a very volatile solar generation profile that leads to more dramatic ramping needs mid-day. August 4th has a much smoother solar profile, but we can see from the Ramping Contributions figure (bottom) that even with the smooth profile solar still contributes most to ramping contributions given the nature of solar daily generation patterns.

Table 1 below is a snapshot, based on a typical expansion plan scenario from 2021 to 2030, of what Tri-State's maximum forecasted ramping risk is at different timescales in June throughout the study window.

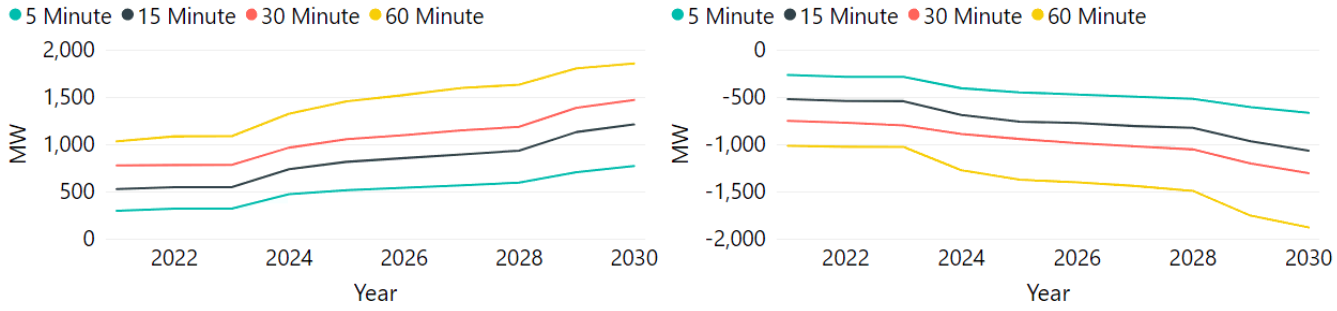
Table 1: June Ramping Risk for Baseline load/renewable forecasts

	Renewable Forecast (MW)		5 Minute Ramps		15 Minute Ramps		30 Minute Ramps		60 Minute Ramps	
Year	**Solar**	**Wind**	**Up**	**Down**	**Up**	**Down**	**Up**	**Down**	**Up**	**Down**
2021	1970	671	79	-83	166	-189	243	-258	326	-378
2022	2007	671	80	-86	170	-188	243	-258	320	-378
2023	2045	671	81	-87	170	-189	244	-258	321	-379
2024	2083	771	164	-178	288	-287	392	-374	563	-502
2025	2109	871	204	-222	355	-362	474	-443	676	-601
2026	2135	971	224	-244	391	-399	525	-489	742	-667
2027	2173	971	244	-267	417	-438	555	-518	801	-705
2028	2212	971	263	-287	452	-464	596	-539	846	-742
2029	2250	971	365	-397	609	-584	795	-709	1104	-928
2030	2288	1071	421	-430	695	-672	914	-811	1269	-1035

Analysis

As Tri-State increases the capacity of renewable resources over time the net ramping risk increases substantially across all timescales, as shown in Figure 7 below.

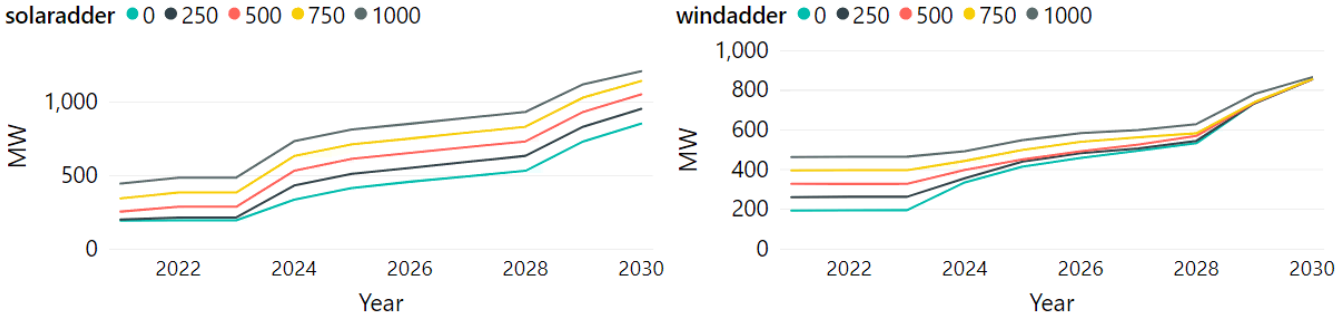
Figure 7: Annual Ramp Up (Left) and Ramp Down (Right) Risk



Ramping requirements grow through time with the ramping requirement increasing more rapidly at longer timescales (e.g. 60-minute ramp risk increases by a larger amount over the 10 year study horizon than 5-minute ramps).

Because of the potential for additional renewables to enter the system that are not currently contracted/planned, Ascend also analyzed ramping risks with solar and wind adders beyond the forecasted quantities to assess the impact of additional intermittent resources on the system. The results of this analysis for an additional 0/250/500/750/1000 MW of added solar/wind capacity (beyond the default forecasted quantity provided by Tri-State) are shown in Figure 8 below.

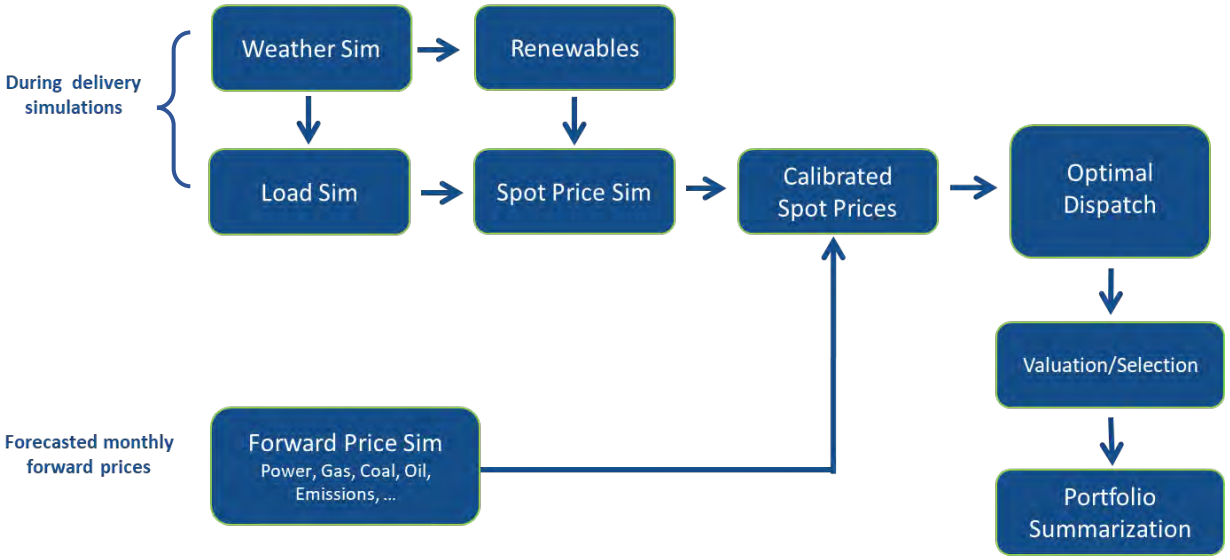
Figure 8: Annual 15 Minute Ramp Up Requirement with Renewable Adders



This analysis suggests that additional solar capacity on the system has a much stronger impact on ramping requirements than additional wind does, which is further supported by the relative ramping contributions of solar shown in Figure 6. Solar has a tendency to be more variable in its generation profile than the wind resources that Tri-State currently has in its portfolio, largely due to the steep ramp-up/ramp-down events that occur daily due to sunrise and sunset and further exaggerated by the effects of clouds and volatile hourly generation.

Appendix: PowerSimm Model Schematic

Figure 7: PowerSimm Modeling Framework



PowerSimm's Sim Engine captures "Meaningful Uncertainty" in weather, load, renewables, and prices

The PowerSimm Resources Planning Suite is a set of software programs consisting of PowerSimm Planner (PowerSimm) production cost model for system operations simulation and PowerFlex for renewable integration planning. The suite is designed and operated by Ascend Analytics for the purposes of Tri-State's2020 ERP. Combined, these tools form a platform for modern resource planning in an era of increasing uncertainty in electricity supply driven by the deployment of renewable generation.

PowerSimm is a dispatch optimization and production cost tool. The tool is comprised of two major elements, the Sim Engine and Dispatch Optimization, that work together to systematically bridge the physical and financial dimensions of electricity provision. PowerSimm uses a simulation-based approach born of the best-in-class techniques to perform decision analysis for portfolio risk management. Managing risk requires characterizing of the volatility in fuel price, power price, renewable generation, and outages. PowerSimm adopts this paradigm into the resource planning context.

The simulation of uncertainty with respect to weather is becoming ever more critical because "weather is the new fuel" in the country's emerging high-renewables system. To capture the changing market dynamics with renewables, PowerSimm simulates weather to capture its effect on renewable output and its effect on energy price formation. We call this "characterizing meaningful uncertainty." It is not simply noise around an arbitrary base scenario, but realistic paths of weather driving renewables, loads, and prices. That means PowerSimm is performing dispatch against system conditions as they really exist, not the idealized system modeled by traditional production cost models with averaged weather patterns, averaged renewable generation profiles, and "expected" load and market conditions. PowerSimm is a stochastic construct and through a multitude of simulations, we probabilistically explore all possible future states through a coherent and appropriately correlated set of data inputs and forecasts. With PowerSimm, resource decision making is supported not only with the mean of the distribution, but also by risk considerations informed by the 5th and 95th percentiles. Therefore, we can solve for the optimal resource portfolio that strikes the best balance between cost and risk.

Attachment Vol II 5-7 Beneficial Electrification Potential Study

BENEFICIAL ELECTRIFICATION POTENTIAL STUDY

FOR TRI-STATE GENERATION & TRANSMISSION

OCTOBER 22, 2020

Prepared by: Mesa Point Energy & BrightLine Group

TRI-STATE GENERGATION & TRANSMISSION
BENEFICIAL ELECTRIFICATION POTENTIAL STUDY

OCTOBER 22, 2020

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EXECUTIVE SUMMARY

Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a beneficial electrification potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing future Integrated Resource Plans (IRP) and Electric Resource Plans (ERP). The primary objective of this study is to assess the available technical electrification, beneficial electrification, and achievable electrification potential from a variety of fuel-switching electrification measures from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State).

For the purposes of this study, electrification can be defined as changing the energy source for an end use from a fossil fuel to electricity. In order to achieve "beneficial" electrification a project must meet one or more of the following conditions without adversely affecting the other three:

1. Saves consumers money over the long run
2. Improves quality of life
3. Enables better grid management
4. Reduces negative environmental impacts

The study focuses on beneficial electrification *achievable* potential. It is not a *program* potential study meaning it does not take into consideration the utility's program-level budget and design constraints. Therefore, the study examines what *could be* (i.e., what impacts could accrue from the qualifying beneficial electrification measures considered in this study) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member distribution system can choose which products and measures from the overall program to offer to their end-use consumers. The study does not select or evaluate specific programs or their costs.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report goes into more detail on methods, results, and findings.

This report is related in several ways to the recent *Demand Side Management and Energy Efficiency Potential Study* for Tri-State completed in May, 2020. The prior report provides an achievable potential assessment for energy efficiency, demand response, and distributed energy resources, and is referenced in sections of this report.

Two separate electronic Reporting Tools are provided with this report. The tools provide the ability to view findings in greater detail by sector, end-use, and region. More detail on the tools, including how they differ from each other, is provided in the main body of the report.

Results

As summarized in Table ES-1, the Mesa Point Team found that the achievable-moderate scenario[1] would result in approximately 2.5 GWh (0.02 percent of baseline sales) of electric load growth from achievable beneficial electrification in 2021 rising to 653 GWh (3.1 percent of baseline sales) of growth through 2040. Using emissions rates based on a forecast of Tri-State's resource mix, the team estimated a lifetime emissions reduction for measures installed in 2021 of 11,414 tons of CO_2, increasing to a lifetime emissions reduction of nearly half a million tons of CO_2 for measures installed in 2040[2]. Over the 20-year study horizon it is estimated that enough fossil fuel consumption could technically be reduced to more than offset the total on-site natural gas consumption in Tri-State's service territory[3].

[1] Four scenarios were modeled, each of which is described later in this Executive Summary and in the methodology section of the body of the report. Results from the achievable-moderate scenario are presented in most portions of this report. That scenario was selected because it represents a balance between aggressive program approaches and a low level of intervention.

[2] Emissions reductions are calculated based on Tri-State's projected resource mix as provided to MPE in March 2020, which was a non-carbon reduced scenario. The actual changes in resource mix over time will impact the net emissions from electrification measures. Updated resource mix projections could be used in future modeling to refine the estimated emissions benefit of electrification over time.

[3] The estimated cumulative reduction in fossil fuel consumption across all measures and baseline fossil fuel types exceeds 631 million therms by 2040 under the technical potential scenario. The study estimates the total annual natural gas consumption by premise-based (non-vehicle) end uses to be approximately 536 million therms at present.

Table ES-1. Portfolio Cumulative Energy Increase and Annual Emissions Reduction by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Growth (MWh)						
2021	52,033	5,487	4,875	3,485	2,524	1,957
2025	417,171	84,088	62,069	43,736	30,905	23,583
2030	1,674,758	474,237	278,910	207,716	144,792	105,867
2040	5,513,285	1,907,671	1,044,310	857,810	652,583	486,764
Increase as % of Baseline Sales						
2021	0.34%	0.04%	0.03%	0.02%	0.02%	0.01%
2025	2.54%	0.51%	0.38%	0.27%	0.19%	0.14%
2030	9.41%	2.66%	1.57%	1.17%	0.81%	0.59%
2040	26.19%	9.06%	4.96%	4.07%	3.10%	2.31%
Annual Net CO_2 Emissions Reduction (tons)						
2021	-152,135	21,155	19,370	14,779	11,414	9,755
2025	90,543	160,778	114,249	85,767	65,253	54,071
2030	1,024,508	749,792	450,864	371,263	290,767	238,362
2040	2,408,393	1,391,801	763,155	620,228	506,031	418,796

Figure ES-1 shows the breakdown of projected load growth by sector. The residential sector makes up nearly half of the potential, owing much of that potential to battery and plug-in hybrid electric vehicles[4] followed by space heating and water heating electrification measures. The commercial sector contributes 35 percent of the potential, having a similar breakdown of end uses with electrification potential. In addition to on-road electric vehicles, the commercial sector also has opportunity for off-road electric vehicles such as forklifts and airport ground support equipment, as well as truckstop electrification measures. These electric vehicles and transportation measures make up over 80 percent of the commercial sector electrification potential with the balance being made up primarily by space heating (heat pump) and water heating (heat pump water heater) measures.

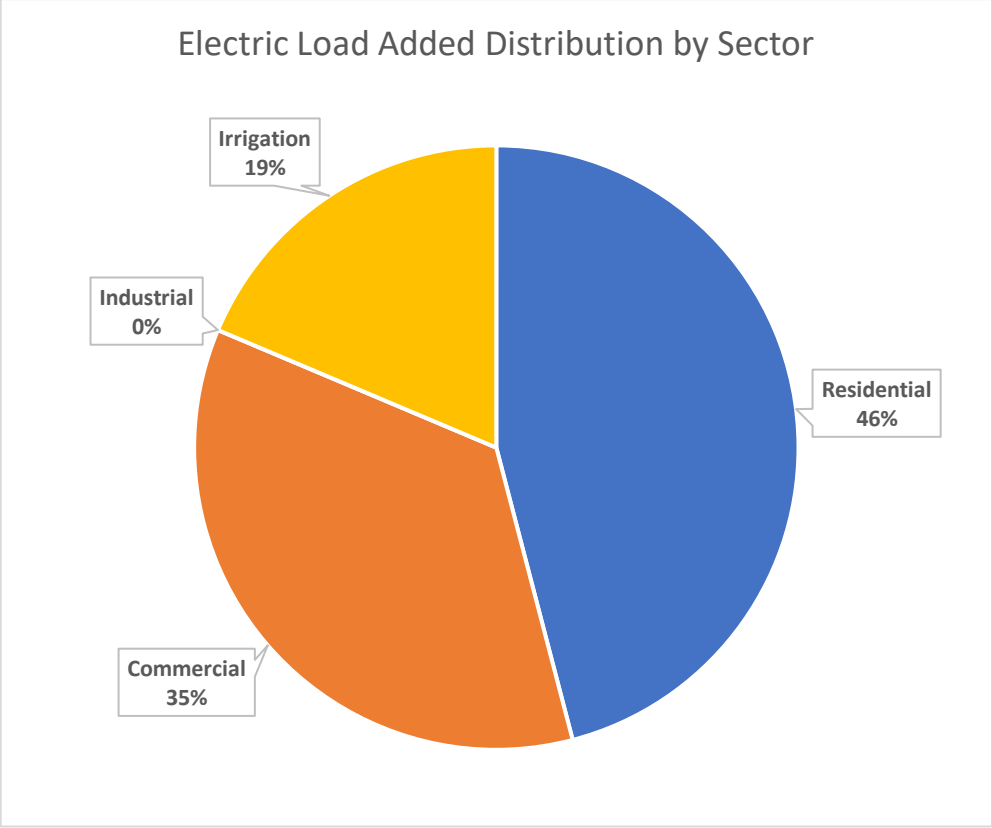
4 As with other electrification measures in this study, electric vehicle potential included in the main body of the report is that directly influenced by Tri-State program activity.

Measures that passed beneficial electrification screening, a process described below and in Section 2.5.2, but contributed a small magnitude towards electrification potential include cooking electrification (electric and induction cooktops) for both the residential and commercial sectors and lawn and garden equipment in the residential sector.

The irrigation sector is estimated to account for nearly 20 percent of the electrification potential in the achievable-moderate scenario by 2040. This potential is made up of the conversion of irrigation pump motors from natural gas, propane, and diesel-driven motors to electric motors.

The industrial sector was shown to have large technical electrification potential from electrification of pipeline compressor stations, but no measure permutation passed the beneficial electrification screening process since each resulted in net emissions increases throughout the 20-year study horizon.

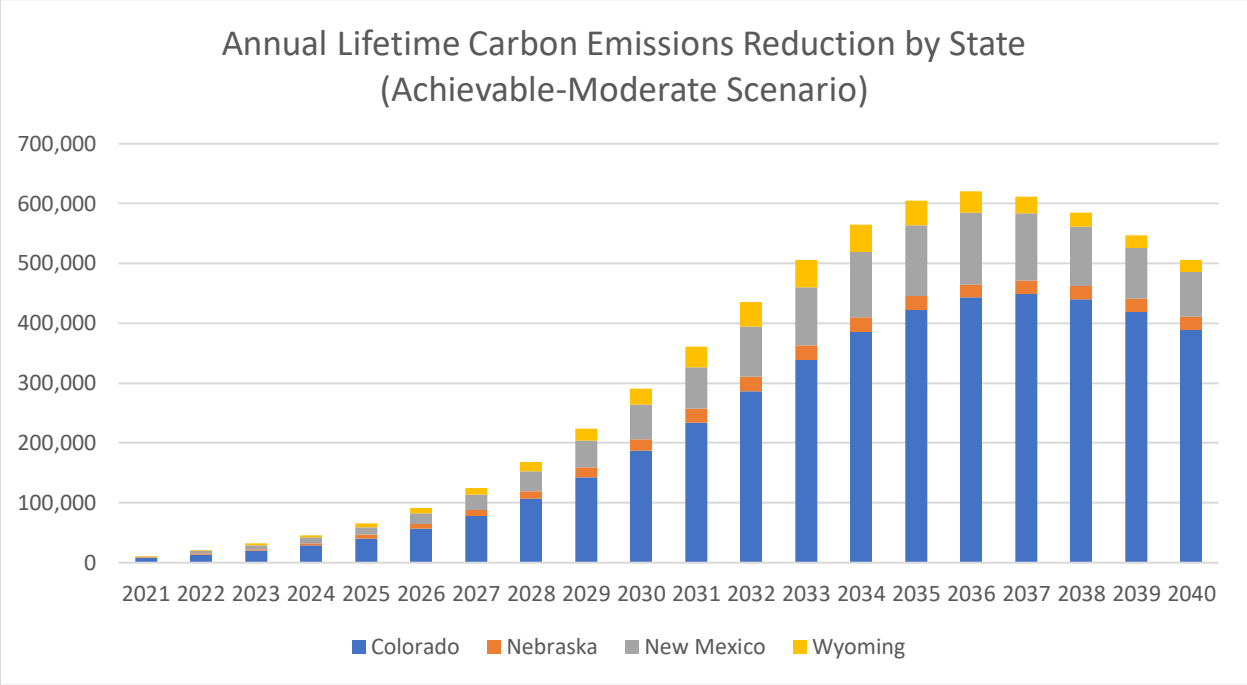
Figure ES-1. Electric Load Added Distribution by Sector (Achievable-Moderate Scenario, 2040)



The estimated emissions reduction associated with beneficial electrification measures under the achievable-moderate scenario, based on Tri-State's forecasted emissions rate as a function of resource mix, is shown in Figure ES-2. The figure represents net emissions expected to be reduced over the lifetime of relevant measures installed in each year of the 20-year study horizon. For some measures analyzed, the net lifetime emissions include both an increase in emissions in the beginning of the measure life and a reduction in emissions later in the life of the measure. This is a function of Tri-State's system-wide emissions rate, measured on a ton/MWh basis, which is expected to decrease over the

study horizon as Tri-State's fuel mix shifts. Other measures represent an immediate emissions reduction in the first year. Figure ES-2 shows the annual carbon emissions reduction estimates broken down by state.

Figure ES-2. Annual Lifetime Carbon Emissions Reduction by State (Achievable-Moderate Scenario)



The commercial sector is expected to make up 58 percent of emissions reduction potential, contributing over 3.7 million tons of CO_2 of the lifetime of measures installed through 2040. The share of emissions reductions as compared to the share of electric load growth potential differs primarily due to energy efficiencies of the baseline and retrofit case equipment. For instance, the commercial sector includes a large portion of emissions reduction from off-road EV measures such as electric forklifts. This type of equipment may contribute a proportionally larger share of emissions reduction potential as compared to its contribution to electric load growth because of the significant efficiency gains realized by switching from internal combustion engines to electric motors.

Table ES-2 summarizes the key cumulative beneficial electrification cost metrics across the portfolio at four time horizons under the achievable-moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 39 GWh of electric load growth is achievable, on average, per year at a cost of $28 million for an acquisition cost of $710/MWh. The 20-year average TRC ratio across the portfolio exceeds 2.0 when considering all achievable measures that pass the beneficial electrification screening.

Table ES-2. Portfolio Electrification Cost Metrics by Time Horizon (Achievable-Moderate Scenario)[5]

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE LOAD ADDED (MWH)	ACQUISTION COST ($/MWH)
2021	1.54	$1,941,462	2,524	$769.09
2025	1.61	$25,575,994	30,905	$827.56
2030	1.83	$121,866,050	146,004	$834.68
2040	2.37	$557,671,021	785,329	$710.11
20-year avg.	2.37	$27,883,551	39,266	$710.11

Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

Segmentation and forecast: For the market segmentation analysis, the Team first determined the fossil fuel technologies that have an electrical fuel source equivalent, such as water heaters. Next, the Team established the number of fossil fuel technologies per current Tri-State member cooperative customer premise for each customer class and premise segment type. In cases where the electric energy efficiency potential assessment determined the saturations of technologies with an electric fuel source, the saturations of fossil fuel source technologies can be inferred. The study assumes that 100 percent of residential premises have water heating. Using Front Range Colorado as an example, 20 percent of the water heaters have an electric fuel source. This means that 80 percent of the water heaters are fossil fuel based[6]. The final step was to segment fossil fuel technologies into unique fossil fuel types, such as natural gas, propane, diesel, and gasoline. Forecasting this segmentation over the 20-year study horizon followed the forecast developed for the prior DSM potential study, adapting the forecast to estimate fossil fuel segmentation by year instead of electric end use saturation by year.

[5] Program costs are estimates based on several factors and may not align with actual program costs in future years due to structural and organizational limitations that impact portfolio design. This study does not address program design or related drivers of cost.

[6] This breakdown represents Front Range Colorado in year 2020. Each region and year has their own saturation estimates.

Segmentation and forecasting for portions of the electric vehicle beneficial electrification analysis utilized different approaches as some EV technologies cannot be tied to customer premises in a reliable manner. The team used bottom-up and top-down approaches to estimate the forecast for each relevant electric vehicle technology. These methods are described in Section 2 of the report.

Measure impacts: With the market segmentation complete, the Team then characterized a wide variety of electrification measures and their end-use-specific reductions in fossil fuel consumption, added electricity consumption, associated net carbon emissions reduction, costs, and lifetimes. Each measure was assigned to the relevant region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened through a four-part beneficial electrification screening process that assessed the measure for customer cost savings, emissions reduction, quality of life, and grid resiliency. The beneficial electrification screening process is described in detail in Section 2.5.2 in the report. The screening involves assessing four criteria of which one or more must exhibit a positive impact while none of the others exhibit a negative impact[7]. The criteria include:

- Saves the customer money
- Reduces emissions
- Improves quality of life
- Fosters grid resiliency

Modeling and data analysis: The Mesa Point Team used industry-standard modeling approaches to estimate the technical electrification, beneficial electrification, and achievable electrification potential and associated costs for the analyzed measures. The projected increase in electricity consumption, reduction in carbon emissions, and associated costs of each measure was forecasted for a 20-year time horizon (2021 – 2040). Four achievable potential scenarios were developed so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from the modeling were developed to show annual energy load impacts (increase in electric consumption and decrease in fossil fuel consumption), net carbon emission reductions, measure lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon. It is important to recognize that the carbon emissions reduction estimates are established as a function of Tri-State's forecasted emissions rates (tons of CO_2 per MWh). Tri-State provided the Mesa Point team with a set of projected carbon emissions rates based on projected changes in Tri-State's resource mix. As those projections come to fruition, or change over time, the emissions reduction estimates in this study could be updated to reflect the impacts.

[7] The screening criteria were drawn from the Beneficial Electrification League's definition of BE (https://beneficialelectrification.com).

1. INTRODUCTION

1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a beneficial electrification (or BE) study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical electrification, beneficial electrification, and achievable electrification potential from a variety of measures from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State).

For the purposes of this study, electrification can be defined as changing the energy source for an end use from a fossil fuel to electricity. For example, electrification could be considered:

- Transportation: Replacement of a gasoline driven vehicle with an electric vehicle
- Space Heating: Replacement of a natural gas fired furnace with a heat pump
- Domestic Water Heating: Replacement of a natural gas water heater with an electric-resistance or heat pump water heater
- Industrial: Use of electrically driven equipment instead of fossil fuel driven equipment in applications such as irrigation pumping and natural gas compressor stations

In order to be "beneficial electrification" a project must meet one or more of the following conditions without adversely affecting the other three:

1. Saves consumers money over the long run
2. Improves quality of life
3. Enables better grid management
4. Reduces negative environmental impacts

In order to *save consumers money*, the electrification measure must reduce the annual cost enough to recover the initial cost of the equipment before the useful life of the electric equipment is reached. *Improved quality of life* may result from enhanced product features, reliability, and other factors. An example of an electrification measure *enabling better grid management* is equipment that allows for some level of demand control by the utility, the customer, or a third-party. An electrification measure *reduces negative environmental impacts* through the elimination of direct emissions in exchange for fewer emissions from the generation of electricity used to power the equipment. This net emissions reduction is examined over the estimated lifetime of the equipment and is based on the projected emissions of the electric generation resources over time.

The beneficial electrification study is intended to assist Tri-State in developing future Integrated Resource Plans (IRP) and Electric Resource Plans (ERP). Tri-State will use the results of this beneficial electrification study to analyze and incorporate potential impacts at various levels of program investment.

The study focuses on beneficial electrification *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-

specific recommendations; rather, the report focuses on identifying market opportunities and costs for electrification initiatives.

Reported emissions reductions in this study rely on information about Tri-State's projected resource mix[8]. Estimated emissions reductions would differ from those presented in this report if Tri-State's generation resource mix forecast changes.

This report is related in several ways to the recent *Demand Side Management and Energy Efficiency Potential Study* for Tri-State completed in May, 2020. The prior report provides an achievable potential assessment for energy efficiency, demand response, and distributed energy resources, and is referenced in sections of this report. Energy efficiency and beneficial electrification are two strategies for achieving demand side management goals. It is important to note that the beneficial nature of electrification measures is substantially impacted by the energy efficiency of the electric equipment being installed. More efficient electric equipment leads to greater emissions reduction over both fossil-fuel equipment and standard electric equipment.

Due to the timing of this report, it is important to note that the assumptions, results, and associated analysis detailed herein do not take into consideration the societal and economic impacts of the COVID-19 virus.

1.2. Achievable v. Planned Potential

This beneficial electrification study examines what *could be* (i.e., what load could be added and emissions reduced from considered beneficial electrification measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

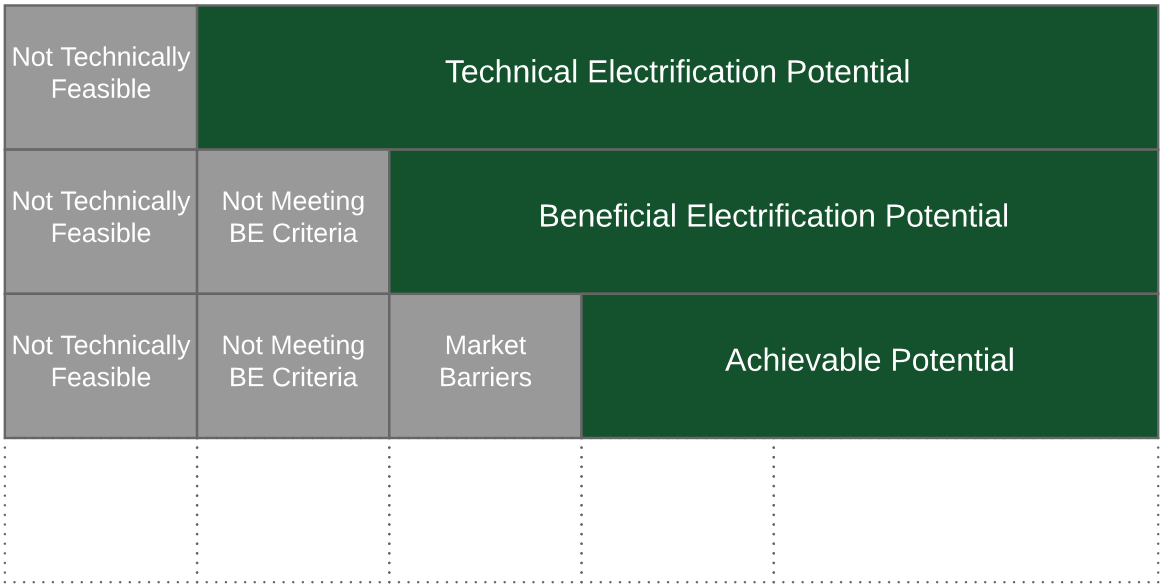
1.3. Study Approach Overview

This study considers measures from the perspective of theoretical maximum benefit, and then accounts for barriers to estimate actual achievable emissions reductions and load growth for the utility.

Specifically, the study begins with *technical electrification potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *beneficial electrification potential* is assessed by estimating costs and reduced emissions associated with implementing measures, and then applying beneficial electrification criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting electrification measure implementation. Not considered in the report are factors affecting *program potential*.

[8] Emissions factors were provided by Tri-State based on a resource mix forecast developed in March 2020.

Figure 1: Conceptual Overview of Beneficial Electrification Resource Potential Definitions



- **Technical Electrification Potential** is the theoretical maximum amount of energy load that could be displaced by the replacement of fossil fuel equipment with electric equipment, regardless of cost, emissions impact, and barriers that may prevent the installation or adoption of a measure. Technical electrification potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Beneficial Electrification Potential** represents the amount of emissions reduced, fossil fuel consumption reduced, and associated electric energy and capacity increases that could result from measures that pass beneficial electrification screening criteria. Beneficial electrification screening criteria is described below and in more detail in Section 2.4.2.
- **Achievable Potential** is the energy and emissions impacts that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of electrification measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy load growth and associated emissions the utility can realize through BE programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

1.4. Organization of the Report and Related Deliverables

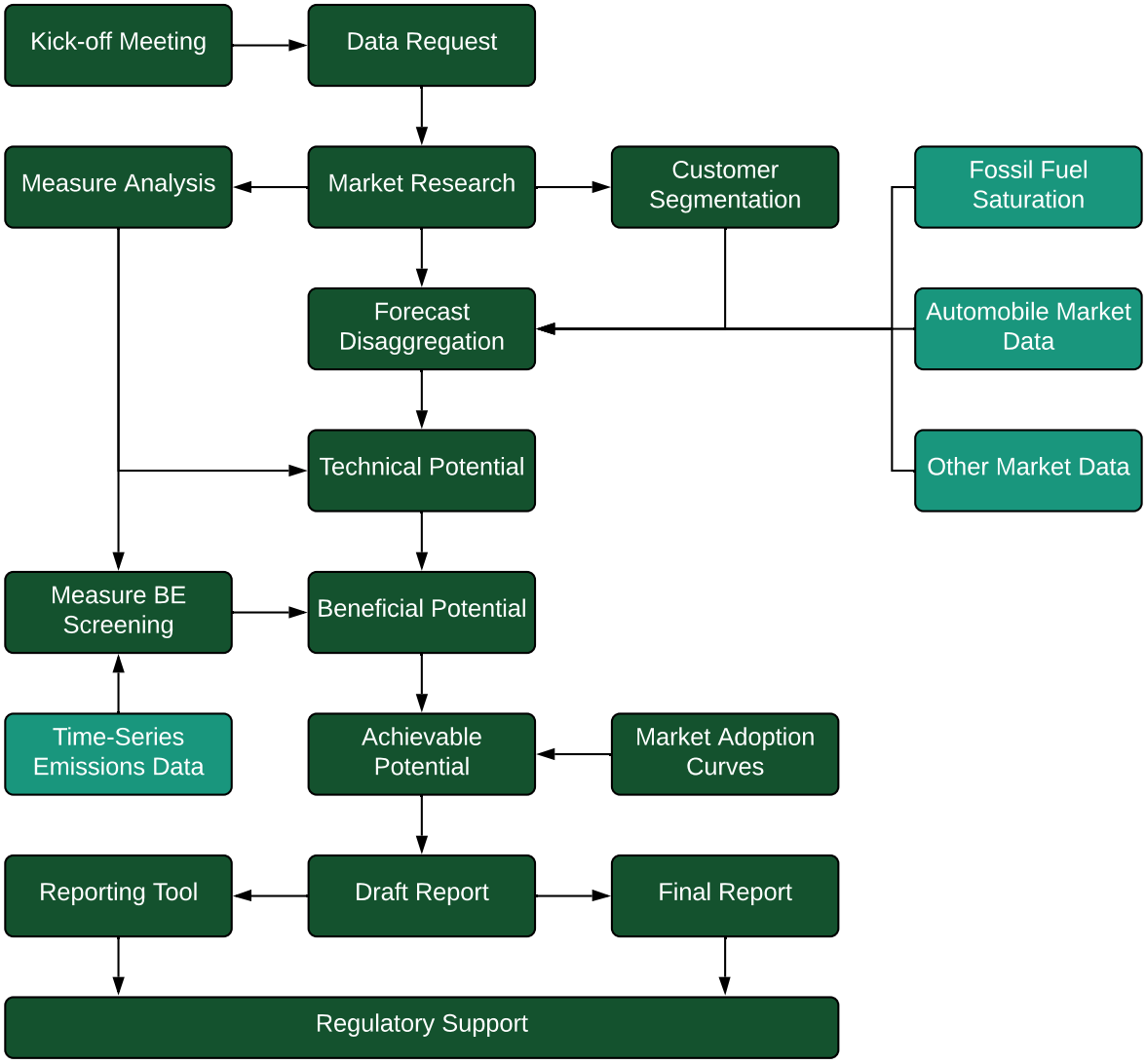
This report presents a summary of the analysis approach, key assumptions, and study findings. Two separate electronic reporting tools are provided with the report, as well as an additional technical appendix spreadsheet that includes select data and input assumptions. The tools provide the ability to view findings by sector, end-use, and region. One reporting tool provides data exclusive of naturally occurring adoption in the EV market, identifying potential that could stem from intervention by Tri-State and its member coops. The main body of this report refers to the results in the version of the tool that excludes naturally occurring adoption. The second reporting tool is inclusive of naturally occurring adoption and is explained further in Appendix C. The intent is for Tri-State and stakeholders to make use of each work product depending on the desired level of detail and perspective.

2. STUDY APPROACH AND METHODS

2.1. Overview

The process shown in Figure 3 depicts the steps taken during a beneficial electrification study.

Figure 2. Approach for Beneficial Electrification Potential Modeling



Each step is described in detail in the sections that follow.

2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable beneficial electrification potential requires a thorough characterization of customer technologies. A beneficial electrification study differs from an electric

energy efficiency study as the base forecast represents the technologies that utilize fossil fuels as an energy source and are eligible to switch an electric fuel source. The forecast for a beneficial electrification study differs from an energy efficiency potential assessment forecast, as the BE forecast characterizes the quantity of fossil fuel equipment/technologies eligible for fuel switching and places less importance on the forecast of energy consumption. The forecast characterization of fossil fuel technologies involves the following steps:

- Determine the fossil fuel equipment/technologies that have an electrical fuel source equivalent, such as water heaters.
- Estimate the number of fossil fuel equipment/technologies per current Tri-State member cooperative customer premise for each customer class and premise segment type.
- In cases where the electric energy efficiency potential assessment determined the saturations of technologies with an electric fuel source, the saturations of fossil fuel fuel source technologies can be inferred. For example, if it assumed that 100 percent of residential premises have water heating and 35 percent of the water heaters have an electric fuel source, then it can be assumed that 65 percent of the remaining fuel sources are fossil fuel based.
- Segment fossil fuel equipment/technologies into unique fossil fuel types, such as natural gas, propane, diesel, and gasoline.

To complete these steps the Team relied on a large dataset consisting of:

- The 2020 electric energy efficiency potential study and associated analysis
- Customer forecast from Tri-State member cooperatives
- Market data including fuel shares and equipment saturations
- Technology characteristics including technologies, fuel types, and useful life.

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in forecast characterization process follows.

2.2.1. Customer Segmentation

First, the Team determined the energy and demand loads for each of the geographical regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1
- **Customer Sectors:** Residential, commercial, irrigation, and industrial (including agricultural)
- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

2.2.1.1. Primary Market Research

Primary market research guided the customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation, specifically electric versus fossil fuel shares and further segmentation between natural gas and propane. Examples of these resources include the United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS) and the EIA Commercial Buildings Energy Consumption Survey (CBECS), among other references, an Environmental Protection Agency-associated technical paper on *National Emissions from Lawn and Garden Equipment*, a U.S. Department of Energy *Energy Storage Technology and Cost Characterization Report*, the U.S. Department of Homeland Security's Homeland Infrastructure Foundation-Level Data (HIFLD) on natural gas compressor stations, among other resources cited throughout this report.

2.2.2. Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and electrification potential by region. Eight (8) regions were defined based on geographic location of the co-ops. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Regional segmentation captures variations in equipment end-use saturation and energy intensity. For instance, electric water heater in the residential sector has a higher saturation and energy intensity in Nebraska as compared to Front Range Colorado.
- Barriers to achievable potential may be regionally specific, such as zero emission vehicle encouragement policy within the State of Colorado.

Similar to the electric energy efficiency potential assessment, the Team developed the regional electric cooperative groups shown in Table 1.

Table 1: Tri-State Cooperative Regional Groups

EASTERN COLORADO	FRONT RANGE COLORADO	MOUNTAIN COLORADO	WESTERN COLORADO
Highline	Mountain View	Gunn County	Empire
K.C.	Poudre Valley	Mountain Parks	La Plata
Morgan County	San Isabel	White River	San Luis Valley
Southeast	United		San Miguel
Y-W			Sangre De Cristo
NEBRASKA	**SOUTHERN NEW MEXICO**	**NORTHERN NEW MEXICO**	**WYOMING**
Chimney Rock	Central NM	Cont. Divide	Big Horn
Midwest	Columbus	Jemez Mtns	Carbon
Northwest	Otero County	Mor San Miguel	Garland
Panhandle	Sierra	North. Rio Arriba	High Plains
Roosevelt	Socorro	Southwestern	High West
Wheat Belt		Springer	Niobrara
			Wheatland
			Wyrulec

2.3. End-Use Load Classification

To further disaggregate the load the Team established technology end-use loads within each sector. Table 2 presents a summary of those end-uses.

Table 2: Technology End-Uses for Each Tri-State Sector

RESIDENTIAL	COMMERCIAL	INDUSTRIAL & IRRIGATION
Boilers (Natural Gas Fuel)	Boilers (Natural Gas Fuel)	Pumps (Natural Gas)
Boilers (Propane Fuel)	Boilers (Propane Fuel)	Pumps (Propane)
Furnaces (Natural Gas Fuel)	Furnaces (Natural Gas Fuel)	Pumps (Diesel)
Furnaces (Propane Fuel)	Furnaces (Propane Fuel)	
Water Heating (Natural Gas Fuel)	Water Heating (Natural Gas Fuel)	
Water Heating (Propane Fuel)	Water Heating (Propane Fuel)	
Cooking (Natural Gas Fuel)	Cooking (Natural Gas Fuel)	
Cooking (Propane Fuel)	Fleet Vehicles	
Lawn Equipment	Forklifts	
Garden Equipment	School Buses	
Battery EVs	Transit Buses	
Plug-in Hybrid EVs	Airport Equipment	
	Truck Stop Electrification	

2.4. Electric Vehicle Forecasting

The team used various approaches to estimate the forecast for each relevant electric vehicle technology using both bottom-up and top-down methods of estimation. With the exception of the residential on-road electric vehicle forecast which is derived based on the disaggregated forecast, each technology forecast was constructed outside of the forecasting methods described in this section utilizing the prior DSM potential study as a starting point, as these technologies did not conform with the forecast taxonomy from that study. However, these independent forecasts did follow the same principles and used Tri-State data when applicable. For example, naturally occurring adoption for electric vehicles in Colorado (i.e. adoption independent of Tri-State or member cooperative influence) is expected to be greater relative to non-Colorado regions due to aggressive state policy and funding. This assumption is applied to both the residential on-road forecast and is also carried through to commercial fleets, airport GSE, and forklifts in Colorado, as these are all eligible technologies for Colorado state funding. More detail on forecasting for specific EV technologies is provided in Appendix B.

2.5. Beneficial Electrification Potential Modeling

Drawing on outcomes from the customer segmentation and forecasts the study modeled first technical, then beneficial, and finally achievable electrification potential. Those steps are described in the following sections.

2.5.1. Estimate Technical Electrification Potential

Technical electrification potential is the theoretical maximum amount of energy consumption and capacity added to the grid, along with associated fossil fuel reduction and emissions reduction, associated with electrification measures, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the electrification measures. Technical electrification potential is only constrained by factors such as technical feasibility of measures and time. The model applies the measure-level inputs to the disaggregated baseline premise count forecast to estimate technical electric load growth potential, as well as net change in emissions, over the planning horizon.

The core equations used in the technical electrification potential analysis for each individual electrification measure are shown in Equation 1 and Equation 2.

Equation 1. Core Equation for Technical Electrification Potential – Electric Growth

Technical Electricity Consumption Growth Potential of Electrification Measures = Total Number of Premises x Saturation Share x Fuel Share x Remaining Factor x Applicability Factor x Proposed Annual Unit Energy Consumption (kWh)

Equation 2. Core Equation for Technical Electrification Potential – Fossil Fuel Reduction

Technical Fossil Fuel Reduction Potential of Elecrification Measures = Total Number of Premises x Saturation Share x Fuel Share x Remaining Factor x Applicability Factor x Baseline Annual Unit Energy Consumption (therms)

Where:

Total Number of Households: *count of customer households in the subject region.*

Saturation Share: *the fraction of households with fossil fuel equipment for a given end-use in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential customers that have fossil fuel water heating in their household.*

Fuel Share*: the fraction of fossil fuel equipment for a particular end-use using a specific type of fossil fuel, either natural gas, propane, gasoline, or diesel. For example, for residential water heating, the fuel share of propane would be the fraction of all residential premises with fossil fuel water heating that use propane as a fuel type.*

Remaining Factor: *the fraction of equipment that is not considered to already be converted from fossil fuel to electric. To extend the example above, the fraction of fossil fuel water heaters that is not already converted to electric.*

Applicability Factor: *the fraction of the applicable units that is technically feasible for conversion to electricity from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to air circulation constraints.*

Baseline Annual Unit Energy Consumption: *the annual energy consumption, in therms, of the baseline fossil fuel equipment.*

Proposed Annual Unit Energy Consumption*: the annual energy consumption, in kWh, of the proposed electrically-operated equipment.*

2.5.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical electrification potential is to accurately detail the various electrification measures under consideration and estimate their end-use-specific energy impacts, costs, and lifetimes. The Team worked with Tri-State to develop a list of electrification measures to analyze. The list of assessed measure types is included in Table 3, and details on the measure permutations and analysis approach for each measure type, is provided in Appendix A.

Table 3: Measure Types Analyzed

RESIDENTIAL	COMMERCIAL	INDUSTRIAL & IRRIGATION
Heat Pump Water Heating	Heat Pump Water Heating	Electric Irrigation Pumps
Heat Pump Space Heating	Heat Pump Space Heating	Pipeline Compressor Station Electrification
Electric Cooking (Electric Resistance and Induction)	Electric Cooking (Electric Resistance and Induction)	
Electric Lawnmowers	Battery Electric Vehicles	
Electric Snow Blowers	Plug-in Hybrid Electric Vehicles	
Electric Leaf Blowers	Electric Forklifts	
Electric Chainsaws	Electric School Busses	
Electric Trimmers, Edgers, Brush Cutters	Electric Transit Busses	
Battery Electric Vehicles	Electric Public Fleet Vehicles	
Plug-in Hybrid Electric Vehicles	Electric Airport Ground Support Vehicles	
	Electric Parking Spaces	
	Electric Transportation Refrigeration Units	

Upon finalizing the electrification measure list, the Team collected data on energy savings and increases, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

Step 1: Define market classifications for application of measures

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Vintage:** Turnover, Early Retirement, New
  - **Replace on Burnout:** Convert equipment to electric when a piece of equipment is at the end of its effective useful life (also referred to as “turnover”)
  - **Early Retirement:** Convert equipment to electric at any time during the life of the equipment

- **New:** Install electric equipment instead of fossil fuel equipment when a new home or building is constructed

Step 2: Screen sectors, segments, and end-uses for applicability

The Team screened market segments and end-uses for applicability of specific electrification measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as warehouses and therefore were analyzed only in limited market segments.

Step 3: Develop base case impacts and costs

The Team determined base case fossil fuel-burning equipment and practices for each of the electrification measures on the final list and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. For each measure, the Team estimated fossil fuel energy consumption for the base equipment, as well as the cost to replace the fossil fuel-burning equipment with a new, similar fossil fuel-burning piece of equipment.

Step 4: Develop electrification measure impacts and costs

The Team developed a description of all electrification (or "change case") measure equipment and practices, including all measure energy consumption assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated electric energy consumption of the proposed equipment, as well as the associated cost to purchase and/or install the equipment.

2.5.2. Estimate Beneficial Electrification Potential

Beneficial electrification potential represents the impacts possible given full adoption of all electrification measures considered to be "beneficial electrification" in that the measures must pass the four BE screening criteria explained below.

To determine whether a measure can be considered beneficial electrification, the Team screened all considered electrification measures using a four-part screening process. This process was established based on the Beneficial Electrification League's (BEL)[9] definition of beneficial electrification as "the application of electricity to end-uses where doing so satisfies at least one of the following conditions, without adversely affecting the others:

- Saves consumers money over time;
- Benefits the environment and reduces greenhouse gas emissions;
- Improves product quality or consumer quality of life; and
- Fosters a more robust and resilient grid.

In order to perform this screening process, each measure was assigned a set of four values, each representing one of the four criteria above. The possible values for each criterion are shown in Table 4.

[9] *Beneficial Electrification League*. (2020). Beneficial Electrification League. https://beneficialelectrification.com/

Table 4: Beneficial Electrification Screening Details

SCREENING CRITERIA	EVALUATION METHOD	PASSING VALUE	FAILING VALUE[10]
Saves consumers money over time	Calculate Participant Cost Test (PCT) for each measure	> 1	< 1
Benefits the environment and reduces greenhouse gas emissions	Calculate net CO_2 emissions reduction for each measure (tons)	> 0	< 0
Improves product quality or consumer quality of life	Identify, qualitatively, whether each measure improves (1), has no impact on (0), or negatively impacts (-1) quality of life	0 or 1	-1
Fosters a more robust and resilient grid	Identify, qualitatively, whether each measure could improve (1), has no impact on (0), or negatively impacts (-1) grid resiliency and flexibility	0 or 1	-1

A value for each of the four criteria was calculated for each measure. Subsequently, a beneficial electrification score (BE score) was calculated for each measure using the following logic: The BE score results in a zero value if any one of the four criteria has a failing value assigned to it. If none of the criteria have a failing value assigned to it, and at least one criterion has a passing value assigned to it, the BE score equals 1.

Measures with a passing BE score of 1 are considered beneficial electrification. Measures with a failing BE score of 0 are screened out of modeling in the beneficial electrification potential scenario and all of the achievable potential scenarios.

2.5.2.1. BE Screening Criteria Descriptions

Approaches to assigning or calculating the score for each BE screening criteria are described in the following sections.

2.5.2.1.1. Criterion 1: Saves the Consumer Money over Time

To evaluate the criterion that a measure saves the customer money, the Team performed a participant cost test on each measure using Equation 3. The PCT considers incentives, tax credit, and the net present value of annual savings on utility bills as benefits and the measure incremental costs,

installation costs, and operation and maintenance costs[11], as costs. Utility bill savings[12] in the context of beneficial electrification is the net savings of reduced fossil fuel costs and increased electricity costs. Annual components of the test inputs are taken to a net present value based on measure life.

Equation 3. Participant Cost Test

$$PCT\ Ratio = \frac{Incentives + Tax\ Credit + Fossil\ Fuel\ Cost\ Savings - Added\ Electric\ Bill\ Costs}{Incremental\ Equipment\ Cost + Installation\ Cost + Maintenance\ Cost}$$

2.5.2.1.2. Criterion 2: Benefits the Environment

To pass this screening criterion, the carbon emissions reduction resulting from reduction of fossil fuel use must be greater than the emissions created from the added electric load. Emission reductions for fossil fuel technologies are a function of the annual consumption, its expected life, and the fuel type.

The emission reduction for the fossil fuels includes transportation to the site from the refining facility, whether that is by pipeline, tanker truck, or other method. This allows a comparison to equivalent emissions added from the electric system, which includes the generation resources emissions and line losses, or the "transportation" to the site from the generation resource. The calculation for added emissions is based on a 20-year forecast of hourly (8760) carbon emissions, with greenhouse gas tons per MWh reducing over time as clean generation resources are expected to be introduced. Consequently, the emission reductions for electric technology are a function of the hourly consumption, its expected life, and the installation. Equation 4, calculated for each year of a measure's life, shows the method to calculate net emissions reductions for each measure.

Equation 4. Net Emissions Reduction Test

$$Net\ Emission\ Reduction = Emissions_{fossil\ fuel} - Emissions_{electrified}$$

Or inserting units,

$$Net\ Emission\ Reduction = \left(\frac{BTU}{year} \times \frac{tons\ CO_2}{BTU}\right) - \left(\sum_{i=0}^{i=8760} \left(kWh_i \times \left(\frac{tons\ CO_2}{kWh}\right)_i\right)\right)$$

Factors used to estimate emissions from the fossil fuel baseline equipment are shown in Table 5.

[11] In many cases for Beneficial Electrical technologies, the Operations and Maintenance costs are negative. Even though this may be presented as a benefit, it is applied a credit to costs within the ratio denominator.

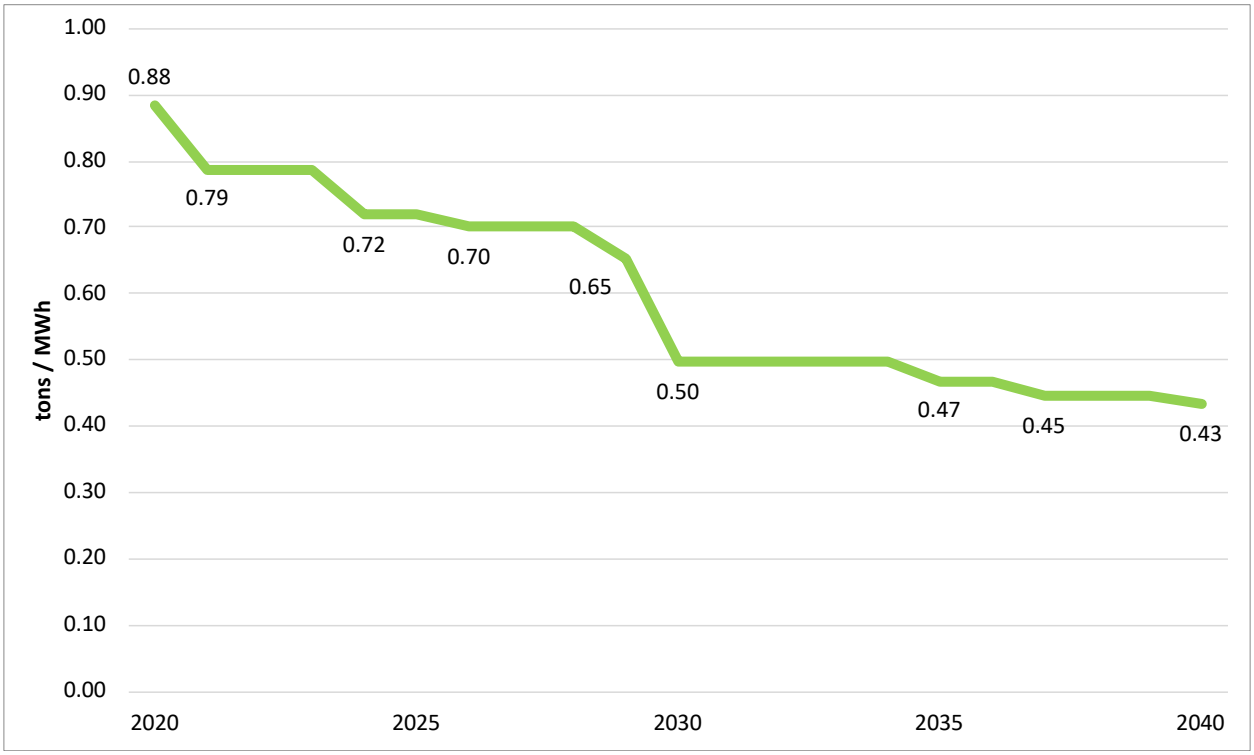
[12] Participant utility bills are based upon the customer rate. Customer rates for this study were generic, not based a specific member cooperative, but were informed by public available, published rates. Generic rates were calculated for each customer segment; residential, commercial, and industrial.

Table 5: Fossil Fuel Carbon Emissions Rates

Fossil Fuel Type	Emissions Rate (tons CO_2/BTU)
Natural Gas	0.00585
Propane	0.00635
Gasoline	0.00971
Diesel	0.00954

Emissions rates used to calculate post/electrified emissions were provided by Tri-State. The rates, measured in tons of CO_2 emissions per megawatt-hour, were provided on an hourly basis for the years 2020 – 2040. The hourly emissions rates were utilized, in conjunction with measure savings and load shape, to calculate the emissions of electrified equipment. The average emissions rates by year are presented in Figure 3, although calculations were done on an hourly basis.

Figure 3: Annual Average Electric Generation Carbon Emission Rates



The emissions rates used in the analysis reflect an individual forecast of Tri-State's resource mix. The forecast could change based on changing regulatory, economic, political, market, and other conditions. Adjustments to Tri-State's resource mix may lead to adjustments in the emissions rates, and therefore adjustments to the emission reduction outcomes. The effects of accelerating or decelerating emissions

rate improvements, or increasing or decreasing the magnitude of the emission rate reductions, would change the post-case emissions and also change which beneficial electrification measures pass the emissions screening criteria.

2.5.2.1.1. Criterion 3: Improves Quality of Life

The Team considered each measure's impact on quality of life in order to assign a value of -1, 0, or 1 to each measure. A value of -1 represents a negative impact, a value of 0 represents no appreciable impact, and a value of 1 represents a positive impact. To assign these values, The Team considered the way in which each measure could improve the quality of life of the customer in terms of comfort, reliability, ease of use, and other aspects. Electrification measures are often associated with these improvements due to the advanced technologies utilized, and reliability of electrically-driven motors, compressors, pumps, etc. Each measures impact on quality of life for the consumer and product quality was carefully considered.

2.5.2.1.2. Criterion 4: Fosters Grid Resiliency

The Team considered whether or not a particular measure may provide an improvement to grid resiliency via potential demand control mechanisms, ability to provide energy storage on the grid, and other aspects. If a particular measure involved a technology that could feasibly provide one of these benefits, the measure received a score of 1 for grid resiliency. If a measure involved a technology that would not feasibly provide these benefits, but would have no negative impact on the grid, the measure received a score of 0 for grid resiliency. If the measure was believed to negatively impact grid resiliency, a score of -1 was assigned to that measure. For example, a heat pump water heater may have the ability to foster grid resiliency by allowing the utility (with customer approval) to adjust the time the unit heats stored water to manipulate the equipment's impact on the system peak demand.

2.5.2.2. Overall Economic Viability

While the beneficial electrification screening process utilized the PCT to screen for cost effectiveness, the Team also assessed the overall economic viability by calculating the Total Resource Cost (TRC) test for each measure. TRC outcomes are presented at the sector and portfolio levels in later sections of this report and at a more granular level in the BE reporting tool. The TRC test is a valuable test to assess measure benefits and costs from the perspective of all the rate payers as a whole. Equation 2 presents the TRC ratio equation.

Equation 5. TRC Ratio

$$TRC\ Ratio = \frac{\left((Avoided\ Electric\ Avoided\ Costs + Avoided\ Fossil\ Fuel\ Costs) \times 10\%\ NEB\ Multiplier\right) + Social\ Cost\ of\ Carbon}{Incremental\ Cost + O\&M\ Costs + Tax\ Credits}$$

The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.

Specifically, the **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy

and capacity were obtained from Tri-State[13]. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure energy impacts to determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak load window definition of noon to 10 PM during weekday summer months was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy impacts for Tri-State, line losses were included. These losses were calculated for each climate zone and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. A financial discount rate of 5 percent was applied to value future avoided costs.

Fossil fuel avoided costs were estimated based on various publicly available sources, largely relying upon data contained within natural gas DSM program regulatory filings for the State of Colorado and United State Energy Information Agency (US EIA) annual[14] and short term[15] energy outlooks (AEO) with region adjustments, as available.

The social cost of carbon at $46/ton[16] of CO_2 was incorporated as a benefit of BE in the TRC calculations. This information was provided by Tri-State as a table with values escalated annually over the study time horizon. An additional 10 percent multiplier was applied to the TRC benefits to account for additional non-energy benefits (NEBs) associated with electrification measures such as job creation and societal health benefits. How the NEBs multiplier is calculated is explained in the section below.

The **costs** are the net present value of all costs to implement the measures. These costs include full incremental costs. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. Additionally, state and/or federal tax credits, where applicable were included.

2.5.2.2.1. NEBs Adder

For this study, we used a 10 percent non-energy benefit adder in addition to the monetized cost of carbon to account for health, environmental, and other benefits of electrification. In part, this factor is intended to include the benefit of reduced non-carbon greenhouse gas emissions such as NO_x and SO_x. Additional non-energy benefits to electrification including improved local air quality, improved public and participant health, and compliance (including cost of compliance) with environmental regulations.

To account for benefits beyond cost savings and carbon reduction, some states explicitly monetize the value of health and environmental benefits, while others use a proxy multiplier on the TRC test. This multiplier has the effect of increasing the TRC, potentially allowing for increased BE efforts, inclusion of more measures, and increased program funding.

[13] Because there is added electrical consumption due to beneficial electrification measures, the avoided electric benefits will be **negative**.

[14] *https://www.eia.gov/outlooks/aeo/*

[15] *https://www.eia.gov/outlooks/steo/*

[16] 2020 dollars

Xcel Energy Colorado, in their settlement agreement and DSM plan, uses a TRC modification factor of 20 percent for all non-low income measures and 50 percent for all low income measures, which includes carbon[17].

The BE analysis shows that the monetized cost of carbon increases benefits by about 10 percent. To achieve an overall environmental benefit multiplier of 20 percent, which is in line with Xcel's filings, this analysis adds another 10 percent to account for non-carbon, non-energy benefits.

2.5.3. Estimate of Achievable Potential

The assessment of realistically achievable electrification potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of participation expected to be achievable through BE programs can be informed by the experience of utilities across the region and nation. For BE measures that have a traditional DSM analog (i.e. heat pump water heaters), program adoption for BE can be informed by traditional DSM program participation rates, adjusting for additional market barriers present for BE measures.
- **Customers' willingness to participate.** The likelihood that customers will participate in electrification programs is a function of several factors, including but not limited to incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of BE programs. The study conceives of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected participation, as well as the most likely value.

Achievable potential electrification impacts were evaluated based on four incentive scenarios as a function of incentive level:

- **Achievable Low**: Incentives below industry standard, with limited administrative expenditures
- **Achievable Moderate**: Incentives and administrative expenditures on par with industry average
- **Achievable Aggressive**: Incentives and administrative expenditures above industry average

[17] Proceeding 17A-0462EG, Xcel Co Settlement Agreement pg 12/34, PSCO DSM plan from Proceeding 18A-0606EG April see pg 333, Proceeding 17A-0462EG decision C18-0417 pg 12 of 45

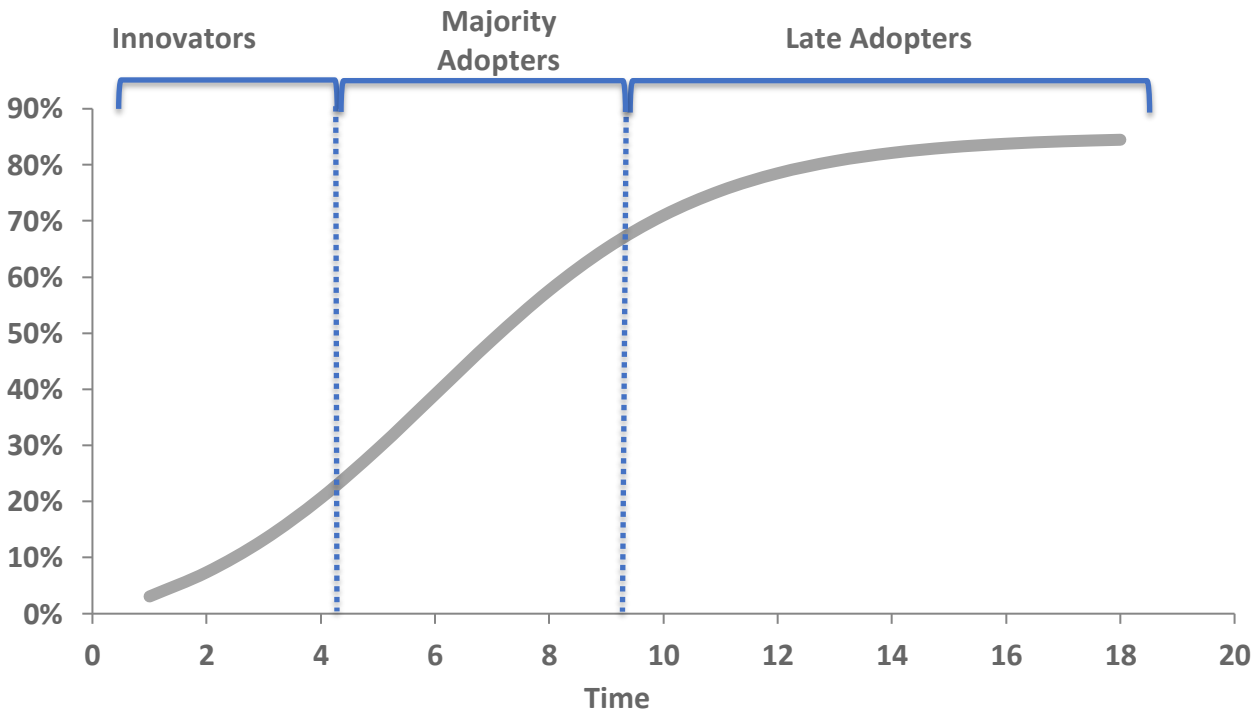
- **Achievable Maximum**: Incentives that cover the full incremental cost of measures, or approximately double industry average, and highly aggressive administrative expenditures

2.5.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, a quantitative approach was developed based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State's experience and other DSM and BE programs in North America.

The Bass Diffusion Model[18] is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

Figure 4: Typical Product Diffusion in the Marketplace



The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

[18] Bass, Frank (1969). "A new product growth for model consumer durables". Management Science.

- Initial Year Measure Adoption

First year adoption levels were informed by recent Tri-State historical performance where possible and applicable. For instance, for building-related BE measures, the initial year measure adoption is considered modestly reduced from recent DSM program performance.

- Long-Term Market Adoption Rates

The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.

- Adoption Curve Shape

Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use Type**: Space Heat, Water Heat, etc.
- **Incentive Level based on Achievable Scenario**: low, moderate, aggressive, maximum

2.5.3.2. Program Costs

To capture the full cost of achievable electrification potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh added. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 6. These assumed non-incentive costs reflect the same costs used in the recent energy efficiency potential study as program delivery for most BE measures is not expected to take significantly more or less resources to implement.

Table 6: Summary of Non-Incentive Program Costs ($/kWh)

SECTOR	ACHIEVABLE LOW	ACHIEVABLE MOD	ACHIEVABLE AGG
Residential	$0.100	$0.115	$0.150
Commercial	$0.050	$0.058	$0.075
Industrial	$0.100	$0.115	$0.150
Irrigation	$0.050	$0.058	$0.075

For program cost analysis, non-EV incentive costs were developed based on secondary research of existing electrification programs instead of assigning incentives as a percentage of incremental cost. For many electrification measures, the incremental cost is very small or even negative – the electric version of the technology in question costs less than the fossil fuel option. Despite this, incentives or other

motivational elements such as education and outreach, are still required to drive market adoption of BE measures. For the purposes of estimating total program costs, prevailing current incentive amounts were assigned to the achievable-moderate scenario and were scaled up or down in proportion to the incentive level percentages assigned to the other achievable scenarios.

2.5.4. Reporting Tools

A pair of BE Reporting Tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. The Reporting Tools, presented as Microsoft Excel workbooks, summarize and illustrate the load growth, fossil fuel reduction, and emissions reduction potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region. The first of the two files presents results that represent the estimated potential directly associated with interventions by Tri-State and its member coops. The second file presents results that represent estimated potential stemming from both Tri-State's interventions, as well as from naturally occurring adoption. Naturally occurring adoption is expected to be significant in the EV market over the 20-year study horizon. The results presented in the following sections are *exclusive* of naturally occurring adoption. Appendix C provides additional context for the second Reporting Tool that is *inclusive* of naturally occurring adoption in the EV market.

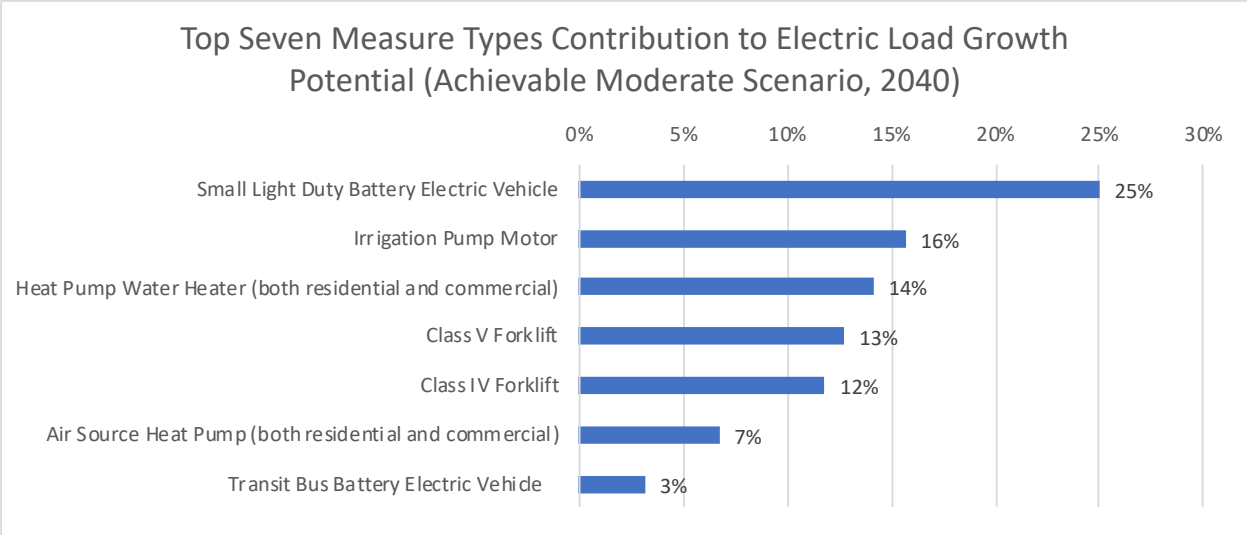
3. PORTFOLIO LEVEL BENEFICIAL ELECTRIFICATION POTENTIAL

3.1. Overview

The study finds that at the portfolio level, in the achievable-moderate scenario, Tri-State can achieve a cumulative reduction of nearly 6.5 million tons CO_2 emissions over the lifetimes of the measures through the electrification of fossil fuel equipment in their service territory. The emissions reduction corresponds to reduction in fossil fuel consumption of nearly 100 million therms (approximately 20 percent of the estimated current on-site natural gas demand in the territory) and an increase in annual electricity consumption of 652,583 MWh, which represents a 3 percent increase in Tri-State's overall load.

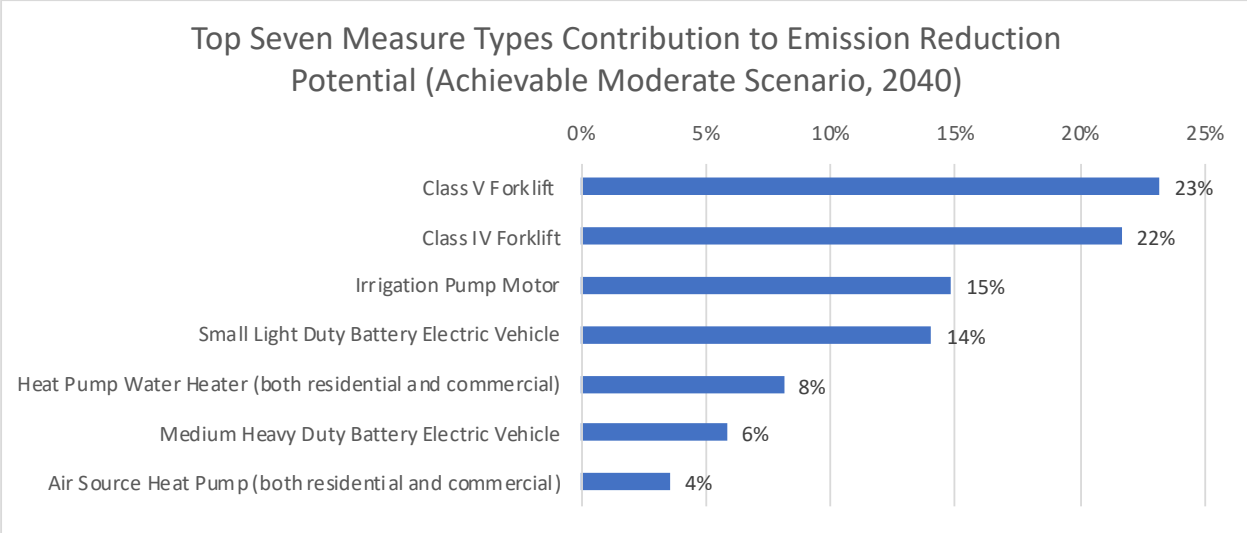
A set of seven measure types constitute nearly 90 percent of the potential load growth from electrification measures. Those seven measures are listed in Figure 5 in order of contribution to electric load growth potential:

Figure 5: Top Seven Measure Types Contribution to Electric Load Growth Potential (Achievable Moderate Scenario, 2040)



A set of seven somewhat overlapping measure types constitute over 90 percent of the cumulative lifetime emissions reduction potential by 2040. Those measure types are listed in Figure 6 in order of contribution to emissions reduction.

Figure 6: Top Seven Measure Types Contribution to Emission Reduction Potential (Achievable Moderate Scenario, 2040)



3.1. Load Growth Potential Results

Table 7 presents portfolio-level potential load growth by time horizon and Figure 7 shows the cumulative growth in electricity consumption potential through 2040. The Achievable-Moderate scenario estimates 2,376 MWh of load growth potential in 2021 rising to 651,520 MWh of cumulative

load growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative load growth potential by approximately 30 percent. The maximum achievable scenario increases load growth potential by another 23 percent over the aggressive scenario.

Table 7. Cumulative Electric Load Potential (MWh) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	52,033	5,487	4,875	3,485	2,524	1,957
2025	417,171	84,088	62,069	43,736	30,905	23,583
2030	1,674,758	474,237	278,910	207,716	144,792	105,867
2040	5,513,285	1,907,671	1,044,310	857,810	652,583	486,764

Figure 7. Portfolio Electric Load Added by Scenario by Year

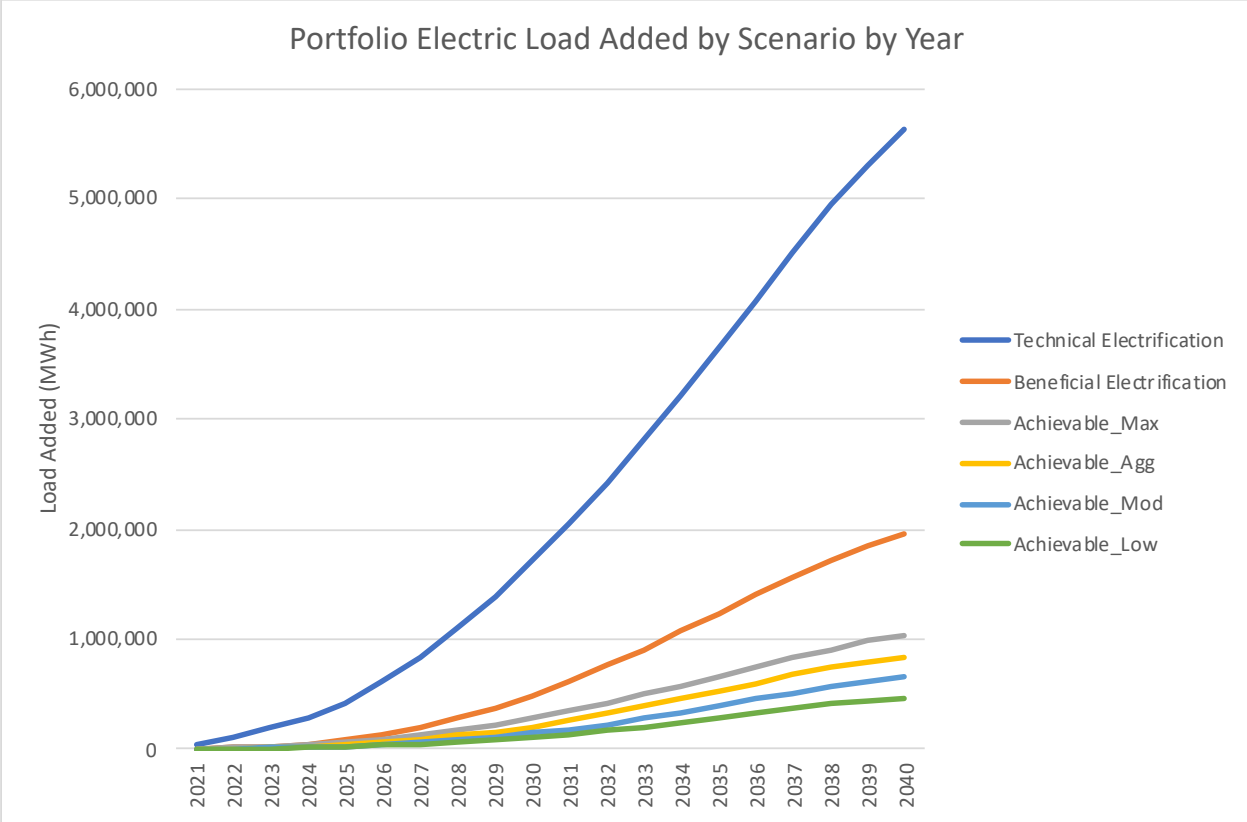


Table 8 shows the impacts of cumulative load growth potential on Tri-State's baseline energy consumption forecast. The cumulative growth associated with the Achievable Moderate scenario would increase Tri-State's baseline forecast consumption by approximately 0.02 percent in 2021. The increase

in baseline energy consumption would grow from 0.19 percent by 2025 to over 3 percent through 2040. The range of potential growth in baseline consumption across the achievable scenarios spans from 2.23 percent (Achievable-Low) to 4.94 percent (Achievable-Max) by 2040.

Table 8. Portfolio Cumulative Load Added as % of Baseline Forecast by Sector by Year

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021 (first year)	0.34%	0.04%	0.03%	0.02%	0.02%	0.01%
2025	2.54%	0.51%	0.38%	0.27%	0.19%	0.14%
2030	9.41%	2.66%	1.57%	1.17%	0.81%	0.59%
2040	26.19%	9.06%	4.96%	4.07%	3.10%	2.31%

Figure 8 shows the impact of the modeled scenarios on the baseline forecast. Each Achievable scenario would increase Tri-State's overall load growth to some degree. Capturing all technically possible electrification measures considered as part of this study would add over 25 percent to Tri-State's load by 2040.

Figure 8. Impact of Electric Load Added on Baseline Forecast by Scenario by Year

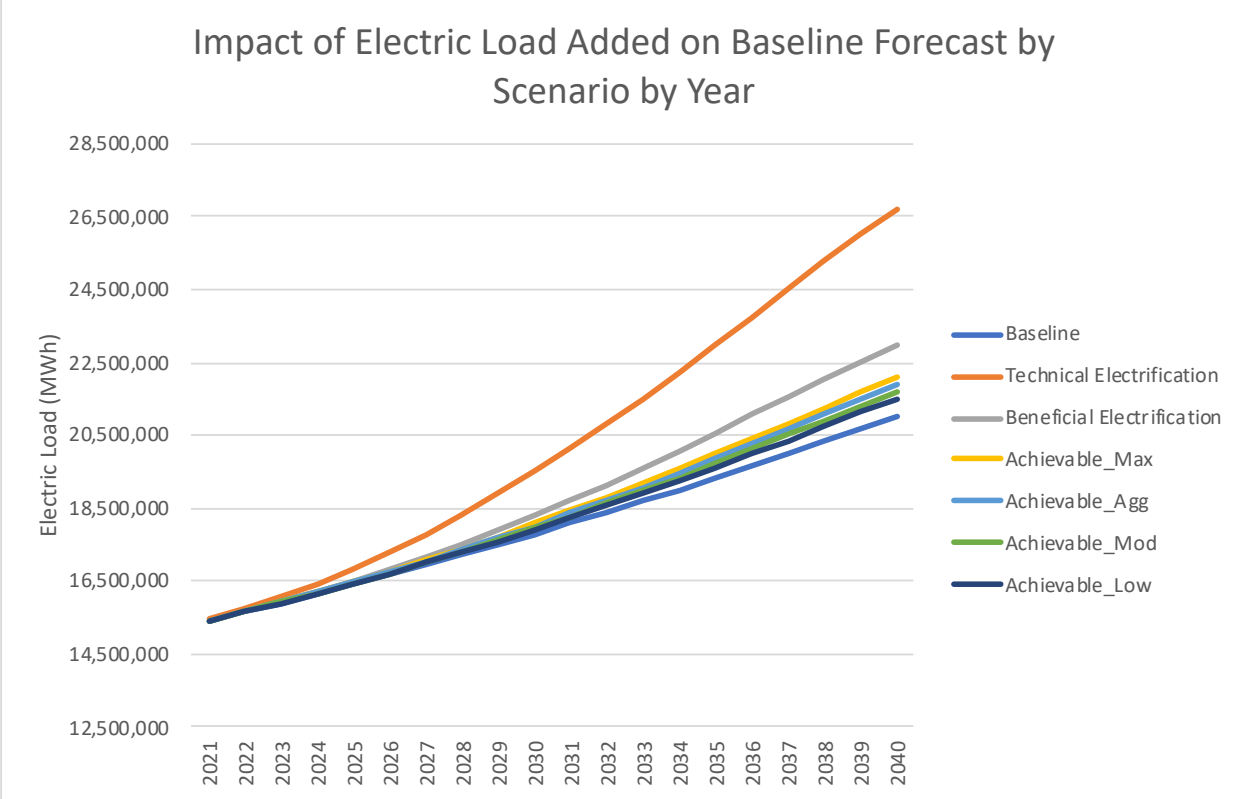


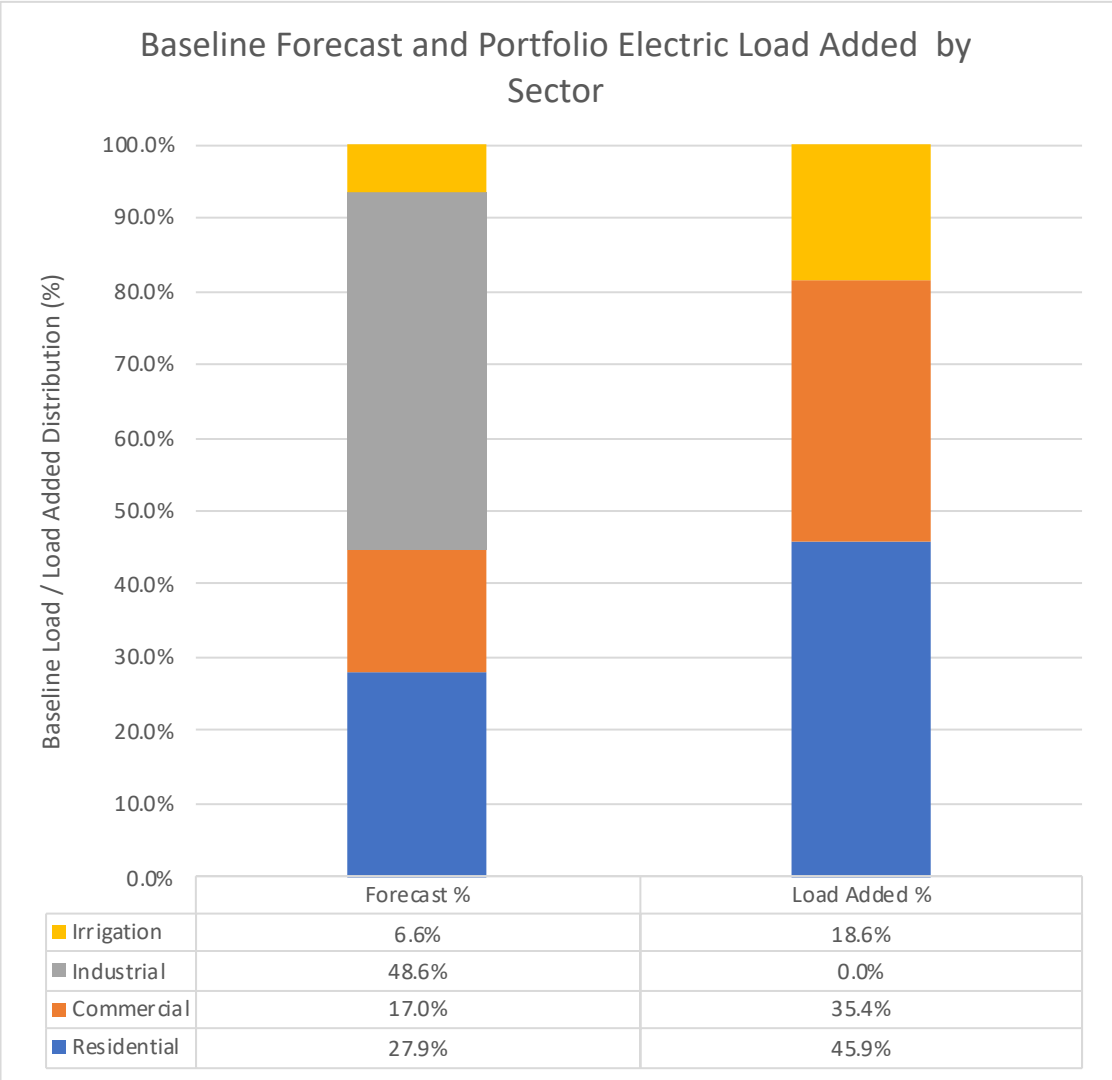
Table 9 presents energy load growth potential by region. Front Range Colorado represents the largest share making up over 42 percent of the total load growth potential. All Colorado regions combined account for nearly three quarters of the load growth potential. The two regions within New Mexico together comprise approximately 15 percent of total potential, while Wyoming accounts for approximately six percent of the total. Nebraska's growth potential is 5 percent of the total. This load growth potential is generally aligned with the distribution of forecast energy load by region. However, Eastern and Western Colorado make up a larger portion of load growth compared to their contribution to the baseline forecast. The outsized contribution to load growth by Eastern Colorado is due, in part, to irrigation pump motor electrification being a highly applicable measure in that region.

Table 9. Cumulative Load Added by Region, Achievable-Moderate Scenario (2040)

STATE / SUB-REGION	POTENTIAL LOAD ADDED (MWH)
Colorado	**460,432**
Eastern	*91,247*
Front Range	*271,902*
Mountain	*32,900*
Western	*64,383*
Wyoming	**38,076**
New Mexico	**118,503**
Northern	*70,475*
Southern	*48,028*
Nebraska	**35,571**
Total	**652,583**

As shown in Figure 9 the residential sector represents the largest opportunity for growth. The residential sector makes up over 45 percent of the total load growth potential, while only accounting for approximately 28 percent of the baseline load. Numerous measures are available to electrify residential energy end uses, with the most substantial growth potential coming from electric vehicles, as discussed further in Section 5. The commercial sector also holds substantial potential load growth at 36 percent of the total growth potential, which is larger than its 17 percent share of the baseline forecast energy consumption. Electric vehicles also contribute a large portion of the growth potential in the commercial sector, at roughly 80 percent of the sector's potential. The irrigation sector contributes less than 20 percent of the achievable electric load growth potential, however that contribution to potential load growth is nearly 3 times the sector's share of the baseline load. Electrification potential in the irrigation sector comes from irrigation pump motor electrification. While the industrial sector comprises nearly 50 percent of the baseline load, the study found no achievable electrification potential for the sector. The study considers pipeline transportation compressor station electrification, which contributes significantly to the technical potential scenario. However, that measure fails the beneficial electrification screen due to increased emissions from electrification over the entire study horizon. More information is presented on the irrigation and industrial sectors in Section 6 and Section 7.

Figure 9. Baseline Forecast and Portfolio Electric Load Added by Sector (2040)



	Forecast %	Load Added %
Irrigation	6.6%	18.6%
Industrial	48.6%	0.0%
Commercial	17.0%	35.4%
Residential	27.9%	45.9%

The portfolio of electrification measures can achieve a cumulative demand growth of 10.6 MW by 2040, as shown in Table 7. The residential sector accounts for the largest share of demand growth, followed by the commercial sector.

Table 10. Portfolio Cumulative Demand Growth Potential by Sector by Year (MW) (Achievable-Moderate Scenario)

MILESTONE YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	IRRIGATION	TOTAL
2021	0.11	0.11	0.00	0.10	**0.31**
2025	0.48	0.44	0.00	0.25	**1.18**
2030	1.76	2.15	0.00	0.71	**4.61**
2040	6.25	2.69	0.00	1.64	**10.58**

Table 11 presents cumulative and average annual cost, added load, and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 2,524 MWh of energy load growth at a cost of approximately $1.9 million, or $769/MWh. As programs expand and become more established annual costs and energy impacts increase substantially to reach a cumulative program expenditure of over $550 million by 2040 and load growth of 785,329 MWh. The 20-year average annual program costs are approximately $28 million and load growth is 39,266 MWh per year.

Table 11. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE LOAD ADDED (MWH)	ACQUISTION COST ($/MWH)
2021	1.54	$1,941,462	2,524	$769.09
2025	1.61	$25,575,994	30,905	$827.56
2030	1.83	$121,866,050	146,004	$834.68
2040	2.37	$557,671,021	785,329	$710.11
20-year avg.	2.37	$27,883,551	39,266	$710.11

3.2. Emissions Reduction Results

Net lifetime emissions reductions represent the total negative emissions from implementing a measure minus any added emissions, typically in the early years of that measure's lifetime, if applicable. Due to the shift in Tri-State's fuel mix over time, several measures exhibit emissions increases over the associated fossil fuel equipment early in their measures lives and shift to emissions reductions later. An example of this is shown for a residential heat pump water heater measure in Figure 10. For this particular example, installing a new heat pump water heater in place of an existing natural gas water heater in 2021 nets an emissions increase in 2021, 2022, and 2023. Starting in 2024, the measure begins to exhibit an emissions benefit and continues that emissions reduction through its 12-year measure life.

Figure 10. Residential Water Heater Example Annual Emissions by Fuel Type by Year

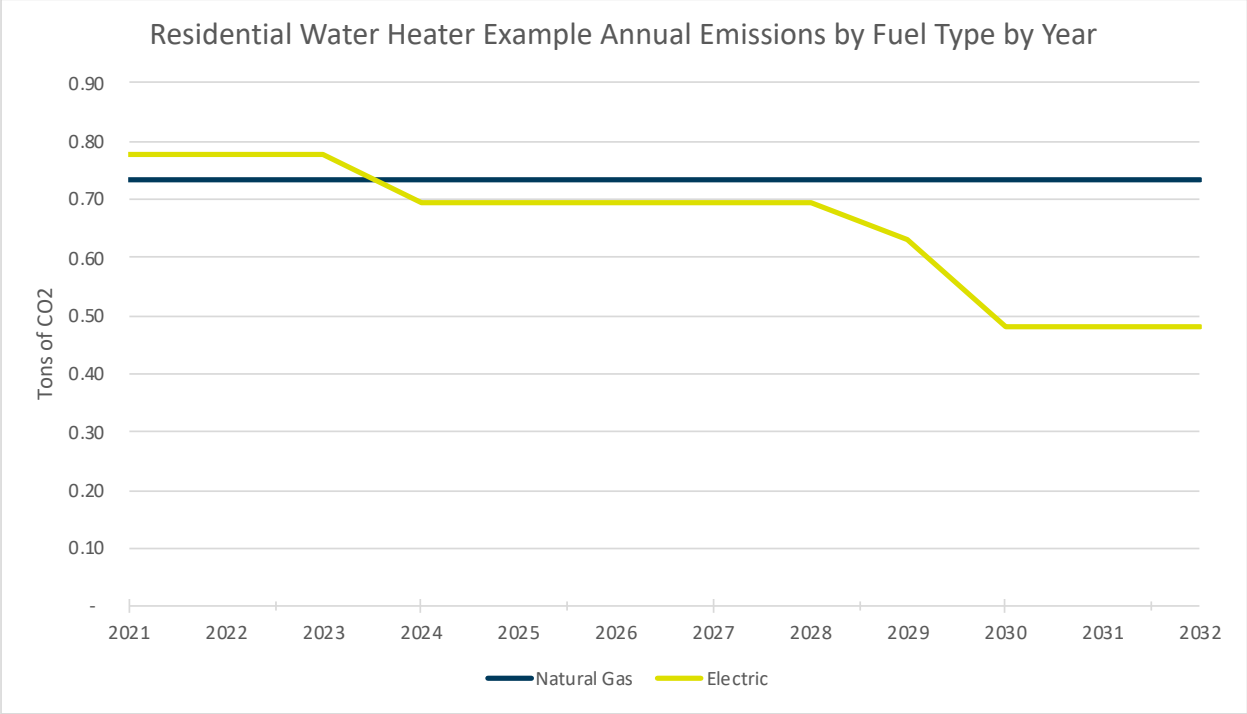


Table 12 shows cumulative net carbon emission reductions by scenario and by time horizon. Since the technical scenario captures all considered electrification measures, that scenario represents measures with lifetime emissions reductions as well as measures that increase emissions.

Table 12. Cumulative Lifetime Carbon Emission Reduction (tons CO_2) by Scenario by Time Horizon

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE MAX	ACHIEVABLE AGG	ACHIEVABLE MOD	ACHIEVABLE LOW
2021	(152,135)	21,155	19,370	14,779	11,414	9,755
2025	(255,722)	393,851	301,303	227,915	175,668	147,926
2030	2,483,894	2,787,472	1,773,723	1,399,013	1,075,264	882,236
2040	23,254,798	16,006,011	9,489,083	7,811,346	6,417,877	5,389,333

Figure 11 show the contribution by region to cumulative lifetime emissions reduction in 2040. The bulk of emissions reduction potential is in the Front Range Colorado region.

Figure 11. Cumulative Lifetime Portfolio Carbon Emissions Reduction (Tons CO_2) by Region (2040)

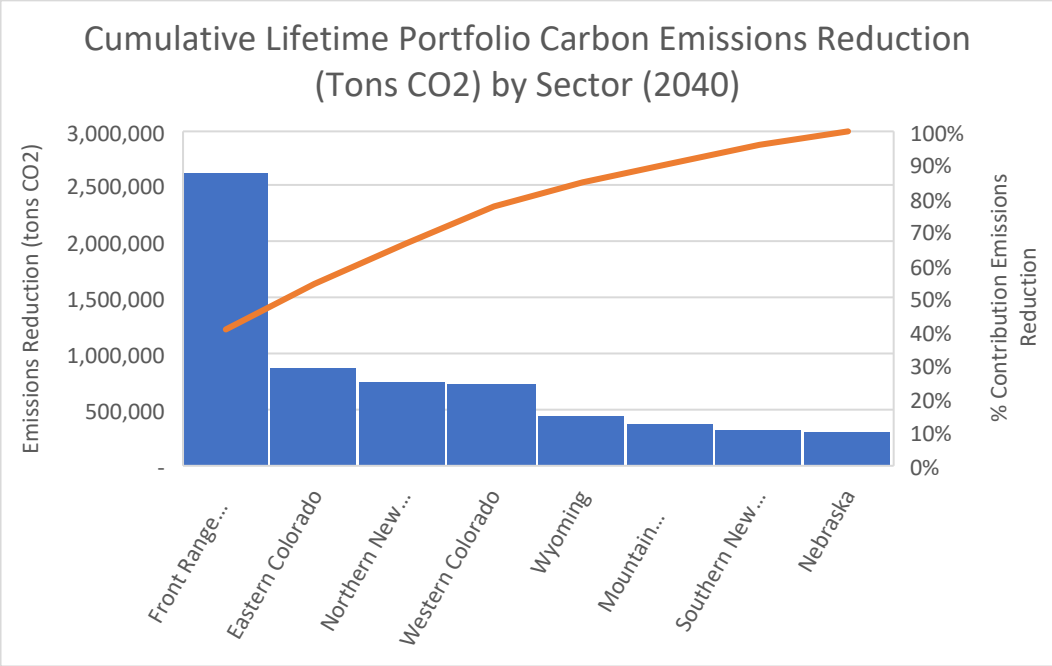
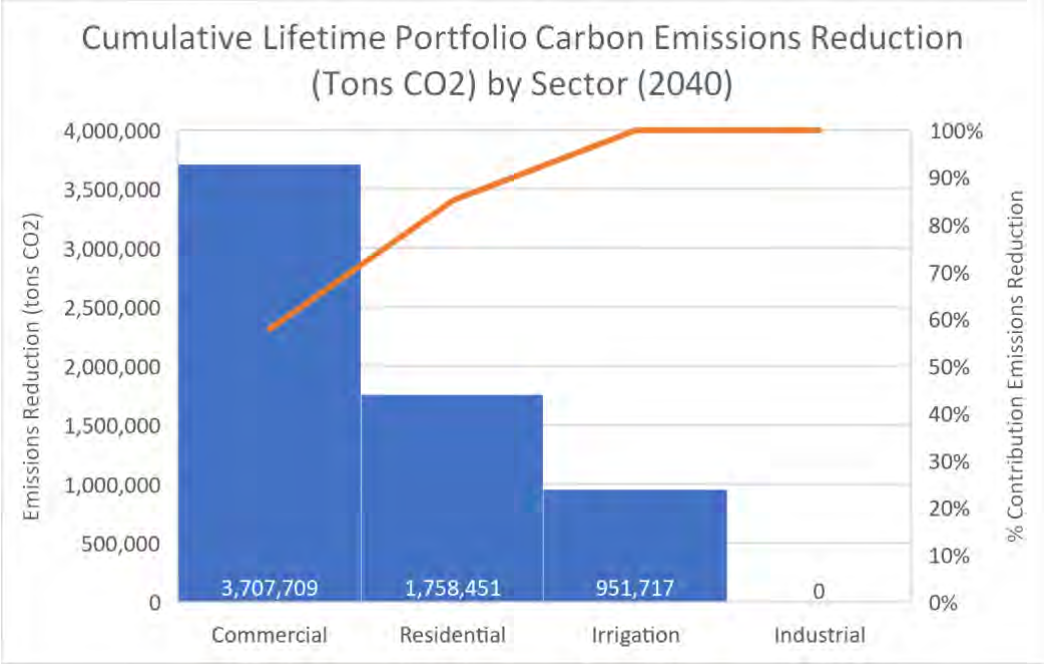


Figure 12 shows the contribution by sector to cumulative lifetime emissions reduction in 2040. The commercial sector makes up over 50 percent of achievable carbon emissions reduction.

Figure 12. Cumulative Lifetime Portfolio Carbon Emissions Reduction (Tons CO_2) by Sector (2040)



4. RESIDENTIAL BENEFICIAL ELECTRIFICATION POTENTIAL

4.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, 46 percent of load growth potential, and 27 percent of projected cumulative emissions reduction. Cumulative electric load growth potential for this sector is estimated to be 299,757 MWh through 2040 (Achievable-Moderate scenario) with plug-in hybrids (28 percent) and battery electric vehicles (37 percent) making up nearly two-thirds of the total energy load growth potential. Space heating and water heating are also large components of the residential sector growth potential, contributing 12 percent and 21 percent respectively.

4.2. Detailed Results

Table 13 presents cumulative potential impacts for the residential sector by scenario at various milestones in the analysis period and Figure 13 shows the growth in cumulative added energy consumption potential through 2040. The Achievable-Moderate scenario estimates 1,054 MWh of load growth potential in 2021 rising to 299,757 MWh of cumulative load growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative load growth potential by approximately 35 percent. The maximum achievable scenario estimates load growth potential approximately 20 percent higher than the aggressive scenario, equating to cumulative increase in electric consumption of an estimated 485,799 MWh through 2040. This equates to an increase of over 8 percent of forecasted sector level baseline sales.

In the achievable-moderate scenario, the residential sector is expected to provide a reduction in carbon emissions of nearly 1.8 million tons of CO_2 by 2040. The achievable-maximum scenario increases that number to nearly 3 million tons of CO_2 by 2040.

Table 13. Cumulative Residential Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	13,979	2,965	2,564	1,567	1,054	742
2025	191,341	41,765	29,152	17,874	11,201	7,562
2030	834,790	215,383	118,945	84,505	54,086	35,248
2040	2,955,794	844,564	485,799	405,492	299,757	209,016
Increase as % of Baseline Sales						
2021	0.31%	0.07%	0.06%	0.03%	0.02%	0.02%
2025	3.99%	0.87%	0.61%	0.37%	0.23%	0.16%
2030	16.28%	4.20%	2.32%	1.65%	1.05%	0.69%
2040	50.38%	14.39%	8.28%	6.91%	5.11%	3.56%
Net CO_2 Emissions Reduction (tons)						
2021	(2,379)	8,492	7,825	4,707	3,185	2,523
2025	146,329	145,341	102,932	62,499	39,652	29,474
2030	1,770,707	933,090	512,420	364,611	237,476	168,946
2040	11,476,214	4,841,494	2,939,543	2,357,711	1,758,451	1,346,869

Figure 13. Residential Annual Electric Consumption Added by Scenario by Year (MWh)

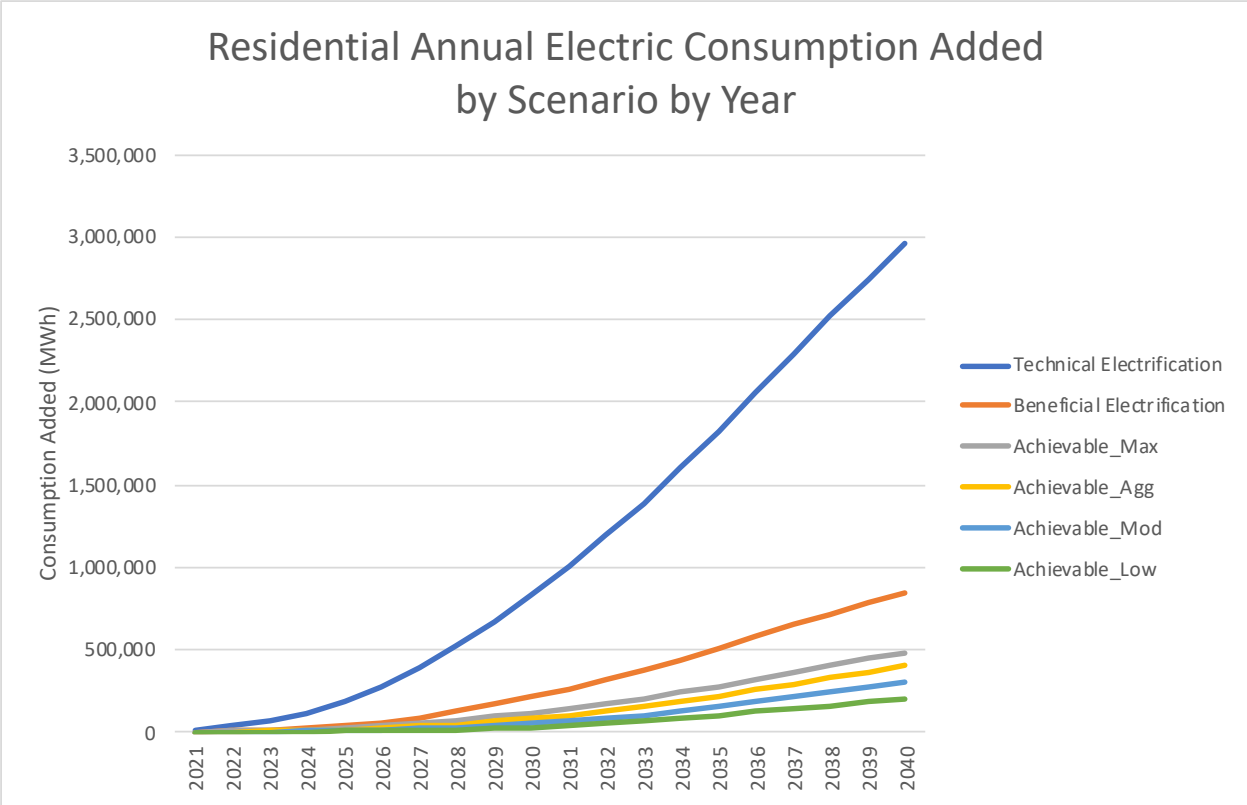
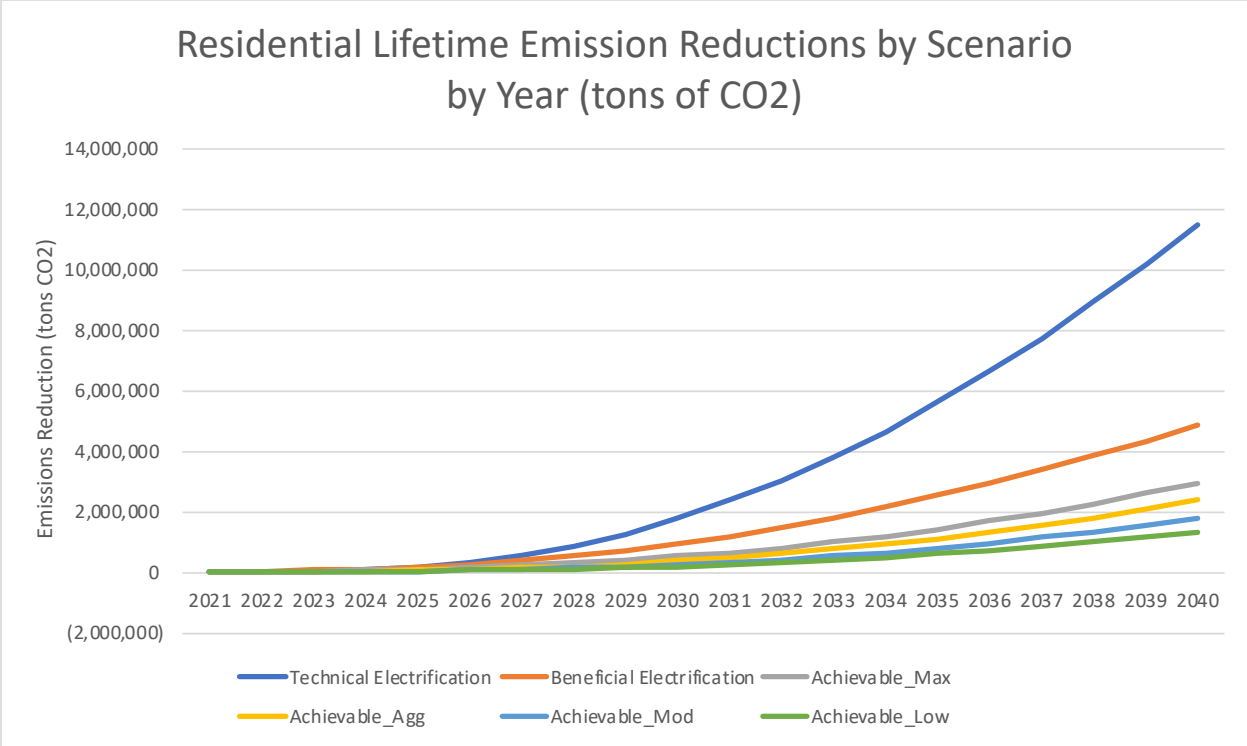


Figure 14 shows the estimated emissions reduction potential by scenario and by year. While in the technical electrification scenario, potential cumulative lifetime emissions reduction is estimated to increase to 11.5 million tons of CO_2 by 2040, the achievable-maximum scenario is estimated to net roughly one-quarter of that amount.

Figure 14. Residential Lifetime Emission Reduction by Scenario by Year (tons of CO_2)



As shown in Figure 15, electric vehicle measures make up approximately two-thirds of the potential electric load growth for the sector. The replacement of fossil fuel space heating equipment (boilers and furnaces) with heat pumps contributes 12 percent to the projected load growth, and heat pump water heaters contribute 21 percent. Less significant measures include electric and induction cooktops and battery-powered electric lawn and garden equipment, together contributing only about 2 percent to the overall project load growth by 2040.

Figure 15. Residential Electric Consumption Added Distribution by End Use

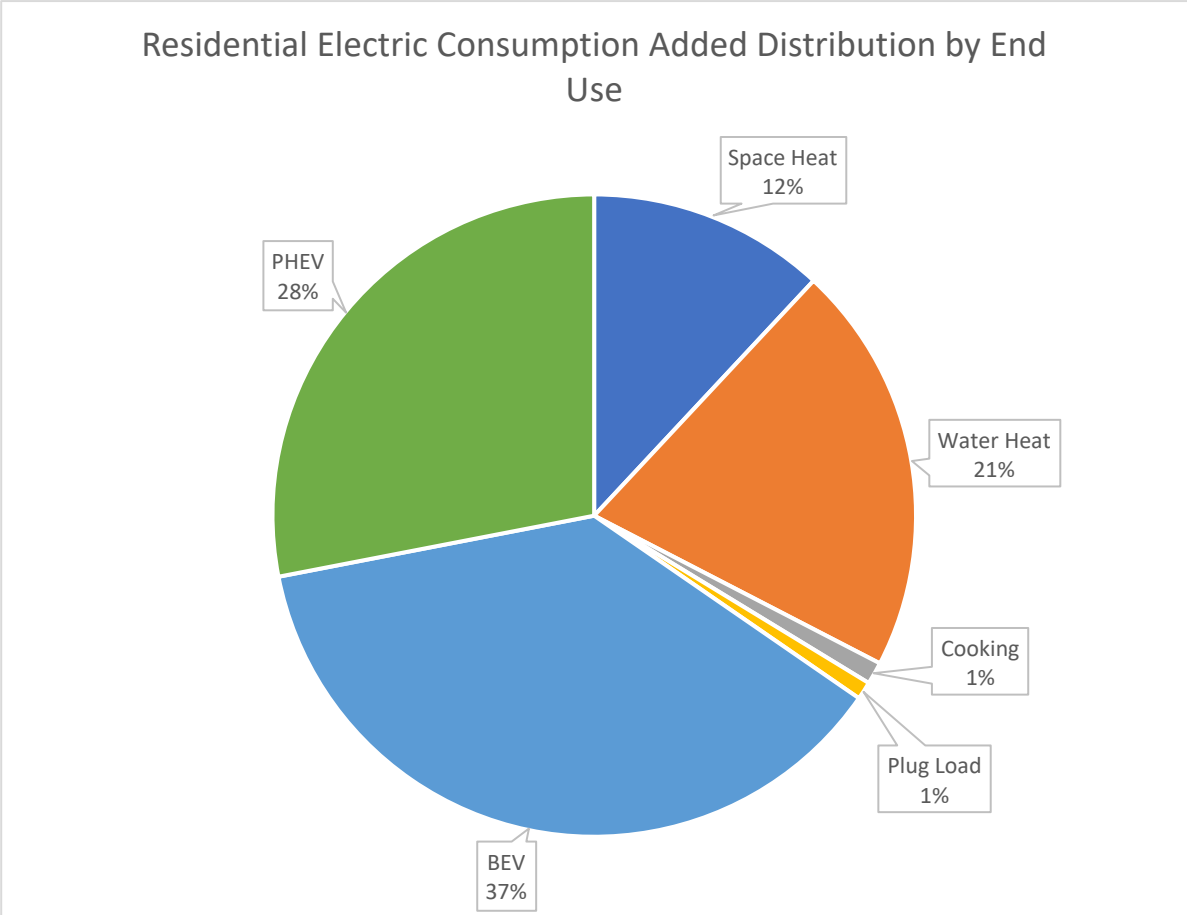


Table 14 presents cumulative program cost metrics by milestone year. As shown, first-year program costs are estimated at $1.4 million, rising to a 20-year average annual cost of approximately $18 million. Acquisition costs decline from $1,370/MWh in 2021 to $1,011/MWh in 2040. At the sector level all residential measures combine to produce TRC ratios of between 1.18 and 1.88 over the study horizon.

Table 14. Residential Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	1.18	$1,444,169	1,054	$1,370
2025	1.29	$14,335,776	11,201	$1,280
2030	1.47	$64,035,447	55,246	$1,159
2040	1.88	$368,948,548	365,013	$1,011
20-year avg.	1.88	$18,447,427	18,251	$1,011

5. COMMERCIAL BENEFICIAL ELECTRIFICATION POTENTIAL

5.1. Overview

The commercial sector accounts for 17 percent of the total baseline forecast energy load and accounts for 35 percent of cumulative energy load growth potential and 58 percent of potential emissions reduction by 2040. Cumulative electric load growth potential for this sector is approximately 231 GWh through 2040 (Achievable-Moderate scenario) with battery electric vehicle measures making up over 80 percent of that potential. Space heating and water heating make up the majority of the remaining potential contributing 7 percent and 12 percent of electric load growth, respectively. The Front Range Colorado region has the largest share of load growth potential in the sector at nearly half of the total. Apart from sector-wide EVs, which are applicable across all segments of the commercial sector, other segments with significant potential include restaurants, lodging, and healthcare facilities.

5.2. Detailed Results

Table 15 presents cumulative potential impacts for the commercial sector by scenario at various milestones in the analysis period and Figure 16 shows the growth in cumulative added energy consumption potential through 2040. Figure 17 shows the estimated reduction in carbon emissions by scenario and by year. The Achievable-Moderate scenario estimates 746 MWh of load growth potential in 2021 rising to 231,185 MWh of cumulative load growth potential through 2040. Pursuing an aggressive incentive approach (achievable-aggressive scenario) could increase cumulative load growth potential by approximately 12 percent. The maximum achievable scenario estimates load growth potential approximately 19 percent higher than the aggressive scenario, equating to cumulative increase in electric consumption of an estimated 305,767 MWh through 2040. This equates to an increase of nearly 9 percent of forecasted sector level baseline sales.

In the achievable-moderate scenario, the commercial sector is expected to provide a reduction in carbon emissions of over 3.7 million tons of CO_2 by 2040. The achievable-maximum scenario increases that number to nearly 4.6 million tons of CO_2 by 2040.

Table 15. Cumulative Commercial Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	1,878	1,179	1,071	917	746	646
2025	30,807	23,337	18,465	15,874	13,449	11,792
2030	186,910	143,038	89,968	77,797	65,650	56,362
2040	890,818	609,836	305,767	258,031	231,185	209,145
Increase as % of Baseline Sales						
2021	0.07%	0.04%	0.04%	0.03%	0.03%	0.02%
2025	1.08%	0.82%	0.65%	0.56%	0.47%	0.41%
2030	6.10%	4.67%	2.94%	2.54%	2.14%	1.84%
2040	24.94%	17.07%	8.56%	7.22%	6.47%	5.85%
Net CO_2 Emissions Reduction (tons)						
2021	7,545	6,302	5,667	5,329	4,798	4,540
2025	145,687	139,370	115,890	108,748	100,753	94,780
2030	1,187,433	1,048,762	780,597	723,429	667,686	617,881
2040	9,731,811	7,653,812	4,594,217	3,941,140	3,707,709	3,504,180

Figure 16. Commercial Annual Electric Consumption Added by Scenario by Year

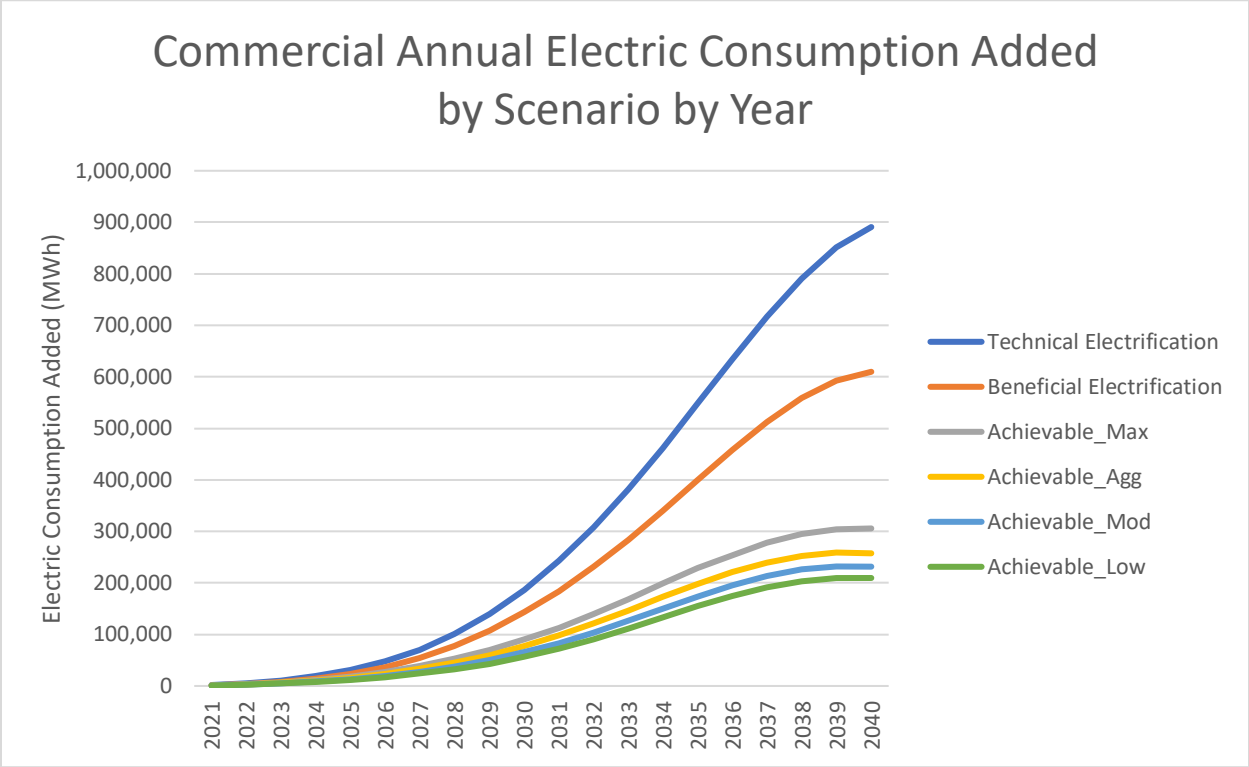
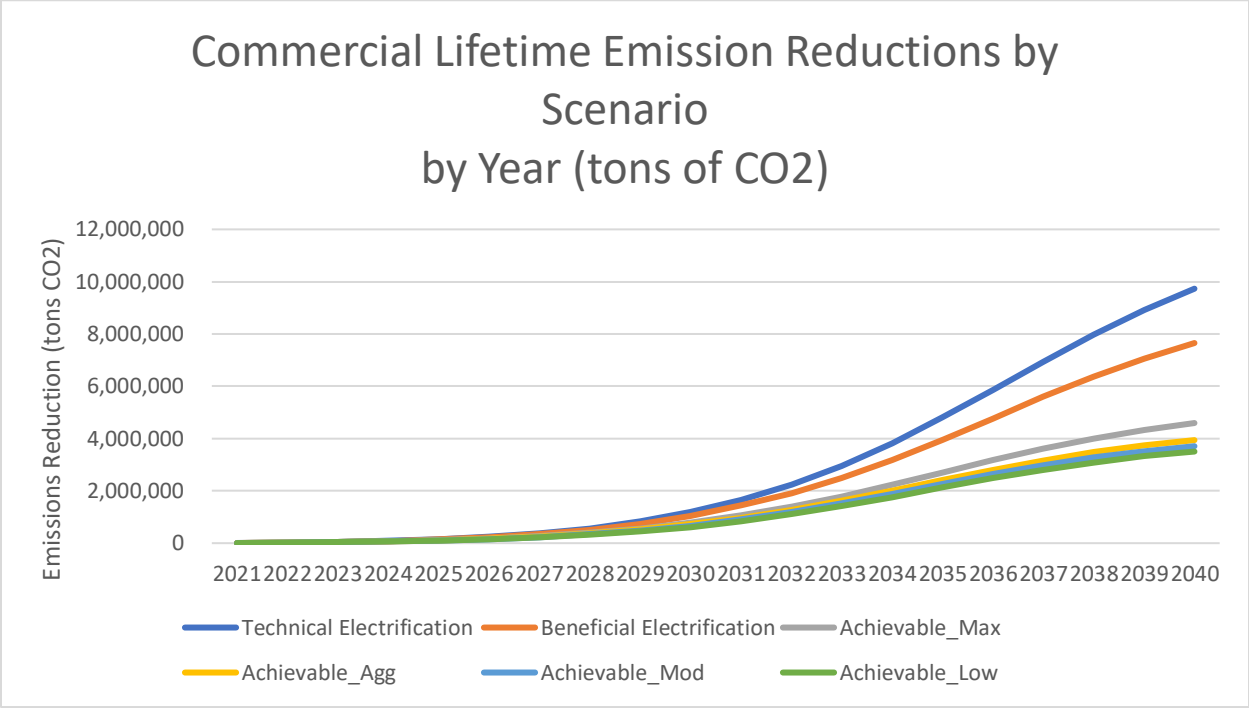


Figure 17. Commercial Lifetime Emission Reductions by Scenario by Year (tons of CO_2)



A large majority of both load growth and emissions reduction (over 80 percent in each case) in the commercial sector is attributable to electric vehicle measures. Figure 18 shows the potential increase in electricity consumption in the commercial sector broken down by end use. Apart from electric vehicles, the remaining 20 percent of load growth potential comes primarily from water heating (12 percent) and space heating (7 percent).

Figure 18. Commercial Electric Consumption Added Distribution by End Use

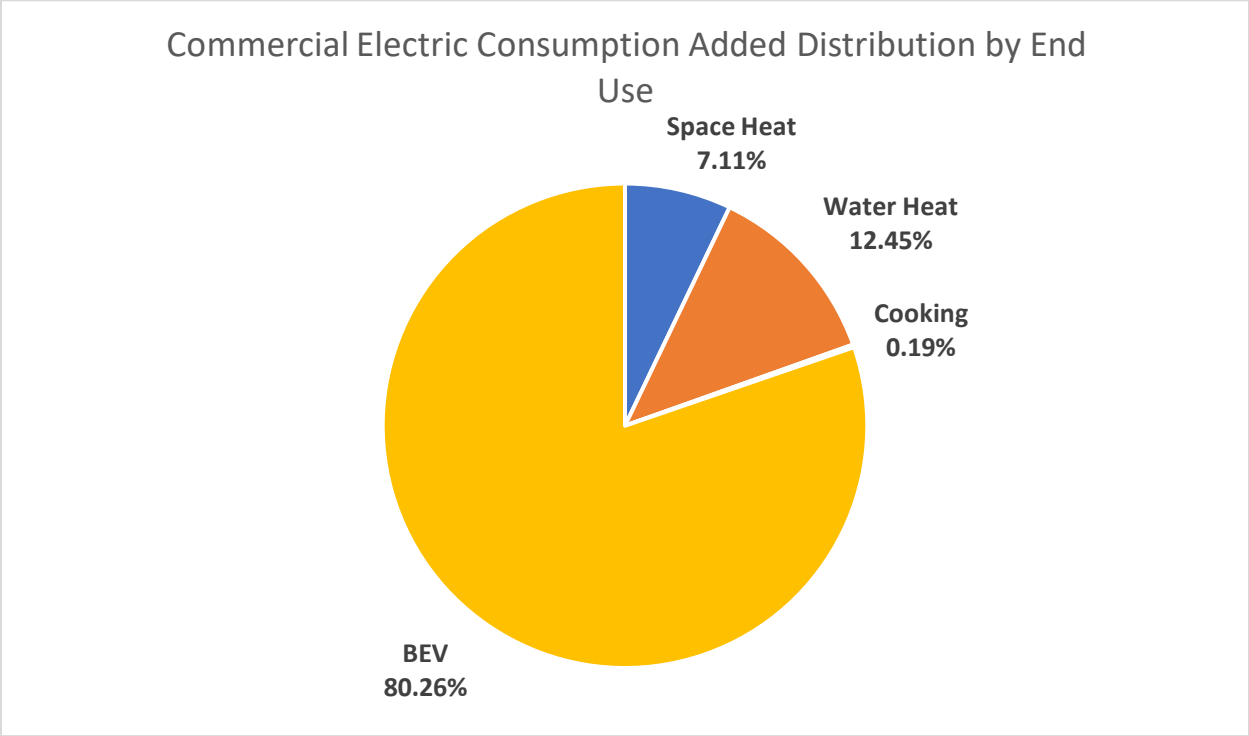


Figure 19 displays the breakdown of electric load growth potential by segment, excluding the sector-wide electric vehicle measures that constitute over 80 percent of the sector's potential. Of the remaining segments, restaurants, lodging, and health facilities contribute the largest shares of load growth potential accounting for 45 percent, 27 percent, and 11 percent of the non-EV potential in the sector, respectively.

Figure 19. Commercial Electric Consumption Added Distribution by Segment (excluding EVs)

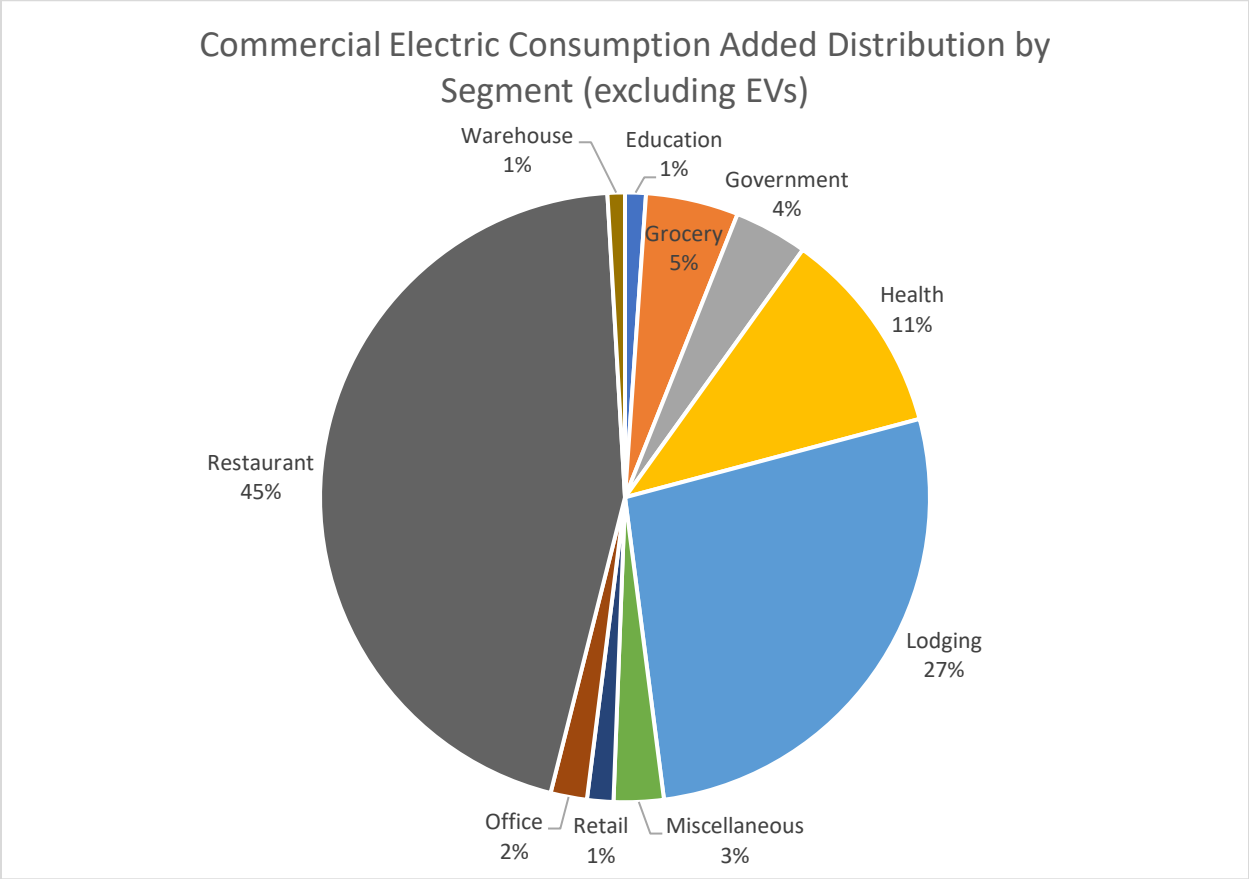


Table 16 presents cumulative program cost metrics by milestone year. As shown, first-year program costs are estimated at $409,700, rising to a 20-year average annual cost of approximately $8.7 million. Acquisition costs shift from $549/MWh in 2021, upward to $834/MWh by 2030, and back down to $585/MWh in 2040. At the sector level all commercial measures combine to produce TRC ratios of between 1.97 and 3.45 over the study horizon.

Table 16. Commercial Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	2.71	$409,700	746	$549
2025	1.97	$10,483,573	13,449	$779
2030	2.23	$54,797,334	65,703	$834
2040	3.45	$173,781,926	297,006	$585
20-year avg.	3.45	$8,689,096	14,850	$585

6. INDUSTRIAL BENEFICIAL ELECTRIFICATION POTENTIAL

6.1. Overview

The study analyzed pipeline transportation compressor station electrification to determine the impact of converting natural gas-powered compressor station motors to electric operation. There are estimated to be 68 compressor stations in the Tri-State service territory of which 10 currently operate electrically and 58 use natural gas. These stations have large motors with an average plant horsepower of nearly 15,000 HP. The measure was found to have large technical electrification impacts, having the ability to increase Tri-State's electric sales in the industrial sector by over 11 percent by 2040. This equates to over a 5 percent overall increase in forecasted energy consumption across Tri-State's service territory.

Compressor station electrification failed the BE screening process on the emissions reduction criteria. Many measures analyzed as part of this study passed the emission reduction screen due, in part, to an efficiency gain inherent in the equipment conversion. However, the motor efficiency in a natural gas compressor station represents a relatively small portion of the overall plant efficiency. The conversion from fossil fuel to electric motors improves the motor efficiency significantly, while the other components of compressor station plant efficiency remain unchanged through electrification. The study finds the impact of electrification in this application does not improve emissions reduction over the study horizon.

6.2. Detailed Results

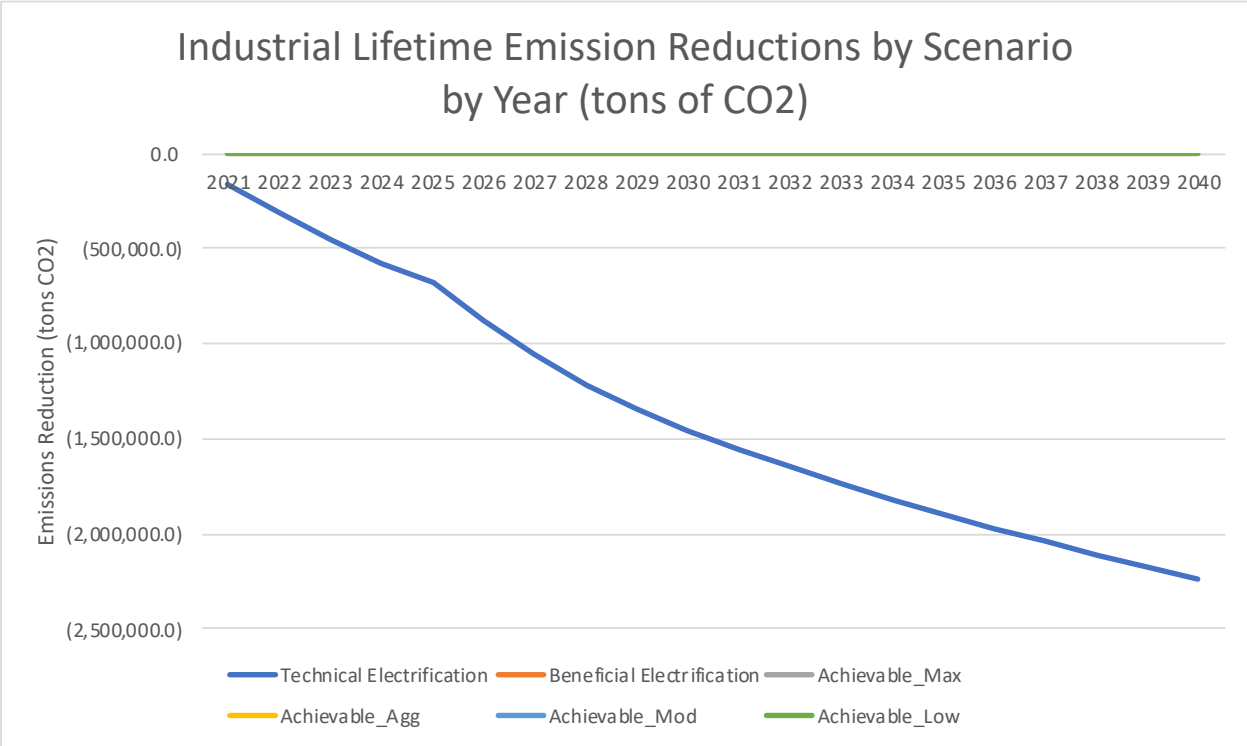
As shown in Table 17, converting natural gas-driven pipeline compressor stations to electrically-driven systems in Tri-State's service territory would add over 1.1 million MWh of cumulative electric consumption by 2040. However, in doing so, an additional 2.2 million tons of CO_2 would be emitted.

Table 17. Cumulative Industrial Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	34,632	0	0	0	0	0
2025	173,160	0	0	0	0	0
2030	519,480	0	0	0	0	0
2040	1,142,856	0	0	0	0	0
Increase as % of Baseline Sales						
2021	0.51%	0.00%	0.00%	0.00%	0.00%	0.00%
2025	2.33%	0.00%	0.00%	0.00%	0.00%	0.00%
2030	6.29%	0.00%	0.00%	0.00%	0.00%	0.00%
2040	11.17%	0.00%	0.00%	0.00%	0.00%	0.00%
Net CO_2 Emissions Reduction (tons)						
2021	(165,256)	0	0	0	0	0
2025	(682,616)	0	0	0	0	0
2030	(1,460,465)	0	0	0	0	0
2040	(2,238,896)	0	0	0	0	0

Figure 20 shows the negative emissions reduction (i.e. increased emissions) projected over the study horizon for the technical electrification scenario in the industrial sector.

Figure 20. Industrial Lifetime Emission Reductions by Scenario by Year (tons of CO_2)



7. IRRIGATION BENEFICIAL ELECTRIFICATION POTENTIAL

7.1. Overview

The irrigation sector represents approximately 8 percent of Tri-State's total baseline energy load and is projected to contribute nearly 15 percent of potential emissions reduction due to electrification. The study examined the electrification of irrigation pump motors, examining natural gas, propane, diesel, and gasoline baselines. Cumulative electric consumption growth potential for this sector is estimated at 121,641 MWh through 2040 (Achievable-Moderate scenario). Eastern Colorado represents the greatest potential for the sector, contributing nearly half of load growth and emissions reductions.

7.2. Detailed Results

Table 15 presents cumulative electric consumption growth potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative electric consumption potential through 2040. The Achievable-Moderate scenario estimates 724 MWh of added consumption potential in 2021 rising to approximately 121,641 MWh of cumulative consumption growth potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative electrification potential by approximately 50 percent. Energy consumption growth potential increases by an additional 30 percent under the maximum achievable

scenario, equating to a cumulative maximum achievable growth of approximately 252,744 MWh through 2040. This represents over 18 percent growth in the sector over the 20 year study horizon.

Table 18. Cumulative Irrigation Electrification Impacts

MILESTONE YEAR	TECHNICAL ELECTRIFICA-TION	BENEFICIAL ELECTRIFICA-TION	ACHIEVABLE _MAX	ACHIEVABLE _ AGG	ACHIEVABLE _MOD	ACHIEVABLE _ LOW
Cumulative Electric Energy Load Increase (MWh)						
2021	1,543	1,342	1,241	1,001	724	568
2025	21,863	18,986	14,452	9,988	6,255	4,229
2030	133,578	115,817	69,996	45,414	25,055	14,258
2040	523,817	453,271	252,744	194,288	121,641	68,604
Increase as % of Baseline Sales						
2021	0.12%	0.10%	0.09%	0.08%	0.06%	0.04%
2025	1.65%	1.43%	1.09%	0.75%	0.47%	0.32%
2030	9.95%	8.63%	5.21%	3.38%	1.87%	1.06%
2040	37.92%	32.82%	18.30%	14.07%	8.81%	4.97%
Net CO_2 Emissions Reduction (tons)						
2021	7,954	6,360	5,878	4,743	3,431	2,693
2025	134,877	109,139	82,480	56,669	35,263	23,671
2030	986,219	805,620	480,705	310,973	170,102	95,409
2040	4,285,669	3,510,706	1,955,323	1,512,496	951,717	538,284

Figure 21. Irrigation Annual Electric Consumption Added by Scenario by Year

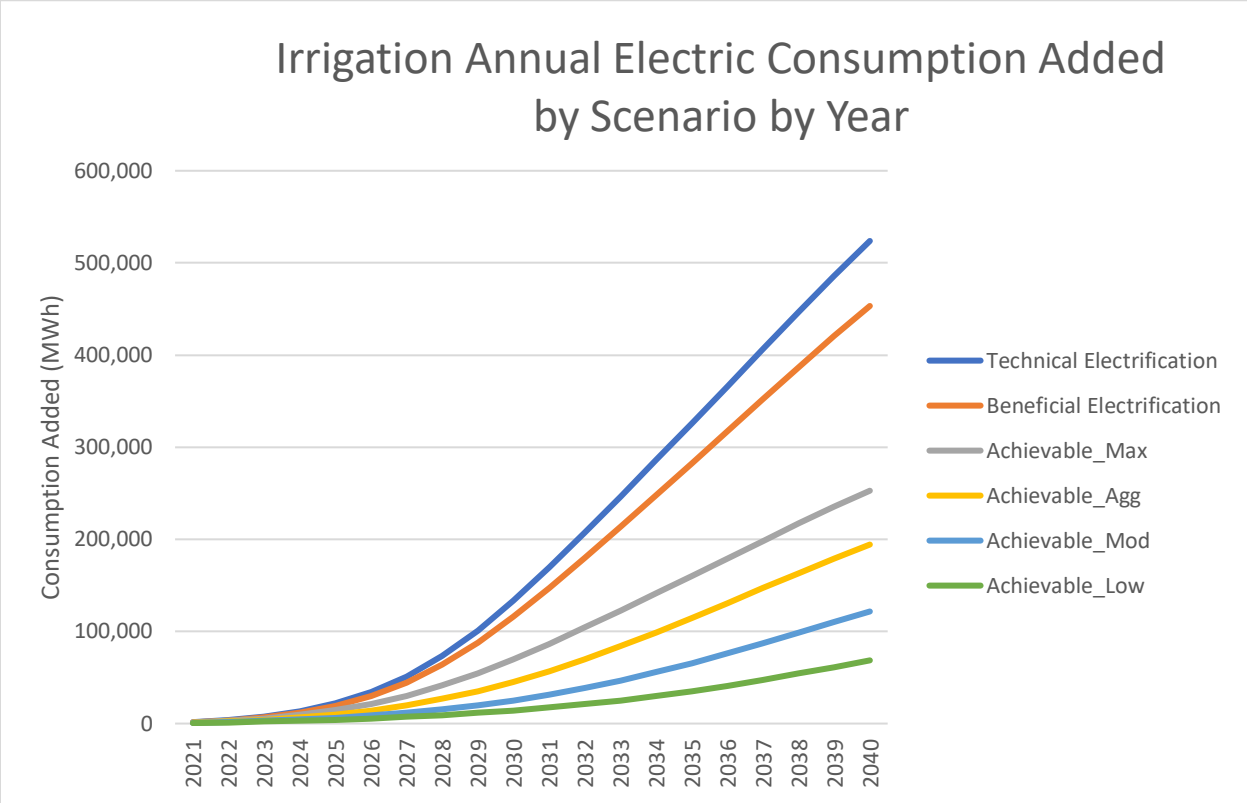


Figure 22 shows the net lifetime emissions reduction potential associated with irrigation electrification. The potential reduction in emissions for the sector approaches 1 million tons of CO_2 by 2040 in the achievable-moderate scenario.

Figure 22. Irrigation Lifetime Emission Reductions by Scenario by Year (tons of CO_2)

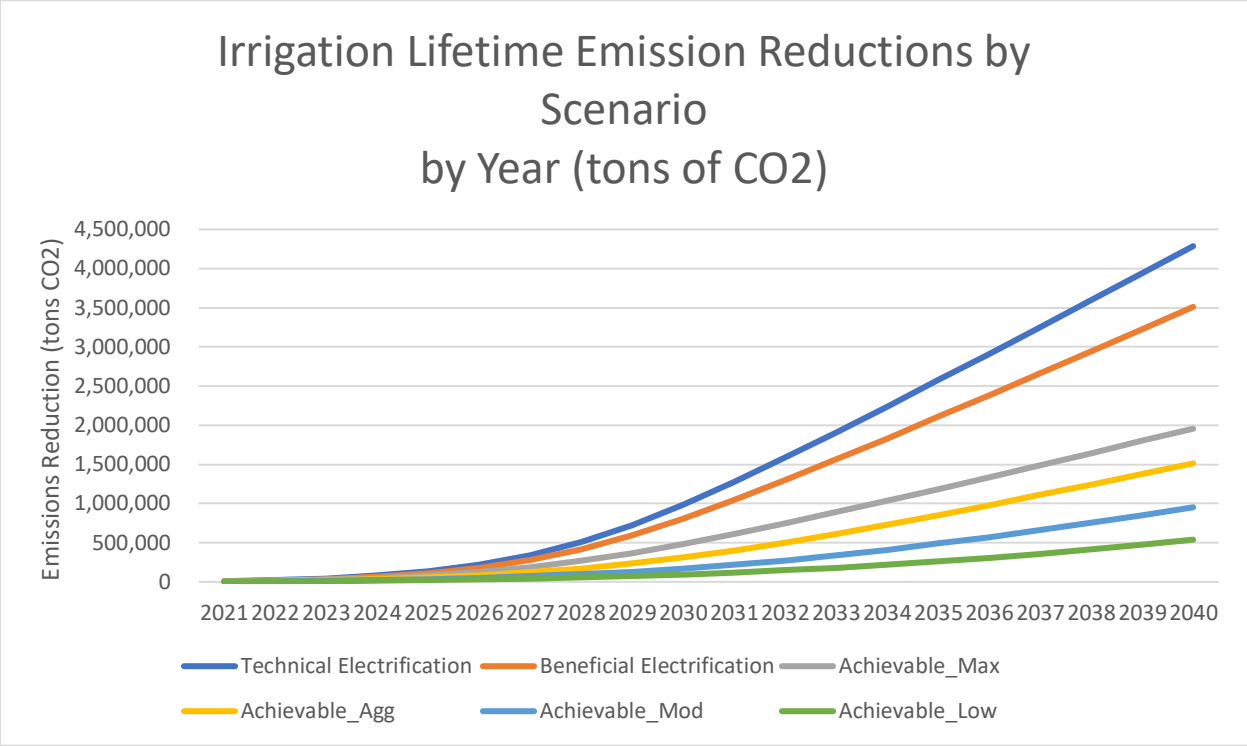


Figure 23 shows the projected breakdown of impacts on electricity consumption in the irrigation sector. Nearly half of the projected load growth is in the Eastern Colorado region, followed by approximately 20 percent contributed by Nebraska and 9 percent by Wyoming.

Figure 24 shows the breakdown of electric consumption impact by segment. In the case of the irrigation sector, and for the purposes of this study, segments refer to the fuel type associated with the baseline irrigation pump motor. The majority of potential comes from converting natural gas pump motors to electric (50 percent). Diesel pump conversions account for 37 percent, while propane pump conversions provide 13 percent of the project electric system growth for the sector.

Figure 23. Irrigation Electric Consumption Added Distribution by Region

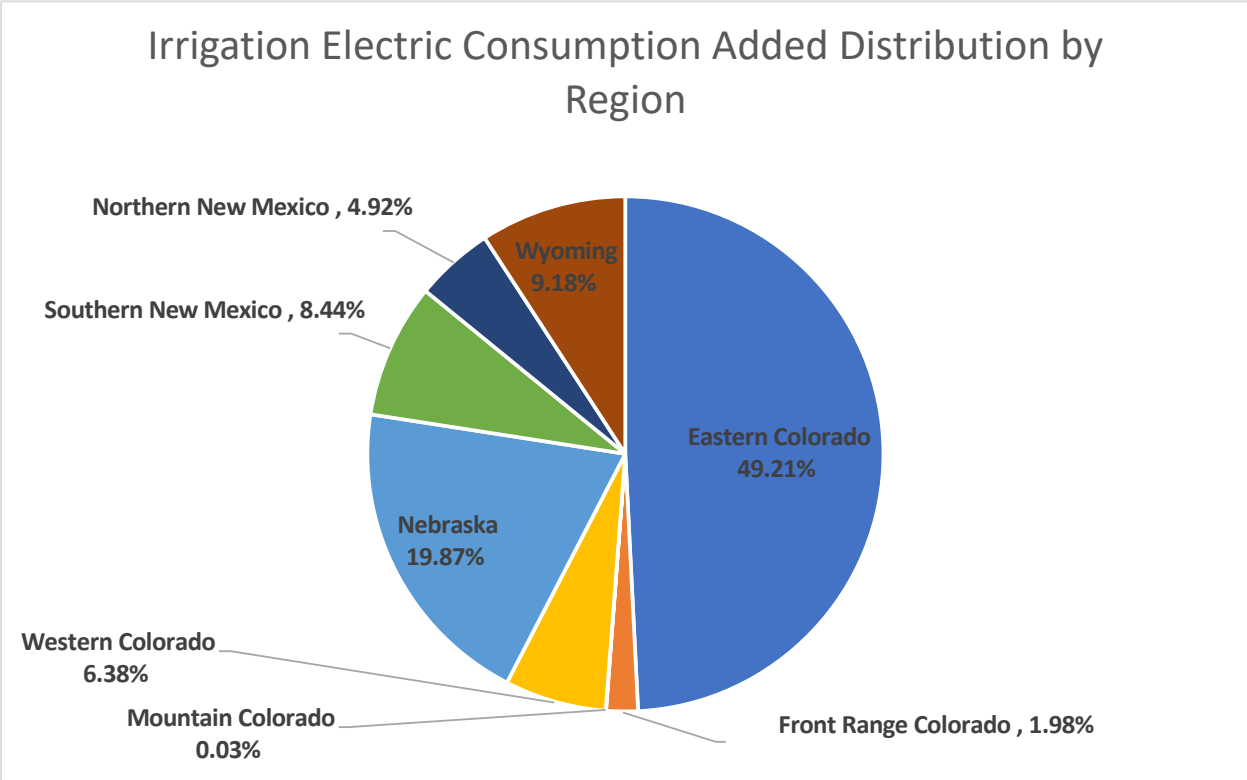


Figure 24. Irrigation Electric Consumption Added Distribution by Segment

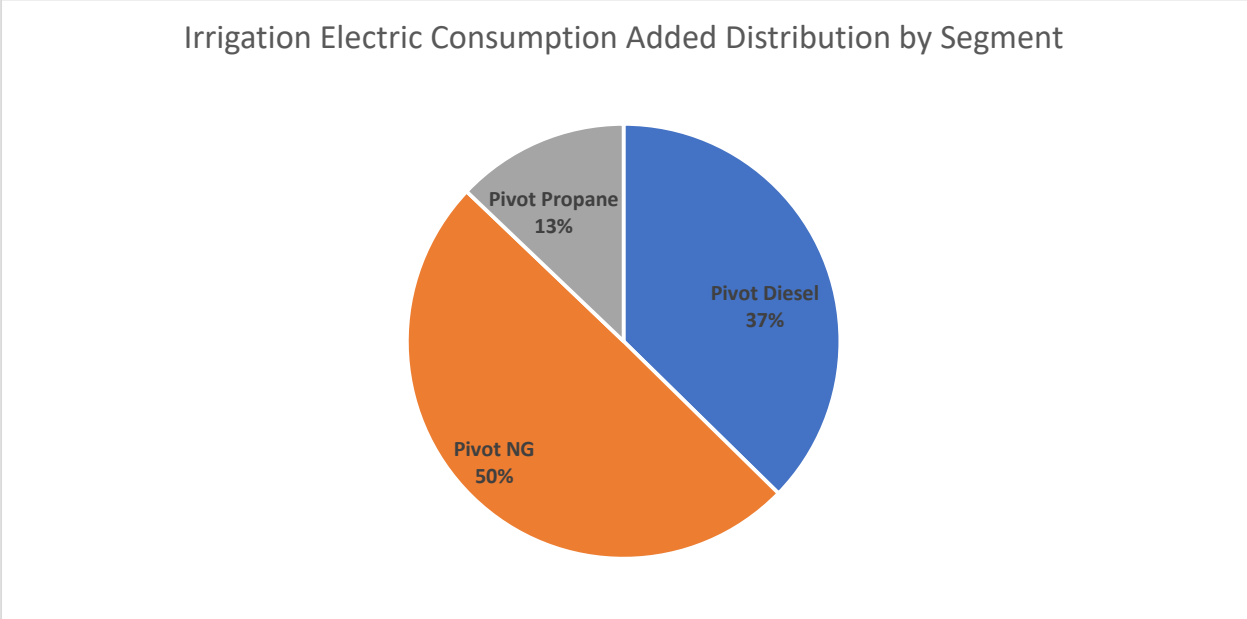


Table 19 presents cumulative and average annual costs, load growth, and TRC metrics associated with the Achievable-Moderate scenario for irrigation electrification measures. As shown, in the first year Tri-State can expect to see an increase in irrigation sector consumption of 724 MWh at a cost of approximately $87,593. As programs expand and become more established annual costs and load impacts increase substantially. The 20-year average annual program costs are approximately $747,027 and the impact on electricity consumption is 6,165 MWh.

Table 19. Irrigation Sector Electrification Cost Metrics – Achievable-Moderate Scenario

MILESTONE YEAR	TRC RATIO	PROGRAM COSTS ($)	CUMULATIVE ADDED CONSUMPTION (MWH)	ACQUISTION COST ($/MWH)
2021	1.20	$87,593	724	$120.95
2025	1.19	$756,645	6,255	$120.97
2030	1.18	$3,033,269	25,055	$121.06
2040	1.18	$14,940,547	123,309	$121.16
20-year avg.	1.18	$747,027	6,165	$121.16

8. KEY FINDINGS AND RECOMMENDATIONS

There are several key findings related to this potential opportunity for Tri-State, some of which are detailed below:

- Over the 20-year period analyzed in this study, Tri-State has the opportunity to reduce carbon emissions in its service territory by over 6 million tons of CO_2 by undertaking the achievable moderate approach to beneficial electrification. This would equate to an associated growth in electricity consumption of over 650 GWh annually, over 3 percent of Tri-State's forecasted baseline load, and a reduction in fossil fuel consumption of nearly 100 million therms across all baseline fuel types. The fossil fuel reduction is estimated to be approximately 20 percent of the total on-site natural gas consumption in Tri-State's service territory.
- Low conversion is a challenge. The difference between the beneficial electrification scenario and the maximum achievable scenario is large, suggesting market adoption is a hurdle to BE potential. Tri-State may benefit from studying innovative ways to increase the saturation level of these beneficial electrification technologies such as implementation strategies, marketing techniques, educational programs, and other techniques.
- Because Tri-State's carbon emissions rate is expected to shift substantially over the study horizon, some measures analyzed result in increased emissions in the early years of their measure life, but provide an emission reduction over the fossil fuel baseline in later years. An example is provided in Figure 10 showing the net emissions by year for a residential water heater measure. Examining the same set of measures over different time horizons and with

different forecasted emissions factors would affect the resulting beneficial electrification potential.

- Equipment load side efficiency gains are integral to passing beneficial electrification screening. As end use efficiency improves, the benefits from electrification also increase. For example air-source heat pumps are much more efficient than electric resistance furnaces, and air-source heat pumps pass BE screening, whereas electric resistance furnaces would not pass under current or forecasted conditions.

- As Tri-State's system-wide emissions rate improves, electrification becomes more beneficial from an emissions reduction standpoint. To continue the example above, were the CO_2 emission rate from Tri-State's generation to approach a range between 0.20 and 0.27 tons/MWh, electric resistance space heating measures would begin to exhibit reduced emissions compared to a fossil fuel baseline. Currently, Tri-State's emission rate is projected to be 0.34 tons/MWh at its lowest over the 20-year study horizon.

- Most measures that passed the beneficial electrification screening also had favorable TRC scores. Even including measures that passed the BE screening, but didn't pass the TRC test, the overall TRC at the portfolio level, and at each sector level, passed at a TRC threshold of 1.0.

- At the measure level, a small number of measures passed BE screening but had TRC scores less than 1. These include electric lawnmowers and leaf blowers, airport bag tractors and pushback tractors, and some permutations of on-road electric vehicles. However, the large majority of measures that exhibit a PCT score greater than 1 also exhibited a TRC score greater than 1. These details can be explored at the measure level in the electronic reporting tool associated with this report.

- When designing traditional DSM programs, energy efficiency measure incentives are often established based on a percentage of the estimated incremental cost of the measure. With BE measures, however, the cost of the electric version of a particular technology is often similar to or lower than the fossil fuel option. Because direct customer incentives are a proven method for driving market adoption of a particular technology, alternative approaches to establishing those incentives may be required for certain measures, such as setting incentives at a percentage of the full measure cost. Additional barriers to adoption may include lack of awareness of electric alternatives to fossil fuel technologies or hesitation to adopt an electric alternative due to lack of knowledge of their operation and reliability. Careful consideration should be taken by Tri-State with respect to the balance between direct customer incentive payments and marketing and outreach efforts.

- There is a large amount of usage in natural gas compressor stations and other pipeline pumping operations but these measures do not pass BE screening at any projected emissions rate. Based upon the Team's calculations, the average electricity consumption of compressor station plants (on an energy per horsepower basis) in the service territory does not represent a significant enough improvement over the natural gas consumption (on an energy per horsepower basis) to result in a net emissions reduction.

- Battery electric vehicles and plug-in hybrid electric vehicles represent the largest opportunity for Tri-State to reduce emissions in the service-territory while increasing electric load on the grid.

- Small light-duty battery-powered electric vehicles provide the largest opportunity for load growth for Tri-State and exhibit a TRC score greater than 3. Of the seven largest contributors to load growth potential, forklifts provide the highest TRC score, greater than 7 for both classes of forklifts.

APPENDIX A. MODELED ELECTRIFICATION MEASURES

A variety of measures were analyzed for input into the beneficial electrification potential model. This Appendix provides additional detail on the measure permutations, energy impacts calculation approach, and resources relevant to each measure.

Electric Lawn and Garden Equipment

The study analyzed several residential lawn and garden measures, including battery-powered:

- Lawnmowers
- Leaf blowers
- Snow blowers
- Chainsaws
- Trimmers, edgers, and brush cutters

Average annual fossil fuel energy consumption for these pieces of equipment was calculated using average equipment horsepower, average annual hours of operation, and brake-specific fuel consumption (BSFC) in gallons per horsepower-hour. Electricity consumption from a battery-powered electric analog was calculated using the output energy estimated for the fossil fuel equipment and applying factors to account for DC/DC roundtrip battery efficiency from charge and discharge cycles, as well as power conversion system efficiency to convert AC to DC at the charger.

Information on average run times, horsepower, and BSFC was drawn from a technical paper associated with the Environmental Protection Agency titled *National Emissions from Lawn and Garden Equipment*[19]. Battery efficiency characteristics were sources from a U.S. DOE paper titled *Energy Storage Technology and Cost Characterization Report*[20].

Heat Pump Water Heating

The study analyzed the conversion of natural gas and propane water heaters to electric heat pump water heaters in the residential sector and applicable segments of the commercial sector. Measures included installation in locations with and without DX cooling and considered the interactive effects on space heating and cooling. Baseline fossil fuel and proposed electricity consumption was calculated adapted from methodologies in Xcel Energy's 2019/2020 DSM Plan's Technical Reference Manual

[19] Banks, J. L., PhD, MS, & McConnell, R. (n.d.). *National Emissions from Lawn and Garden Equipment* (Tech.).

[20] U.S. Department of Energy. (2019, July). *Energy Storage Technology and Cost Characterization Report*. https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

appendix[21]. The calculations relied on inputs including average gallons per day of hot water demand, storage temperature, supply water temperature, draw pattern, and energy factor.

Heat Pump Space Heating

The study analyzed the conversion of natural gas and propane furnaces and boilers to air-source heat pumps in the residential sector and applicable segments of the commercial sector. Measures included installation in locations with and without existing DX cooling and with and without existing ductwork (in the case of a fossil fuel boiler baseline). Baseline fossil fuel and proposed electricity consumption was calculated based on methodologies from Xcel Energy's 2019/2020 DSM Plan's Technical Reference Manual appendix[21]. The calculations relied on inputs including system capacity, baseline fossil fuel efficiency, baseline cooling SEER (if applicable), proposed SEER and HSPF, and heating and cooling equivalent full load hours.

For systems being installed where no ductwork currently exists, the full cost of installing ductwork was taken into account for measure cost estimation.

Electric Cooking

Converting natural gas cooktops to electric resistance and induction type cooktops was analyzed for both the residential and applicable segments of the commercial sector. For residential applications, the Team utilized average annual consumption figures drawn from an Electric Power Research Institute (EPRI) white paper, *Induction Cooking Technology Design and Assessment*[22], for gas, electric, and induction type cooktops. For commercial applications, the Team utilized a methodology from the Minnesota Technical Reference Manual, version 3.0 along with inputs from a D.O.E. Building Technologies Office paper[23], *Energy Savings Potential and Research, Development, & Demonstration Opportunities for Commercial Building Appliances*[24].

Oil and Gas Pipeline Transportation Compressor Stations

The study analyzed the electrification potential for natural gas (or other) pipeline transportation compressor stations in the Tri-State territory. The Team drew from an ArcGIS data set published by the Department of Homeland Security to identify counts of natural gas-driven and electrically-driven

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[21] Public Service Company of Colorado. (2019, April 18). *2019/2020 Demand-Side Management Plan Electric and Natural Gas*. Xcel Energy. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/DSM-Plan.pdf

[22] Electric Power Research Institute (EPRI), Sweeney, M., Dols, J., Fortenbery, B., & Sharp, F. (2014). Induction Cooking Technology Design and Assessment. ACEEE Summer Study on Energy Efficiency in Buildings. https://www.aceee.org/files/proceedings/2014/data/papers/9-702.pdf

[23] Minnesota Commerce Department. (2019, January). State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs. https://mn.gov/commerce-stat/pdfs/mn-trm-v3.0.pdf

[24] Navigant Consulting, Inc. (2009, December). Energy Savings Potential and RD&D Opportunities for Commercial Building Appliances. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Office. https://www.energy.gov/sites/prod/files/2014/07/f17/commercial_appliance_research_opportunities.pdf

compressor stations in the service territory[25]. There are approximately 68 stations in the region, 10 of which currently operate off of electricity. Data was drawn from the data set to estimate the average annual consumption per horsepower, in natural gas or electricity, for the specific plants in the territory. That data was used, along with average plant total horsepower, to establish the annual consumption by fuel type for these large plants. Cost data was also available from this resource.

Irrigation Pumping Electrification

To identify fossil fuel consumption and electricity consumption for the relevant types of irrigation pump motors, the Team drew from a University of Nebraska report on energy use in irrigation pumping[26]. The resource identified typical water-horsepower-hours per fuel unit which was used to determine average therms of natural gas, propane, diesel, and gasoline per water-horsepower-hour. To determine average pump motor runtime, the Team analyzed Tri-State-specific consumption data for irrigation accounts in each region to determine an average pump run time by region. The therms per water-horsepower-hour values were multiplied by the regional pumping hours figures, as well as by the stipulated horsepower determined by the measure definition, to determine fossil fuel baseline consumption. A kWh per water-horsepower-hour value was used similarly to determine the electricity consumption in the proposed case.

On-road vehicles

The potential study defined on-road vehicle measures based on gross vehicle weight rating (GVWR) according the Federal Highway Administration classification system:

- Light-duty vehicles – GVWR <10,000 pounds
- Medium-duty vehicles – GVWR 10,001 – 26,000 pounds
- Heavy-duty vehicles – GVWR >26,001 pounds

Light-duty vehicles represented the largest sample of analyzed vehicles, and the team stratified light-duty vehicles as small, medium, large passenger vehicles and light-duty trucks. These strata are approximate to vehicle Class 1 (small and medium light-duty vehicles) and Class 2a (large light-duty vehicles and light-duty trucks). Medium-duty vehicles are represented as delivery step vans for the purpose of this potential study. Finally, heavy-duty vehicles are represented as school bus and transit bus vehicles.

[25] U.S. Department of Homeland Security, Homeland Infrastructure Foundation-Level Data (HIFLD). (2019, July 31). Natural Gas Compressor Stations [Dataset]. ArcGIS. https://hifld-geoplatform.opendata.arcgis.com/datasets/natural-gas-compressor-stations/data?selectedAttribute=ELEC_COMPR

[26] University of Nebraska Haskell Agricultural Laboratory, Kranz, W. L., Martin, D. L., Dorn, T. W., Melvin, S. R., & Corr, A. J. (2011, February). Evaluating Energy Use for Pumping Irrigation Water. Proceedings of the 23rd Annual Central Plains Irrigation Conference, Burlington, CO. https://www.ksre.k-state.edu/irrigate/oow/p11/Kranz11a.pdf

Off-road vehicles

Airport Ground Support Equipment

Airports are serviced by various forms of ground support equipment (GSE) to assist in air travel operations. Among the various GSE, the team reviewed the following technologies as opportunities for electrification:

- Pushbacks
- Tow tractors
- Belt loaders

These three GSE are typically operated as ICE vehicles; however, the aviation industry has begun adopting electric counterparts for these GSE over the past decade. The transition has been gradual with market estimates of approximately 10 percent electric GSE market saturation.

Electric Forklifts

Forklifts are categorized based on multiple classes that span Class I through Class VII with each class forklift intended for specific abilities and operation in specific environments. Class IV and V forklifts are most prevalently ICE vehicles. However, research conducted by EPRI[27] on behalf of Tri-State found the market offers electric equivalent forklift models for all class IV forklifts and 80 percent electric equivalent forklift models for class V forklifts. Class IV forklifts are characterized as counterbalanced with cushioned or solid tires designed for indoor usage whereas and Class V forklifts are characterized as counterbalanced with pneumatic tires intended for outdoor usage.

Electric Parking Space Infrastructure: *Truck Stop Electrification*

Electric parking space technologies considered in this analysis included truck stop electrification (TSE) and electric transport refrigeration units (eTRU). These systems allow truck drivers to shut down their diesel engines while at truck stops by relying on electricity rather than the truck's engine to provide power for necessities such as cab plug loads or HVAC as well as cargo refrigeration. For TSE, the team reviewed on-board electrification commonly known as shore power in which truck stops are equipped with parking spaces with electric infrastructure that provides a pedestal providing electric power that the truck is able to connect to via a heavy duty extension plug. A competing TSE technology known as off-board electrification is available and provides amenities to trucks such as cooling, heating, plug load, internet, etc. via a module that connects to the truck's cab side window. However, these systems are less prevalent relative to the shore power option due to higher installation costs, operating costs, and market trends at time of reporting. For these reasons, only shore power TSE technology was considered in the potential analysis.

eTRU technology is broadly defined in this report as trailers that have the ability to be powered by grid-supplied electricity. Various TRU technologies are available on the market; however, for the purposes of

[27]EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

this report, we focus on eTRUs that have the option to be powered via shore power when parked at a truck stop. These eTRUs are connected to pedestals like the TSE described above but provide three phase 480 volt power supply to the eTRU. In doing so, the truck driver is able to rely on the electricity provided through the grid rather than on the eTRU generator powered by the truck's diesel engine.

APPENDIX B. EV POTENTIAL ASSESSMENT APPROACH ADDITIONAL DETAILS

As mentioned several times in the body of the report, the assessment of electrification potential for electric on-road and off-road vehicles and related electric parking infrastructure measures involved alternate approaches to several aspects of the study. EV measures are less related to customer premise counts and forecasts than the other measures analyzed as part of the study which can be readily tied to buildings/premises. Some ways in which the approach to analyzing EV measures differed were identified in the body of this report. Additional details on those methods are described in this Appendix.

Beneficial Electrification Screening

As discussed in Section 2.5.2, the team screened each electric vehicle technology against a set criteria qualifying beneficial electrification including impacts on the environment, quality of life, cost savings for the end user, and grid resiliency. As noted, this screening process is largely qualitative to assess if the beneficial electrification technology can successfully contribute a neutral or positive impact within each category. Similar to building technologies, the team assessed electric vehicles based on greenhouse gas and criteria pollutant net emission impacts, technology capital and O&M costs, as well as the technology's ability to reduce stress on the grid. The findings of this screening exercise are discussed in this section.

Cost Effectiveness Screening

As presented in Section 2.5.2, the team calculated PCT cost effectiveness for each measure based on net cost savings for the customer, tax credits, and incentives (benefits) and incremental cost, installation cost, and maintenance costs (costs). TRC cost effectiveness for each measure was based on benefits including reduced net emissions and net O&M savings, while costs were based on initial incremental capital costs and avoided energy costs. Discussed below are the processes used to estimate incremental costs for each EV technology assessed in this potential study.

Incremental Costs (Capital and O&M)

The team performed cost research on a variety of sources ranging from current market data to literature review of secondary research. Our approach to assessing incremental costs included review of capital costs for the purchase of the electric vehicle and its ICE equivalent as well as the incremental cost of operation and maintenance (O&M) between the two technologies. O&M costs are typically negative as electric vehicles usually have lower fuel costs and reduced maintenance requirements[28]. These parameters informed the cost effectiveness analysis to determine the various benefit-cost ratios.

Of the technologies reviewed, data for on-road vehicles was most prevalent. Incremental capital costs were gleaned primarily from manufacturer websites that had both ICE and equivalent electric vehicle models; however, certain information for measures such as the heavy-duty vehicle were sourced from secondary studies. We additionally developed permutations of on-road vehicles in the residential sector that included and excluded the cost of purchasing and installing charging equipment in a home. The team defined fuel costs for on-road vehicles based on fuel economy rates (both electric and gasoline

[28] Vehicle and/or equipment depreciation was not included as an O&M cost as part of this study.

mileage rates) provided by the Environmental Protection Agency (EPA) and annual vehicle miles travelled (VMT) provided by the Federal Highway Administration (FHA) and the Argonne National Laboratory's Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET) model. Maintenance cost estimates were based on various secondary studies and data that provided information on the lifetime costs associated with repairs and general maintenance for ICE vehicles and their electric counterparts.

We assessed incremental costs for off-road technologies based on the same parameters outlined above for on-road vehicles. Each category of off-road vehicles – forklifts, airport GSE, and TSE – were reviewed using secondary data sources. The team leveraged prior research conducted by EPRI[29] on behalf of Tri-State to develop capital and O&M costs for forklifts and charging equipment. To assess costs for the various airport GSE, the team used the Idaho National Laboratory's GSE Cost Model v1.1 which provides capital and operating costs for ICE and electric bag tractors, belt loaders, pushbacks as well as GSE charging equipment. Finally, TSE costs were defined based on literature reviews of various TSE pilot programs.

Estimate Load Growth Potential

Load growth is characterized as the increased electricity consumption resulting from the replacement of ICE vehicles to electric vehicles. For the purposes of this analysis, the team assumed a one-for-one substitution between the ICE and electric vehicles thereby assuming that each technology operates for the same number of miles driven or hours operated. Load growth estimation begins with understanding the expected forecast of ICE vehicle stock across the study timeframe and estimating the portion of that stock that can and will be converted to electric technology as characterized as technical and achievable potential, respectively. Due to the various electric vehicle technology types, the team completed independent analyses to estimate overall load growth.

Technology Forecasts

The team used various approaches to estimate the forecast for each relevant electric vehicle technology using both bottom-up and top-down methods of estimation. With the exception of the residential on-road electric vehicle forecast which is derived based on the disaggregated forecast, each technology forecast was constructed outside of the forecasting methods described in Section 2.2, as these technologies did not conform with the forecast taxonomy. However, these independent forecasts did follow the same principles described in that section and used Tri-State data when applicable. For example, naturally occurring adoption for electric vehicles in Colorado is expected to be greater relative to non-Colorado regions due to aggressive state policy and funding. This assumption is applied to both the residential on-road forecast and is also carried through to commercial fleets, airport GSE, and forklifts in Colorado, as these are all eligible technologies for Colorado state funding. Forecast methods for each EV technology are described in this section.

[29] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

On-road Electric Vehicles

The on-road vehicles are comprised of both the residential and commercial sectors. To estimate the residential on-road vehicle stock and forecast, the team was able to leverage the existing residential forecast of households across the Tri-State territory. We applied a multiplier to each household to serve as a proxy for the number of vehicles owned per household. The team assumed an average of 1.9 vehicles per household[30]. After applying the multiplier to estimate the total residential vehicle stock, we extrapolated the forecast based on residential growth rate for each Tri-State region derived from the disaggregated forecast. To calculate the percentage of these stock forecasts that serve as potential for conversion to either plug-in hybrids (PHEV) or battery electric vehicles (BEV), the team applied various electric vehicle sales forecasts by state to estimate the amount of naturally occurring adoption. For the states of New Mexico, Wyoming, and Nebraska, the natural occurring adoption was considered less aggressive due to minimal state policy and was modeled based on the US Energy Information Agency's 2020 Annual Energy Outlook base case sales scenario. Colorado, however, has very aggressive policies oriented at electric vehicle adoption and charging infrastructure build out. To estimate this natural occurring adoption, the team used a Colorado-specific electric vehicle sales forecast which reflects near-term investments planned by the state[31]. The remaining vehicle stock net of natural occurring adoption serves as the basis for the technical and achievable potential analysis for residential on-road electric vehicles.

Unlike the residential vehicle stock, the commercial vehicle stock is considered to be far more heterogeneous insofar as vehicles in the commercial sector serve a wider range of customers and segments. The team narrowed its commercial on-road vehicle forecast analysis to the following vehicle types and categories:

- Public fleets
  - Municipalities, counties, school districts
    - Transit buses, school buses, light-duty vehicles
- Private fleets
  - Company fleets
    - Medium-duty vehicles

To estimate the public fleet forecasts, the team conducted a linear regression analysis based on municipal fleet size relative to the associated population based on various locations throughout Tri-State's Colorado territory. We subsequently applied the regression model to the populations of each non-Colorado cooperative served by Tri-State to estimate public fleet sizes for those locations. As many public fleets are comprised of both vehicles and equipment, we estimated approximately 40 percent of fleet units are vehicles based on select municipal data. Having established the estimated number of public fleet vehicles within each Tri-State region eligible for conversion to electric, the team calculated

[30] US Bureau of Transportation Statistics.

[31] Colorado Energy Office, June 2019.

the fleet forecast based on weighted average growth rates across the residential and commercial sectors derived from the disaggregated forecast discussed in Section 2.2.

The analysis of private fleets focused on medium-duty ground delivery and freight vehicles. To derive the forecast for each vehicle type, our analysis relied on data from private fleets owned by United Parcel Service (UPS) and FedEx. The team located all UPS and FedEx customer centers and shipment centers for ground delivery and service centers for freight in Tri-state's territory based on maps and company inventories. Using a national average number of vehicles per facility, we estimated the total private fleet base size within Tri-State's territory. The forecast across the study timeframe is based on the disaggregated forecast growth rates.

The team estimated the total number of transit buses based on the population locations within Tri-state service area. Our analysis excluded cities and towns with a population fewer than 2,000 with the exception of specific towns that have low populations but high visitation from non-residents which consequently support the presence of a transit bus system. We assumed the average number of buses per 1,000 people as 0.5 to 1.2 based on research provided by the World Bank Group and PPIAF[32]. With these data, we estimated the number of transit buses based on each Tri-State region's population and extrapolated the forecast across the study horizon using weighted residential and commercial growth rates from the disaggregated forecast.

Lastly, school buses were forecasted based on K-12 enrollment in all school districts within Tri-state service area. We assumed 55 percent of students will ride the bus to school[33]. To determine school bus capacity, we classified school districts into urban, rural and small rural designation. School buses in rural districts are assumed to have a smaller capacity as they travel a longer distance compared with those in urban areas. Based on the reported number of students, we estimated the total expected demand for school buses across Tri-State's service territory. The forecast growth rates are based on the residential sector disaggregated forecast.

Each of the above-described forecasts for public and private fleets as well as transit and public buses within the state of Colorado were further adjusted to reflect possible naturally occurring adoption. Specifically, we adjusted the forecast downward based on Colorado's Beneficiary Mitigation Plan[34] which may provide grant funding for the conversion of these vehicles from ICE to electric technology. These funds are expected to be administered from 2021 – 2023 but no indication of the level of funding to cities and towns within Tri-State's territory was available at the time of reporting. The team ultimately applied a conservative adjustment of five percent to each forecast for these three years. However, we do note that future policy and/or funding may further increase naturally occurring adoption such as a zero emissions vehicle standard for medium- and heavy-duty vehicles which was under consideration of adoption by the state of Colorado at the time of reporting.

[32] "Number of Buses per 1,000 Population." Urban Bus Toolkit, ppiaf.org. Accessed 8 July 2020.

[33] "School Bus." *Amalgamated Transit Union*, www.atu.org/work/school. Accessed 8 July 2020.

[34] Colorado Beneficiary Mitigation Plan Volkswagen, Audi, and Prosche Clean Air Act Settlements, September 2019.

Off-road Electric Vehicles

The team used various data sources and approaches to estimate stock forecasts for the off-road vehicle technologies analyzed in the potential study. The categories of off-road vehicles examined did not conform to the potential study's taxonomy described in Section 2.2. Therefore, the team developed custom forecasts similarly to how on-road commercial fleet vehicles were assessed.

Airport GSE reviewed in the analysis include pushbacks, tow tractors, and belt loaders. Our analysis of GSE centered on commercial airports within Tri-State's territory of which five were identified across the Western Colorado and Mountain Colorado regions. The team's approach to estimate the stock of existing GSE used data from each airport to estimate the number of pushbacks and derived ratios of the number of tow tractors and belt loaders to pushbacks based on secondary research. The average forecast growth rate for the GSE is based on the commercial operations forecasts cited in each airport's master plan. The GSE forecast was further adjusted to reflect possible naturally occurring adoption based on Colorado's Beneficiary Mitigation Plan[35] which makes grant funding available through 2023 for converting GSE from ICE to electric technology. Consequently, the forecast from 2021-2023 was adjusted downward by five percent.

Forklift forecasts are based on prior research conducted by EPRI[36] on behalf of Tri-State that provided an estimate of total forklift shipments to facilities within Tri-State's territory for Class I, II, III, IV, and V forklifts. We focused our analysis on Class IV and V forklifts as these technologies are typically built as ICE vehicles and eligible to be converted to electric technology. Leveraging data from the disaggregated forecast, the team allocated total forklift shipments to each state and region based on energy consumption. Growth rates associated with the disaggregated forecast were used to estimate increases in forklift shipments by state through 2040. To estimate total potential stock available for conversion, the team made adjustments to the forklift forecasts to account for technological constraints as well as possible naturally occurring adoption. Based on research completed by EPRI, it is assumed all ICE Class IV forklifts have an electric equivalent while 80 percent of ICE Class V forklifts have an electric equivalent. Therefore, the Class V forecast was reduced to account for this market technological constraint. The Class IV forklift forecast was also adjusted to reflect technical constraints of businesses and facilities that cannot accommodate charging schedules and/or infrastructure within their facility. As noted earlier, we further reduced the Colorado forecast for both classes of forklifts to account for Colorado's Beneficiary Mitigation Plan[37] which has set aside funding for forklift conversion to electric technology. These funds are expected to be administered from 2021 – 2023; the team adjusted the shipment counts for these years accordingly by five percent. These adjusted forecasts provided the basis for the technical potential assessment.

Electric Vehicle Infrastructure

Truck stop electrification (TSE) forecasts are based on prior research conducted by EPRI on behalf of Tri-State and secondary research. As TSE measures analyzed are associated with the availability of

[35] ibid.

[36] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

[37] Colorado Beneficiary Mitigation Plan Volkswagen, Audi, and Porsche Clean Air Act Settlements, September 2019.

commercial truck stops, the forecasts assess the growth of existing truck stops across the project timeframe. EPRI's research identified all truck stops and associated parking spaces within Tri-State's territory. The team used this research to establish the number of truck stops within each state and Tri-State region. Forecasted growth of truck stops to 2040 was based on secondary research on demand for truck stop capacity[38]. Because there are currently no existing codes or standards nor known policies directly incenting the installation of TSE measures, the team did not adjust the forecast for any natural occurring adoption.

Technical Potential

The beneficial electrification study assessed potential for both load growth resulting from the conversion of transportation technologies to electric as well as the consequent reduction in use of transportation fuels and associated emissions. The team estimated these impacts by analyzing consumption of each measure technology based on various data sources as discussed below.

The on-road measures were comprised of various light-duty, medium-duty, and heavy-duty vehicles. The team calculated energy consumption based on vehicle miles travelled (VMT) and the efficiency of each vehicle based on miles per gallon for ICE technologies and miles per kWh for electric vehicles. The product of the vehicle efficiency and annual VMT determined the annual energy impact for the measure. For example, using the EPA-published miles per gallon and miles per kWh efficiencies for various light-duty vehicles with a GVWR less than 5,000 pounds, the team found an average ICE vehicle miles per gallon of 35.8 and an average kWh per mile of 3.5. Based on an annual VMT of 13,252 miles for the state of New Mexico, the expected avoided annual gasoline consumption was estimated at approximately 370 gallons while estimated electricity consumption was approximately 3,824 kWh. The team applied this approach to each on-road measure.

The team relied on various sources to estimate the impacts for off-road vehicles. Impacts associated with forklifts and TSE/eTRU were estimated based on primary research completed by EPRI[39] on behalf of Tri-State. The EPRI analysis provided data on electricity and fuel usage for these technologies. The team used these data in conjunction with other studies to validate, and if necessary, adjust parameter assumptions used in the EPRI study to estimate the impacts of forklifts and TSE/eTRU equipment. Airport GSE estimates were also based on secondary sources. Specifically, the team used data from an EPRI study (not specific to Tri-State) as well as data from the Idaho National Laboratory's GSE Cost Model (version 1.1) to estimate the electric and fuel impacts for each GSE technology type.

Achievable Potential

The approach to assessing achievable potential for electric vehicles followed the same logic and methods as outlined in Section 2.5.3. Similar to the analysis used for building measures, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

[38] Estimating the Supply and Demand for Commercial Heavy Truck Parking on Interstate Highways. Virginia Transportation Research Council and Federal Highway Administration, December 2002.

[39] EPRI Electrification Initiative. Tri-State Generation and Transmission Association, Inc. Case Study Report, 2016.

- Maximum estimated number of vehicles and/or units eligible to be converted to electric
- Adoption rates based on customer willingness to participate

The team estimated the first parameter based on the technology forecast, i.e., the summation of units available for conversion to electric after accounting for naturally occurring adoption and any technical constraints. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed both residential and non-residential customers. The team used data from residential customers who were asked their willingness to purchase an electric vehicle based on rebate values that covered a percent of the incremental cost. The survey did not ask non-residential customers specifically about converting existing vehicles and equipment to electric; therefore, the team used non-residential customers' response to willingness to install solar PV on their facility based on the number of years of investment payback as a proxy adoption rate. While the team acknowledges the disparity between solar PV and electric vehicles, we assumed this data as a proxy due to the fact that the adoption is based on investment payback which focuses decision making from an economic perspective and that both solar PV and electric vehicles are newer disruptor technologies. Future studies would benefit from primary data collection throughout Tri-State's territory. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on literature review of electric vehicle adoption models.

Estimate Emissions Reduction

Environmental Life Cycle Analysis

In order to estimate the CO_2 emission impacts resulting from the replacement of ICE vehicles with electric vehicles, the team defined analogous boundaries on the value chain for each energy source. We defined these boundaries beginning at the production of each energy source and ending with the energy consumption. For the fossil fuel-derived energy sources, including gasoline and diesel, the team conducted an environmental life cycle analysis to estimate the emissions associated with all processes beginning with the refining of crude oil to gasoline and/or diesel, delivery to distribution locations and retail stations, and combustion in end user vehicles. Similarly, we estimated emission impacts for the generation of electricity based on Tri-State's generation mix and transmission and distribution to charging infrastructure. No CO_2 emissions are associated with consumption of the electricity after being delivered to the electric vehicle.

The team used data from Argonne National Laboratory's AFLEET model to provide parameter estimates of CO_2 emissions resulting from the production, distribution, and combustion of conventional gasoline and conventional diesel. The AFLEET model provided parameters for upstream emissions (fuel refining and distribution to retail stations) and downstream emissions (combustion in ICE). The team used these data to develop emission factors per gallon of fuel consumed. Upstream CO_2 emissions comprise 16 percent of the total emissions for the value chain. To estimate CO_2 emissions associated with electric vehicles, we applied the hourly emissions forecast data provided by Tri-State (see Section 2.2) to the energy consumption of the electric vehicle inclusive of line losses.

APPENDIX C. NATURALLY OCCURRING ADOPTION OF ELECTRIC VEHICLES

As discussed in Appendix B, the Team reviewed and applied applicable naturally occurring adoption to most of the technologies in the electric vehicle study. Naturally occurring adoption was applied to technology forecasts with the purpose of calculating the total stock available of fossil fueled vehicles that could be converted to electric based on a Tri-State program intervention. The adjustment to the forecast for naturally occurring adoption is a standard process in potential study modeling which effectively isolates the potential opportunity a utility has to achieve its goals above and beyond a business-as-usual scenario. While energy efficiency potential studies typically represent naturally occurring adoption based on codes and standards, this beneficial electrification potential study bases naturally occurring adoption primarily on existing policies that incent uptake of electric vehicles.

While this study presents electric vehicles with naturally occurring adoption removed, the Team also assessed the impacts for electric vehicles inclusive of the vehicle stock that is expected to be converted through naturally occurring adoption. The purpose of this exercise is to present the overall load increase Tri-State could expect beyond any form of program intervention. The naturally occurring adoption adjustments made by the Team applied mostly to the Colorado regions due to significant state-level policies currently in place that provide various incentives for both the residential and commercial sectors to adopt electrified vehicles (conservative natural occurring adoption was also applied to on-road vehicles for non-Colorado regions). To include these impacts, the Team conducted separate model runs based on technology forecasts that did not adjust for naturally occurring adoption. This resulted in a larger available stock for conversion; however, in certain cases, the larger stock requires more years before reaching maximum market adoption. Of the two Reporting Tools provided with this report, and described in Section 2.5.4, one provides results *exclusive* of naturally occurring adoption of EVs and the other provides results *inclusive* of naturally occurring adoption of EVs.

Attachment Vol II 6-1 Annual Emissions and Water Usage

Attachment Vol 2 6-1 Emissions and Water Usage

Base Case

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	NM200MWCT	1495	0.01	0.38	N/A	0.0621	0.001	57
	SWCO200MWCT	1495	0.008	0.378	N/A	0.06205	0.0009	57
	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1937	1597	1918	1777	1661	1897	1907	1686	1880	1884	1644	1883	1855	1616	1859	1853	1670	1860	1870	1671
LRS 3	1639	1712	1870	1448	1898	1861	1646	1870	1654	1867	1871	1666	1837	1831	1645	1835	1857	1646	1853	1851
Craig 1	692	671	685	685	651	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	809	793	681	751	722	762	800	600	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3179	3492	3254	3076	3159	3579	3253	3692	3501	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1969	1693	1896	1784	1923	2252	2436	2384	2557	2728	2450	2790	2778	2631	2819	2730	2410	2535	2565	2554
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	10	22	10	4	26	34	33	37	29	23	31	26	29	33	34	35	41	33	31	25
Pyramid 2	7	22	8	4	26	34	35	38	30	22	31	25	30	31	34	31	40	30	29	20
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	8	21	8	4	25	34	35	38	30	22	31	23	30	31	33	32	39	29	29	20
Rifle	0	0	0	0	14	33	29	25	2	29	27	34	35	39	52	17	14	22	26	26
Limon 1	0	0	0	0	13	24	21	6	0	0	0	1	0	2	0	3	3	7	4	2
Limon 2	0	0	0	0	14	23	19	6	0	0	0	1	0	1	0	3	3	8	6	2
Knutson 1	0	0	0	0	14	23	19	7	0	0	0	0	0	1	0	5	3	7	4	2
Knutson 2	0	0	0	0	14	23	21	7	0	0	0	0	0	1	0	3	4	7	7	2
J. M. Shafer	462	328	390	326	769	627	553	505	367	463	498	481	460	484	520	572	658	627	560	496
Basin Nebraska	680	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	763	575	498	307	435	254	676	667	894	2464	2496	2214	1897	2027	2109	2337	2770	2528	2263	2128
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
NM200MWCT	0	0	0	0	0	0	0	0	0	162	222	180	224	198	227	211	295	196	176	122
SWCO200MWCT	0	0	0	0	0	0	0	0	0	202	291	262	280	285	299	307	355	359	387	354
SWCO300MWCC	0	0	0	0	0	0	0	0	0	353	399	394	393	405	409	374	425	544	421	373
Total	13932	13374	13667	12617	13818	13916	13944	14030	13411	12689	12465	12456	12327	12098	12529	12840	13084	12937	12733	12269
																		Scenario sum		261136

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2133715	1759471	2112345	1956964	1829815	2089160	2100735	1857575	2070520	2075123	1810815	2074035	2043719	1780043	2047718	2041291	1839380	2049123	2059488	1840662
LRS 3	1972795	2060737	2250917	1743262	2284549	2239159	1981423	2249974	1991113	2247123	2252240	2004796	2210457	2203272	1980078	2208294	2235342	1980409	2230467	2227123
Craig 1	801977	778357	793995	794048	754324	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	950206	931310	800735	882535	848521	895647	939458	705022	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3321639	3649324	3400945	3214252	3300872	3740310	3399537	3857679	3658155	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	2105429	1811117	2027598	1908430	2056815	2408387	2605299	2550218	2734457	2917918	2619863	2983488	2971437	2814188	3014901	2919415	2577673	2711432	2743726	2732015
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	6407	13407	6024	2385	16222	21126	20517	23080	18282	14150	19276	15993	17868	20160	21159	21754	25728	20458	19152	15232
Pyramid 2	4477	13394	4864	2421	15830	20976	21409	23270	18493	13316	18850	15178	18334	19207	21225	19290	24693	18173	18054	12579
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	5080	13078	5078	2344	15698	21355	21608	23544	18624	13872	18993	14374	18359	19035	20459	19722	24388	17932	18109	12299
Rifle	0	0	0	0	8302	19832	17324	14810	1274	17705	16455	20282	20913	23410	31217	10048	8338	13288	15748	15681
Limon 1	342	342	0	0	9519	17631	16033	4403	0	0	91	684	0	1134	0	2243	2243	5311	2927	1459
Limon 2	341	341	0	291	10354	17195	14456	4669	0	91	291	581	0	672	191	1943	2375	5820	4387	1262
Knutson 1	343	343	0	0	10627	17008	14565	4915	0	0	0	293	0	485	192	3433	2394	5635	2948	1272
Knutson 2	342	342	0	91	10602	17262	15424	5089	0	0	292	292	0	867	192	2054	2992	5267	4894	1269
J. M. Shafer	226754	161025	191294	160021	377248	307341	271446	247654	180197	227171	244126	235814	225417	237334	254857	280568	322799	307761	274555	243441
Basin Nebraska	421495	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	488389	368052	318956	196250	222850	130294	346104	341437	457695	1261490	1278043	1133678	971477	1038035	1079835	1196779	1418120	1294160	1158908	1089349
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
NM200MWCT	0	0	0	0	0	0	0	0	0	121007	165958	134857	167416	147902	169800	158032	220643	146618	131712	90892
SWCO200MWCT	0	0	0	0	0	0	0	0	0	150784	217839	196095	209509	212753	223664	229840	265670	268428	288992	264805
SWCO300MWCC	0	0	0	0	0	0	0	0	0	132606	149855	147851	147407	152134	153712	140523	159469	204239	157978	140150
Total	13575649	13112030	13465748	12418246	13311462	13503812	13328387	13458489	12695812	10741321	10364206	10531882	10578004	10228549	10579417	10817841	10697018	10621067	10701330	10332855
																		Scenario Sum tons:		235,063,123
																		Scenario lbs/MWh		1800

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1066	879	1056	978	914	1044	1050	928	1035	1037	905	1037	1021	890	1023	1020	919	1024	1029	920
LRS 3	1494	1561	1705	1320	1730	1696	1501	1704	1508	1702	1706	1518	1674	1669	1500	1673	1693	1500	1689	1687
Craig 1	131	127	129	129	123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	139	137	118	130	125	131	138	104	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2079	2284	2128	2012	2066	2341	2128	2414	2289	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	825	710	794	748	806	944	1021	999	1071	1143	1026	1169	1164	1103	1181	1144	1010	1062	1075	1070
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	2	1	3	2	2	2	1	2	2	2	2	2	2	2	3	2	2	2
Basin Nebraska	351	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0
SWCO200MWCT	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	1	2	2	2	1
Total	6413	6377	6612	5999	6450	6843	6526	6840	6595	4578	4336	4424	4562	4365	4411	4545	4334	4299	4508	4452

Scenario Sum tons:	107,467
Scenario lbs/MWh	0.82

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2258	1862	2235	2071	1936	2211	2223	1966	2191	2196	1916	2195	2162	1883	2167	2160	1946	2168	2179	1948
LRS 3	1975	2063	2254	1745	2287	2242	1984	2253	1994	2250	2255	2007	2213	2206	1983	2211	2238	1983	2233	2230
Craig 1	958	930	949	949	901	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	272	266	229	252	243	256	269	202	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3573	3925	3658	3457	3550	4023	3657	4149	3935	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	775	666	746	702	757	886	959	938	1006	1074	964	1098	1093	1035	1109	1074	948	998	1009	1005
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	6	14	6	2	16	21	21	23	18	14	19	16	18	20	21	22	26	21	19	15
Pyramid 2	4	13	5	2	15	20	20	22	18	13	18	14	17	18	20	18	23	17	17	12
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	5	13	5	2	15	21	21	23	18	14	19	14	18	19	20	19	24	18	18	12
Rifle	0	0	0	0	18	43	38	32	3	38	36	44	45	51	68	22	18	29	34	34
Limon 1	0	0	0	0	3	5	5	1	0	0	0	0	0	0	0	1	1	2	1	0
Limon 2	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	0	1	1	1	0
Knutson 1	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	1	1	1	1	0
Knutson 2	0	0	0	0	2	4	3	1	0	0	0	0	0	0	0	0	1	1	1	0
J. M. Shafer	173	123	146	122	287	234	207	189	137	173	186	180	172	181	194	214	246	234	209	185
Basin Nebraska	251	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	31	42	34	42	37	43	40	56	37	33	23
SWCO200MWCT	0	0	0	0	0	0	0	0	0	38	55	50	53	54	57	58	67	68	73	67
SWCO300MWCC	0	0	0	0	0	0	0	0	0	132	149	147	147	151	153	140	159	203	157	139
Total	10820	10697	11054	10129	10861	10799	10238	10629	10149	6802	6491	6632	6816	6493	6671	6819	6594	6622	6829	6559

Scenario Sum tons:	168,703
Scenario lbs/MWh	1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0428	0.0353	0.0424	0.0393	0.0367	0.0419	0.0422	0.0373	0.0416	0.0417	0.0364	0.0416	0.0410	0.0357	0.0411	0.0410	0.0369	0.0411	0.0413	0.0369
LRS 3	0.0413	0.0431	0.0471	0.0365	0.0478	0.0468	0.0415	0.0471	0.0417	0.0470	0.0471	0.0419	0.0462	0.0461	0.0414	0.0462	0.0468	0.0414	0.0467	0.0466
Craig 1	0.0063	0.0062	0.0063	0.0063	0.0060	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0061	0.0060	0.0051	0.0057	0.0054	0.0058	0.0060	0.0045	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1336	0.1468	0.1368	0.1293	0.1328	0.1505	0.1368	0.1552	0.1472	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1368
Springerville 3	0.0171	0.0147	0.0165	0.0155	0.0167	0.0196	0.0212	0.0208	0.0223	0.0237	0.0213	0.0243	0.0242	0.0229	0.0245	0.0238	0.0210	0.0221	0.0223	0.0222
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO200MWCT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2473	0.2521	0.2542	0.2325	0.2455	0.2646	0.2476	0.2648	0.2526	0.1124	0.1048	0.1079	0.1115	0.1047	0.1071	0.1109	0.1047	0.1046	0.1103	0.1058
																		Scenario Sum tons:		3.446
																		Scenario lbs/MWh		0.000024

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	99	82	98	91	85	97	98	86	96	97	84	97	95	83	95	95	86	95	96	86
LRS 3	156	163	178	138	181	177	157	178	158	178	178	159	175	174	157	175	177	157	176	176
Craig 1	16	15	16	16	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	20	20	17	19	18	19	20	15	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	105	116	108	102	105	118	108	122	116	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	33	28	32	30	32	37	41	40	43	45	41	46	46	44	47	45	40	42	43	43
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Rifle	0	0	0	0	2	4	3	3	0	4	3	4	4	5	6	2	2	3	3	3
Limon 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	19	13	16	13	31	25	22	20	15	19	20	20	19	20	21	23	27	25	23	20
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	5	7	6	7	6	7	7	9	6	6	4
SWCO200MWCT	0	0	0	0	0	0	0	0	0	6	9	8	9	9	9	10	11	11	12	11
SWCO300MWCC	0	0	0	0	0	0	0	0	0	14	16	16	16	16	17	15	17	22	17	15
Total	449	440	465	409	474	487	456	470	431	370	362	358	374	360	363	376	374	367	380	360
																		Scenario Sum tons:		8,125
																		Scenario lbs/MWh		0.06

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1,022,788,531	843,395,797	1,012,544,975	938,063,576	877,115,073	1,001,431,245	1,006,979,548	890,421,623	992,496,132	994,702,434	868,007,512	994,181,028	979,649,435	853,257,173	981,566,223	978,485,578	881,700,105	982,239,418	987,207,939	882,314,790
LRS 3	865,505,411	904,087,546	987,523,402	764,804,568	1,002,278,174	982,364,612	869,290,520	987,109,533	873,541,901	985,858,842	988,103,634	879,544,772	969,772,601	966,620,255	868,700,781	968,823,642	980,690,075	868,845,965	978,551,210	977,084,470
Craig 1	340,295,438	330,273,189	336,908,459	336,930,948	320,075,244	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	397,873,308	389,961,376	335,286,340	369,537,974	355,295,600	375,028,285	393,373,036	295,209,382	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,563,872,240	1,718,150,728	1,601,210,376	1,513,313,022	1,554,094,750	1,760,988,148	1,600,547,674	1,816,246,784	1,722,308,477	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1,074,861,427	924,609,728	1,035,127,095	974,289,596	1,050,043,053	1,229,527,220	1,330,054,374	1,301,934,784	1,395,992,307	1,489,652,383	1,337,489,655	1,523,126,994	1,516,975,084	1,436,696,217	1,539,163,973	1,490,416,875	1,315,950,869	1,384,237,203	1,400,724,003	1,394,745,306
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1,239,986	2,594,936	1,165,969	461,636	3,139,764	4,088,830	3,971,111	4,467,113	3,538,431	2,738,696	3,730,895	3,095,342	3,458,397	3,901,996	4,095,315	4,210,370	4,979,703	3,959,504	3,706,859	2,948,197
Pyramid 2	872,086	2,609,253	947,441	471,638	3,083,708	4,086,327	4,170,533	4,533,115	3,602,527	2,594,057	3,672,133	2,956,789	3,571,549	3,741,648	4,134,739	3,757,726	4,810,299	3,540,136	3,517,070	2,450,529
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	984,902	2,535,329	984,439	454,369	3,043,180	4,139,914	4,188,986	4,564,220	3,610,387	2,689,282	3,681,955	2,786,519	3,559,141	3,690,144	3,966,268	3,823,348	4,727,795	3,476,258	3,510,694	2,384,282
Rifle	0	0	0	0	17,527,167	41,867,379	36,572,333	31,266,005	2,689,211	37,377,689	34,738,405	42,817,453	44,150,547	49,421,031	65,902,898	21,212,958	17,601,458	28,051,510	33,246,305	33,104,047
Limon 1	26,020	26,020	0	0	724,411	1,341,740	1,220,155	335,064	0	0	6,925	52,039	0	86,294	0	170,680	170,680	404,176	222,733	111,003
Limon 2	26,020	26,020	0	22,203	791,132	1,313,812	1,104,533	356,780	0	6,925	22,203	44,401	0	51,326	14,563	148,480	181,483	444,727	335,178	96,440
Knutson 1	9,586	9,586	0	0	296,753	474,953	406,730	137,252	0	0	0	8,179	0	13,544	5,365	95,865	66,865	157,348	82,328	35,531
Knutson 2	9,586	9,586	0	2,553	296,856	483,328	431,878	142,481	0	0	8,179	8,179	0	24,276	5,365	57,517	83,788	147,478	137,031	35,531
J. M. Shafer	160,877,259	114,244,268	135,719,454	113,531,974	267,650,241	218,052,033	192,585,505	175,705,405	127,846,000	161,173,669	173,202,489	167,305,657	159,928,559	168,383,721	180,815,767	199,057,633	229,019,626	218,350,088	194,791,582	172,716,429
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NM200MWCT	0	0	0	0	0	0	0	0	0	9,227,286	12,655,01	10,283,40	12,766,16	11,278,12	12,947,93	12,050,63	16,824,93	11,180,266	10,043,595	6,930,915
SWCO200MWCT	0	0	0	0	0	0	0	0	0	11,497,884	16,611,10	14,953,06	15,975,92	16,223,30	17,055,31	17,526,27	20,258,43	20,468,776	22,036,875	20,192,451
SWCO300MWCC	0	0	0	0	0	0	0	0	0	122,894,40	138,879,94	137,022,75	136,611,16	140,992,10	142,454,43	130,232,09	147,790,55	189,281,070	146,407,982	129,885,576

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,575,649	6413	10,820	0.2473	449	6,063,231,450	*C*	*C*
2022	13,112,030	6377	10,697	0.2521	440	5,866,523,011	*C*	*C*
2023	13,465,748	6612	11,054	0.2542	465	6,081,369,710	*C*	*C*
2024	12,418,246	5999	10,129	0.2325	409	5,645,835,819	*C*	*C*
2025	13,311,462	6450	10,861	0.2455	474	6,089,406,874	*C*	*C*
2026	13,503,812	6843	10,799	0.2646	487	6,259,139,589	*C*	*C*
2027	13,328,387	6526	10,238	0.2476	456	6,078,848,688	*C*	*C*
2028	13,458,489	6840	10,629	0.2648	470	6,146,381,311	*C*	*C*
2029	12,695,812	6595	10,149	0.2526	431	5,759,577,146	*C*	*C*
2030	10,741,321	4578	6,802	0.1124	370	4,454,365,320	*C*	*C*
2031	10,364,206	4336	6,491	0.1048	362	4,214,761,807	*C*	*C*
2032	10,531,882	4424	6,632	0.1079	358	4,412,138,345	*C*	*C*
2033	10,578,004	4562	6,816	0.1115	374	4,480,370,331	*C*	*C*
2034	10,228,549	4365	6,493	0.1047	360	4,288,332,918	*C*	*C*
2035	10,579,417	4411	6,671	0.1071	363	4,454,780,697	*C*	*C*
2036	10,817,841	4545	6,819	0.1109	376	4,464,021,434	*C*	*C*
2037	10,697,018	4334	6,594	0.1047	374	4,258,808,429	*C*	*C*
2038	10,621,067	4299	6,622	0.1046	367	4,348,735,743	*C*	*C*
2039	10,701,330	4508	6,829	0.1103	380	4,418,473,131	*C*	*C*
2040	10,332,855	4452	6,559	0.1058	360	4,258,987,351	*C*	*C*
Total	235,063,123	107,467	168,703	3.446	8,125	102,044,089,106		
per MWh**	1,197	1	0.86	0.00002	0.04	260		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1800	0.82	1.29	0.000024	0.06	391

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1197	0.55	0.86	0.00002	0.04	260

80pct CR Version 1

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1491	1906	1588	1659	1869	1887	1666	1851	1722	1544	1741	1760	1525	1676	1640	1521	1567	1568	1536
LRS 3	1613	1620	1864	1320	1879	1816	1625	1827	1629	1633	1733	1526	152	0	0	0	0	0	0	0
Craig 1	672	758	733	737	609	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	780	667	747	651	730	743	321	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3418	3100	3087	2753	3401	3067	2636	737	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1665	1838	1738	1556	1647	1898	1871	2150	2064	1958	2204	2584	2384	2571	2657	2108	207	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	23	10	5	39	28	23	24	23	17	28	23	30	32	35	22	5	43	42	38
Pyramid 2	1	23	9	3	37	28	22	24	25	17	28	22	26	28	32	20	4	43	39	35
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	22	9	4	38	28	23	24	24	17	28	21	26	29	33	20	5	43	40	36
Rifle	0	0	0	0	10	8	1	0	37	1	2	0	3	1	1	0	0	0	0	0
Limon 1	0	0	0	0	22	18	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	25	18	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	17	20	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	19	18	3	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	321	353	300	739	527	357	255	145	27	35	28	30	38	73	70	52	63	37	35
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	702	596	398	669	210	449	507	1645	1341	1556	1334	1574	1651	1592	1702	1682	2215	2346	2716
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	679	706	720	719	736	636	628	635	644	653	646
Total	13886	13270	13533	12381	13175	12823	12561	11618	10733	9987	10090	10097	9384	8909	9136	9249	8506	7323	7226	7665
																		Scenario sum		211552

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1642784	2099730	1749148	1827505	2059117	2078391	1834564	2038633	1896825	1701169	1918194	1938936	1680302	1846175	1806047	1674912	1726406	1726891	1691504
LRS 3	1941677	1949508	2242764	1589215	2261738	2185631	1956064	2199254	1961069	1965660	2085214	1836743	182535	0	0	0	0	0	0	0
Craig 1	778917	879364	850358	855027	705738	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	916188	784037	877691	765205	857661	873187	376905	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3571450	3239200	3226399	2877121	3553838	3204788	2754905	770183	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1780200	1965846	1858710	1664088	1761622	2029590	2001050	2299042	2206982	2094037	2357577	2763391	2549979	2749300	2841981	2254484	221491	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	51	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	13990	6209	2874	23954	17172	14143	15092	14065	10658	17206	14266	18524	19593	21715	13388	3272	26572	25814	23723
Pyramid 2	570	13909	5447	2114	22561	17094	13569	14947	15168	10210	16951	13276	16237	17376	20014	12157	2738	26222	24331	21811
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	13880	5657	2356	23733	17304	13932	14586	14756	10459	17076	12896	16214	17787	20219	12226	2851	26773	24639	22402
Rifle	0	0	0	0	6088	4935	372	0	22239	490	1058	196	1512	588	529	0	0	294	0	0
Limon 1	342	342	0	292	16183	13642	675	0	84	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	18420	13724	2043	0	257	0	0	0	0	91	0	0	0	0	0	0
Knutson 1	343	343	0	293	12952	15029	981	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	342	342	0	292	14605	13248	2045	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	157484	172958	147145	362345	258501	175021	125317	71320	13363	17286	13638	14832	18837	35806	34323	25378	30711	17988	17074
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	449335	381479	255030	342362	107584	229926	259364	842441	686591	796589	683021	805924	845520	814900	871345	861030	1133943	1200951	1390815
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	254986	265137	270432	269843	276464	238656	235845	238409	241788	245195	242643
Total	13248122	12940848	13306681	12121536	12483909	12437232	12137777	11141134	9596311	8605190	8562944	8673832	7583638	6984456	7307532	7389922	6627845	5001214	4835095	5053335
																		Scenario Sum tons:		186,038,552
																		Scenario lbs/MWh		1759

SO2
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	821	1049	874	913	1029	1039	917	1019	948	850	959	969	840	923	903	837	863	863	845
LRS 3	1471	1477	1699	1204	1713	1655	1481	1666	1485	1489	1579	1391	138	0	0	0	0	0	0	0
Craig 1	127	143	139	139	115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	115	129	112	126	128	55	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2235	2027	2019	1801	2224	2006	1724	482	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	697	770	728	652	690	795	784	901	865	820	924	1083	999	1077	1113	883	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	2	3	3	3
Total	6056	6188	6480	5776	5993	6412	6137	5835	4577	3995	3946	3971	2890	2540	2703	2721	2427	1659	1574	1618

Scenario Sum tons: 83,497
Scenario lbs/MWh 0.79

Nox
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1738	2222	1851	1934	2179	2199	1941	2157	2007	1800	2030	2052	1778	1953	1911	1772	1827	1827	1790
LRS 3	1944	1952	2246	1591	2265	2188	1959	2202	1964	1968	2088	1839	183	0	0	0	0	0	0	0
Craig 1	931	1051	1016	1022	843	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	262	224	251	219	245	250	108	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3841	3484	3470	3095	3823	3447	2963	828	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	655	723	684	612	648	747	736	846	812	770	867	1017	938	1012	1046	829	81	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	14	6	3	24	17	14	15	14	11	17	14	19	20	22	14	3	27	26	24
Pyramid 2	1	13	5	2	21	16	13	14	14	10	16	13	15	16	19	12	3	25	23	21
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	14	6	2	23	17	14	14	15	10	17	13	16	17	20	12	3	26	24	22
Rifle	0	0	0	0	13	11	1	0	48	1	2	0	3	1	1	0	0	1	0	0
Limon 1	0	0	0	0	5	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	120	132	112	276	197	133	95	54	10	13	10	11	14	27	26	19	23	14	13
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	254	264	269	268	275	237	235	237	241	244	241
Total	10257	10482	10886	9812	10165	10180	9604	8918	6770	5913	5819	5889	4418	3896	4129	4093	3707	3092	3001	2997

Scenario Sum tons: 134,028
Scenario lbs/MWh 1

Hg
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0330	0.0422	0.0351	0.0367	0.0413	0.0417	0.0368	0.0409	0.0381	0.0341	0.0385	0.0389	0.0337	0.0371	0.0363	0.0336	0.0347	0.0347	0.0340
LRS 3	0.0406	0.0408	0.0469	0.0332	0.0473	0.0457	0.0409	0.0460	0.0410	0.0411	0.0436	0.0384	0.0038	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0069	0.0067	0.0068	0.0056	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0050	0.0056	0.0049	0.0055	0.0056	0.0024	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1437	0.1303	0.1298	0.1158	0.1430	0.1289	0.1108	0.0310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0145	0.0160	0.0151	0.0135	0.0143	0.0165	0.0163	0.0187	0.0180	0.0170	0.0192	0.0225	0.0208	0.0224	0.0231	0.0183	0.0018	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2448	0.2471	0.2257	0.2238	0.2499	0.2337	0.2124	0.1316	0.0972	0.0948	0.0961	0.0652	0.0545	0.0594	0.0594	0.0520	0.0365	0.0347	0.0340

Scenario Sum tons: 2.683
Scenario lbs/MWh 0.000023

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	76	98	81	85	96	97	85	95	88	79	89	90	78	86	84	78	80	80	79
LRS 3	154	154	177	126	179	173	155	174	155	156	165	145	14	0	0	0	0	0	0	0
Craig 1	15	17	17	17	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	16	18	19	8	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	113	103	102	91	113	101	87	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	27	32	31	36	34	33	37	43	40	43	44	35	3	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	1	1
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1
Rifle	0	0	0	0	1	1	0	0	4	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	13	14	12	30	21	14	10	6	1	1	1	1	2	3	3	2	3	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	28	29	29	29	30	26	26	26	26	27	26
Total	429	424	457	387	450	456	421	399	323	309	310	304	181	153	161	159	141	117	113	110

Scenario Sum tons:	5,804
Scenario lbs/MWh	0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	787,462,557	1,006,497,937	838,447,519	876,007,804	987,030,333	996,269,237	879,391,726	977,211,345	909,236,085	815,449,346	919,479,288	929,422,072	805,446,404	884,957,025	865,722,203	802,862,779	827,546,307	827,778,937	810,816,102
LRS 3	851,853,147	855,288,853	983,946,420	697,220,943	992,270,663	958,881,055	858,165,393	964,857,489	860,361,110	862,375,296	914,826,103	805,816,714	80,081,798	0	0	0	0	0	0	0
Craig 1	330,510,581	373,132,437	360,824,688	362,805,728	299,459,148	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	383,629,470	328,294,491	367,509,804	320,409,148	359,122,613	365,623,883	157,819,084	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,681,486,422	1,525,058,908	1,519,031,797	1,354,587,004	1,673,194,435	1,508,857,000	1,297,046,170	362,612,481	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	908,825,738	1,003,601,522	948,906,778	849,548,232	899,341,513	1,036,144,334	1,021,574,043	1,173,704,443	1,126,706,119	1,069,045,484	1,203,587,802	1,410,763,583	1,301,812,464	1,403,569,909	1,450,885,003	1,150,956,803	113,075,186	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	430	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,707,713	1,201,744	556,237	4,636,163	3,323,648	2,737,297	2,921,038	2,722,225	2,062,781	3,330,110	2,761,178	3,585,251	3,792,224	4,202,808	2,591,307	633,286	5,142,927	4,996,317	4,591,536
Pyramid 2	111,000	2,709,624	1,061,054	411,722	4,394,914	3,329,952	2,643,277	2,911,793	2,954,755	1,988,994	3,302,055	2,586,311	3,163,083	3,384,849	3,898,880	2,368,273	533,325	5,108,103	4,739,794	4,248,838
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,690,706	1,096,609	456,735	4,600,818	3,354,533	2,700,834	2,827,656	2,860,666	2,027,532	3,310,338	2,500,119	3,143,232	3,448,265	3,919,673	2,370,196	552,778	5,190,236	4,776,602	4,342,809
Rifle	0	0	0	0	12,851,988	10,417,795	786,076	0	46,950,004	1,034,797	2,234,115	413,725	3,192,579	1,241,175	1,117,058	0	0	620,586	0	0
Limon 1	26,020	26,020	0	22,203	1,231,579	1,038,203	51,357	0	6,355	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	1,407,433	1,048,626	156,061	0	19,661	0	0	0	0	6,921	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	361,694	419,680	27,404	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	8,179	408,940	370,954	57,259	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	111,731,773	122,710,105	104,396,303	257,076,320	183,401,325	124,173,961	88,910,200	50,600,266	9,480,933	12,264,412	9,675,949	10,522,693	13,364,311	25,403,848	24,351,379	18,005,318	21,789,054	12,762,469	12,113,479
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	236,312,262	245,719,822	250,626,332	250,080,759	256,217,417	221,178,010	218,572,752	220,948,766	224,080,826	227,237,644	224,872,751
Total	5726854057	5743726155	5968245238	5473733883	5613203615	5718226438	5532345142	5052210960	4113955505	3785176555	3703433547	3831399175	3327906815	3022665802	3182198961	3200812875	2828444813	1836504994	1716243528	1694937259

Scenario Sum (Gallons):	81,072,225,351
Scenario gallons/MWh	383

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,940,848	6188	10,482	0.2448	424	5,743,726,155	*C*	*C*
2023	13,306,681	6480	10,886	0.2471	457	5,968,245,238	*C*	*C*
2024	12,121,536	5776	9,812	0.2257	387	5,473,733,881	*C*	*C*
2025	12,483,909	5993	10,165	0.2238	450	5,613,203,615	*C*	*C*
2026	12,437,232	6412	10,180	0.2499	456	5,718,226,436	*C*	*C*
2027	12,137,777	6137	9,604	0.2337	421	5,532,345,140	*C*	*C*
2028	11,141,134	5835	8,918	0.2124	399	5,052,210,969	*C*	*C*
2029	9,596,311	4577	6,770	0.1316	323	4,113,955,503	*C*	*C*
2030	8,605,190	3995	5,913	0.0972	309	3,785,176,551	*C*	*C*
2031	8,562,944	3946	5,819	0.0948	310	3,703,433,543	*C*	*C*
2032	8,673,832	3971	5,889	0.0961	304	3,831,399,175	*C*	*C*
2033	7,583,638	2890	4,418	0.0652	181	3,327,906,815	*C*	*C*
2034	6,984,456	2540	3,896	0.0545	153	3,022,665,802	*C*	*C*
2035	7,307,532	2703	4,129	0.0594	161	3,182,198,961	*C*	*C*
2036	7,389,922	2721	4,093	0.0594	159	3,200,812,876	*C*	*C*
2037	6,627,845	2427	3,707	0.0520	141	2,828,444,813	*C*	*C*
2038	5,001,214	1659	3,092	0.0365	117	1,836,504,994	*C*	*C*
2039	4,835,095	1574	3,001	0.0347	113	1,716,243,528	*C*	*C*
2040	5,053,335	1618	2,997	0.0340	110	1,694,937,299	*C*	*C*
Total	186,038,552	83,497	134,028	2.683	5,804	81,072,225,351		
per MWh**	947	0.43	0.68	0.00001	0.03	206		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1759	0.79	1.27	0.000023	0.05	383

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	947	0.43	0.68	0.00001	0.03	206

80pct CR Version 2

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1471	1904	1598	1661	1876	1885	1669	1855	1729	1560	1759	1778	1540	1705	1619	1540	1616	1627	1580
LRS 3	1613	1616	1864	1334	1877	1825	1625	1835	1637	1645	1752	1546	155	0	0	0	0	0	0	0
Craig 1	672	763	741	748	604	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	782	673	753	652	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3450	3144	3141	2720	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1669	1848	1747	1643	1787	1910	1928	2280	2082	1875	2291	2530	2400	2617	2756	2347	221	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	25	11	5	38	29	26	30	23	20	30	27	33	36	35	22	6	48	49	46
Pyramid 2	1	23	11	5	37	30	27	29	24	19	30	25	31	33	35	21	6	49	51	42
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	37	29	27	30	25	18	31	24	31	35	35	20	6	49	51	43
Rifle	0	0	0	0	11	14	4	0	59	0	1	1	1	1	0	0	3	0	1	0
Limon 1	0	0	0	0	23	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	27	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	18	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	19	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	338	382	341	773	550	447	296	148	29	33	31	29	35	79	75	58	65	49	44
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	722	620	420	735	212	535	659	1727	1494	1816	1533	1935	2014	2070	2231	2231	2844	3051	3544
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	734	780	793	810	808	641	632	655	672	654	669
Total	13886	13331	13657	12548	13327	13069	12741	11870	10968	10239	10381	10507	9813	9387	9704	9868	9347	8063	8037	8590
																		Scenario sum		219334

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1620555	2097656	1760013	1829238	2066196	2075993	1838426	2042820	1903965	1718521	1937045	1958357	1696586	1877728	1783033	1696427	1780364	1792538	1740259
LRS 3	1941677	1944812	2243827	1605732	2258576	2196727	1955167	2208491	1970563	1979807	2108347	1860165	187100	0	0	0	0	0	0	0
Craig 1	778917	884559	858945	866819	699891	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	919061	790783	885027	765924	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3605275	3285479	3282063	2842178	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1785058	1976004	1868468	1757301	1911628	2042531	2061667	2437945	2226655	2005246	2450127	2705806	2566815	2798600	2947372	2510197	236330	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	15423	6771	3154	23744	18270	15918	18330	14347	12291	18901	16848	20424	22622	21981	13361	3975	29805	30492	28696
Pyramid 2	570	14262	6629	2948	22526	18269	16581	17966	14848	11758	18671	15694	19350	20198	21289	13145	3505	30198	31456	25918
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14755	6602	2951	23024	18175	16696	18793	15258	11326	18962	15002	19161	21372	21627	12565	3622	30209	31700	26439
Rifle	0	0	0	0	6768	8165	2313	0	35810	294	431	750	568	747	0	0	1607	59	901	0
Limon 1	342	342	0	0	16856	16689	4603	0	537	0	0	0	0	73	0	0	0	0	200	0
Limon 2	341	341	0	291	20105	17588	6270	0	1251	0	136	206	62	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	13584	15795	3453	0	145	0	0	0	0	143	0	0	0	0	64	0
Knutson 2	342	342	0	0	14549	16600	3731	0	163	0	0	0	0	71	0	0	0	0	356	0
J. M. Shafer	241699	165878	187553	167193	378935	269863	219271	145266	72374	14056	15978	15308	14082	17331	38927	36793	28505	32061	23965	21615
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	462080	396633	268718	376323	108571	274015	337296	884400	765092	929603	784983	990536	1031002	1059940	1142428	1142161	1456149	1561961	1814752
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	275495	293049	297638	304183	303350	240528	237400	245975	252437	245620	251207
Total	13248122	12984474	13409879	12268619	12588836	12677176	12216747	11303247	9791318	8749703	8679065	8947358	7775321	7238511	7640839	7748707	7200745	5414627	5288539	5552251
																		Scenario Sum tons:		190,724,082
																		Scenario lbs/MWh		1739

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	810	1048	880	914	1033	1038	919	1021	952	859	968	979	848	938	891	848	890	896	870
LRS 3	1471	1473	1699	1216	1711	1664	1481	1673	1492	1499	1597	1409	142	0	0	0	0	0	0	0
Craig 1	127	144	140	141	114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	130	112	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2256	2056	2054	1779	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	699	774	732	688	749	800	808	955	872	786	960	1060	1006	1096	1155	983	93	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	3	3	3	3
Total	6056	6197	6515	5836	6005	6508	6120	5824	4630	4017	3938	4035	2881	2556	2738	2751	2538	1692	1607	1643

Scenario Sum tons: 84,087
Scenario lbs/MWh 0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1715	2220	1862	1936	2186	2197	1945	2162	2015	1818	2050	2072	1795	1987	1887	1795	1884	1897	1841
LRS 3	1944	1947	2247	1608	2261	2199	1958	2211	1973	1982	2111	1862	187	0	0	0	0	0	0	0
Craig 1	931	1057	1026	1036	836	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	263	226	253	219	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3878	3534	3530	3057	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	657	727	687	647	703	752	759	897	819	738	901	996	944	1030	1084	924	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	16	7	3	24	18	16	19	14	12	19	17	21	23	22	14	4	30	31	29
Pyramid 2	1	14	6	3	21	17	16	17	14	11	18	15	18	19	20	12	3	29	30	25
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	6	3	23	18	16	18	15	11	19	15	19	21	21	12	4	30	31	26
Rifle	0	0	0	0	15	18	5	0	78	1	1	2	1	2	0	0	3	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	126	143	127	289	205	167	111	55	11	12	12	11	13	30	28	22	24	18	16
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	274	291	296	303	302	239	236	245	251	244	250
Total	10257	10508	10964	9936	10167	10319	9618	8906	6848	5967	5859	6003	4462	3955	4186	4112	3839	3176	3096	3074

Scenario Sum tons: 135,252
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0325	0.0421	0.0353	0.0367	0.0415	0.0417	0.0369	0.0410	0.0382	0.0345	0.0389	0.0393	0.0341	0.0377	0.0358	0.0341	0.0357	0.0360	0.0349
LRS 3	0.0406	0.0407	0.0469	0.0336	0.0473	0.0460	0.0409	0.0462	0.0412	0.0414	0.0441	0.0389	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0070	0.0068	0.0069	0.0055	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0049	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1450	0.1322	0.1320	0.1143	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0145	0.0161	0.0152	0.0143	0.0156	0.0166	0.0168	0.0198	0.0181	0.0163	0.0199	0.0220	0.0209	0.0228	0.0240	0.0204	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2457	0.2492	0.2287	0.2231	0.2531	0.2324	0.2101	0.1324	0.0978	0.0949	0.0977	0.0652	0.0549	0.0605	0.0598	0.0545	0.0377	0.0360	0.0349

Scenario Sum tons: 2.699
Scenario lbs/MWh 0.000022

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	75	98	82	85	96	97	86	95	89	80	90	91	79	87	83	79	83	83	81
LRS 3	154	154	178	127	179	174	155	175	156	157	167	147	15	0	0	0	0	0	0	0
Craig 1	15	17	17	17	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	16	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	114	104	104	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	27	30	32	32	38	35	31	38	42	40	44	46	39	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	1	1	1	1	1	3	3	2	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	30	32	32	33	33	26	26	27	27	27	27
Total	429	425	460	392	452	463	425	402	329	313	314	312	186	157	164	160	148	122	118	115

Scenario Sum tons: 5,884
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	776,807,074	1,005,503,755	843,655,733	876,838,623	990,423,405	995,119,524	881,242,933	979,218,425	912,658,573	823,766,728	928,515,514	938,731,194	813,252,173	900,081,959	854,690,430	813,175,920	853,410,935	859,246,534	834,186,876
LRS 3	851,853,147	853,228,904	984,412,812	704,467,256	990,883,430	963,749,146	857,771,661	968,910,189	864,525,974	868,581,724	924,974,831	816,092,283	82,084,524	0	0	0	0	0	0	0
Craig 1	330,510,581	375,336,854	364,468,311	367,809,167	296,978,394	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	384,832,350	331,119,446	370,581,316	320,710,153	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,697,411,637	1,546,847,621	1,545,239,455	1,338,135,269	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	911,306,087	1,008,787,534	953,888,053	897,135,423	975,922,486	1,042,750,954	1,052,520,219	1,244,617,109	1,136,749,766	1,023,716,001	1,250,836,072	1,381,365,271	1,310,407,506	1,428,738,433	1,504,689,376	1,281,502,879	120,651,134	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,985,102	1,310,464	610,484	4,595,653	3,536,116	3,080,805	3,547,768	2,776,883	2,378,842	3,658,211	3,260,977	3,953,054	4,378,539	4,254,379	2,586,047	769,289	5,768,715	5,901,767	5,554,102
Pyramid 2	111,000	2,778,230	1,291,287	574,232	4,388,278	3,558,952	3,229,983	3,499,900	2,892,379	2,290,485	3,637,265	3,057,238	3,769,547	3,934,767	4,147,302	2,560,737	682,886	5,882,817	6,127,832	5,049,031
Pyramid 3	37,884	37,884	0	0	0	0	5,764	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,860,391	1,279,827	572,054	4,463,394	3,523,380	3,236,611	3,643,222	2,957,854	2,195,602	3,675,911	2,908,268	3,714,536	4,143,165	4,192,643	2,435,919	702,252	5,856,139	6,145,327	5,125,574
Rifle	0	0	0	0	14,288,324	17,236,193	4,881,955	0	75,598,151	620,588	910,196	1,583,948	1,199,805	1,576,676	0	0	3,392,546	124,118	1,903,135	0
Limon 1	26,020	26,020	0	0	1,282,750	1,270,084	350,325	0	40,885	0	0	0	0	5,529	0	0	0	0	15,221	0
Limon 2	26,020	26,020	0	22,203	1,536,143	1,343,843	479,040	0	95,606	0	10,369	15,716	4,769	21,563	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	379,344	441,093	96,418	0	4,053	0	0	0	0	3,990	0	0	0	0	1,791	0
Knutson 2	9,586	9,586	0	0	407,373	464,812	104,482	0	4,553	0	0	0	0	1,978	0	0	0	0	9,968	0
J. M. Shafer	171,480,537	117,686,970	133,065,134	118,619,870	268,846,974	191,462,411	155,568,309	103,063,249	51,347,661	9,972,185	11,335,898	10,860,871	9,991,157	12,295,705	27,617,965	26,103,568	20,223,654	22,746,667	17,002,807	15,335,239
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	255,318,709	271,587,657	275,840,259	281,906,001	281,134,069	222,912,796	220,014,033	227,961,288	233,949,614	227,632,034	232,809,948
Total	5726854057	5759294460	6012037957	5539999761	5654821295	5838902658	5556389500	5092449011	4212956177	3824718238	3701224831	3926922913	3340671623	3065107428	3225897233	3247031866	2982362473	1882342021	1757938157	1732012501

Scenario Sum (Gallons): 82,079,934,163
Scenario gallons/MWh 374

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,984,474	6197	10,508	0.2457	425	5,759,294,460	*C*	*C*
2023	13,409,879	6515	10,964	0.2492	460	6,012,037,957	*C*	*C*
2024	12,268,619	5836	9,936	0.2287	392	5,539,999,761	*C*	*C*
2025	12,588,836	6005	10,167	0.2231	452	5,654,821,299	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,749,703	4017	5,967	0.0978	313	3,824,718,238	*C*	*C*
2031	8,679,065	3938	5,859	0.0949	314	3,701,224,831	*C*	*C*
2032	8,947,358	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,775,321	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,238,511	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,640,839	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,748,707	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,200,745	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,414,627	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,288,539	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,552,251	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	190,724,082	84,087	135,252	2.699	5,884	82,079,934,163		
per MWh**	971	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1739	0.77	1.23	0.000022	0.05	374

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	971	0.43	0.69	0.00001	0.03	209

80pct CR Version 3

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1503	1903	1613	1661	1876	1885	1669	1855	1679	1534	1759	1778	1540	1705	1619	1540	1616	1627	1580
LRS 3	1613	1650	1863	1352	1876	1825	1625	1835	1637	1604	1710	1546	155	0	0	0	0	0	0	0
Craig 1	672	671	680	685	557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	785	675	758	661	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3473	3191	3169	2730	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1675	1849	1746	1560	1787	1910	1928	2280	2070	1962	2291	2530	2400	2617	2756	2347	221	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	24	11	5	38	29	26	30	23	19	29	27	33	36	35	22	6	48	49	46
Pyramid 2	1	23	11	5	37	30	27	29	24	19	29	25	31	33	35	21	6	49	51	42
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	36	29	27	30	25	18	29	24	31	35	35	20	6	49	51	43
Rifle	0	0	0	0	11	14	4	0	59	1	25	1	1	1	0	0	3	0	1	0
Limon 1	0	0	0	0	25	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	29	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	22	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	22	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	333	382	343	766	550	447	296	148	29	32	31	29	35	79	75	58	65	49	44
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	714	627	413	808	212	535	659	1727	1392	1628	1533	1935	2014	2070	2231	2231	2844	3051	3544
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	730	757	793	810	808	641	632	655	672	654	669
Total	13886	13322	13650	12546	13293	13069	12741	11870	10968	10030	10208	10507	9813	9387	9704	9868	9347	8063	8037	8590
																		Scenario sum		218900

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1655303	2095923	1776784	1829163	2066196	2075993	1838426	2042820	1849376	1690012	1937045	1958357	1696586	1877728	1783033	1696427	1780364	1792538	1740259
LRS 3	1941677	1986209	2242100	1627219	2257199	2196727	1955167	2208491	1970563	1930100	2058133	1860165	187100	0	0	0	0	0	0	0
Craig 1	778917	777981	788170	794713	646235	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	921846	793271	890641	776986	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3629287	3334168	3311884	2852495	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1791116	1977786	1867400	1667992	1911628	2042531	2061667	2437945	2214011	2097899	2450127	2705806	2566815	2798600	2947372	2510197	236330	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	14937	6791	3249	23752	18270	15918	18330	14347	11581	18108	16848	20424	22622	21981	13361	3975	29805	30492	28696
Pyramid 2	570	14037	6531	2892	22679	18269	16581	17966	14848	11406	17637	15694	19350	20198	21289	13145	3505	30198	31456	25918
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14939	6712	2912	22547	18175	16696	18793	15258	11203	17748	15002	19161	21372	21627	12565	3622	30209	31700	26439
Rifle	0	0	0	0	6866	8165	2313	0	35810	628	15072	750	568	747	0	0	1607	59	901	0
Limon 1	342	342	0	0	18768	16689	4603	0	537	0	0	0	0	73	0	0	0	0	200	0
Limon 2	341	341	0	0	21715	17588	6270	0	1251	0	0	206	62	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	16225	15795	3453	0	145	0	0	0	0	143	0	0	0	0	64	0
Knutson 2	342	342	0	292	16624	16600	3731	0	163	0	130	0	0	71	0	0	0	0	356	0
J. M. Shafer	241699	163507	187283	168350	375950	269863	219271	145266	72374	14032	15859	15308	14082	17331	38927	36793	28505	32061	23965	21615
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	457109	401472	264118	413511	108571	274015	337296	884400	712680	833332	784983	990536	1031002	1059940	1142428	1142161	1456149	1561961	1814752
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	219403	227489	238110	243346	242680	192422	189920	196780	201950	196496	200966
Total	13248122	12979028	13393204	12265698	12508020	12677176	12216747	11303247	9791318	8523385	8542638	8887830	7714484	7177841	7592733	7701227	7151550	5364139	5239415	5502009
																		Scenario Sum tons:		189,779,811
																		Scenario lbs/MWh		1734

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	827	1047	888	914	1033	1038	919	1021	924	845	968	979	848	938	891	848	890	896	870
LRS 3	1471	1504	1698	1232	1710	1664	1481	1673	1492	1462	1559	1409	142	0	0	0	0	0	0	0
Craig 1	127	127	128	130	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	131	114	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2271	2087	2073	1785	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	702	775	732	653	749	800	808	955	867	822	960	1060	1006	1096	1155	983	93	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	3	3	3	3	3	2	2	3	3	3	3
Total	6056	6247	6533	5868	5969	6508	6120	5824	4630	3947	3921	4035	2881	2556	2738	2751	2538	1692	1607	1643

Scenario Sum tons: 84,063
Scenario lbs/MWh 0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1751	2218	1880	1935	2186	2197	1945	2162	1957	1788	2050	2072	1795	1987	1887	1795	1884	1897	1841
LRS 3	1944	1989	2245	1629	2260	2199	1958	2211	1973	1933	2061	1862	187	0	0	0	0	0	0	0
Craig 1	931	930	942	950	772	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	264	227	255	222	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3904	3586	3562	3068	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	659	728	687	614	703	752	759	897	815	772	901	996	944	1030	1084	924	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	15	7	3	24	18	16	19	14	12	18	17	21	23	22	14	4	30	31	29
Pyramid 2	1	13	6	3	22	17	16	17	14	11	17	15	18	19	20	12	3	29	30	25
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	7	3	22	18	16	18	15	11	17	15	19	21	21	12	4	30	31	26
Rifle	0	0	0	0	15	18	5	0	78	1	33	2	1	2	0	0	3	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	5	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	125	143	128	286	205	167	111	55	11	12	12	11	13	30	28	22	24	18	16
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	273	283	296	303	302	239	236	245	251	244	250
Total	10257	10486	10930	9924	10083	10319	9618	8906	6848	5853	5833	6003	4462	3955	4186	4112	3839	3176	3096	3074

Scenario Sum tons: 134,957
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0332	0.0421	0.0357	0.0367	0.0415	0.0417	0.0369	0.0410	0.0371	0.0339	0.0389	0.0393	0.0341	0.0377	0.0358	0.0341	0.0357	0.0360	0.0349
LRS 3	0.0406	0.0416	0.0469	0.0340	0.0472	0.0460	0.0409	0.0462	0.0412	0.0404	0.0431	0.0389	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0050	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1460	0.1341	0.1332	0.1148	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0146	0.0161	0.0152	0.0136	0.0156	0.0166	0.0168	0.0198	0.0180	0.0171	0.0199	0.0220	0.0209	0.0228	0.0240	0.0204	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2474	0.2505	0.2302	0.2224	0.2531	0.2324	0.2101	0.1324	0.0955	0.0941	0.0977	0.0652	0.0549	0.0605	0.0598	0.0545	0.0377	0.0360	0.0349

Scenario Sum tons: 2.700
Scenario lbs/MWh 0.000022

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	98	83	85	96	97	86	95	86	79	90	91	79	87	83	79	83	83	81
LRS 3	154	157	177	129	179	174	155	175	156	153	163	147	15	0	0	0	0	0	0	0
Craig 1	15	15	15	16	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	17	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	106	105	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	30	32	32	38	34	33	38	42	40	44	46	39	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	3	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	1	1	1	1	1	3	3	2	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWC0300MWCC	0	0	0	0	0	0	0	0	0	30	31	32	33	33	26	26	27	27	27	27
Total	429	428	460	395	450	463	425	402	329	306	312	312	186	157	164	160	148	122	118	115

Scenario Sum tons: 5,879
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	793,463,646	1,004,673,227	851,694,858	876,802,700	990,423,405	995,119,524	881,242,938	979,218,425	886,491,456	810,101,247	928,515,516	938,731,196	813,252,178	900,081,959	854,690,430	813,175,922	853,410,935	859,246,534	834,186,876
LRS 3	851,853,147	871,390,299	983,655,031	713,894,288	990,279,070	963,749,146	857,771,667	968,910,189	864,525,976	846,774,239	902,944,882	816,092,283	82,084,524	0	0	0	0	0	0	0
Craig 1	330,510,581	330,113,561	334,436,758	337,213,266	274,210,876	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	385,998,568	332,161,126	372,932,085	325,342,089	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,708,716,751	1,569,770,951	1,559,279,216	1,342,992,935	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	914,398,777	1,009,696,979	953,342,939	851,541,691	975,922,486	1,042,750,956	1,052,520,219	1,244,617,109	1,130,294,766	1,071,017,058	1,250,836,072	1,381,365,271	1,310,407,506	1,428,738,432	1,504,689,374	1,281,502,878	120,651,134	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,891,098	1,314,466	628,816	4,597,115	3,536,116	3,080,809	3,547,769	2,776,883	2,241,483	3,504,749	3,260,977	3,953,054	4,378,539	4,254,373	2,586,047	769,289	5,768,715	5,901,767	5,554,102
Pyramid 2	111,000	2,734,545	1,272,178	563,419	4,418,047	3,558,952	3,229,983	3,499,900	2,892,379	2,221,898	3,435,773	3,057,238	3,769,547	3,934,767	4,147,302	2,560,737	682,884	5,882,817	6,127,832	5,049,031
Pyramid 3	37,884	37,884	0	0	0	0	5,766	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,896,057	1,301,272	564,535	4,370,920	3,523,380	3,236,615	3,643,222	2,957,854	2,171,827	3,440,601	2,908,268	3,714,536	4,143,165	4,192,641	2,435,919	702,252	5,856,316	6,145,327	5,125,574
Rifle	0	0	0	0	14,495,223	17,236,191	4,881,955	0	75,598,151	1,324,782	31,819,173	1,583,948	1,199,803	1,576,676	0	0	3,392,545	124,118	1,903,135	0
Limon 1	26,020	26,020	0	0	1,428,286	1,270,084	350,329	0	40,885	0	0	0	0	5,529	0	0	0	0	15,221	0
Limon 2	26,020	26,020	0	0	1,659,184	1,343,841	479,040	0	95,606	0	0	15,716	4,769	21,562	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	453,097	441,095	96,416	0	4,053	0	0	0	0	3,990	0	0	0	0	1,791	0
Knutson 2	9,586	9,586	0	8,179	465,478	464,812	104,482	0	4,557	0	3,647	0	0	1,976	0	0	0	0	9,963	0
J. M. Shafer	171,480,537	116,004,883	132,873,701	119,440,660	266,728,900	191,462,411	155,568,309	103,063,249	51,347,667	9,955,626	11,251,351	10,860,871	9,991,157	12,295,705	27,617,965	26,103,563	20,223,654	22,746,607	17,002,807	15,335,210
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWC0300MWCC	0	0	0	0	0	0	0	0	0	254,168,322	263,535,345	275,840,259	281,906,001	281,134,069	222,912,795	220,014,031	227,961,283	233,949,614	227,632,014	232,809,943
Total	572685057	5762669045	6005107457	5543522205	5593737378	5838902658	5556389500	5092449011	4212956177	3769596165	3735005592	3926922913	3340671623	3065107428	3225897233	3247031866	2982362473	1882342021	1757938157	1732012501

Scenario Sum (Gallons): 81,997,475,457
Scenario gallons/MWh 375

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,523,385	3947	5,853	0.0955	306	3,769,596,165	*C*	*C*
2031	8,542,638	3921	5,833	0.0941	312	3,735,005,592	*C*	*C*
2032	8,887,830	4035	6,003	0.0977	312	3,926,922,913	*C*	*C*
2033	7,714,484	2881	4,462	0.0652	186	3,340,671,623	*C*	*C*
2034	7,177,841	2556	3,955	0.0549	157	3,065,107,428	*C*	*C*
2035	7,592,733	2738	4,186	0.0605	164	3,225,897,233	*C*	*C*
2036	7,701,227	2751	4,112	0.0598	160	3,247,031,866	*C*	*C*
2037	7,151,550	2538	3,839	0.0545	148	2,982,362,473	*C*	*C*
2038	5,364,139	1692	3,176	0.0377	122	1,882,342,021	*C*	*C*
2039	5,239,415	1607	3,096	0.0360	118	1,757,938,157	*C*	*C*
2040	5,502,009	1643	3,074	0.0349	115	1,732,012,501	*C*	*C*
Total	189,779,811	84,063	134,957	2.700	5,879	81,997,475,457		
per MWh*	966	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	1734	0.77	1.23	0.000022	0.05	375

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
Scenario Average	966	0.43	0.69	0.00001	0.03	209

80pct CR Version 4

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1503	1903	1613	1661	1876	1885	1669	1855	1718	1553	1750	1770	1535	1703	1644	1534	1619	1626	1578
LRS 3	1613	1650	1863	1352	1876	1825	1625	1835	1637	1646	1743	1536	155	0	0	0	0	0	0	0
Craig 1	672	671	680	685	557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	785	675	758	661	731	735	376	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3473	3191	3169	2730	3440	3037	2555	721	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1675	1849	1746	1560	1787	1910	1928	2280	2066	1861	2277	2502	2370	2611	2663	2169	220	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	24	11	5	38	29	26	30	23	15	31	28	33	36	37	23	6	49	50	45
Pyramid 2	1	23	11	5	37	30	27	29	24	14	31	25	31	33	35	23	6	53	46	40
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	24	11	5	36	29	27	30	25	14	30	25	30	34	36	22	5	53	47	41
Rifle	0	0	0	0	11	14	4	0	59	2	1	5	2	3	1	2	2	0	1	0
Limon 1	0	0	0	0	25	22	6	0	1	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	29	24	8	0	2	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	22	21	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	22	22	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	333	382	343	766	550	447	296	148	141	34	31	29	36	80	72	62	65	53	39
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	714	627	413	808	212	535	659	1727	1085	1797	1513	1935	1991	2042	2241	2275	2822	3003	3484
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1163	775	787	785	809	639	630	652	668	661	672
Total	13886	13322	13650	12546	13293	13069	12741	11870	10968	10334	10330	10454	9751	9332	9672	9811	9206	8048	7989	8521
																		Scenario sum		218794

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1655303	2095923	1776784	1829163	2066196	2075993	1838426	2042820	1892262	1710673	1927315	1950079	1690960	1876386	1810325	1689619	1783581	1791176	1737849
LRS 3	1941677	1986209	2242100	1627219	2257199	2196727	1955167	2208491	1970563	1981090	2097947	1849016	185956	0	0	0	0	0	0	0
Craig 1	778917	777981	788170	794713	646235	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	921846	793271	890641	776986	859144	863342	442244	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3629287	3334168	3311884	2852495	3594365	3173784	2669618	753855	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1791116	1977786	1867400	1667992	1911628	2042531	2061667	2437945	2209991	1990773	2435291	2675991	2534764	2792957	2848025	2319655	235394	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	14937	6791	3249	23752	18270	15918	18330	14347	9395	19252	17128	20236	22582	23095	14183	3825	30543	30768	27984
Pyramid 2	570	14037	6531	2892	22679	18269	16581	17966	14848	8734	18967	15558	18854	20029	21529	13958	3437	32808	28604	24777
Pyramid 3	197	197	0	0	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	14939	6712	2912	22547	18175	16696	18793	15258	8875	18477	15347	18265	21161	22128	13473	3244	32599	29336	25612
Rifle	0	0	0	0	6866	8165	2313	0	35810	1434	510	2914	1444	2036	745	1254	1097	59	862	0
Limon 1	342	342	0	0	18768	16689	4603	0	537	0	0	0	0	149	0	0	0	0	0	0
Limon 2	341	341	0	0	21715	17588	6270	0	1251	0	132	202	0	282	0	0	0	0	0	0
Knutson 1	343	343	0	293	16225	15795	3453	0	145	0	0	0	0	67	0	0	0	0	0	0
Knutson 2	342	342	0	292	16624	16600	3731	0	163	0	0	0	0	70	0	0	0	0	0	0
J. M. Shafer	241699	163507	187283	168350	375950	269863	219271	145266	72374	68983	16746	15391	14364	17714	39096	35332	30508	31854	25959	19055
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	457109	401472	264118	413511	108571	274015	337296	884400	555345	920261	774789	990526	1019439	1045601	1147469	1164610	1445030	1537299	1783770
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	436795	290949	295430	294613	303733	239899	236663	244864	250816	248046	252290
Total	13248122	12979028	13393204	12265698	12508020	12677176	12216747	11303247	9791318	8721869	8635907	8901974	7726018	7190904	7621654	7683293	7025629	5409698	5261336	5514701
																		Scenario Sum tons:		190,075,543
																		Scenario lbs/MWh		1737

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	827	1047	888	914	1033	1038	919	1021	946	855	963	975	845	938	905	844	891	895	869
LRS 3	1471	1504	1698	1232	1710	1664	1481	1673	1492	1500	1589	1400	141	0	0	0	0	0	0	0
Craig 1	127	127	128	130	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	135	116	131	114	126	127	65	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2271	2087	2073	1785	2249	1986	1671	472	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	702	775	732	653	749	800	808	955	866	780	954	1048	993	1094	1116	909	92	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	3	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	5	3	3	3	3	2	2	3	3	3	3
Total	6056	6247	6533	5868	5969	6508	6120	5824	4630	4008	3920	4016	2864	2540	2735	2726	2460	1693	1606	1641
																		Scenario Sum tons:		83,964
																		Scenario lbs/MWh		0.77

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1751	2218	1880	1935	2186	2197	1945	2162	2002	1810	2039	2063	1789	1985	1916	1788	1887	1895	1839
LRS 3	1944	1989	2245	1629	2260	2199	1958	2211	1973	1984	2101	1851	186	0	0	0	0	0	0	0
Craig 1	931	930	942	950	772	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	264	227	255	222	246	247	126	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3904	3586	3562	3068	3866	3414	2871	811	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	659	728	687	614	703	752	759	897	813	732	896	985	933	1028	1048	853	87	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	15	7	3	24	18	16	19	14	9	19	17	20	23	23	14	4	31	31	28
Pyramid 2	1	13	6	3	22	17	16	17	14	8	18	15	18	19	20	13	3	31	27	24
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	15	7	3	22	18	16	18	15	9	18	15	18	21	22	13	3	32	29	25
Rifle	0	0	0	0	15	18	5	0	78	3	1	6	3	4	2	3	2	0	2	0
Limon 1	0	0	0	0	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	5	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	125	143	128	286	205	167	111	55	53	13	12	11	13	30	27	23	24	20	15
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	434	289	294	293	302	239	235	244	249	247	251
Total	10257	10486	10930	9924	10083	10319	9618	8906	6848	6146	5834	5979	4432	3940	4186	4108	3760	3183	3093	3068
																		Scenario Sum tons:		135,098
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0332	0.0421	0.0357	0.0367	0.0415	0.0417	0.0369	0.0410	0.0380	0.0343	0.0387	0.0391	0.0339	0.0377	0.0363	0.0339	0.0358	0.0360	0.0349
LRS 3	0.0406	0.0416	0.0469	0.0340	0.0472	0.0460	0.0409	0.0462	0.0412	0.0414	0.0439	0.0387	0.0039	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0050	0.0055	0.0055	0.0028	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1460	0.1341	0.1332	0.1148	0.1446	0.1277	0.1074	0.0303	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0146	0.0161	0.0152	0.0136	0.0156	0.0166	0.0168	0.0198	0.0180	0.0162	0.0198	0.0218	0.0206	0.0227	0.0232	0.0189	0.0019	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2474	0.2505	0.2302	0.2224	0.2531	0.2324	0.2101	0.1324	0.0974	0.0944	0.0972	0.0648	0.0546	0.0604	0.0595	0.0528	0.0377	0.0360	0.0349
																		Scenario Sum tons:		2.699
																		Scenario lbs/MWh		0.000022

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	98	83	85	96	97	86	95	88	80	90	91	79	87	84	79	83	83	81
LRS 3	154	157	177	129	179	174	155	175	156	157	166	146	15	0	0	0	0	0	0	0
Craig 1	15	15	15	16	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	17	18	19	10	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	106	105	90	114	101	85	24	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	26	30	32	32	38	34	31	38	42	39	43	44	36	4	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	2
Pyramid 2	0	1	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	2	2	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	1	1	1	1	1	0	1	1	1	1	1	1	0	2	2	1
Rifle	0	0	0	0	1	2	0	0	7	0	0	1	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	14	16	14	31	22	18	12	6	6	1	1	1	1	3	3	3	3	2	2
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	47	31	32	32	33	26	26	26	27	27	27
Total	429	428	460	395	450	463	425	402	329	334	313	310	184	157	164	160	145	122	118	114

Scenario Sum tons: 5,901
Scenario lbs/MWh 0.05

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	793,463,646	1,004,673,227	851,694,858	876,802,700	990,423,405	995,119,524	881,242,938	979,218,427	907,048,653	820,005,082	923,851,239	934,763,209	810,555,277	899,438,908	867,772,875	809,912,849	854,952,926	858,593,546	833,031,544
LRS 3	851,853,147	871,390,299	983,655,033	713,894,288	990,279,070	963,749,146	857,771,661	968,910,189	864,525,976	869,144,662	920,411,964	811,201,199	81,582,767	0	0	0	0	0	0	0
Craig 1	330,510,581	330,113,561	334,436,756	337,213,266	274,210,876	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	385,998,568	332,161,126	372,932,085	325,342,089	359,743,814	361,501,708	185,177,873	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,708,716,753	1,569,770,955	1,559,279,216	1,342,992,930	1,692,275,160	1,494,260,177	1,256,891,887	354,924,866	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	914,398,777	1,009,696,979	953,342,938	851,541,691	975,922,486	1,042,750,954	1,052,520,219	1,244,617,109	1,128,242,134	1,016,327,114	1,243,261,955	1,366,143,974	1,294,045,247	1,425,857,543	1,453,970,787	1,184,227,703	120,173,346	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,891,098	1,314,466	628,816	4,597,115	3,536,116	3,080,809	3,547,768	2,776,883	1,818,403	3,726,273	3,315,087	3,916,634	4,370,709	4,470,007	2,745,149	740,323	5,911,509	5,955,108	5,416,257
Pyramid 2	111,000	2,734,545	1,272,178	563,419	4,418,043	3,558,952	3,229,983	3,499,900	2,892,375	1,701,452	3,694,879	3,030,876	3,672,879	3,901,714	4,194,047	2,719,067	669,536	6,391,168	5,572,268	4,826,735
Pyramid 3	37,884	37,884	0	0	0	5,766	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,896,057	1,301,272	564,539	4,370,920	3,523,288	3,236,615	3,643,222	2,957,854	1,720,613	3,581,947	2,975,277	3,540,839	4,102,223	4,289,677	2,611,986	628,847	6,319,652	5,687,088	4,965,170
Rifle	0	0	0	0	14,495,223	17,236,193	4,881,955	0	75,598,151	3,027,174	1,075,685	6,152,321	3,047,736	4,298,855	1,572,155	2,647,840	2,316,860	124,118	1,820,350	0
Limon 1	26,020	26,020	0	0	1,428,288	1,270,084	350,325	0	40,885	0	0	0	0	11,314	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	1,659,184	1,343,843	479,040	0	95,606	0	10,083	15,431	0	21,510	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	8,179	453,097	441,099	96,416	0	4,053	0	0	0	0	1,858	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	8,179	465,478	464,812	104,482	0	4,557	0	0	0	0	1,955	0	0	0	0	0	0
J. M. Shafer	171,480,537	116,004,883	132,873,709	119,440,666	266,728,900	191,462,411	155,568,309	103,063,249	51,347,661	48,941,821	11,881,044	10,919,771	10,190,994	12,568,039	27,737,735	25,067,570	21,644,794	22,599,781	18,417,337	13,519,035
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	404,806,141	269,641,053	273,794,344	273,037,187	281,488,988	222,329,541	219,330,802	226,930,871	232,447,176	229,880,488	233,813,203
Total	5726854057	5762669045	6005107457	5543522205	5593737378	5838902658	5556389500	5092449011	4212956177	4000402823	3684306893	3912469252	3313847970	3049319450	3223841371	3210817842	2881023549	1882871435	1759877993	1729523811

Scenario Sum (Gallons): 81,980,889,875
Scenario gallons/MWh 375

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RPS CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,979,028	6247	10,486	0.2474	428	5,762,669,045	*C*	*C*
2023	13,393,204	6533	10,930	0.2505	460	6,005,107,457	*C*	*C*
2024	12,265,698	5868	9,924	0.2302	395	5,543,522,205	*C*	*C*
2025	12,508,020	5969	10,083	0.2224	450	5,593,737,378	*C*	*C*
2026	12,677,176	6508	10,319	0.2531	463	5,838,902,658	*C*	*C*
2027	12,216,747	6120	9,618	0.2324	425	5,556,389,500	*C*	*C*
2028	11,303,247	5824	8,906	0.2101	402	5,092,449,011	*C*	*C*
2029	9,791,318	4630	6,848	0.1324	329	4,212,956,177	*C*	*C*
2030	8,721,869	4008	6,146	0.0974	334	4,000,402,823	*C*	*C*
2031	8,635,907	3920	5,834	0.0944	313	3,684,306,893	*C*	*C*
2032	8,901,974	4016	5,979	0.0972	310	3,912,469,252	*C*	*C*
2033	7,726,018	2864	4,432	0.0648	184	3,313,847,970	*C*	*C*
2034	7,190,904	2540	3,940	0.0546	157	3,049,319,450	*C*	*C*
2035	7,621,654	2735	4,186	0.0604	164	3,223,841,371	*C*	*C*
2036	7,683,293	2726	4,108	0.0595	160	3,210,817,842	*C*	*C*
2037	7,025,629	2460	3,760	0.0528	145	2,881,023,549	*C*	*C*
2038	5,409,698	1693	3,183	0.0377	122	1,882,871,435	*C*	*C*
2039	5,261,336	1606	3,093	0.0360	118	1,759,877,993	*C*	*C*
2040	5,514,701	1641	3,068	0.0349	114	1,729,523,811	*C*	*C*
Total	190,075,543	83,964	135,098	2.699	5,901	81,980,889,875		
per MWh**	968	0.43	0.69	0.00001	0.03	209		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1737	0.77	1.23	0.000022	0.05	375

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	968	0.43	0.69	0.00001	0.03	209

Low Load 80pct Version 1

2018 ERP Emissions and Water Usage Rates by Unit

UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1506	1862	1577	1658	1869	1892	1694	1888	1771	1553	1744	1761	1566	1764	1735	1609	1739	1789	1661
LRS 3	1613	1508	1792	1246	1880	1804	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	709	655	638	560	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	740	621	672	600	728	733	343	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	2976	2465	2375	2581	3334	2982	2587	690	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1398	1569	1487	1171	1419	1884	1877	2078	1895	1762	2024	2024	1887	2139	2007	1677	1990	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	7	0	0	20	19	20	22	17	12	16	13	14	19	16	12	2	1	31	21
Pyramid 2	1	5	0	0	21	20	22	22	17	12	16	13	13	19	17	12	2	0	28	20
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	5	0	0	21	20	22	22	17	13	15	13	13	18	17	12	2	1	28	20
Rifle	0	0	0	0	0	8	1	1	13	0	0	0	0	3	0	0	0	1	0	0
Limon 1	0	0	0	0	3	6	7	0	0	0	0	0	0	1	0	0	0	0	0	0
Limon 2	0	0	0	0	3	7	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	3	6	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	3	7	5	0	0	0	0	0	0	1	0	0	0	0	0	0
J. M. Shafer	493	133	162	94	610	462	519	304	129	36	46	37	43	47	62	43	44	45	32	29
Basin Nebraska	664	484	471	463	458	455	453	452	452	453	454	455	457	459	461	463	465	467	469	472
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	395	301	154	595	96	425	878	1774	1204	1171	895	1086	1169	987	896	1020	819	1793	1990
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	602	633	599	644	649	618	611	628	624	621	627
Total	13886	11631	11661	10468	11949	12022	10738	9965	8839	7760	7428	7556	7816	7599	7843	7554	7211	7448	6554	6603
																		Scenario sum		182532

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1658380	2050571	1737226	1825881	2059237	2083538	1865405	2079504	1950624	1710514	1920903	1939720	1724678	1943120	1911451	1771967	1914993	1970616	1829077
LRS 3	1941677	1815274	2156102	1499346	2262993	2171577	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	821747	759839	739943	649679	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	869384	729808	789217	704941	855834	860878	403465	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3110432	2576250	2481839	2697159	3483695	3115946	2703790	721067	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1495426	1678378	1590274	1252619	1517119	2014514	2007006	2222936	2026212	1884056	2164387	2164774	2018596	2287981	2146789	1793711	2128220	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	84	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	92	0	0	0	0	0	0
Pyramid 1	1055	4214	0	0	12510	11958	12652	13332	10721	7748	10134	8189	8485	11903	9728	7419	1300	363	19046	13329
Pyramid 2	570	3081	0	0	12830	12442	13389	13506	10671	7633	9764	7959	7999	11751	10543	7154	1343	245	17126	12535
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	2970	0	0	12922	12245	13348	13803	10360	7953	9530	8129	7799	11425	10625	7374	1136	429	17253	12362
Rifle	0	0	0	0	0	4801	431	588	7566	59	0	0	0	1529	0	0	216	901	0	0
Limon 1	342	342	0	0	2526	4638	5396	0	130	0	0	0	0	484	0	0	0	0	0	0
Limon 2	341	341	0	0	2224	4866	6167	0	130	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	2062	4437	3646	0	0	0	0	0	0	82	0	0	0	0	0	0
Knutson 2	342	342	0	0	2616	5468	3531	0	275	0	0	0	0	484	0	0	0	0	0	0
J. M. Shafer	241699	65459	79337	46043	299077	226692	254627	149284	63499	17802	22392	18382	20893	22974	30226	21327	21428	21836	15898	14377
Basin Nebraska	411673	300213	292197	287169	283818	281800	280719	280371	280308	280638	281392	282393	283349	284484	285733	287095	288349	289685	291061	292507
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	252721	192812	98471	304454	49083	217704	449752	908187	616403	599739	458216	555785	598303	505478	458554	522146	419131	918222	1019117
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	225980	237704	224846	241829	243569	231924	229495	235753	234203	233218	235501
Total	13248122	11528749	11643176	10397412	11438864	11816446	9997041	9010857	7425906	6251603	5875778	6203957	6341186	6040991	6425910	6187211	5747902	6120559	4592993	4539358
																		Scenario Sum tons:		160,834,022
																		Scenario lbs/MWh		1762

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	829	1025	868	913	1029	1041	932	1039	975	855	960	969	862	971	955	886	957	985	914
LRS 3	1471	1375	1633	1136	1714	1645	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	134	124	121	106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	128	107	116	103	126	126	59	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	1947	1612	1553	1688	2180	1950	1692	451	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	586	658	623	491	594	789	786	871	794	738	848	848	791	896	841	703	834	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	0	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	250	243	239	236	235	234	234	234	234	234	235	236	237	238	239	240	241	243	244
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	2	2	2	3	3	2	2	2	2	2	2
Total	6056	5574	5728	4982	5579	6137	4469	4031	2921	2331	2156	2371	2382	2218	2434	2364	2157	2360	1556	1486
																		Scenario Sum tons:		69,290
																		Scenario lbs/MWh		0.76

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1755	2170	1838	1932	2179	2205	1974	2200	2064	1810	2033	2052	1825	2056	2023	1875	2026	2085	1935
LRS 3	1944	1818	2159	1501	2266	2174	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	982	908	884	776	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	249	209	226	202	245	246	115	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3346	2771	2669	2901	3747	3352	2908	776	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	550	618	585	461	558	741	738	818	746	693	796	796	743	842	790	660	783	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
Pyramid 1	1	4	0	0	13	12	13	13	11	8	10	8	9	12	10	7	1	0	19	13
Pyramid 2	1	3	0	0	12	12	13	13	10	7	9	8	8	11	10	7	1	0	16	12
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	3	0	0	13	12	13	14	10	8	9	8	8	11	10	7	1	0	17	12
Rifle	0	0	0	0	0	10	1	1	16	0	0	0	0	3	0	0	0	2	0	0
Limon 1	0	0	0	0	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	50	60	35	228	173	194	114	48	14	17	14	16	17	23	16	16	17	12	11
Basin Nebraska	245	179	174	171	169	168	167	167	167	167	167	168	169	169	170	171	172	172	173	174
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	225	236	224	241	242	231	228	234	233	232	234
Total	10257	9507	9637	8479	9543	9864	7518	6627	4626	3807	3522	3828	3867	3605	3921	3819	3531	3804	3124	2962
																		Scenario Sum tons:		115,849
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0333	0.0412	0.0349	0.0367	0.0413	0.0418	0.0374	0.0417	0.0392	0.0343	0.0386	0.0389	0.0346	0.0390	0.0384	0.0356	0.0384	0.0396	0.0367
LRS 3	0.0406	0.0380	0.0451	0.0314	0.0473	0.0454	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0065	0.0060	0.0058	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0056	0.0047	0.0051	0.0045	0.0055	0.0055	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1251	0.1036	0.0998	0.1085	0.1402	0.1254	0.1088	0.0290	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0122	0.0137	0.0129	0.0102	0.0123	0.0164	0.0163	0.0181	0.0165	0.0153	0.0176	0.0176	0.0164	0.0186	0.0175	0.0146	0.0173	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2207	0.2143	0.1899	0.2124	0.2448	0.1891	0.1651	0.0888	0.0556	0.0497	0.0562	0.0566	0.0510	0.0576	0.0558	0.0502	0.0558	0.0396	0.0367
																		Scenario Sum tons:		2.320
																		Scenario lbs/MWh		0.000023

PM

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	95	81	85	96	97	87	97	91	80	89	90	80	90	89	82	89	92	85
LRS 3	154	144	171	119	179	172	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	16	15	14	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	19	16	17	15	18	19	9	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	99	82	79	85	110	99	86	23	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	23	26	25	19	24	31	31	35	32	29	34	34	31	36	33	28	33	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Pyramid 2	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	1	1	1	1	1	0	1	0	0	1	1	0	0	0	1	1
Rifle	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	5	7	4	25	19	21	12	5	1	2	2	2	2	3	2	2	2	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	24	26	24	26	26	25	25	25	25	25	25
Total	429	383	411	338	424	443	270	227	163	150	138	150	153	142	155	150	138	150	121	114

Scenario Sum tons: 4,651
Scenario lbs/MWh 0.05

Water

Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	794,938,201	982,933,504	832,733,045	875,229,422	987,087,923	998,736,325	894,174,911	996,802,683	935,024,384	819,928,731	920,777,869	929,797,726	826,717,939	931,427,348	916,247,250	849,385,875	917,944,819	944,607,636	876,761,459
LRS 3	851,853,147	796,397,538	945,925,796	657,793,523	992,821,273	952,715,063	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	348,684,482	322,415,618	313,973,249	275,672,393	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	364,031,440	305,587,638	330,463,619	295,175,117	358,357,617	360,469,841	168,940,401	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,464,432,976	1,212,933,033	1,168,482,895	1,269,858,433	1,640,170,498	1,467,029,045	1,272,980,772	339,488,164	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	763,443,264	856,843,597	811,864,785	639,485,782	774,518,143	1,028,447,516	1,024,614,749	1,134,850,694	1,034,419,489	961,846,366	1,104,960,752	1,105,157,994	1,030,531,670	1,168,057,511	1,095,976,326	915,723,538	1,086,496,494	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	781	0	0	0	0	0	0
Pyramid 1	204,150	815,548	0	0	2,421,197	2,314,492	2,448,833	2,580,403	2,074,951	1,499,541	1,961,461	1,585,040	1,642,337	2,303,751	1,882,812	1,435,868	251,550	70,321	3,686,400	2,579,847
Pyramid 2	111,000	600,115	0	0	2,499,409	2,423,773	2,608,333	2,631,133	2,078,803	1,486,929	1,901,996	1,550,469	1,558,334	2,289,251	2,053,841	1,393,669	261,675	47,747	3,336,206	2,441,803
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	575,859	0	0	2,505,123	2,373,884	2,587,700	2,675,955	2,008,393	1,541,689	1,847,579	1,575,855	1,511,985	2,214,827	2,059,813	1,429,479	220,318	83,052	3,344,775	2,396,602
Rifle	0	0	0	0	0	10,136,263	910,195	1,241,175	15,972,383	124,118	0	0	0	3,227,054	0	0	455,098	1,903,135	0	0
Limon 1	26,020	26,020	0	0	192,229	352,932	410,643	0	9,899	0	0	0	0	36,808	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	169,939	371,823	471,203	0	9,899	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	57,570	123,910	101,811	0	0	0	0	0	0	2,288	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	0	73,253	153,092	98,879	0	7,699	0	0	0	0	13,559	0	0	0	0	0	0
J. M. Shafer	171,480,537	46,441,857	56,287,721	32,666,880	212,189,212	160,833,190	180,652,985	105,913,982	45,051,470	12,629,824	15,886,401	13,041,344	14,823,053	16,299,570	21,444,459	15,131,000	15,202,405	15,492,271	11,279,148	10,199,961
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	209,430,235	220,295,988	208,378,929	224,118,559	225,731,271	214,938,475	212,687,814	218,487,188	217,051,002	216,137,909	218,254,276
Total	5726854057	5214427141	5316878666	4781929764	5202302115	5525884368	4678925102	4109705244	3172306802	2830107973	2657620282	2885822022	2912561750	2743321204	2975816027	2878253164	2633939407	2873040605	1816343814	1746585719

Scenario Sum (Gallons): 72,682,620,234
Scenario gallons/MWh 398

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	11,528,749	5574	9,507	0.2207	383	5,214,422,141	*C*	*C*
2023	11,643,176	5728	9,637	0.2143	411	5,316,878,666	*C*	*C*
2024	10,397,412	4982	8,479	0.1899	338	4,781,929,764	*C*	*C*
2025	11,438,864	5579	9,543	0.2124	424	5,202,302,115	*C*	*C*
2026	11,816,446	6137	9,864	0.2448	443	5,525,884,368	*C*	*C*
2027	9,997,041	4469	7,518	0.1891	270	4,678,925,102	*C*	*C*
2028	9,010,857	4031	6,627	0.1651	227	4,109,705,244	*C*	*C*
2029	7,425,906	2921	4,626	0.0888	163	3,172,306,802	*C*	*C*
2030	6,251,603	2331	3,807	0.0556	150	2,830,107,973	*C*	*C*
2031	5,875,778	2156	3,522	0.0497	138	2,657,620,281	*C*	*C*
2032	6,203,957	2371	3,828	0.0562	150	2,885,822,021	*C*	*C*
2033	6,341,186	2382	3,867	0.0566	153	2,912,561,758	*C*	*C*
2034	6,040,991	2218	3,605	0.0510	142	2,743,321,204	*C*	*C*
2035	6,425,910	2434	3,921	0.0576	155	2,975,816,027	*C*	*C*
2036	6,187,211	2364	3,819	0.0558	150	2,878,253,164	*C*	*C*
2037	5,747,902	2157	3,531	0.0502	138	2,633,939,407	*C*	*C*
2038	6,120,559	2360	3,804	0.0558	150	2,873,040,605	*C*	*C*
2039	4,592,993	1556	3,124	0.0396	121	1,816,343,814	*C*	*C*
2040	4,539,358	1486	2,962	0.0367	114	1,746,585,719	*C*	*C*
Total	**160,834,022**	**69,290**	**115,849**	**2.320**	**4,651**	**72,682,620,234**		
per MWh**	**975**	**0.42**	**0.70**	**0.00001**	**0.03**	**220**		

TS Thermal Gen Emissions & Water per TS Thermal Gen	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)***	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
:enario Averag	1762	0.76	1.27	#######	0.05	398

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	**CO2 (lbs/net MWH)**	**SO2 (lbs/net MWH)**	**NOx (lbs/net MWH**	**Hg (lbs/gross MWh)**	**PM (lbs gross MWh)**	**Water (gallons/net MWH**
:enario Averag	975	0.42	0.70	0.00001	0.03	220

Low Load 80pct Version 2

2018 ERP Emissions and Water Usage Rates by Unit

UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1506	1862	1577	1656	1868	1890	1693	1882	1764	1546	1735	1756	1568	1779	1733	1611	1733	1798	1664
LRS 3	1613	1508	1792	1246	1861	1802	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	709	655	638	542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	740	621	672	591	729	732	341	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	2976	2465	2375	2601	3334	2998	2592	743	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1398	1569	1487	1220	1526	1884	1878	2074	1906	1761	2015	2101	1885	2262	2181	1689	1915	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	7	0	0	20	21	20	21	18	13	19	16	18	20	18	13	2	1	32	23
Pyramid 2	1	5	0	0	20	21	21	22	17	14	17	15	16	19	18	14	2	0	30	21
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	5	0	0	20	20	21	22	17	13	18	15	16	19	18	13	2	0	30	21
Rifle	0	0	0	0	0	8	1	1	29	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	9	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	9	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	8	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	8	5	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	133	162	94	620	487	507	301	142	49	57	46	55	49	62	46	52	47	30	26
Basin Nebraska	664	484	471	463	458	455	453	452	452	453	454	455	457	459	461	463	465	467	469	472
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	395	301	154	578	82	434	915	1779	1283	1281	1002	1198	1275	1076	992	1184	1016	2030	2263
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	1396	395	301	154	578	82	0	0	0	612	638	630	643	662	624	621	629	642	643	637
Total	15282	12026	11962	10622	12529	12231	10748	9999	8916	7869	7553	7691	8023	7718	8081	7839	7399	7585	6824	6889
																		Scenario sum		187788

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1658380	2050571	1737226	1823746	2058101	2081416	1864626	2073178	1943105	1703070	1911589	1933798	1727444	1959800	1908373	1774804	1909052	1980363	1832797
LRS 3	1941677	1815274	2156102	1499346	2239400	2168638	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	821747	759839	739943	628318	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	869384	729808	789217	694791	856872	859923	400867	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3110432	2576250	2481839	2718037	3483529	3133017	2708189	776184	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1495426	1678378	1590274	1305025	1632001	2014893	2008145	2217763	2038546	1883133	2154655	2246553	2016216	2419439	2332682	1806526	2048364	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	4214	0	0	12206	13271	12582	12982	10986	8219	11917	9630	11264	12109	10854	8152	1399	378	19796	13994
Pyramid 2	570	3081	0	0	12450	12779	13235	13661	10454	8476	10705	9249	9933	11707	11116	8350	1382	267	18255	13194
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	2970	0	0	12398	12568	13136	13764	10745	8216	10896	9052	9936	11797	11268	8222	1166	218	18361	13028
Rifle	0	0	0	0	0	4605	372	588	17211	59	59	0	59	59	0	0	0	59	0	0
Limon 1	342	342	0	0	676	6587	5730	0	197	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	674	6878	6319	0	278	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	394	6342	2445	0	198	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	342	342	0	0	677	5730	4093	0	323	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	65459	79337	46043	304138	239066	248855	147484	69743	23886	28072	22640	27119	23920	30301	22657	25549	23093	14513	12791
Basin Nebraska	411673	300213	292197	287169	283818	281800	280719	280371	280308	280638	281392	282393	283349	284484	285733	287095	288349	289685	291061	292507
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	252721	192812	98471	295760	41882	222205	468362	910869	656846	655690	512993	613551	652870	551154	507888	606138	520012	1039616	1158421
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	524320	148276	113126	57775	216910	30716	0	0	0	229863	239508	236586	241574	248569	234360	233347	236318	241240	241569	239221
Total	13772442	11677025	11756302	10455187	11659972	11971919	10009492	9029592	7488990	6308408	5934993	6259339	6487689	6099728	6624580	6427319	5852185	6142921	4734087	4686507
																		Scenario Sum tons:		163,378,677
																		Scenario lbs/MWh		1740

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	829	1025	868	911	1029	1040	932	1036	971	851	955	966	863	979	954	887	954	990	916
LRS 3	1471	1375	1633	1136	1696	1642	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	134	124	121	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	128	107	116	102	126	126	59	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	1947	1612	1553	1701	2180	1961	1695	486	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	586	658	623	511	639	789	787	869	799	738	844	880	790	948	914	708	802	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	0	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	250	243	239	236	235	234	234	234	234	234	235	236	237	238	239	240	241	243	244
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	5	2	1	1	2	0	0	0	0	2	2	2	3	3	2	2	2	3	3	2
Total	6061	5575	5729	4982	5591	6179	4478	4033	2951	2332	2152	2363	2411	2219	2494	2435	2163	2326	1561	1488
																		Scenario Sum tons:		69,524
																		Scenario lbs/MWh		0.74

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1755	2170	1838	1930	2178	2202	1973	2194	2056	1802	2023	2046	1828	2074	2019	1878	2020	2095	1939
LRS 3	1944	1818	2159	1501	2242	2171	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	982	908	884	751	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	249	209	226	199	245	246	115	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3346	2771	2669	2924	3747	3370	2913	835	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	550	618	585	480	600	741	739	816	750	693	793	827	742	890	858	665	754	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	4	0	0	12	13	13	13	11	8	12	10	11	12	11	8	1	0	20	14
Pyramid 2	1	3	0	0	12	12	13	13	10	8	10	9	9	11	11	8	1	0	17	13
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	3	0	0	12	12	13	14	11	8	11	9	10	12	11	8	1	0	18	13
Rifle	0	0	0	0	0	10	1	1	37	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	50	60	35	232	182	189	112	53	18	21	17	21	18	23	17	19	18	11	10
Basin Nebraska	245	179	174	171	169	168	167	167	167	167	167	168	169	169	170	171	172	172	173	174
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	522	147	113	57	216	31	0	0	0	229	238	235	240	247	233	232	235	240	240	238
Total	10778	9655	9750	8537	9748	9945	7529	6629	4703	3814	3524	3833	3902	3609	3992	3891	3542	3774	3145	2970
																		Scenario Sum tons:		117,270
																		Scenario lbs/MWh		1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0333	0.0412	0.0349	0.0366	0.0413	0.0418	0.0374	0.0416	0.0390	0.0342	0.0384	0.0388	0.0347	0.0393	0.0383	0.0356	0.0383	0.0398	0.0368
LRS 3	0.0406	0.0380	0.0451	0.0314	0.0469	0.0454	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0065	0.0060	0.0058	0.0050	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0056	0.0047	0.0051	0.0045	0.0055	0.0055	0.0026	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1251	0.1036	0.0998	0.1094	0.1401	0.1260	0.1090	0.0312	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0122	0.0137	0.0129	0.0106	0.0133	0.0164	0.0163	0.0180	0.0166	0.0153	0.0175	0.0183	0.0164	0.0197	0.0190	0.0147	0.0167	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2207	0.2143	0.1899	0.2129	0.2456	0.1897	0.1653	0.0909	0.0556	0.0495	0.0559	0.0571	0.0511	0.0590	0.0573	0.0503	0.0550	0.0398	0.0368
																		Scenario Sum tons:		2.327
																		Scenario lbs/MWh		0.000023

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	77	95	81	85	96	97	87	96	90	79	89	90	80	91	89	83	89	92	85
LRS 3	154	144	171	119	177	172	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	16	15	14	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	19	16	17	15	18	19	9	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	99	82	79	86	110	99	86	25	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	23	26	25	20	25	31	31	35	32	29	34	35	31	38	36	28	32	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	1	1	1	1	1	0	1	1	1	1	1	0	0	0	1	1
Pyramid 2	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	0	0	0	1	1
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	1	1	1	1	1	0	1	0	1	1	1	0	0	0	1	1
Rifle	0	0	0	0	0	1	0	0	3	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
z	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	5	7	4	25	20	21	12	6	2	2	2	2	2	3	2	2	2	1	1
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	57	16	12	6	23	3	0	0	0	25	26	26	26	27	25	25	26	26	26	26
Total	486	400	423	344	447	449	270	227	167	150	139	152	155	143	159	154	139	149	123	115

Scenario Sum tons: 4,788
Scenario lbs/MWh 0.05

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	794,938,201	982,933,504	832,733,045	874,206,004	986,542,989	997,719,209	893,801,699	993,770,128	931,420,294	816,360,307	916,313,408	926,959,217	828,044,204	939,423,189	914,771,427	850,745,881	915,096,966	949,279,813	878,544,410
LRS 3	851,853,147	796,397,538	945,925,790	657,793,521	982,470,672	951,425,633	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	348,684,482	322,415,618	313,973,249	266,608,545	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	364,031,440	305,587,638	330,463,619	290,925,408	358,792,540	360,069,796	167,852,207	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,464,432,976	1,212,933,033	1,168,482,895	1,279,688,033	1,640,092,183	1,475,066,259	1,275,051,685	365,437,917	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	763,443,264	856,843,597	811,864,789	666,240,084	833,167,261	1,028,640,904	1,025,196,169	1,132,209,931	1,040,716,419	961,374,961	1,099,992,034	1,146,907,697	1,029,316,247	1,235,169,497	1,190,878,524	922,265,659	1,045,728,826	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	815,548	0	0	2,362,365	2,568,533	2,435,230	2,512,648	2,126,353	1,590,852	2,306,426	1,863,796	2,180,035	2,343,759	2,100,830	1,577,717	270,870	73,200	3,831,450	2,708,497
Pyramid 2	111,000	600,115	0	0	2,425,375	2,489,456	2,578,274	2,661,142	2,036,572	1,651,152	2,085,377	1,801,798	1,934,931	2,280,495	2,165,480	1,626,580	269,214	52,061	3,556,116	2,570,356
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	575,859	0	0	2,403,495	2,436,460	2,546,494	2,668,285	2,082,985	1,592,808	2,112,320	1,754,828	1,926,235	2,287,005	2,184,402	1,593,986	226,106	42,244	3,559,565	2,525,668
Rifle	0	0	0	0	0	9,722,538	786,078	1,241,175	36,333,300	124,118	124,118	0	124,118	124,118	0	0	0	124,118	0	0
Limon 1	26,020	26,020	0	0	51,469	501,269	436,064	0	15,029	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	51,469	525,565	482,811	0	21,233	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	10,993	177,104	68,269	0	5,537	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	9,586	9,586	0	0	18,962	160,451	114,593	0	9,051	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	46,441,857	56,287,721	32,666,880	215,780,185	169,612,757	176,557,901	104,637,098	49,481,068	16,946,719	19,916,207	16,062,536	19,240,547	16,970,766	21,498,284	16,075,026	18,126,233	16,383,737	10,296,747	9,075,218
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	485,920,844	137,417,022	104,841,265	53,543,733	201,024,523	28,466,550	0	0	0	213,028,756	221,967,708	219,259,037	223,882,351	230,365,029	217,196,649	216,257,797	219,011,342	223,572,905	223,877,650	221,701,696
Total	6212774902	5351839163	5421719931	4835473497	5418219347	5620633053	4681453646	4109573873	3217480869	2841022883	2660199189	2890999203	2957106895	2745683389	3053690095	2976732821	2644867071	2835025820	1828353105	1751077609

Scenario Sum (Gallons): 74,053,926,362
Scenario gallons/MWh 394

Year	CO_2 (tons)	SO_2 (tons)	NO_x (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,772,442	6061	10,778	0.2305	486	6,212,774,902	*C*	*C*
2022	11,677,025	5575	9,655	0.2207	400	5,351,839,163	*C*	*C*
2023	11,756,302	5729	9,750	0.2143	423	5,421,719,931	*C*	*C*
2024	10,455,187	4982	8,537	0.1899	344	4,835,473,497	*C*	*C*
2025	11,659,972	5591	9,748	0.2129	447	5,418,219,347	*C*	*C*
2026	11,971,919	6179	9,945	0.2456	449	5,620,633,053	*C*	*C*
2027	10,009,492	4478	7,529	0.1897	270	4,681,453,646	*C*	*C*
2028	9,029,592	4033	6,629	0.1653	227	4,109,573,873	*C*	*C*
2029	7,488,990	2951	4,703	0.0909	167	3,217,480,869	*C*	*C*
2030	6,308,408	2332	3,814	0.0556	150	2,841,022,883	*C*	*C*
2031	5,934,993	2152	3,524	0.0495	139	2,660,199,189	*C*	*C*
2032	6,259,339	2363	3,833	0.0559	152	2,890,999,203	*C*	*C*
2033	6,487,689	2411	3,902	0.0571	155	2,957,106,895	*C*	*C*
2034	6,099,728	2219	3,609	0.0511	143	2,745,683,389	*C*	*C*
2035	6,624,580	2494	3,992	0.0590	159	3,053,690,095	*C*	*C*
2036	6,427,319	2435	3,891	0.0573	154	2,976,732,821	*C*	*C*
2037	5,852,185	2163	3,542	0.0503	139	2,644,867,071	*C*	*C*
2038	6,142,921	2326	3,774	0.0550	149	2,835,025,820	*C*	*C*
2039	4,734,087	1561	3,145	0.0398	123	1,828,353,105	*C*	*C*
2040	4,686,507	1488	2,970	0.0368	115	1,751,077,609	*C*	*C*
Total	163,378,677	69,524	117,270	2.327	4,788	74,053,926,362		
per MWh**	990	0.42	0.71	0.00001	0.03	224		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1740	0.74	1.25	0.000023	0.05	394

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	990	0.42	0.71	0.00001	0.03	224

Social Cost of Carbon

2018 ERP Emissions and Water Usage Rates by Unit

	UNIT	CO_2 lbs per Net MWh	SO_2 lbs per Net MWh	NOx lbs per Net MWh	Hg lbs per Gross MWh	PM lbs per Gross MWh	VOC lbs per Gross MWh	Water Usage (gal/MWh)
	LRS 2	2203	1.101	2.331	0.0000411	0.0953	0.036	528
	LRS 3	2407	1.823	2.410	0.0000468	0.1770	0.036	528
	Craig 1	2319	0.378	2.771	0.000017	0.0421	0.00209	492
	Craig 2	2350	0.345	0.672	0.000014	0.0469	0.00210	492
	Craig 3	2090	1.308	2.248	0.000078	0.0614	0.0304	492
	Springerville 3	2139	0.838	0.787	0.000016	0.0306	0.034	546
	Burlington 1	2212	0.206	12.482	N/A	0.162	0.0054	8.82
	Burlington 2	2086	0.182	12.283	N/A	0.153	0.0051	8.82
	Pyramid 1	1240	0.013	1.253	N/A	0.071	0.021	120
	Pyramid 2	1232	0.017	1.169	N/A	0.072	0.019	120
	Pyramid 3	1250	0.012	1.253	N/A	0.072	0.020	120
	Pyramid 4	1238	0.006	1.218	N/A	0.065	0.020	120
	Rifle	1206	0.00063	2.611	N/A	0.239	0.227	1273
	Limon 1	1498	0.008	0.432	N/A	0.0616	0.0010	57
	Limon 2	1492	0.008	0.324	N/A	0.0625	0.0008	57
	Knutson 1	1504	0.0085	0.345	N/A	0.1237	0.000	21
	Knutson 2	1500	0.0098	0.337	N/A	0.1237	0.000	21
	J. M. Shafer	981	0.0078	0.747	N/A	0.0804	0.0694	348
	Basin Nebraska	1240	1.0332	0.738	N/A	N/A	N/A	N/A
	Basin Electric- Colorado/Wyoming	1280	0.40	0.70	N/A	N/A	N/A	390
	Market Purchases	1280	0.40	0.70	N/A	N/A	N/A	N/A
	Energy Imbalance	1280	0.40	0.70	N/A	N/A	N/A	N/A
Expansion Plan Units*	SWCO300MWCC	751	0.008	0.747	N/A	0.0804	0.0694	348
	SWCO545MWCC	710	0.008	0.747	N/A	0.0804	0.0694	348

GWh Generation

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1891	1538	1904	1626	1646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1613	1678	1863	1356	1835	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	672	671	677	682	640	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	742	788	676	752	698	766	788	580	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	2880	3479	3172	3133	3032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1754	1654	1840	1728	1830	2500	2558	2413	2650	2534	2157	2613	2606	2467	2660	2616	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	2	19	8	4	13	53	49	40	36	15	24	18	20	24	24	20	78	80	76	79
Pyramid 2	1	19	7	2	14	54	50	39	33	12	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	1	19	7	3	14	55	50	39	34	8	21	16	18	23	22	19	77	79	77	79
Rifle	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	6	66	24	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	4	66	27	1	0	2	2	0	0	0	1	2	2	2	2	1
Knutson 2	0	0	0	0	3	66	25	2	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	493	302	343	294	556	845	721	581	509	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	664	683	686	689	692	694	698	701	704	707	711	715	718	722	725	729	733	736	740	859
Basin Electric- Colorado/Wyoming	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627	1627
Market Purchases	1396	677	598	376	370	2017	1942	1785	2155	2328	2167	1752	1821	1859	1697	1716	2472	2387	2294	2546
Energy Imbalance	148	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
SWCO300MWCC	0	0	0	0	0	0	0	0	0	175	63	101	87	102	131	78	117	131	147	146
SWCO545MWCC	0	0	0	0	0	276	256	178	164	370	329	327	284	354	442	350	447	496	498	560
Total	13886	13290	13543	12409	13122	9221	8951	8122	8047	7913	7236	7303	7316	7313	7464	7293	5688	5672	5595	6033
																		Scenario sum		175418

CO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2082842	1694623	2097310	1791227	1812722	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1941677	2019613	2242683	1632416	2208534	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	778917	777969	785226	791159	741596	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	872202	925439	793736	884134	820733	899773	925949	680916	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3009639	3635514	3315051	3274050	3168810	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	1876411	1769162	1967351	1848620	1957471	2673365	2735711	2580414	2833846	2710127	2306919	2794159	2787163	2637924	2844614	2798190	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1055	11511	5120	2202	8100	33045	30511	24708	22343	9225	15073	11132	12176	14964	15011	12469	48232	49335	46815	49268
Pyramid 2	570	11503	4378	1472	8464	33411	31069	23941	20401	7266	0	0	0	0	0	0	0	0	0	0
Pyramid 3	197	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	505	11699	4393	1609	8578	33937	30687	24351	21074	5220	12968	9738	11048	14148	13324	11550	47616	48677	47481	48845
Rifle	0	0	0	0	1697	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	342	342	0	0	2530	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	341	341	0	0	4152	49030	18161	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	343	343	0	0	3306	49291	20649	1090	0	1401	1553	0	101	293	696	1392	1694	1392	1483	1019
Knutson 2	342	342	0	0	2622	49777	18648	1781	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	241699	148074	168169	144236	272686	414623	353702	285012	249644	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	411673	423307	425113	427068	428761	430577	432497	434596	436450	438412	440667	443039	445137	447366	449665	452056	454218	456462	458732	532811
Basin Electric- Colorado/Wyoming	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228	1041228
Market Purchases	893648	433137	382731	240566	189597	1032800	994550	913996	1103340	1191816	1109410	896878	932388	951853	868982	878383	1265871	1222016	1174414	1303447
Energy Imbalance	94493	86656	86656	86656	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325	69325
SWCO300MWCC	0	0	0	0	0	0	0	0	0	65583	23528	37965	32599	38227	49026	29436	43904	49200	55080	54814
SWCO545MWCC	0	0	0	0	0	97932	90934	63312	58067	131364	116844	116213	100967	125670	156909	124418	158745	176108	176967	198830
Total	13248122	12991001	13319145	12166643	12750912	6908114	6793620	6144670	5855718	5670966	5137515	5419677	5432133	5340999	5508779	5418447	3130833	3113742	3071525	3299587
																		Scenario Sum tons:		140,722,148
																		Scenario lbs/MWh		1604

SO2

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	1041	847	1048	895	906	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1471	1530	1699	1236	1673	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	127	127	128	129	121	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	128	136	117	130	120	132	136	100	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1884	2275	2075	2049	1983	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	735	693	771	724	767	1047	1072	1011	1110	1062	904	1095	1092	1033	1114	1096	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	1
Pyramid 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	2	1	1	1	2	3	3	2	2	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	343	353	354	356	357	359	360	362	364	365	367	369	371	373	375	377	378	380	382	444
Basin Electric- Colorado/Wyoming	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325	325
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0	0	1	1	1
SWCO545MWCC	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	1	2	2	2	2
Total	6056	6287	6518	5846	6255	1870	1899	1802	1803	1755	1598	1791	1790	1734	1817	1800	707	709	711	773

Scenario Sum tons: 53,518
Scenario lbs/MWh 0.61

Nox

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	2204	1793	2219	1895	1918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	1944	2022	2245	1634	2211	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	931	930	938	945	886	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	249	265	227	253	235	257	265	195	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	3237	3910	3566	3522	3408	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	690	651	724	680	720	984	1007	949	1043	997	849	1028	1025	971	1047	1030	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	1	12	5	2	8	33	31	25	23	9	15	11	12	15	15	13	49	50	47	50
Pyramid 2	1	11	4	1	8	32	29	23	19	7	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	12	4	2	8	33	30	24	21	5	13	10	11	14	13	11	47	48	47	48
Rifle	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	1	11	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	1	11	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	1	11	4	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	184	113	128	110	208	316	269	217	190	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	245	252	253	254	255	256	257	259	260	261	262	264	265	266	268	269	270	272	273	317
Basin Electric- Colorado/Wyoming	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569	569
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	65	23	38	32	38	49	29	44	49	55	55
SWCO545MWCC	0	0	0	0	0	103	96	67	61	138	123	122	106	132	165	131	167	185	186	209
Total	10257	10539	10884	9868	10442	2617	2567	2328	2186	2053	1855	2042	2022	2006	2126	2052	1146	1173	1178	1248

Scenario Sum tons: 80,589
Scenario lbs/MWh 1

Hg

short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	0.0418	0.0340	0.0421	0.0360	0.0364	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
LRS 3	0.0406	0.0423	0.0469	0.0342	0.0462	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 1	0.0062	0.0061	0.0062	0.0063	0.0059	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 2	0.0056	0.0059	0.0051	0.0057	0.0053	0.0058	0.0059	0.0044	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Craig 3	0.1211	0.1463	0.1334	0.1317	0.1275	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Springerville 3	0.0153	0.0144	0.0160	0.0150	0.0159	0.0218	0.0223	0.0210	0.0231	0.0221	0.0188	0.0227	0.0227	0.0215	0.0232	0.0228	0.0000	0.0000	0.0000	0.0000
Burlington 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Burlington 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Pyramid 4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rifle	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Limon 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Knutson 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
J. M. Shafer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO545MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	0.2305	0.2490	0.2497	0.2288	0.2371	0.0275	0.0282	0.0254	0.0231	0.0221	0.0188	0.0227	0.0227	0.0215	0.0232	0.0228	0.0000	0.0000	0.0000	0.0000

Scenario Sum tons: 1.453
Scenario lbs/MWh 0.000015

PM
short tons (2000 pounds = 1 ton)

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	97	79	98	83	84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	154	160	177	129	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	19	20	17	19	18	19	20	15	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	95	115	105	104	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	29	28	31	29	30	42	43	40	44	42	36	43	43	41	44	44	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	0	1	0	0	0	2	2	1	1	1	1	1	1	1	1	1	3	3	3	3
Pyramid 2	0	1	0	0	1	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0
Pyramid 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	0	1	0	0	0	2	2	1	1	0	1	1	1	1	1	1	3	3	3	3
Rifle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	0	0	0	0	0	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 2	0	0	0	0	0	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	20	12	14	12	23	34	29	24	21	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO545MWCC	0	0	0	0	0	11	10	7	7	15	13	13	12	14	18	14	18	20	20	23
Total	429	431	458	392	447	123	111	90	75	59	51	58	56	57	64	59	24	26	26	28

Scenario Sum tons: 3,063
Scenario lbs/MWh 0.03

Water
Gallons

Generator	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LRS 2	998,402,713	812,311,565	1,005,337,944	858,618,042	868,921,436	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LRS 3	851,853,147	886,045,503	983,910,799	716,174,149	968,928,748	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 1	330,510,581	330,108,532	333,187,727	335,705,312	314,674,744	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Craig 2	365,211,193	387,502,795	332,355,812	370,207,587	343,660,002	376,755,985	387,716,353	285,115,297	0	0	0	0	0	0	0	0	0	0	0	0
Craig 3	1,416,978,435	1,711,648,867	1,560,770,248	1,541,466,550	1,491,918,332	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Springerville 3	957,943,556	903,190,647	1,004,370,114	943,755,639	999,326,195	1,364,803,408	1,396,632,421	1,317,350,325	1,446,732,137	1,383,571,039	1,177,725,963	1,426,471,183	1,422,899,716	1,346,710,095	1,452,229,111	1,428,528,780	0	0	0	0
Burlington 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burlington 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 1	204,150	2,227,874	991,032	426,119	1,567,744	6,395,825	5,905,361	4,782,169	4,324,433	1,785,444	2,917,343	2,154,585	2,356,679	2,896,251	2,905,279	2,413,356	9,335,211	9,548,672	9,060,876	9,535,824
Pyramid 2	111,000	2,240,819	852,849	286,847	1,648,814	6,508,697	6,052,435	4,663,769	3,974,316	1,415,405	0	0	0	0	0	0	0	0	0	0
Pyramid 3	37,884	37,884	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pyramid 4	97,884	2,268,034	851,578	311,916	1,662,973	6,579,124	5,948,933	4,720,739	4,085,451	1,011,914	2,513,975	1,887,797	2,141,784	2,742,837	2,582,939	2,239,013	9,230,896	9,436,667	9,204,684	9,469,105
Rifle	0	0	0	0	3,581,764	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 1	26,020	26,020	0	0	192,539	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limon 2	26,020	26,020	0	0	317,220	3,746,248	1,387,607	0	0	0	0	0	0	0	0	0	0	0	0	0
Knutson 1	9,586	9,586	0	0	92,333	1,376,470	576,622	30,428	0	39,133	43,372	0	2,825	8,179	19,435	38,870	47,302	38,870	41,422	28,447
Knutson 2	9,586	9,586	0	0	73,424	1,393,742	522,154	49,864	0	0	0	0	0	0	0	0	0	0	0	0
J. M. Shafer	171,480,537	105,055,846	119,312,833	102,332,352	193,465,413	294,167,112	250,944,293	202,210,542	177,117,444	0	0	0	0	0	0	0	0	0	0	0
Basin Nebraska	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Basin Electric- Colorado/Wyoming	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765	633,951,765
Market Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Energy Imbalance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCO300MWCC	0	0	0	0	0	0	0	0	0	60,779,798	21,804,548	35,184,469	30,211,586	35,427,700	45,435,253	27,280,619	40,689,079	45,596,403	51,046,238	50,799,737
SWCO545MWCC	0	0	0	0	0	96,001,212	89,140,941	62,063,814	56,921,573	128,773,558	114,540,288	113,921,019	98,975,798	123,191,645	153,815,333	121,964,638	155,614,810	172,635,137	173,477,142	194,905,781
Total	5726854057	5776661343	5975892700	5503236276	5823983444	2791679589	2778778901	2514938704	2327107117	2211328045	1953497247	2213570810	2190540133	2144928469	2290939115	2216417034	848869064	871207757	876782122	898694707

Scenario Sum (Gallons): 57,935,906,637
Scenario gallons/MWh 330

Year	CO2 (tons)	SO2 (tons)	NOx (tons)	Hg (tons)	PM (tons)	Water (gallons)	RES CO	RPS NM (SB489)
2021	13,248,122	6056	10,257	0.2305	429	5,726,854,057	*C*	*C*
2022	12,991,001	6287	10,539	0.2490	431	5,776,661,343	*C*	*C*
2023	13,319,145	6518	10,884	0.2497	458	5,975,892,700	*C*	*C*
2024	12,166,643	5846	9,868	0.2288	392	5,503,236,276	*C*	*C*
2025	12,750,912	6255	10,442	0.2371	447	5,823,983,448	*C*	*C*
2026	6,908,114	1870	2,617	0.0275	123	2,791,679,589	*C*	*C*
2027	6,793,620	1899	2,567	0.0282	111	2,778,778,901	*C*	*C*
2028	6,144,670	1802	2,328	0.0254	90	2,514,938,704	*C*	*C*
2029	5,855,718	1803	2,186	0.0231	75	2,327,107,117	*C*	*C*
2030	5,670,966	1755	2,053	0.0221	59	2,211,328,045	*C*	*C*
2031	5,137,515	1598	1,855	0.0188	51	1,953,497,247	*C*	*C*
2032	5,419,677	1791	2,042	0.0227	58	2,213,570,810	*C*	*C*
2033	5,432,133	1790	2,022	0.0227	56	2,190,540,133	*C*	*C*
2034	5,340,999	1734	2,006	0.0215	57	2,144,928,469	*C*	*C*
2035	5,508,779	1817	2,126	0.0232	64	2,290,939,115	*C*	*C*
2036	5,418,447	1800	2,052	0.0228	59	2,216,417,034	*C*	*C*
2037	3,130,833	707	1,146	0.0000	24	848,869,064	*C*	*C*
2038	3,113,742	709	1,173	0.0000	26	871,207,757	*C*	*C*
2039	3,071,525	711	1,178	0.0000	26	876,782,122	*C*	*C*
2040	3,299,587	773	1,248	0.0000	28	898,694,707	*C*	*C*
Total	140,722,148	53,518	80,589	1.453	3,063	57,935,906,637		
per MWh**	717	0.27	0.41	0.00001	0.02	148		

TS Thermal Gen Emissions & Water per TS Thermal Gen	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)*	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	1604	0.61	0.92	0.000015	0.03	330

*** This is divided by all thermal MWH even though gas does not have a Mercury impact**

TS Thermal Gen Emissions& Water per Member Load Energy	CO2 (lbs/net MWH)	SO2 (lbs/net MWH)	NOx (lbs/net MWH	Hg (lbs/gross MWh)	PM (lbs gross MWh)	Water (gallons/net MWH
Scenario Average	717	0.27	0.41	0.00001	0.02	148

Attachment Vol II 6-2 RES/RPS

Hyperion Data

Base Case

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,235,474	11,468,302	11,710,122	11,931,568	12,142,495	12,379,349	12,614,855	12,869,179	13,119,887	13,342,451	13,575,587	13,798,708	14,021,025	14,265,209	14,520,163	14,775,306	15,021,402	15,261,838	15,510,303	15,767,501
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,247,095	2,293,660	2,342,024	2,386,314	2,428,499	2,475,870	2,522,971	2,573,836	2,623,977	2,668,490	2,715,117	2,759,742	2,804,205	2,853,042	2,904,033	2,955,061	3,004,280	3,052,368	3,102,061	3,153,500
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	358,064	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,274	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWPV	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
WYO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465	10,375,907
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465	10,375,907
Rollover, Vintage -1 year	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007	9,062,465
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802	8,641,007
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,158,423	4,010,703	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540	8,066,802
Rollover, Vintage -4 year	1,596,193	1,455,566	1,321,801	1,303,657	1,561,141	2,291,065	3,825,898	4,026,187	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903	8,255,540
Rollover, Vintage -5 year	133,754	-	-	-	-	-	-	1,302,927	2,755,278	5,384,987	5,356,089	5,351,905	5,331,757	5,318,738	6,297,612	6,542,964	7,050,423	7,460,169	8,125,171	8,528,379	8,487,903
Expiring RECs		-	-	-	-	-	-	-	-	131,301	2,716,497	2,640,972	2,592,163	2,527,552	2,465,696	3,393,580	3,587,902	4,046,143	4,407,801	5,023,111	5,374,879
BALANCE AFTER COMPLIANCE		**11,741,562**	**13,458,605**	**15,142,768**	**18,141,441**	**21,069,032**	**23,945,067**	**26,753,853**	**29,498,756**	**33,041,090**	**34,199,066**	**35,893,400**	**38,001,664**	**40,795,078**	**44,004,719**	**46,195,010**	**47,907,587**	**48,923,966**	**50,104,804**	**51,042,097**	**52,889,625**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,773,756	2,804,086	2,835,823	2,869,044	2,803,594	2,739,229	2,768,895	2,800,445	2,830,124	2,860,568	2,891,298	2,923,241	2,952,642	2,983,400	3,014,802	3,047,239	3,077,495	3,108,543	3,139,854	3,172,211
New Mexico Member Retail Sales6	2%	2,718,281	2,748,005	2,779,106	2,811,664	2,747,523	2,684,445	2,713,517	2,744,436	2,773,522	2,803,357	2,833,472	2,864,776	2,893,589	2,923,732	2,954,506	2,986,294	3,015,945	3,046,372	3,077,056	3,108,767
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		271,828	274,800	277,911	281,166	1,099,009	1,073,778	1,085,407	1,097,775	1,109,409	1,401,678	1,416,736	1,432,388	1,446,795	1,461,866	1,477,253	1,493,147	1,507,972	1,523,186	1,538,528	1,554,384
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,496	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	475	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
Total RECs Generated		831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,134,131	1,134,723	1,024,461	1,031,736
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,134,131	1,038,837	524,770	2,123
Rollover, Vintage -1 year	258,073	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	1,286,902	1,293,457	1,225,115	1,055,657	878,724	665,536	293,169	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	831,267	829,372	827,490	932,886	930,339	927,691	922,797	718,569	220,070	74,584	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	203,133	186,406	744,118	831,267	829,372	778,293	625,772	458,336	276,619	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	462,951	195,209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,128,096**	**2,682,667**	**3,232,247**	**3,883,966**	**3,715,296**	**3,569,209**	**3,406,600**	**3,229,656**	**3,038,485**	**2,923,708**	**2,800,429**	**2,671,910**	**2,517,523**	**2,355,977**	**2,158,683**	**1,801,141**	**1,427,300**	**1,038,837**	**524,770**	**2,123**

Notes:

1 Project is not registered with WREGIS
2 Contract expired
3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.
4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)
5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.
6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513	13,129,917
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513	13,129,917
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903	13,429,513
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912	13,646,903
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075	12,750,912
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606	12,681,075
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	8,955,517	10,603,759	10,348,748	10,824,666	11,049,414	11,853,488	12,424,606
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,133,862	7,731,817	7,428,018	7,856,432	8,032,066	8,785,512
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**42,850,828**	**48,069,599**	**52,283,924**	**56,087,171**	**59,909,674**	**63,635,590**	**67,104,679**	**69,181,996**	**71,584,159**	**74,406,397**	**76,786,497**	**78,062,926**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	10,991,049	10,719,326	11,202,903	11,434,396	12,237,606	12,809,609
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,119,107	7,798,596	8,234,668	8,417,048	9,169,630
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**48,854,878**	**53,439,782**	**57,621,265**	**61,828,750**	**65,938,784**	**69,394,887**	**71,491,233**	**73,904,165**	**76,744,481**	**79,137,508**	**80,412,512**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 3

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422	13,512,610
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219	13,827,422
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258	14,043,219
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395	13,132,258
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609	13,087,395
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,378,340	11,089,904	11,202,903	11,434,396	12,237,606	12,809,609
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,506,398	8,169,174	8,234,668	8,417,048	9,169,630
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**49,242,169**	**54,197,650**	**58,379,133**	**62,586,619**	**66,696,653**	**70,152,756**	**71,861,811**	**73,904,165**	**76,744,481**	**79,137,508**	**80,412,512**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	**-**	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 4

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower/Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC050MWPV01	1	-	-	-	-	-	-	-	-	-	126,390	124,601	126,329	122,179	125,035	122,578	126,699	126,012	124,663	124,109	122,324
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531	13,634,934
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531	13,634,934
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882	13,951,531
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270	14,167,882
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094	13,258,270
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186	13,214,094
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,134,423	7,021,419	7,226,910	8,127,572	9,353,505	11,117,439	10,843,926	11,329,232	11,556,574	12,362,640	12,932,186
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,499,300	4,342,496	4,503,898	5,356,317	6,531,851	8,245,497	7,923,197	8,360,997	8,539,227	9,294,665
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,197,644**	**26,820,143**	**31,601,646**	**37,233,775**	**43,248,817**	**48,981,268**	**53,690,772**	**57,998,584**	**62,328,248**	**66,563,316**	**70,141,997**	**72,238,652**	**74,652,995**	**77,491,645**	**79,886,602**	**81,158,896**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,520,423	1,909,930	1,778,863	1,800,025
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	722,799	168,243	-	41,348	457,079	726,488	1,001,366
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	846,533	340,025	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	890,887	420,747	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,351,174**	**3,182,544**	**2,725,082**	**2,250,397**	**1,758,279**	**1,249,171**	**722,799**	**168,243**	-	**41,348**	**457,079**	**726,488**	**1,001,366**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,573,755	3,459,085	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806
Expiring RECs		-	-	-	-	-	-	-	1,299,474	1,831,997	3,160,758	3,099,707	3,311,348	3,889,119	4,262,322	5,212,562	7,169,739	7,637,847	8,092,749	7,751,673	8,139,605
BALANCE AFTER COMPLIANCE		11,790,054	13,805,318	15,812,890	19,156,167	22,446,747	25,950,209	30,032,029	33,187,941	36,763,732	40,974,601	45,718,058	50,708,468	54,785,106	58,879,291	62,308,119	64,290,495	65,542,548	66,787,861	67,642,272	67,823,782
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
Retail Load																					
New Mexico Member Load																					
New Mexico Member Retail Sales	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,111,330	1,134,723
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	774,312	622,118	466,144	295,346	-	41,728
Rollover, Vintage -4 year	-	-	-	10,174	615,103	560,237	538,302	517,163	602,857	687,328	558,507	425,021	288,986	150,198	8,224	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		2,143,548	2,738,385	3,333,615	4,035,807	4,080,323	4,156,707	4,230,876	4,304,515	4,376,885	4,236,331	4,093,740	3,948,619	3,800,738	3,649,670	3,484,297	3,171,780	3,243,073	3,313,022	3,270,514	3,616,792

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241	10,890,693
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210	11,138,241
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599	11,834,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233	11,351,599
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,160,150	4,010,703	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806	11,578,233
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,573,755	3,459,085	4,026,187	5,384,987	5,356,089	5,598,487	6,207,193	6,614,998	7,601,978	9,595,857	10,099,547	10,588,897	10,283,830	10,709,183	11,030,806
Expiring RECs		-	-	-	-	-	-	-	1,299,474	1,831,997	3,160,758	3,099,707	3,311,348	3,889,119	4,262,322	5,212,562	7,169,739	7,637,847	8,092,749	7,751,673	8,139,605
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,805,318**	**15,812,890**	**19,156,167**	**22,446,747**	**25,950,209**	**30,032,029**	**33,187,941**	**36,763,732**	**40,974,601**	**45,718,058**	**50,708,468**	**54,785,106**	**58,879,291**	**62,308,119**	**64,290,495**	**65,542,548**	**66,787,861**	**67,642,272**	**67,823,782**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
New Mexico Member Retail Sales6	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,134,131	1,134,723	1,024,461
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	911,746	909,145	906,864	893,977	748,822	1,111,330	1,134,723
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	920,831	918,237	915,959	913,691	774,312	622,118	466,144	295,346	-	41,728
Rollover, Vintage -4 year	-	-	-	10,174	615,103	560,237	538,302	517,163	602,857	687,328	558,507	425,021	288,986	150,198	8,224	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,738,385**	**3,333,615**	**4,035,807**	**4,080,323**	**4,156,707**	**4,230,876**	**4,304,515**	**4,376,885**	**4,236,331**	**4,093,740**	**3,948,619**	**3,800,738**	**3,649,670**	**3,484,297**	**3,171,780**	**3,243,073**	**3,313,022**	**3,270,514**	**3,616,792**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Social Cost of Carbon

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	231,363	231,363	231,363	232,138	231,363	231,363	231,363	232,138	231,363	211,775	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,263	461,263	461,263	462,550	461,263	461,263	461,263	462,550	461,263	461,263	461,263	461,250	-	-	-	-	-	-	-	-
Carousel-E.CO	1	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	666,400	664,520	664,520	664,520	664,520
San Isabel Solar	1	76,103	75,730	75,370	75,140	74,570	74,160	73,810	73,580	73,020	72,630	72,230	72,020	71,470	71,080	70,700	70,460	69,910	69,550	69,150	69,150
Twin Buttes	1	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430	302,430
Spanish Peaks Solar	1	-	-	12,706	267,735	266,395	265,056	263,716	262,377	261,038	259,698	258,359	257,020	255,680	254,341	253,001	251,662	250,323	237,306	-	-
Crossing Trails Wind	1	439,001	439,001	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	439,000	421,191	-	-	-	-
Niyol Wind	1	-	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712	842,712
Axial Basin Solar	1	-	-	-	369,907	368,057	366,207	364,357	362,507	360,657	358,807	356,957	355,107	353,257	351,407	349,557	347,707	345,858	344,089	-	-
Dolores Canyon Solar	1	-	-	-	297,092	295,606	294,121	292,635	291,149	289,663	288,177	286,692	285,206	283,720	282,234	280,748	279,263	277,777	276,359	-	-
Spanish Peaks II Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Coyote Gulch Solar	1	-	-	-	331,082	329,427	327,771	326,115	324,459	322,803	321,148	319,492	317,836	316,180	314,524	312,869	311,130	309,557	307,977	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND7	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWINDBATT01	1	-	-	-	-	-	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540
SWCO100MWPV	1	-	-	-	-	-	246,582	248,928	251,403	248,291	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND8	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND9	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	361,544	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWPV	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWWINDBATT02	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
ECO100MWWINDBATT03	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
SWCO100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377	15,389,737
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377	15,389,737
Rollover, Vintage -1 year	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113	15,729,377
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708	15,402,113
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,160,150	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717	14,764,708
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,641,344	4,010,703	4,026,187	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662	13,877,717
Rollover, Vintage -5 year	133,754	-	-	-	-	-	242,423	1,807,719	3,338,463	5,384,987	6,120,412	8,951,736	9,599,383	10,631,705	10,724,298	11,460,479	11,912,369	13,050,255	13,333,170	13,381,772	13,689,662
Expiring RECs		-	-	-	-	-	-	-	-	793,272	2,795,845	3,485,290	6,272,812	6,876,370	7,860,450	7,902,644	8,588,537	8,991,640	10,082,021	10,315,822	10,313,797
BALANCE AFTER COMPLIANCE		**11,790,054**	**13,581,552**	**15,340,798**	**18,415,391**	**22,183,634**	**28,736,448**	**35,890,424**	**44,026,685**	**51,412,520**	**57,488,012**	**63,279,970**	**67,378,489**	**71,112,277**	**73,862,344**	**76,827,708**	**79,244,945**	**82,097,284**	**84,449,142**	**86,845,349**	**88,853,314**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	176,813	175,271	173,733	172,195	170,657	169,119	167,580	166,042	164,504	162,965	161,426	159,890	158,351	156,812	144,658	-	-	-	-	-
Alta Luna Solar	1	76,231	75,850	75,471	75,093	74,717	74,089	73,670	73,440	72,880	72,510	72,110	71,900	71,340	70,950	70,570	70,350	69,800	69,410	69,020	69,020
Escalante Solar	1	-	-	-	107,124	106,588	106,052	105,516	104,981	104,445	103,909	103,373	102,838	102,302	101,766	101,230	100,695	100,159	99,649	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	386,965	378,013	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,520,423	1,522,326	1,401,662	1,415,881
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,520,423	1,522,326	1,401,662	1,415,881
Rollover, Vintage -1 year	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,307,796	1,296,251	1,286,902	1,293,457	1,303,869	1,292,408	1,300,320	1,279,959	1,135,605	1,457,209	1,470,081	1,346,596
Rollover, Vintage -2 year	265,817	258,073	835,623	830,956	829,372	827,490	932,886	930,339	927,691	922,797	1,277,851	1,185,725	1,068,763	943,967	814,601	658,476	494,496	295,381	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	830,956	829,372	827,490	724,765	579,854	420,678	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	249,490	27,403	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,143,548**	**2,703,624**	**3,258,727**	**3,916,002**	**3,769,576**	**3,645,808**	**3,505,592**	**3,738,139**	**3,947,522**	**3,861,004**	**3,766,084**	**3,666,089**	**3,540,243**	**3,407,329**	**3,238,755**	**2,910,060**	**2,951,408**	**2,979,535**	**2,871,743**	**2,762,477**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

PO Data

Base Case

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,235,474	11,468,302	11,710,122	11,931,568	12,142,495	12,379,349	12,614,855	12,869,179	13,119,887	13,342,451	13,575,587	13,798,708	14,021,025	14,265,209	14,520,163	14,775,306	15,021,402	15,261,838	15,510,303	15,767,501
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,247,095	2,293,660	2,342,024	2,386,314	2,428,499	2,475,870	2,522,971	2,573,836	2,623,977	2,668,490	2,715,117	2,759,742	2,804,205	2,853,042	2,904,033	2,955,061	3,004,280	3,052,368	3,102,061	3,153,500
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	358,064	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,274	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWPV	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244,648
WYO100MWWIND	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	379,717
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994	10,382,817
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994	10,382,817
Rollover, Vintage -1 year	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314	9,111,994
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831	8,532,314
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,134,857	3,998,561	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149	7,956,831
Rollover, Vintage -4 year	1,596,193	1,455,566	1,321,801	1,303,657	1,561,141	2,267,499	3,790,190	4,058,444	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969	8,154,149
Rollover, Vintage -5 year	133,754	-	-	-	-	-	-	1,267,219	2,751,827	5,196,675	5,182,850	5,188,992	5,176,348	5,162,218	6,132,614	6,383,839	6,878,246	7,311,578	7,938,840	8,362,440	8,297,969
Expiring RECs		-	-	-	-	-	-	-	-	127,850	2,528,185	2,467,732	2,429,250	2,372,143	2,309,176	3,228,581	3,428,778	3,873,965	4,259,210	4,836,779	5,208,940
BALANCE AFTER COMPLIANCE		**11,717,996**	**13,422,897**	**15,139,316**	**17,949,678**	**20,704,029**	**23,417,151**	**26,070,528**	**28,658,909**	**32,039,696**	**33,226,860**	**34,922,256**	**37,044,841**	**39,807,333**	**43,007,556**	**45,172,911**	**46,943,222**	**48,021,807**	**49,242,543**	**50,415,698**	**52,436,075**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,773,756	2,804,086	2,835,823	2,869,044	2,803,594	2,739,229	2,768,895	2,800,445	2,830,124	2,860,568	2,891,298	2,923,241	2,952,642	2,983,400	3,014,802	3,047,239	3,077,495	3,108,543	3,139,854	3,172,211
New Mexico Member Retail Sales6	2%	2,718,281	2,748,005	2,779,106	2,811,664	2,747,523	2,684,445	2,713,517	2,744,436	2,773,522	2,803,357	2,833,472	2,864,776	2,893,589	2,923,732	2,954,506	2,986,294	3,015,945	3,046,372	3,077,056	3,108,767
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		271,828	274,800	277,911	281,166	1,099,009	1,073,778	1,085,407	1,097,775	1,109,409	1,401,678	1,416,736	1,432,388	1,446,795	1,461,866	1,477,253	1,493,147	1,507,972	1,523,186	1,538,528	1,554,384
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,496	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	475	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
Total RECs Generated		836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,122,898	1,124,701	1,028,585	1,035,128
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,122,898	1,005,180	495,237	-
Rollover, Vintage -1 year	258,073	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	1,290,498	1,295,696	1,217,534	1,048,342	873,017	661,648	280,767	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,574	829,088	834,758	921,804	920,973	925,818	915,327	698,330	200,626	58,736	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	203,133	186,406	744,118	836,574	829,088	790,584	626,981	450,180	266,589	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	462,951	200,516	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,133,403**	**2,687,690**	**3,244,538**	**3,885,175**	**3,707,139**	**3,559,178**	**3,389,099**	**3,209,417**	**3,019,040**	**2,907,860**	**2,786,820**	**2,664,328**	**2,510,208**	**2,350,270**	**2,154,795**	**1,788,740**	**1,403,665**	**1,005,180**	**495,237**	-

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043	13,136,828
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043	13,136,828
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210	13,479,043
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940	13,538,210
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684	12,640,940
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672	12,579,684
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	8,790,518	10,444,634	10,176,570	10,676,075	10,863,082	11,687,548	12,234,672
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	5,968,863	7,572,692	7,255,840	7,707,840	7,845,734	8,619,573
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**41,849,434**	**47,097,393**	**51,312,780**	**55,130,348**	**58,921,929**	**62,638,426**	**66,082,581**	**68,217,631**	**70,682,001**	**73,544,136**	**76,160,097**	**77,609,376**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,831,925	10,547,148	11,054,311	11,248,064	12,071,666	12,619,675
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	7,959,983	7,626,419	8,086,077	8,230,716	9,003,691
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**47,882,672**	**52,468,637**	**56,664,442**	**60,841,006**	**64,941,621**	**68,372,789**	**70,526,868**	**73,002,006**	**75,882,220**	**78,511,108**	**79,958,962**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs																	-				
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 3

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952	13,519,520
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525	13,876,952
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286	13,934,525
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004	13,022,286
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675	12,986,004
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	11,219,215	10,917,726	11,054,311	11,248,064	12,071,666	12,619,675
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	8,347,273	7,996,997	8,086,077	8,230,716	9,003,691
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**48,269,963**	**53,226,506**	**57,422,311**	**61,598,874**	**65,699,489**	**69,130,657**	**70,897,446**	**73,002,006**	**75,882,220**	**78,511,108**	**79,958,962**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

80% Carbon Reduction Version 4

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
ECO100MWWIND	1	-	-	-	-	396,172	395,541	393,345	361,548	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower/Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV3	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND3	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV4	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV5	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV6	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV7	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWC0100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC0100MWPV9	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWC050MWPV01	1	-	-	-	-	-	-	-	-	-	126,390	124,601	126,329	122,179	125,035	122,578	126,699	126,012	124,663	124,109	122,324
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
SWC0100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWC0100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWC0100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWPV	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
ECO100MWPV4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061	13,641,844
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061	13,641,844
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188	14,001,061
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298	14,059,188
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703	13,148,298
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252	13,112,703
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,961,183	6,858,506	7,071,501	7,971,051	9,188,507	10,958,314	10,671,748	11,180,640	11,370,242	12,196,701	12,742,252
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,326,061	4,179,583	4,348,488	5,199,797	6,366,852	8,086,372	7,751,019	8,212,406	8,352,895	9,128,726
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,832,641**	**26,292,226**	**30,918,320**	**36,393,928**	**42,247,423**	**48,009,062**	**52,719,627**	**57,041,761**	**61,340,503**	**65,566,153**	**69,119,898**	**71,274,287**	**73,750,836**	**76,629,384**	**79,260,203**	**80,705,346**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591														
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387,603	377,201	384,144
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144	
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144	
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,509,189	1,899,908	1,782,988	1,803,417
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	717,092	164,355	-	30,115	435,823	709,356	987,626
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	832,925	332,444	-	-	-	-	-	-	-
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	870,647	401,303	-	-	-	-	-	-	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,330,935**	**3,163,100**	**2,709,234**	**2,236,788**	**1,750,697**	**1,241,855**	**717,092**	**164,355**	**-**	**30,115**	**435,823**	**709,356**	**987,626**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 1

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
	Inventory									**REC Balance after Compliance is Met for the Year, (includes multipliers)**											
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,550,189	3,423,377	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872
Expiring RECs	-	-	-	-	-	-	-	-	-	1,263,766	1,864,255	2,972,446	2,926,467	3,148,435	3,733,710	4,105,801	5,047,563	7,010,614	7,465,669	7,944,158	7,565,341	7,973,666
BALANCE AFTER COMPLIANCE		11,766,487	13,769,610	15,809,439	18,964,404	22,081,744	25,422,293	29,348,703	32,383,803	35,762,338	40,002,395	44,746,914	49,751,646	53,797,361	57,882,128	61,286,021	63,326,130	64,640,390	65,925,600	67,015,872	67,370,232
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
Retail Load																					
New Mexico Member Load																					
New Mexico Member Retail Sales	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
	Inventory									**REC Balance after Compliance is Met for the Year, (includes multipliers)**											
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,087,694	1,124,701
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	908,307	766,730	614,803	460,436	291,458	-	18,093
Rollover, Vintage -4 year	-	-	-	10,174	615,103	565,544	543,324	529,454	604,066	679,171	548,476	407,521	268,746	130,753	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		2,148,856	2,743,408	3,345,906	4,037,016	4,072,166	4,146,676	4,213,375	4,284,276	4,357,441	4,220,483	4,080,131	3,941,037	3,793,423	3,643,962	3,480,409	3,159,379	3,219,438	3,279,365	3,240,981	3,590,651

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Low Load 80% Carbon Reduction Version 2

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	9,977,192	10,093,076	10,208,551	10,327,548	10,475,126	10,626,864	10,798,057	10,970,948	11,121,149	11,281,911	11,435,692	11,590,367	11,763,379	11,947,079	12,130,590	12,308,499	12,480,739	12,660,788	12,847,891
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	1,995,438	2,018,615	2,041,710	2,065,510	2,095,025	2,125,373	2,159,611	2,194,190	2,224,230	2,256,382	2,287,138	2,318,073	2,352,676	2,389,416	2,426,118	2,461,700	2,496,148	2,532,158	2,569,578
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,981	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2	0																				
Tri-County Hydropower / Ridgway1	1.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
SWCO100MWPV	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV2	1	-	-	-	-	-	-	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND2	1	-	-	-	-	-	-	-	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV3	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
WYO100MWWIND3	1	-	-	-	-	-	-	-	-	-	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770	10,897,604
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516	11,187,770
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628	11,725,516
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842	11,241,628
Rollover, Vintage -4 year	1,596,193	1,502,331	1,666,787	1,972,053	2,574,140	3,136,584	3,998,561	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872	11,476,842
Rollover, Vintage -5 year	133,754	-	-	-	-	508,630	1,550,189	3,423,377	4,058,444	5,196,675	5,182,850	5,435,574	6,051,783	6,458,477	7,436,979	9,436,732	9,927,369	10,440,306	10,097,498	10,543,244	10,840,872
Expiring RECs	-	-	-	-	-	-	-	-	1,263,766	1,864,255	2,972,446	2,926,467	3,148,435	3,733,710	4,105,801	5,047,563	7,010,614	7,465,669	7,944,158	7,565,341	7,973,666
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,769,610**	**15,809,439**	**18,964,404**	**22,081,744**	**25,422,293**	**29,348,703**	**32,383,803**	**35,762,338**	**40,002,395**	**44,746,914**	**49,751,646**	**53,797,361**	**57,882,128**	**61,286,021**	**63,326,130**	**64,640,390**	**65,925,600**	**67,015,872**	**67,370,232**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,393,217	2,370,000	2,354,020	2,259,751	2,171,703	2,164,869	2,161,203	2,157,825	2,156,149	2,155,679	2,156,870	2,157,195	2,159,045	2,161,937	2,165,998	2,169,058	2,173,008	2,177,489	2,182,861
New Mexico Member Retail Sales6	2%	2,560,648	2,345,353	2,322,600	2,306,939	2,214,556	2,128,269	2,121,572	2,117,979	2,114,668	2,113,026	2,112,566	2,113,733	2,114,051	2,115,864	2,118,698	2,122,678	2,125,677	2,129,547	2,133,939	2,139,203
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	234,535	232,260	230,694	885,822	851,308	848,629	847,191	845,867	1,056,513	1,056,283	1,056,866	1,057,026	1,057,932	1,059,349	1,061,339	1,062,838	1,064,774	1,066,970	1,069,602
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,122,898	1,124,701	1,028,585
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	915,931	917,773	909,412	908,471	895,796	740,308	1,087,694	1,124,701
Rollover, Vintage -3 year	209,144	218,896	242,434	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	918,092	919,032	919,555	908,307	766,730	614,803	460,436	291,458	-	18,093
Rollover, Vintage -4 year	-	-	-	10,174	615,103	565,544	543,324	529,454	604,066	679,171	548,476	407,521	268,746	130,753	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,743,408**	**3,345,906**	**4,037,016**	**4,072,166**	**4,146,676**	**4,213,375**	**4,284,276**	**4,357,441**	**4,220,483**	**4,080,131**	**3,941,037**	**3,793,423**	**3,643,962**	**3,480,409**	**3,159,379**	**3,219,438**	**3,279,365**	**3,240,981**	**3,590,651**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Social Cost of Carbon

Colorado Compliance

(current RPS as it pertains to a QWU and energy provided at wholesale)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
Colorado Member Load5		11,001,652	11,096,023	11,334,704	11,551,975	11,760,844	11,994,606	12,227,035	12,477,215	12,725,959	12,945,710	13,175,611	13,394,617	13,615,062	13,856,273	14,108,272	14,359,711	14,603,647	14,841,172	15,086,738	15,339,875
RPS Percent		20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
RECs Required		2,200,330	2,219,205	2,266,941	2,310,395	2,352,169	2,398,921	2,445,407	2,495,443	2,545,192	2,589,142	2,635,122	2,678,923	2,723,012	2,771,255	2,821,654	2,871,942	2,920,729	2,968,234	3,017,348	3,067,975
RPS Compliant RECs	Multiplier																				
Kit Carson Renewable Energy	1.25	229,148	217,782	239,856	223,709	234,134	237,995	228,894	220,305	229,456	207,070	-	-	-	-	-	-	-	-	-	-
Colorado Highlands Wind	1.25	461,352	457,957	464,712	464,805	474,110	455,605	467,680	461,110	458,947	451,773	461,352	463,264	-	-	-	-	-	-	-	-
Carousel-E.CO	1	666,843	648,237	672,506	643,626	639,494	658,276	630,020	665,358	649,569	653,199	637,988	658,407	665,672	627,181	651,272	679,557	654,028	666,149	664,391	650,333
San Isabel Solar	1	71,416	72,000	71,416	70,005	70,097	67,964	68,110	69,242	67,104	67,207	66,599	68,868	68,448	61,991	67,776	67,942	64,638	65,203	63,018	64,757
Twin Buttes	1	307,567	308,270	308,267	309,311	308,177	307,740	307,790	308,827	308,191	307,745	308,151	309,102	307,792	308,336	308,286	308,690	307,454	308,290	307,612	309,840
Spanish Peaks Solar	1	-	-	14,113	248,894	242,914	243,911	245,119	246,209	242,205	244,985	240,271	242,341	233,157	237,357	231,467	238,193	236,903	223,417	-	-
Crossing Trails Wind	1	414,777	404,512	408,546	405,177	412,565	411,480	420,353	403,092	413,927	408,330	406,225	400,442	402,187	414,951	366,722	-	-	-	-	-
Niyol Wind	1	10	896,119	882,203	885,459	896,156	893,988	907,129	892,039	895,011	890,207	896,119	884,163	872,514	899,628	893,988	865,549	887,474	882,726	893,321	860,792
Axial Basin Solar	1	-	-	-	321,943	314,757	315,363	316,550	317,270	312,010	315,286	310,320	312,558	302,518	306,310	300,111	307,916	304,682	300,423	-	-
Dolores Canyon Solar	1	-	-	-	254,843	248,539	249,756	249,772	251,760	246,302	250,291	244,935	247,590	238,872	242,817	237,571	243,392	241,020	237,793	-	-
Spanish Peaks II Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Coyote Gulch Solar	1	-	-	-	284,737	277,322	279,034	279,203	281,148	275,754	279,776	273,785	276,551	266,867	271,253	265,310	271,546	269,304	265,384	-	-
Boulder Canyon Hydro	1.25	20,241	20,241	20,241	20,241	20,241	20,241	20,241	6,233	-	-	-	-	-	-	-	-	-	-	-	-
Denver Water Board	1.25	16,008	16,008	16,008	16,008	16,008	16,008	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Garland Canal Hydro	1	9,733	9,733	9,733	9,733	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mancos Water Cons Dist1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Platte River2																					
Tri-County Hydropower / Ridgway1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vallecito	1.25	19,164	19,164	19,164	9,845	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	359,801	363,753	362,662	362,580	360,495	359,420	358,351	358,278	356,227	354,962	354,125	354,061	352,044	351,011	349,983	349,599	347,944	346,932	345,925	345,878
Policy 115 Growth	1	4,264	8,526	12,756	17,013	21,156	25,323	29,470	33,687	37,701	41,779	45,851	50,030	53,920	57,925	61,908	65,997	69,811	73,735	77,641	81,747
LAP <=30 MW (incl. Basin)3	1.25	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920	661,920
CRSP <=30 MW (not NM)3	1.25	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340	33,340
WYO100MWWIND	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND2	1	-	-	-	-	382,161	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND3	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND4	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND5	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND6	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND7	1	-	-	-	-	-	390,404	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWINDBATT01	1	-	-	-	-	-	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540	373,835	373,835	373,835	375,540
SWCO100MWPV	1	-	-	-	-	-	246,582	248,928	251,403	248,291	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV2	1	-	-	-	-	-	246,582	249,062	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND8	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
WYO100MWWIND9	1	-	-	-	-	-	-	377,311	396,682	378,508	377,561	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
ECO100MWWIND	1	-	-	-	-	-	-	-	361,544	397,989	387,291	370,578	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWPV	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV3	1	-	-	-	-	-	-	-	251,448	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV4	1	-	-	-	-	-	-	-	-	248,628	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV2	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWPV3	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV5	1	-	-	-	-	-	-	-	-	-	252,779	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
WYO100MWWIND10	1	-	-	-	-	-	-	-	-	-	-	386,188	395,126	389,363	388,143	388,184	387,918	379,721	384,936	394,835	379,717
SWCO100MWPV6	1	-	-	-	-	-	-	-	-	-	-	249,201	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND3	1	-	-	-	-	-	-	-	-	-	-	-	378,237	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV7	1	-	-	-	-	-	-	-	-	-	-	-	252,658	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND4	1	-	-	-	-	-	-	-	-	-	-	-	-	384,982	384,118	385,003	406,320	381,346	396,315	397,909	382,693
SWCO100MWPV8	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
SWCO100MWPV9	1	-	-	-	-	-	-	-	-	-	-	-	-	244,357	250,069	245,155	253,397	252,024	249,326	248,218	244,648
ECO100MWWIND5	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	385,003	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	406,320	381,346	396,315	397,909	382,693
ECO100MWWIND7	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND8	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
ECO100MWWIND9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381,346	396,315	397,909	382,693
SWCO100MWPV10	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
SWCO100MWPV11	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	249,326	248,218	244,648
ECO100MWWINDBATT02	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
ECO100MWWINDBATT03	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	373,835	375,540
SWCO100MWPV12	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV13	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
SWCO100MWPV14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,218	244,648
Voluntary Program		(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)	(139,000)
Total RECs Generated		3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906	15,396,648
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906	15,396,648
Rollover, Vintage -1 year	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419	15,778,906
Rollover, Vintage -2 year	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736	15,293,419
Rollover, Vintage -3 year	1,972,714	2,159,895	2,323,881	2,643,797	3,136,584	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326	14,654,736
Rollover, Vintage -4 year	1,596,193	1,502,331	1,443,021	1,499,961	1,833,363	2,617,778	3,998,561	4,058,444	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728	13,776,326
Rollover, Vintage -5 year	133,754	-	-	-	-	-	218,857	1,772,011	3,335,012	5,196,675	5,947,172	8,788,823	9,443,973	10,475,184	10,559,299	11,301,355	11,740,191	12,901,664	13,146,838	13,215,833	13,499,728
Expiring RECs		-	-	-	-	-	-	-	-	789,820	2,607,533	3,312,050	6,109,899	6,720,961	7,703,929	7,737,645	8,429,413	8,819,462	9,933,430	10,129,490	10,147,858
BALANCE AFTER COMPLIANCE		**11,766,487**	**13,545,844**	**15,337,347**	**18,223,627**	**21,818,631**	**28,208,532**	**35,207,098**	**43,186,839**	**50,411,126**	**56,515,806**	**62,308,825**	**66,421,667**	**70,124,532**	**72,865,180**	**75,805,609**	**78,280,580**	**81,195,125**	**83,586,881**	**86,218,949**	**88,399,764**
Other REC Sources																					
LAP >30MW (incl, Basin)3		414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548	414,548
CRSP >30MW (not NM)3		955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817	955,817
Basin (MRETs Forecast)4		566,906	642,417	666,581	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898	694,898

New Mexico Compliance

(Energy Transfer Act)

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Retail Load																					
New Mexico Member Load		2,612,907	2,747,921	2,779,463	2,812,346	2,746,850	2,682,294	2,711,769	2,742,982	2,772,621	2,802,899	2,833,421	2,865,028	2,894,395	2,924,969	2,956,189	2,988,368	3,018,519	3,049,387	3,080,519	3,112,544
New Mexico Member Retail Sales6	2%	2,560,648	2,692,963	2,723,874	2,756,099	2,691,913	2,628,648	2,657,533	2,688,123	2,717,168	2,746,841	2,776,753	2,807,728	2,836,507	2,866,470	2,897,065	2,928,600	2,958,149	2,988,399	3,018,908	3,050,293
RPS Percent		10%	10%	10%	10%	40%	40%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
RECs Required		256,065	269,296	272,387	275,610	1,076,765	1,051,459	1,063,013	1,075,249	1,086,867	1,373,420	1,388,376	1,403,864	1,418,254	1,433,235	1,448,533	1,464,300	1,479,074	1,494,200	1,509,454	1,525,147
RPS Compliant RECs	Multiplier																				
Cimarron 1 Renewable Energy	3	183,641	178,584	182,474	178,018	177,813	182,492	176,748	177,520	181,129	177,199	176,727	178,087	173,107	171,650	159,594	-	-	-	-	-
Alta Luna Solar	1	74,710	72,253	73,998	72,825	74,357	74,265	71,143	72,803	72,056	74,707	73,318	72,628	72,242	71,235	72,164	74,249	70,955	72,525	73,144	72,412
Escalante Solar	1	-	-	-	92,486	90,426	90,629	91,406	91,401	89,439	91,075	89,104	89,940	86,910	88,250	86,520	88,283	87,770	86,512	-	-
Truth or Consequences (RECs only)		3,348	3,181	3,022	2,870	2,727	2,591	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Policy 115	1.2	55,186	55,218	54,942	54,808	54,394	54,122	53,851	53,720	53,314	53,027	52,782	52,654	52,256	51,995	51,735	51,538	51,219	50,963	50,708	50,584
Policy 115 Growth	1	474	947	1,417	1,890	2,351	2,814	3,274	3,743	4,189	4,642	5,095	5,559	5,991	6,436	6,879	7,333	7,757	8,193	8,627	9,083
CRSP New Mexico3	1	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905	518,905
NM100MWWind	1	-	-	-	-	-	-	-	386,965	378,013	370,943	379,766	392,123	383,262	393,457	385,983	386,783	386,291	387,603	377,201	384,144
NM100MWWIND2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	386,291	387,603	377,201	384,144
Total RECs Generated		836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,509,189	1,512,304	1,405,786	1,419,273
	Inventory	**REC Balance after Compliance is Met for the Year, (includes multipliers)**																			
Current Year Rollover	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,509,189	1,512,304	1,405,786	1,419,273
Rollover, Vintage -1 year	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,305,057	1,297,046	1,290,498	1,295,696	1,309,896	1,292,674	1,301,928	1,281,779	1,127,092	1,433,573	1,436,424	1,317,063
Rollover, Vintage -2 year	265,817	258,073	835,623	836,264	829,088	834,758	921,804	920,973	925,818	915,327	1,257,612	1,166,281	1,052,915	930,358	807,019	651,160	488,788	291,492	-	-	-
Rollover, Vintage -3 year	209,144	218,896	207,673	770,908	836,264	829,088	834,758	725,974	571,698	410,648	-	-	-	-	-	-	-	-	-	-	-
Rollover, Vintage -4 year	-	-	-	-	495,298	254,797	32,425	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expiring RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BALANCE AFTER COMPLIANCE		**2,148,856**	**2,708,647**	**3,271,018**	**3,917,211**	**3,761,419**	**3,635,778**	**3,488,092**	**3,717,899**	**3,928,078**	**3,845,155**	**3,752,476**	**3,658,507**	**3,532,928**	**3,401,621**	**3,234,867**	**2,897,659**	**2,927,773**	**2,945,878**	**2,842,210**	**2,736,336**

Notes:

1 Project is not registered with WREGIS

2 Contract expired

3 For WAPA Colorado River Storage Projects (CRSP) and the Loveland Area Projects (LAP) the 5 year average REC allocation was used rather then actual generation because generation data is not differentiated by size.

4 RECs for Basin include 2019 MRETs accrual with estimates of known projects (207.58MW Prevailing Wind & 142MW Aurora Wind 2021, 200MW Northern Divide 2022, 128MW Wild Springs Solar 2023, 150MW Cabin Creek Solar 2024) (50% CF for wind and 25% CF for solar)

5 Colorado load determined by deducting 16% of Highline load and adding 17% of High West.

6 2% deducted from NM Load because RPS is based on Retail Sales
Generation from Member Net-Metering programs are not included

Attachment Vol II 7-1 Phase II All-Source RFP

REQUEST FOR PROPOSALS
FOR
CAPACITY AND ENERGY SUPPLY

Tri-State
Generation and Transmission
Association, Inc.

1100 W. 116th Avenue
Westminster, CO 80234

Issue date: [Date TBD]

Tri-State Generation and Transmission Association, Inc.
Request for Proposals (RFP)

Introduction

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a member-owned rural electric generation & transmission (G&T) cooperative headquartered in Westminster, Colorado. Tri-State provides wholesale power and energy to its 42 utility member electric distribution cooperatives and public power districts that collectively deliver electricity over a 200,000 square mile area to consumers in Colorado, Nebraska, New Mexico and Wyoming.

Purpose and Background

Tri-State is evaluating the procurement of renewable, semi-dispatchable and dispatchable resources as part of an All-Source RFP approved by the Colorado Public Utilities Commission (Commission).

Product Description

This single RFP covers three distinct types of resources as described below. Bidders should clearly indicate which resource type they are submitting a proposal for and be cognizant that there are distinct model contracts and Bidder Response Forms depending on the resource type. This RFP focuses on Power Purchase Agreements (PPA) as the transactional structure and does not focus on utility-build or ownership options.

Renewable Resources
All intermittent renewable and carbon-free resources without co-located storage whose pricing will be offered on an annual energy-only basis. This includes, but is not limited to, wind and solar, hydroelectric, geothermal, biomass and in Colorado, recycled energy or eligible coal-mine methane.

Semi-Dispatchable Resources
All stand-alone energy storage systems or resources coupled with storage systems that are limited in the amount of energy delivered during a particular cycle. This includes, but is not limited to, stand-alone battery systems, pumped hydro, compressed air energy storage systems as well as renewable resources with co-located thermal or battery storage.

Firm-Capacity Resources
New or existing gas generation or any other resource that can be dispatched by Tri-State for a reasonable amount of time without any restriction on duration at the rated maximum capacity threshold. Renewable or carbon-free resources such as hydroelectric, biomass or geothermal capable of this requirement may be bid into this resource type. Resources that include carbon capture technologies may be considered under this category as well.

Quantity, Timing and Term[1]

Tri-State is seeking energy and capacity deliveries from projects with nameplate capacity ratings of greater than 20 MW and up to a maximum of [TBD] MW for delivery in [TBD].

A Resource Acquisition Period through 2030 is required by Commission Rule 3605(a)(IV)(A); however, given changes in technologies, load and various other factors that can change over time, commitments to negotiate agreements for specific projects with commercial operation dates more than [four] years from the date of this RFP may be contingent on future RFPs.

Tri-State will only consider projects sourced from a unit-specific generation asset or from a group of generation assets with a single interconnection point. Tri-State will consider PPA terms between fifteen (15) and twenty-five (25) years.

System Description

Tri-State's 2019 member system peak demand was approximately 3,000 MW. Tri-State's current generation portfolio consists of a combination of owned baseload and peaking power plants that use coal and natural gas as their primary fuels, along with leased and contracted supplies of power that include a significant federal hydroelectric allocation, numerous utility scale wind and solar projects, and several small hydroelectric projects.

Tri-State owns and operates approximately 5,600 miles of transmission lines and is a network transmission service customer of Western Area Power Administration, PacifiCorp, Platte River Power Authority, Public Service Company of New Mexico, Public Service Company of Colorado, and Black Hills/Colorado Electric Utility Co. Tri-State also maintains various firm transmission rights on the Tri-State transmission system and with other transmission providers.

Tri-State dispatches generation owned by or under contract to Tri-State and performs wholesale market-related functions on its own behalf. Tri-State is a member of the Western Electric Coordinating Council (WECC) and the Western Systems Power Pool (WSPP). Tri-State currently meets its contingency reserve requirements through its membership in two regional reserve sharing groups.

Tri-State will be operating in two energy imbalance markets in the near term – the WEIM (Western Energy Imbalance Market) and the WEIS (Western Energy Imbalance Service) and expects the development of fully-organized markets in the western region over the course of this decade.

[1] The scope for new resources to be acquired through an all-source competitive acquisition process is expected to be defined by the Commission's Phase I decision approving and/or modifying Tri-State's ERP application.

Location and Delivery

Tri-State will consider delivery of energy and capacity under this RFP to points of delivery in New Mexico, Colorado, Wyoming or Nebraska in the Western Interconnection. Transmission constraints in several areas of the Tri-State system may require generation curtailment, among other actions, to preserve the safe and reliable operation of the transmission grid as well as compliance with North American Electric Reliability Corporation (NERC) reliability standards applicable in the WECC. Bidder has the obligation to operate its project in a manner that preserves grid reliability and safety, and is solely responsible for any costs associated with such curtailment of its project. Such restrictions may be mitigated or eliminated by Network Upgrades as identified by the transmission provider during the interconnection process for projects located in transmission-constrained areas.

Proposals must identify the project's proposed delivery and interconnection point(s) as well as costs included and not included in the pricing with any and all transmission provider(s) required to provide delivery of the output from the proposed resource(s) to Tri-State.

Bidder will be responsible for meeting transmission provider requirements for interconnection, voltage regulation and associated reactive power capability, voltage ride through, power quality, and other criteria as required by the transmission provider's posted Generator Interconnection Procedures. A generator owner and operator will be required to register as appropriate with WECC and NERC.

Bidder is encouraged to consult each transmission provider's OASIS sites for information on generator interconnection requirements.

If the proposed project is intended to be interconnected with the Tri-State transmission system, Tri-State requests that bidders complete and submit a Voluntary Form of Consent with their proposals to allow Tri-State transmission personnel to communicate non-public, project-specific transmission/interconnection information to Tri-State's merchant function personnel. This document is posted on the RFP website [Link TBD].

Pricing and Total Cost of Power Delivered to Tri-State

Prices shall be quoted in U.S. dollars and shall be binding upon the bidder unless expressly stated otherwise. If the bidder's pricing involves escalation or an index, the escalation terms and conditions, or specific index must be included for evaluation.

Proposals must include the total cost of power at the proposed delivery point(s), including but not limited to losses, transmission charges, and the cost of any other services required to be provided by the bidder or third parties. Bidder must clearly explain the costs and breakdown of the pricing components so that the total cost of power under the terms of the proposal can be evaluated on a stand-alone basis. Bidder should take care to

separately identify and specify any transmission, interconnection and network upgrade costs both included and not included in the pricing on the Bidder Response Forms.

Environmental Attributes

Bidder shall provide and Tri-State will retain all environmental attributes associated with the proposed project's output, including but not limited to, renewable energy credits, green tags, greenhouse gas or carbon credits, and any other emissions attributes.

Financial Stability and Performance Guarantees

Financial capability and stability of the bidder and the demonstrated ability to fulfill its contractual obligations are important to Tri-State and will be an integral part of the bid evaluation process.

A successful bidder must satisfy Tri-State's financial security requirements. Tri-State will require financial security arrangements for PPAs, which may include a letter of credit, cash deposit, or other instrument to secure performance under the PPA that is acceptable to Tri-State. Bidder should describe the proposed credit enhancements or other means proposed to guarantee performance under any contract that might result from this RFP.

Bidder must provide sufficient evidence of financial and operational capability to provide the services outlined in the proposal during the contract term. Bidder, its parent, and any other guarantor of services under the bidder's proposal must provide audited financial statements and annual reports from the previous three years in order to demonstrate financial viability. The financial and operational viability of any third parties relied upon by the bidder for providing service to Tri-State must also be demonstrated. If bidder, its parent, and any other guarantor of services has a credit rating, the most recent ratings reports must also be provided.

Finally, bidder must provide references for any current and/or prior power supply agreements to wholesale customers.

Other Terms and Conditions

Tri-State will require that projects comply with all applicable federal, state, and local laws. All permits, licenses, fees, emissions allowances, and environmental requirements are the responsibility of the bidder. If a project is not in service as of the proposal submittal deadline, a detailed milestone schedule describing major project activities, including a permitting schedule, leading up to the commercial operation date must be provided.

Notice of Intent to Submit Proposal

Each potential bidder should complete and return the **Notice of Intent to Submit Proposal** form included on the RFP website to be included in the RFP process. The form must be submitted by 5:00 PM Mountain Daylight Time on [Date TBD]. Although a notice of intent is not required to submit a bid, only those entities that have provided this notice to Tri-State will be notified of any RFP clarifications or corrections that may occur.

A bidder must use best efforts to provide accurate information about its planned proposal in the completed Notice of Intent to Submit Proposal form; however, bidder will not be bound by the information provided in the completed Notice of Intent to Submit Proposal form.

There is no fee required to submit a Notice of Intent to Submit Proposal form.

Bid Fee

Bidders are required to submit a nonrefundable bid fee of $5,000.00 for each project they submit under this RFP. The funds must be received by Tri-State on or prior to the proposal due date of [Date TBD] and may be sent in the form of a check made out to "Tri-State Generation and Transmission Association, Inc." or via electronic funds transfer. Detailed instructions for sending funds to Tri-State are included on the RFP website. Please provide a reference to the bidding organization/proposal on the form of payment. Failure to submit the required bid fee will result in a proposal being disqualified from further evaluation.

A bid fee is applicable to a single project location and single project technology. A bidder may propose up to three (3) different combinations of pricing, contract term, size, or commercial operation date options for a single project without having to submit an additional fee. The table below provides illustrative examples. Projects that are proposed with additional technology options (i.e., wind + solar or solar + battery storage) or different interconnection points will be considered a different project requiring an additional bid fee.

Bid Examples	**Required Bid Fee**
Project with five different pricing options (could offer six pricing options for the same two bid fees)	Two Bid Fees
2023 and 2024 COD dates with two pricing options for the 2023 date and one for the 2024 data	One Bid Fee
Two different project sizes, each with two pricing options (could add a third pricing option to each size for the same two bid fees)	Two Bid Fees

Proposal Content

Bidder Response Forms

Tri-State requires that all proposals submitted to this RFP contain, at a minimum, a completed set of Bidder Response Forms and requested information as applicable. The Bidder Response Forms are contained in a separate file on the RFP website and a distinct, completed set shall be submitted in Microsoft Excel format to the email below **for each project option**. Tri-State will review and may utilize information, if any, submitted by a bidder which is not specifically requested as a part of the Bidder Response Form. Tri-State may request additional information from a bidder during the proposal evaluation process.

For proposals that contain options for different project sizes and/or pricing options, bidders should submit **a separate set of Bidder Response Forms for each option proposed**.

Narrative Topics

In addition to the Bidder Response Forms, each proposal shall describe the following as they relate to any project.

Executive Summary - Summary of the overall project

Development and Siting Status - Bidders shall provide a thorough description of the development status of its proposed project. The information provided should include status of the following:

- Site, Zoning and Construction Permitting - Include the size of the project in acres and any zoning restrictions that would impact development or use of facility
- Environmental Assessments and Studies
- Emissions and Environmental Permitting
- Regulatory and Governmental Approvals
- Engineering and Design Activities
- Resource Acquisitions (i.e., land, equipment such as wind turbines or solar panels, inverters, fuel supply, waste disposal arrangements, etc.) Proof of equipment supply is viewed favorably
- Construction Status
- Project Schedule and Milestones - Include construction start through commercial operation date
- Project retirement / decommissioning plan

Technical Description and Resource Type Data - Bidders shall provide assurance to Tri-State that the project will be able to meet is projected production estimates for the duration of the project life.

- Wind Resources - Provide a correlation of the long-term wind speed data in the region to the collected resource data at the proposed or existing project site.

Please include a general plot plan showing site location, turbine positions, IEC wind class, annual wind production average capacity factor, minimum operating temperature, proposed wind turbine power curve data, nameplate ratings, and manufacturers of proposed turbine equipment. Wind data provided should also include projections by month and hourly patterns to the extent the data is available. Forecasting information should include projections or guarantees of forecasting accuracy as a function of time of delivery. Please include any turbine blade shadowing studies for light and radio wave impacts, any avian (bird or bat) impact studies performed for the project site and confirmation that the site does not conflict with any training area requirements of the US armed services. Bidder should also include any droop response for wind generation.

- Solar Resources - Please describe the proposed solar generation equipment specifications including brand, model, nameplate ratings, size, type and capabilities, modules, inverters, and tracking equipment, and all UL and IEEE equipment compliance information. Water consumption requirements should be included. If applicable, all energy storage devices should be identified. Provide a guaranteed minimum output performance level on an annual basis and detail the design of the specific proposed solar generation system including array configuration, overall system efficiency and total energy output. Please also include a general plot plan showing site location, equipment positions, pertinent meteorological data, annual solar energy production, expected panel degradation and average capacity factor.
- Biomass or Biogas Resources - For proposals that include resources that use a combustion or digester process (such as biomass, biogas or other renewable waste product), the bidder shall provide information describing applicable gas quality, fuel types, fuel sources, fuel contracts, fuel procurement/transportation plans, fuel price risk and availability risk issues. Proposals involving combustion type resources shall also include combustion process by-product emission rates, including SOX, NOX, CO_2, methane, nitrous oxide, CFCs, HCFCs, heavy metals, halides, unburned hydrocarbons and other emissions in gaseous or liquid form, dissolved in another liquid or mixed with a solid for offsite disposal. Describe the quantity and type of all environmental permits for air and water compliance required to develop the project, and if such permits and approvals are not already in the bidder's possession, provide information regarding the plan to acquire such permits and associated approvals. Proposals should also include gas production forecasts for resources identified, including decay rate of gas production from landfill or digester processes for closed or active sources, and forecast for future sources planned.
- Geothermal Resources - Please provide a summary of all collected geothermal data for the proposed or existing site and characterize the geothermal resource quality, quantity and proposed production levels. Describe land lease and rights issues and describe and test drilling performed (if applicable). Provide a table or graph that illustrates the annual and monthly projection of geothermal resources.
- Hydro Resources (including pumped hydro) - Provide a description and map of the project area and any information about the project's water rights and any ongoing or anticipated disputes, legal challenges or regulations affecting those

water rights. Identify if the project is run-of-river or has storage/pondage capability. Identify the volume of the storage and any hourly, daily or seasonal restrictions to the use of the storage for power production. Provide an estimate of the average firm generation expected over the life of the project. Identify anticipated generation by month during an average water year and a low water year. Provide monthly flow duration curves based upon daily stream flow records.

- Energy Storage Systems - For co-located or stand-alone energy storage systems, please provide the type of storage facility, describe any system limitations such as the number of discharges per day, per year and over the contract term as well any limitations on the depth of discharges. Also, please discuss any expected degradation or potential of adding capacity during the contract term. Further, specifically for battery systems, please provide information on the ability to charge from the grid and about the battery chemistry selected.
- Other Resources - Provide a description of the fuel source and identify its thermal (heat content), delivery and storage characteristics. Provide an estimate of the average generation expected from the fuel source over the life of the project. Describe the methodology and the in-house or consulting expertise used to arrive at the generation estimates.

Pricing Methodology - Please describe the pricing structure. Tables to list prices are provided in the Bidder Response Forms, however, Tri-State is interested in the methodology used by all bidders to ensure pricing includes all applicable charges. Examples of items to discuss, as applicable, are: demand charges versus energy charges. Are there start up charges, or start-up fuel costs? If there is a separate demand component, describe the methodology for calculating the kW billing demand determinant. Is pricing fixed or subject to change? Is pricing dependent upon certain subsidies or credits? Is there a separate transmission charge component?

Transmission & Interconnection - Please indicate the transmission provider for which you have applied for interconnection and describe the timing and status of the interconnection and/or transmission application and results.

Best Value Employment Metrics – Please provide information on the following as they relate to the bid project.

- Availability, cost and duration of training programs including training through apprenticeship programs register with the United States Department of Labor Office of Apprenticeship and Training.
- Estimates of the number of man-hours worked by Colorado workers as compared to total man-hours for each job classification.
- Long-term career opportunities for each job classification
- Wages and fringe benefits (healthcare, pension and other compensation) by job classification.

Financing and Credit - Describe proposed financing arrangements including potential sources of funding, contingencies, and interest during construction.

- Is financing required to fund the transmission and/or generation facilities? If yes, have financing arrangements been made prior to submitting this proposal?
- Describe any financial instruments the bidder will use to guarantee the financial security requirements described in the indicative term sheet.
- If company is rated by S&P, Moody's and/or Fitch, please provide latest credit report from (if responding company is not rated, then please provide for parent company and/or any other guarantor).
- Please include the most recent SEC form 10K and most recent SEC Form 10Q Report
- Please include the most recent Annual Report

References - Please list client references who may be contacted and for whom services have been rendered in the last 24 months. Include names, titles, address, phone numbers and e-mail addresses.

Project Team – Please describe the company and personnel to be involved as follows:

- Please provide a bidder profile, including office location, age of company, average number of employees over the past 5 years, and any ownership interests.
- Description of the bidder's pertinent experience for all power projects, projects of similar technology, and projects located in the same state as proposed for this project. The bidder should designate if the experience is in (1) development, (2) construction, (3) ownership and/or (4) operation and maintenance of the projects.
- State whether there is any current litigation regarding any power supply matter involving the bidder and any of its subsidiaries or off-balance sheet companies in which it has an interest. If there is any current litigation, provide a discussion of the current litigation.
- Provide a bidder organization chart and identify qualifications of key staff.

Model Contracts

Model contracts are posted on the RFP website. Each bidder is required to review the applicable model contract depending on resource type and identify any modifications or objections and include this mark-up with its proposal(s). It is expected that bidders offer meaningful input, comments such as "will be discussed" is not considered meaningful.

Proposal Submittal

All proposals must be received by Tri-State by no later than 5:00 PM Mountain Daylight Time on [Date TBD]. All proposals must be sent via email and a single hard copy delivered by this deadline. Emailed proposals must be sent to the email address listed below. Hard copies may be submitted by U.S. mail, overnight or courier service, or hand delivery. A hard copy submittal must include a signed original. If there is a discrepancy between the electronic and hard copies, the hard copy will prevail.

Proposals received after the deadline will not be considered unless Tri-State determines in its sole discretion that extenuating circumstances led to late delivery.
Proposal submittals should be directed to Tri-State's RFP administrator as follows:

Origination Manager
Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234

E-mail: renewablerfp@tristategt.org

Proposal Checklist

To assist bidders in ensuring their proposals are complete and eligible for evaluation by Tri-State, a checklist of required and optional items is listed below:

	Item	Due Date
	Notice of Intent to Bid	[Date TBD] by 5:00 PM MDT
	Bidder Response Forms	[Date TBD] by 5:00 PM MDT
	Narrative Topics	[Date TBD] by 5:00 PM MDT
	Model Contract comments	[Date TBD] by 5:00 PM MDT
	Bid Fee	[Date TBD] by 5:00 PM MDT
	Form of Voluntary Consent	[Date TBD] by 5:00 PM MDT

Tentative RFP Schedule*

RFP Release Date	[Date TBD]
Notice of Intent to Submit a Proposal due	[Date TBD]
Proposals Due	[Date TBD]
Identify Short-listed Proposals	[Date TBD]
Execute Project Agreements**	[Date TBD]

** Tri-State will make a concerted effort to maintain the tentative schedule but reserves the right to revise the schedule to accommodate changing circumstances.*
***Contingent on Commission Phase II decision*

Proposal Duration

All proposals must be valid through the Phase II evaluation period and short-listed and back-up bids must remain valid through the subsequent negotiation period following the issuance of a final Phase II Commission Decision.

Project Agreements

Tri-State's selection of bidders for project agreement negotiations does not create an implicit contract between Tri-State and the bidder, nor is the selection process, including negotiations, a guarantee of contract between Tri-State and the bidder as a result of this RFP.

Collusion

By submitting a proposal to Tri-State under this RFP, bidder certifies that it has not divulged, discussed or compared its proposal with other bidders and has not colluded whatsoever with any other bidder or parties with respect to this proposal.

Bid Evaluation Criteria

Bidders to this solicitation should provide all relevant financial and operational information necessary to allow Tri-State to conduct a thorough analysis of their proposals. Proposals will be analyzed over a range of scenarios defined by price and non-price variables.

An initial economic analysis will be conducted where the Levelized Cost of Energy (LCoE) for each project option is calculated using the discount rate approved by the Commission in its Phase I decision. The LCoE will be calculated by determining the "all in" Net Present Value (NPV) of the average annual costs divided by the NPV of the average annual energy.

The projects will then be reviewed with respect to non-price factors. These will include:

- Best Value Employment Metrics
- Contribution to meeting GHG reduction goals of Colorado
- Location in a Tri-State utility member system service territory
- Financial viability of the bidder, including its parent or any other guarantor of services under the bidder's proposal
- Bidder's prior experience with project development
- Certainty of outside funding sources (i.e. tax credits or government subsidies)
- Compliance with all applicable local, state and federal laws, rules and orders
- Renewal and purchase options at the end of PPA
- Project retirement / decommissioning plan
- Legal, engineering and other costs required to implement the proposed project
- Forecasting capability

Each of these factors is important to the addition of a new capacity and/or energy supply resource to Tri-State's existing resource portfolio. Tri-State reserves the right to consider any other factors that it deems to be relevant to its supply portfolio needs.

Bids will then be evaluated with respect to transmission interconnection and network upgrade costs. It is expected that any electric interconnection network upgrades, firm transmission and/or wheeling costs necessary to deliver a project's output to a system where Tri-State is a network transmission customer are included in the pricing. Potential bidders should review and clearly understand Tri-State's Transmission Provider function's interconnection process.

While, at a minimum, having initiated an LGIP application can better define a project's potential viability, it is not required for bids proposing to connect to the Tri-State transmission system. Projects that have only just submitted interconnection requests or have not begun the LGIP with Tri-State should still include estimates of these costs and assumptions in the pricing offered and provide the specific amounts in the bid forms. Tri-State's Transmission Provider function will then review estimated transmission costs based on existing interconnection studies. This evaluation is not a substitute for the LGIP and does not guarantee the viability of a project. Projects utilizing incremental transmission capacity resulting from network upgrades that have received a CPCN will not be assessed costs associated with those upgrades.

Projects connecting to other transmission systems will be required to provide network upgrade and interconnection costs developed through an LGIP application (and associated studies) or an equivalent independent study. In addition, any bidder connecting a project to a system where Tri-State does not hold network transmission rights must be able to provide a transmission service request and system impact study demonstrating the availability of firm transmission service to a system where Tri-State does hold network transmission rights and include these costs along with any wheeling, losses and other costs associated with such services in its bid pricing.

Inquiries and Other Communications

For information and inquiries relating to the RFP, an e-mail address has been established at renewablerfp@tristategt.org. This e-mail address will be the primary means of communication for all inquiries, responses to questions, updates and clarifications. Bidders are asked not to contact the RFP administrator or any other Tri-State employee directly.

In order to facilitate a clear and timely response to critical inquiries, all bidders are encouraged to submit questions via e-mail on or prior to [DATA TBD]. Questions and responses to specific questions and general information, clarification of items, etc. will be posted on the RFP website, without bidder identification or attribution.

Confidentiality and Disclosure

Bidders may identify any information in their proposals that they consider to be confidential or proprietary. Nonetheless, Tri-State reserves the right to release all or a portion of the proposals to its affiliates and members and their agents, advisors and consultants for purposes of proposal evaluation. Tri-State will, to the extent required by law, advise each member, agent, advisor or consultant that receives such claimed confidential information of its obligations to protect such information. In addition, Tri-State reserves the right to release and disclose, without any obligation of confidentiality and at any time, (a) the general location or generation technology type of any of proposals submitted to Tri-State provided it does not identify the individual bidders and (b) aggregated bid pricing information that does not identify particular bids or bidders. Furthermore, all information, regardless of its confidential or proprietary nature, will be subject to review by the Commission and other governmental authorities and courts with jurisdiction, and may be subject to legal discovery. It is not Tri-State's intent to enter into any separate confidentiality, nondisclosure, or similar agreements as a condition to receiving a bidder's proposal.

Notwithstanding the above paragraph, a reasonable number of attorneys and a reasonable number of subject matter experts representing a party to the Tri-State's 2020 ERP proceeding may, upon the execution of the appropriate nondisclosure agreement, request and receive access to all bid information provided in response to this RFP regardless of a bidder's claim of confidentiality or propriety. In addition, upon completion of the competitive acquisition process, Tri-State is required by Commission Rule 3605(h)(IV), to post on its website and thereby make publicly available the following information from all bids: bidder name; bid price and utility cost; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed PPA includes an option for the utility to purchase the bid facility during or at the end of the contract term.

Acceptance of Proposals

Tri-State reserves the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. A bidder who submits a proposal does so without recourse against Tri-State for either rejection by Tri-State or failure to execute an agreement for purchase of capacity and/or energy for any reason. Additionally, Tri-State reserves the right to accept proposals other than the lowest cost proposal and bidders should recognize that factors other than cost, as described above, will be considered during the proposal evaluation process. Tri-State will not reimburse any bidders for any cost incurred in preparing and submitting a proposal or any subsequent contract negotiations or the bid fee. Under no circumstances will Tri-State be contractually bound by the terms of any bidder's proposal until a fully-executed agreement has been entered into between the parties.

Tri-State Board of Directors and Regulatory Approval

The projects offered in this RFP will be evaluated as described above and ultimately be presented as portfolios of resources in an ERP Implementation Report to be filed for approval with the Commission. It is expected that the Commission will issue a decision approving, modifying or denying any of the portfolios within 90 days. Depending on the outcome of the decision, preliminary contract negotiations may be initiated but Tri-State cannot fully move forward without Commission approval. Once there is a final Commission decision in place, Tri-State can commence or finalize preliminary contract negotiations with the ability to commit to specific projects.

Any contracts that may be considered as a result of this RFP or subsequent negotiations will be subject to Tri-State Board of Directors approval and inclusion in the resource portfolio approved by the Commission as part of the Electric Resource Planning process and may be subject to other regulatory approvals.

Thank you for your interest.

Attachment Vol II 7-2 Bidder Highly Confidential Non-Disclosure Agreement

Commission Confidentiality Order

BIDDER HIGHLY CONFIDENTIAL NONDISCLOSURE AGREEMENT

I, _____, state that I am employed by a bidder in Tri-State's 2021 All-Source RFP.

For purposes of this highly confidential nondisclosure agreement "Potential Resources" means the new or existing resource of the bidder by which I am employed.

For purposes of this highly confidential nondisclosure agreement "Highly Confidential Information" means highly confidential modeling inputs and assumptions that reasonably relate to the Potential Resource or to the transmission of electricity from that Potential Resource to Tri-State.

I understand that I may obtain Highly Confidential Information for the sole purpose of assisting the bidder to identify modeling errors or omissions concerning its Potential Resource so that the modeling errors or omissions may be corrected before the competitive acquisition process is completed.

I hereby state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1104. With respect to all Highly Confidential information that may be provided to me, I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100.

I hereby state that I will properly implement and maintain extraordinary confidentiality provisions for the Highly Confidential Information I receive.

I hereby state that I will not disclose or disseminate any Highly Confidential Information I receive to any third party other than to those who are specifically authorized to review such Highly Confidential Information and who have signed a highly confidential nondisclosure agreement. At the conclusion of the 2021 All-Source RFP competitive acquisition process, I agree to return all Highly Confidential Information to Tri-State Generation and Transmission Association, Inc.

_____

Name

_____

Title

_____

Employer or Firm

_____

Business Address

_____

Bidder Represented

_____

Date

_____

Signature

Attachment Vol II 7-3 Dispatchable PPA

Tri-State 11/19/2020
Model Dispatchable PPA
TS-XX-XXXX

POWER PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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POWER PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This Power Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a **_insert generation technology_** electric generating facility consisting of _____(__) _____ with an expected total nameplate capacity of ___ (the "Expected Nameplate Capacity Rating"), and which is further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility **[**to Interconnection Provider's existing _____ transmission line in the vicinity of the Site**][**at the Interconnection Provider's _____ Substation**]**; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric power and energy produced by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Capacity and Contract Energy to be generated by the Facility. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(B).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Capacity Availability Factor" or "CAF" equals (AE + SME) ÷ PE

Where:

AE = Available Energy, stated in MWh, means the amount of Contract Energy that is available from the Facility for dispatch and receipt by Tri-State, regardless of the extent to which Tri-State actually dispatches the Facility, during such period. For purposes of calculating AE:

- The Facility shall be derated for Forced Outages (regardless of whether caused by Force Majeure Event) and ambient conditions.
- Contract Capacity that is unavailable for dispatch by Tri-State nevertheless shall be considered to be available for the purposes of determining Available Energy when (and only when):

(i) the Facility is disconnected from the Transmission System pursuant to the Interconnection Agreement, and the disconnection is not caused by actions of Seller or problems with the Facility;

(ii) the Contract Capacity and associated Contract Energy cannot be delivered by Seller or received by Tri-State due to an Emergency Condition or Force Majeure Event affecting the Transmission System at or beyond the Point of Delivery;

(iii) Tri-State has contracted for non-firm transmission service, and the Contract Capacity and associated Contract Energy cannot be received at the Point of Delivery due to transmission constraints affecting the Transmission System; and/or

(iv) [if any – generation technology, project specific- the Facility cannot operate because its emissions have exhausted the annual limits of its Permits but the Facility has generated the Planned Permitted Energy for such year].

SME = Scheduled Maintenance Energy for any period, stated in MWh, means the amount of Energy that is not available from the Facility for dispatch and receipt by Tri-State during such period, due to Scheduled Maintenance Outages not to exceed **_insert – generation technology and project specific-** MWhs.

PE = Period Energy for any period, stated in MWh, means the product of the Expected Capacity Rating and the total number of hours in such period.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Capacity" means all net generating capacity including any and all capacity attributes and all net generating capacity available from the Facility, including uncommitted and undispatched capacity, not exceeding the Nameplate Capacity Rating.

"Contract Energy" means all net electric Energy generated by the Contract Capacity as dispatched by Tri-State from time to time, and any other attributes resulting from the generation or the output of the Facility or produced by the Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy.

"Capacity Payment" means the payment specified in Section 7.1.

"Contract Energy Payment" means the payment specified in Section 7.2.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Capacity and/or Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2(A).

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all metering and data processing equipment used to measure, record, or transmit data relating to the power and Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs).

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to Contract Energy, Contract Capacity, and/or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation from the Facility (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in

part, to sell Contract Capacity and/or Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the **_insert – generation technology and project specific-** and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means Seller's **_insert generation technology_** electric generating facility and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including turbines, step-up transformers, fuel piping systems, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such electric generating facility. The term "Facility" includes the **_insert – generation technology and project specific-**, and generator step up transformer.

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration,

prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, or (iv) an Emergency Condition.

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit (including land use, air quality, and emissions control), exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA or the purchase of power and energy from the Facility.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit J.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in electric generation relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Minimum Loading" means the minimum capacity of the Facility that can be scheduled for continuous operation consistent with Prudent Utility Practices, including equipment manufacturer's warranties and performance standards.

“Month” means a calendar month.

“Moody’s” means Moody’s Investors Services, Inc., or any successor thereto.

“MPT” means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

“MW” means megawatt.

“MWh” means megawatt hours.

“Nameplate Capacity Rating” means the maximum installed instantaneous generation capacity of the completed Facility, expressed in MW, when operated in compliance with the Interconnection Agreement and consistent with the Facility manufacturer’s recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW.

“NERC” means the North American Electric Reliability Corporation, or any successor organization.

“O&M Records” shall have the meaning set forth in Section 13.7.

“Operating Committee” means one representative each from Tri-State and Seller, appointed pursuant to Section 9.9(A).

“Operating Procedures” means those procedures developed pursuant to Section 9.9(B).

“Operating Records” means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

“Operating Reserve” means the undispatched portion of the Contract Capacity, which is maintained to respond to system needs as determined by Tri-State.

“Operating Requirements and Restrictions” means the operating requirements, parameters and restrictions set forth in Exhibit G.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

[if any – generation technology, project specific- "Planned Permitted Energy" means **Insert – generation technology and project specific-** MWh per calendar year of Contract Energy authorized or expected to be authorized to be generated in accordance with Seller required Governmental Approvals.]

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Capacity and Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this Power Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, steam pressure, temperature, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, rotational speed, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (i) has operated, for a period of at least five (5) years, multiple electric energy generating facilities of a similar type, size in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Facility.

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State for the Energy, capacity, ancillary services and Enviromental Attributes which are necessary to replace that which Seller, in accordance with this PPA, is required to produce at the Facility and deliver to Tri-State, but will fail to so

provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a resource and any penalties incurred as a result of Seller's non-performance.

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down, derated, or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Successful Start" means, in response to a request from Tri-State to start the Facility, Seller's start and operation of the Facility that:

(A) achieves the Minimum Loading level for the requested operating configuration within **_ Insert – generation technology and project specific-** minutes after the time Tri-State requests the Facility start to begin, and

(B) upon achieving such Minimum Loading level, generates continuously for a period of not less than one hour while synchronized to the Transmission System at or above such Minimum Loading level without experiencing any abnormal operating conditions.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken prior to and in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2, which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.6.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Capacity and Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Capacity and Contract Energy is subject to PUC Approvals. Tri-State shall

(i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of _____ and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating**. Exhibit B provides a detailed description of the Facility,

including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Facility on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State for AGC, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State; and

(D) meet the Operating Requirements and Restrictions.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing and delivering the Contract Capacity and Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a

Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW of nameplate capacity not installed, operating and capable of generating Test Energy below the Expected Nameplate Capacity Rating until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-

State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20^{th}) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery of Contract Capacity and Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility with any Governmental Authority or other Person as requested by Tri-State pursuant to Section 10.2(A);

(6) Seller having successfully completed Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated at a generation level acceptable to the

Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility;

(J) the Facility has achieved at least two Successful Starts, without experiencing any abnormal operating conditions and the Facility has demonstrated the ability to meet the Operating Requirements and Restrictions;

(K) generation technology specific- the Facility has generated continuously for a period not less than **_insert – generation technology and project specific-** consecutive hours, at an output level not less than **_insert – generation technology and project specific-** % of Expected Nameplate Capacity (adjusted for ambient conditions), without experiencing any abnormal operating conditions; and

(L) the Facility is configured and available for operation in a manner to permit accreditation of the Facility as a Capacity Resource, in an amount substantially equal to the Expected Nameplate Capacity Rating.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase all such Test Energy in accordance with this PPA, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery, Metering and Fuel Supply

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Capacity and Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Capacity and Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Capacity and Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-firm transmission service or network integration transmission service for the delivery of Contract Capacity and Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [_____] trips and the causes of such trips, Facility failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Capacity and Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering

Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(C) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(D) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made

correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Capacity and Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 Fuel Supply

(A) generation technology specific- Seller shall be solely responsible for all fuel interconnection, transportation, delivery and metering arrangements, and all associated costs, required to receive fuel to operate the Facility. Seller shall, at its sole expense, construct, operate and maintain the pipelines, compressors, meters, heaters, filter/separation equipment, electronics, and other necessary equipment, of sufficient capacity and industrial specifications to receive, regulate, meter and transport fuel to the Facility, to allow for full operation of the Facility over the Term.

(B) generation technology specific- Seller shall procure and pay for all fuel for the generation of Contract Capacity and Contract Energy. The cost of fuel is included in applicable price set forth in Article 7.

Article 6
Contract Capacity and Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Capacity and Contract Energy and all other products and services required by this PPA; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any capacity or Energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Capacity and/or Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Capacity and Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Capacity and Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Capacity and Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Reactive Power

Tri-State shall have access to the full reactive output capability of the generating facility limited by the generator capability curves. Tri-State will notify Seller of required reactive power dispatch as a normal part of the generation dispatch process, or via a schedule of VAR output as a function of MW output.

6.4 Dispatch

Tri-State's RDD shall have dispatch control of the Facility, including the start-ups, shutdowns and generation (MW and MVar) loading levels associated with Contract Capacity and Contract Energy, subject to the Operating Requirements and Restrictions. Tri-State will not dispatch the Facility below Minimum Load. Subject to the Operating Requirements and Restrictions, at least thirty (30) Days prior to the Commercial Operation Date, Seller shall notify Tri-State of the Minimum Load. Thereafter, any changes to the Minimum Load shall be in accordance with the Operating Procedures. For any Facility trip, Seller shall restart the Facility in coordination with RDD and in accordance with Prudent Utility Practices. Tri-State shall make reasonable efforts to provide Seller at least day-ahead notice of the generation levels anticipated by Tri-State from the Facility, provided that such notice shall be subject to and may be pre-empted by real-time operating conditions on Tri-State's electric system, including, but not limited to, Emergency Condition, reliability, stability and economic conditions.

6.5 Operating Reserve.

All Operating Reserve, if any, associated with the Contract Capacity shall be deemed to have been purchased by Tri-State, and shall be made available to Tri-State, consistent with the terms of this PPA. Seller shall use reasonable commercial efforts to maximize the Operating Reserve available to Tri-State from the Contract Capacity, consistent with and subject to the Operating Requirements and Restrictions and Prudent Utility Practice.

6.6 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Capacity and/or Contract Energy due to a Forced Outage or Emergency Condition resulting in a capacity reduction of more than ten (10) MW and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

In addition to the foregoing notification, for any Forced Outage, shutdown or derating of the Facility of more than ten (10) MW, Seller shall conduct a root cause analysis, immediately provide the root cause analysis to Tri-State, and take corrective action to prevent reoccurrences as soon as practicable thereafter, at Seller's sole expense. Such corrective action includes weather protective modifications to the Facility, additional operating or maintenance procedures and other appropriate preventative measures in accordance with Prudent Utility Practices. Seller shall diligently complete such analysis and corrective actions as soon as possible and provide to Tri-State a written report containing such analysis and a summary of the corrective action taken or to be taken as soon as diligently possible.

6.7 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Capacity and Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

6.8 Permit Limitations.

[if any – generation technology, project specific-

(A) Neither Party shall take any action that would create a restriction under any Seller required Governmental Approvals that would preclude or limit the generation or delivery of Contract Capacity or Contract Energy to Tri-State.

(B) Seller covenants that Seller has, or will receive prior to, the generation of Contract Capacity or Contract Energy authority under Applicable Law, and obtain the applicable Governmental Approvals, to generate and deliver Contract Capacity and Contract Energy to Tri-State. Seller accepts the risk that its Governmental Approvals or other Applicable Law will preclude or limit its legal authority to generate and deliver all of the Planned Permitted Energy.

(C) Upon request by Tri-State from time to time, Seller shall provide to Tri-State such detailed data regarding emissions from the Facility, as Tri-State may reasonably request.]

Article 7
Payment Calculations

7.1 Contract Capacity Payment

Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller a monthly payment for Contract Capacity ("Capacity Payment") based on the following formula set forth in Exhibit C.

7.2 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for Contract Energy delivered each Month (the "Contract Energy Payment") determined by the formula set forth in Exhibit C.

7.3 Adjustments to Payments.

[if any – generation technology, project and payment formula specific]

7.4 Testing of Facility.

[if any – generation technology, project and payment formula specific]

7.5 Payment for Facility Starts

[if any – generation technology, project specific- Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller for the number of successful start of the Facility requested by Tri-State in the monthly billing period. The monthly " Start Payment" shall be determined by the formula set forth in Exhibit C.]

7.6 Test Energy Payment.

During Testing, Tri-State shall pay Seller an energy payment for Test Energy delivered each Month (the "Test Energy Payment") determined by the formula set forth in Exhibit C.

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for the services provided by Seller and purchased by Tri-State under this PPA during the previous calendar month billing period. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street Journal* (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law

("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Capacity or Contract Energy within one hundred eighty (180) Days of delivery of such Contract Capacity or Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy and providing capacity from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such Taxes, allowances and credits during the Term. If Tri-State is

assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price set forth in this PPA.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity of the Facility or the output of Contract Capacity and/or Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State

shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations, Prudent Utility Practices, and Exhibit G and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. generation technology specific- Personnel of Seller capable of starting, operating, and stopping the Facility shall be physically present at the Facility 24x7 during Commercial Operation.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver Contract Capacity and Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

(A) Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State (i) the Scheduled Maintenance Outages (including the date, start time and expected duration of the outage), for the subsequent Year and (ii) the projected long-term Scheduled Maintenance Outages encompassing the following four Years or the remainder of the Term, whichever period of time is shorter. Within thirty (30) days of receipt of the maintenance schedule, Tri-State may reasonably change the annual maintenance schedule proposed by Seller by written notification to Seller. Seller shall notify Tri-State of any changes to the Scheduled Maintenance Outage, including start date, as follows:

Scheduled Outage Expected Duration	Advance Notice to Tri-State
(1) Less than 2 Days	at least 24 hours

(2) 2 to 5 Days — at least 7 days

(3) Major overhauls (over 5 Days) — at least 90 days

(B) In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.7 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.8 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Capacity and Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.9 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Capacity and Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; changes in the Minimum Load, Contract Capacity deration reports; Contract Energy reports; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. The prices set forth in Article 7 include the consideration for the assignment, purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the services provided by Seller and purchased by Tri-State under this PPA, including Contract Energy and Contract Capacity. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy and/or Contract Capacity at the Facility that gives rise to such Environmental Attributes or the creation of the Environmental Attributes, as applicable. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(B) Duration. Environmental Attributes associated with the Facility, Contract Energy and Contract Capacity are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Registration of Environmental Attributes.

(A) Seller Registration. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities or such other Persons requested by Tri-State in order to qualify the Facility or qualify the Contract Energy, Contract Capacity and/or Environmental Attributes with such Governmental Authority or such other Persons and maintain such registration/certification for the Term for Tri-State to obtain the full benefit of the Environmental Attributes.

(B) Tri-State Registration. Upon request from Tri-State in lieu of Seller registering as provided above, Seller hereby irrevocably assigns to Tri-State all rights, title and authority for Tri-State to register the Facility and own, hold and manage the Environmental Attributes associated with the Facility in Tri-State's own name and to Tri-State's account, including any rights associated with any reporting or tracking system that exists or may be established with regard to monitoring, registering, tracking, certifying, and/or trading such Environmental Attributes. Seller hereby authorizes Tri-State to act as its agent for the purposes of registering the Facility and tracking, certifying, registering and reporting such Environmental Attributes. Seller grants to Tri-State full authority to hold, use, sell and/or trade such Environmental Attributes for its own account in all applicable reporting or tracking systems.

(C) Attestations. Upon request from Tri-State, Seller shall, at its expense, (i) deliver or cause to be delivered to Tri-State appropriate attestations/certifications of Environmental Attributes, and (ii) cooperate with tracking, registration, reporting and certification of Environmental Attributes.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); *provided* that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions: (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars

($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) for the period beginning with the Effective Date until the Commercial Operation Date; and (ii) **Insert $125*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 12.3 and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-

State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Capacity and/or Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(6) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(7) A persistent pattern of willful misconduct by Seller resulting in a failure by Seller to provide Contract Capacity and Contract Energy to Tri-State in accordance with this PPA;

(8) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(9) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Capacity and/or Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Beginning on the Second Commercial Operation Year, Seller's failure to maintain a CAF of at least eighty-five percent (85%) on a twelve (12) month rolling average basis shall constitute an Event of Default of Seller upon its occurrence; *provided* that to the extent such failure of performance is attributable to Force Majeure Event, the contribution of such Force Majeure Event shall be eliminated from the CAF calculation for the purposes of, and only for the purposes of, establishing an Event of Default of Seller pursuant to this this Section 12.1(D); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the Event of Default, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the CAF (again with periods of Force Majeure Event excluded from the calculation) equals or exceeds ninety percent (90%).

Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the CAF fails to equal or exceed ninety percent (90%) for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include any Replacement Costs incurred and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof, upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination

of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will

remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and

the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Capacity and Contract Energy committed to Tri-State under this PPA other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's

representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date hourly operating log, in electronic format, at the Facility, that identifies real-time operating information for the Facility, including levels of capacity availability; energy production; changes in operating status; Forced Outages; Scheduled Maintenance Outages; information required by Governmental Authorities in the prescribed format; and other information reasonably requested by Tri-State (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

Seller shall deliver to Tri-State information on Facility performance during each calendar month within five Business Days after the end of the month. Using definitions provided by (or consistent with) the NERC Generation Availability Data System ("GADS") Manual, or any successor document, the data reported shall include planned and unplanned derated hours, average derated kW from the Nameplate Capacity Rating during the derated hours, scheduled maintenance hours, average derated kW during scheduled maintenance hours, the number of successful and unsuccessful starts, hours on-control, hours on-line, and the monthly operating log of the Facility.

13.8 Availability Reporting.

(A) Seller shall provide accurate and timely updates to Tri-State on the current availability of the Contract Capacity ("Reported Availability"), adjusted for ambient conditions, via such electronic means as may be reasonably specified by Tri-State. The amount of Contract Capacity available for any individual hour shall be integrated over the hour, on a prorated basis, to reflect any updates in Seller's Reported Availability made effective during such hour.

(B) Tri-State may verify Seller's then-current Reported Availability at any time, without prior notice to Seller, by dispatching the Facility to the level of Reported Availability. Tri-State shall notify Seller as soon as possible by telephone and thereafter in writing whenever Tri-State identifies an issue with Reported Availability.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve

the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Capacity and Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure any equipment or parts for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure any equipment or any parts for the Facility, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller,

unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; (xi) [if any – generation technology, project specific-restriction in any Seller required Governmental Approvals that precludes or limits the generation or delivery of Contract Energy below the Planned Permitted Energy]; or (xii) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Capacity and Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Capacity Rate, Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Capacity and/or Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each

Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Section 7.1.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business

in _____ and in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank

moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the Indemnifying Party shall be entitled, at its option, to assume and control the defense of

such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below, settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf

of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the

Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a "Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the

safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Change in Law

[if any – generation technology and project specific]

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State

for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Capacity and Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The

Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[ ]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[ ]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[ ]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[ ]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[ ]	Delivery of major components to the Site shall have commenced.
[ ]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[ ]	The step-up transformer shall have been delivered to the Site.
[ ]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.
[ ]	Start-up testing of the Facility shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Facility on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

PRICING

Contract Capacity Formula

TBD – project specific

Contract Energy Payment Formula

TBD – project specific

Start Payment Formula

TBD – project specific

Test Energy Payment Formula

TBD – project specific

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

> primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

EXHIBIT G

OPERATING REQUIREMENTS AND RESTRICTIONS

TBD - generation technology and project specific

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain Power Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____ electric generating facility having an Expected Nameplate Capacity Rating of _____ MW to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.
    a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
    b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

    a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
    b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
    c. any defense based upon an election of remedies by Company;
    d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have

been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN POWER PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS

LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

Attachment Vol II 7-4 Semi-Dispatchable PPA

Tri-State 11/19/2020
Model Semi-Dispatchable PPA
TS-XX-XXXX

[WIND] [SOLAR] AND STORAGE ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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[WIND] [SOLAR] AND STORAGE ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This [Wind][Solar] and Storage Energy Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a _____ -powered electric energy generating facility consisting of _____(__) _____ [wind turbines][solar panels] (each, a "Generating Unit" and collectively, the "Generating Units") with an expected total nameplate capacity of ___ MW [*solar only-* AC] (the "Expected Nameplate Capacity Rating"), plus an energy storage facility consisting of _____(__) _____ (each, a "Storage Unit" and collectively, the "Storage Units") with an expected storage capacity ___ MW (the "Expected Energy Storage Capacity"), which is collectively further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility [to Interconnection Provider's existing _____ transmission line in the vicinity of the Site][at the Interconnection Provider's _____ Substation]; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric energy produced and/or stored by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as

commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

[solar only- "AC" means alternating electric current.*]*

"Additional Tax Benefits" means any new Tax Benefits or changes to, extensions of, or qualification for existing Tax Benefits which become available to Seller or the Facility during the Term, from and after the Effective Date, and which provide an overall net increase in the Tax Benefits attributable to the Facility.

"Additional Tax Benefit Amount" means an amount equal to (i) the aggregate amount of all Tax Benefits received by or on behalf of Seller with respect to any Additional Tax Benefits, minus (ii) the aggregate amount of all Additional Tax Benefit

Costs with respect to such Additional Tax Benefits. For the avoidance of doubt, if the Additional Tax Benefit Amount is a negative amount, it shall be deemed to be zero.

"Additional Tax Benefit Costs" means all additional costs, if any, incurred by Seller resulting directly from production, qualification, or verification of an Additional Tax Benefit.

"Additional Maintenance Outages" shall have the meaning set forth in Section 9.7.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production and storage via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Energy to be generated by the Facility or stored/discharged by the Storage System. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Allowable Curtailment" means the amount of otherwise compensable Curtailed Contract Energy in any Commercial Operation Year to be applied at the election of Tri-State at any time during a Commercial Operation Year, which amount equals (i) one percent (1%) in MWh of the Expected Contract Energy for that Commercial Operation Year plus (ii) any unused Allowable Curtailment from prior Commercial Operation Years. Any unused Allowable Curtailment from a Commercial Operation Year does not expire at the end of a Commercial Operation Year and is carried forward to future Commercial Operation Years.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(D).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-

interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Charging Energy" means all Energy applied to the Storage System for the purpose of supplying Discharging Energy at a later time per the terms of this PPA. Charging Energy does not include House Energy.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Energy" means all net electric Energy including any and all associated capacity attributes, ancillary services, all associated Environmental Attributes, and any other attributes resulting from the generation or the output of the Generating Facility or

produced by the Generating Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy and any Excess Contract Energy.

"Contract Energy Payment" means the payment specified in Section 7.1(A).

"Contract Energy Rate" means _____ and __/100 Dollars per MWh ($_____/MWh)**[**, escalating at a rate of ___ (__) percent per year on the anniversary of each Commercial Operation Year and as further set forth in Exhibit C**]**.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Curtailed Contract Energy" shall have the meaning set forth in Section 7.2(A).

"Curtailed Contract Energy Payment" shall have the meaning set forth in Section 7.2(A).

[wind only - "Cut-Out Event" means the temporary shutting down of Generating Units where the output from the Generating Facility decreases by an aggregate of thirty (30) MW or greater during a five (5) minute interval due to wind speeds in excess of operating parameters specified by the Generating Unit manufacturer.]

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Deficiency MWhs" means the amount of Energy in MWh, if a positive number, for any Month, equal to (i) ninety percent (90%) of the product of the Expected Contract Energy multiplied by the monthly production percentage for the applicable Month specified on Exhibit G less (ii) the actual amount of Contract Energy during the same period.

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2.

"Discharging Energy" means all Contract Energy discharged by the Storage System, less transformation and transmission losses, if any, and delivered to the Point of Delivery.

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all revenue quality metering and data processing equipment used to measure, record, or transmit data relating to the Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs). Electric Metering Devices shall include Storage System Electric Metering Devices.

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to renewable energy, Contract Energy, or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, RECs; greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation of renewable energy (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in part, to sell Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the Generating Units and Storage Units and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Excess Contract Energy" means that amount of Contract Energy in excess of one hundred ten percent (110%) of the Expected Contract Energy.

"Excess Contract Energy Payment" means the payment specified in Section 7.1(C).

"Excess Contract Energy Rate" means fifty percent (50%) of the Contract Energy Rate.

"Expansion Right" shall have the meaning set forth in Section 20.2(A).

"Expected Contract Energy" means _____ MWh of Contract Energy in any given Commercial Operation Year.

"Expected Energy Storage Capacity" shall have the meaning set forth in the recitals to this PPA.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means the Generating Facility, Storage System, and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce and store electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including Generating Units, Storage Units, step-up transformers, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, weather station hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such capacity and energy subject to this PPA.

"Facility Assets" shall have the meaning set forth in Section 20.3(B).

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver or store, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, (iv) an Emergency Condition, or (v) a curtailment as set forth in Section 6.3(A).

"Generating Facility" means the portion of the Facility that is used to generate Contract Energy using the Generating Units, as identified and described in Article 3 and Exhibit B, including all of the following, generators, step-up transformers, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the foregoing.

"Generating Unit" shall have the meaning set forth in the recitals to this PPA.

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranteed Energy Production" means that amount of Contract Energy equal to ninety percent (90%) of the Expected Contract Energy.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit L.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in [wind][solar]-power electric generation with energy storage relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the

Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Mean Absolute Percent Error" or "MAPE" equals:

$$\frac{1}{n}\sum_{t=1}^{n}\left|\frac{A_{t-}F_t}{NC}\right|$$

Where:

n = number of hours in the quarter of the Year;

A_t = actual value of Contract Energy deliveries in MWh for the forecast hour;

F_t = hour-ahead forecasted value in MWh for the forecast hour, as provided by Seller in accordance with Section 6.4(E); provided if no hour-ahead forecast was provided for such hour, the amount of the forecast for that hour will be zero; and

NC = Nameplate Capacity Rating.

"Month" means a calendar month.

"Moody's" means Moody's Investors Services, Inc., or any successor thereto.

"MPT" means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

"MW" means megawatt.

"MWh" means megawatt hours.

"Nameplate Capacity Rating" means the maximum installed instantaneous generation capacity of the completed Generating Facility, expressed in MW [*solar only-* AC], when operated in compliance with the Interconnection Agreement and consistent with the Generating Unit manufacturer's recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Generating Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC].

"NERC" means the North American Electric Reliability Corporation, or any successor organization.

"Notice of Intent to Purchase" shall have the meaning set forth in Section 20.3(D).

"O&M Records" shall have the meaning set forth in Section 13.7.

"Offered Assets Notice" shall have the meaning set forth in Section 20.1(A).

"Operating Committee" means one representative each from Tri-State and Seller, appointed pursuant to Section 9.10(A).

"Operating Procedures" means those procedures developed pursuant to Section 9.10(B), and also the Storage Operating Procedures.

"Operating Records" means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this [Wind][Solar] and Storage Energy Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

[*wind only-* "Production Tax Credit" mean the production tax credits applicable to electricity produced from certain renewable resources under Section 45 of the Internal Revenue Code of 1986 or any substantially similar federal tax credits under Applicable Law that provides Seller with a tax credit based on energy production from the Facility.]

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the [wind][solar]-power electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and

expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Purchase Notice" shall have the meaning set forth in Section 20.3(I).

"Purchase Option" shall have the meaning set forth in Section 20.3(A).

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (a) (i) has operated, for a period of at least five (5) years, multiple utility-scale [wind][solar]-powered electric energy generating facilities in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Generating Facility and (b) (y) has operated, for a period of at least two (2) years, multiple [_____] energy storage facilities in North America, of at least 20 MW and 40 MWh of energy storage capacity in aggregate with at least one facility that has at least 5 MW and 10 MWh of [_____] energy storage capacity and (z) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of energy storage facilities similar to the Storage System .

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601); (ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"RECs" means renewable energy credits or certificates representing all right, title and interest in and to all Environmental Attributes associated with each MWh of energy from a generation facility in the specific period, including title to and claim over such Environmental Attributes, reporting and all other rights arising therefrom or connected therewith under Applicable Law.

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State to replace the products and services which Seller was required to provide under this PPA, including Energy, storage capability, ancillary services and Environmental Attributes, but has or will fail to so provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement renewable energy, replacement energy storage capabilities, ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a [wind][solar] resource with storage and any penalties incurred as a result of Seller's non-performance.

"ROFO Transfer" shall have the meaning set forth in Section 20.1(A).

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State, including any Storage System Planned Outage.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Seller's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Shortfall MWh" means the amount of Energy in MWh, for any period of determination, equal to the Guaranteed Energy Production less the actual amount of Contract Energy during the same period.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Storage Availability" means total hours during each Month during a Commercial Operation Year that the Storage System is fully operational and is calculated as follows: (Hours – Total Forced Outage Hours – Total Planned Outage Hours) / (Hours – Total Planned Outage Hours)

Where:

"Hours" means, for each Month during the Commercial Operation Year, the total number of hours in such Month.

"Total Forced Outage Hours" means the sum of the number of hours during Storage System Forced Outages during the applicable Month.

"Total Planned Outage Hours" means the sum of the number of hours during Storage System Planned Outages during the applicable Month.

"Storage Operating Day" means any Day during Commercial Operation on which the Storage System operates.

"Storage Operation Test" means the commercial operation test described in Exhibit N.

"Storage System" means the portion of the Facility that is used to store Energy using the Storage Units, as identified and described in Article 3 and Exhibit B, including, without limitation, step-up transformers, output breakers, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible and intangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate, owned or used for construction, operation, maintenance, storage, and delivery of the foregoing.

"Storage System Electric Metering Devices" means revenue quality meters and data processing equipment used to measure, record or transmit data related to the Charging Energy delivered to and the Discharging Energy delivered from the Storage System. Storage System Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs). All Charging Energy and Discharging Energy values measured by the Storage System Electric Metering

Devices will be normalized for electrical losses between the Storage System Electric Metering Devices and the Point of Delivery.

"Storage System Excused Outage" means any Storage System Outage of the Storage System resulting from (i) a Storage System Planned Outage, (ii) a Force Majeure Event, (iii) an Emergency Conditions, or (iv) any event solely or substantially due to actions or omissions by Tri-State which causes an Outage.

"Storage System Forced Outage" means any Storage System Outage of the Storage System that is not a Storage System Excused Outage.

"Storage System Nameplate Capacity" means the designed maximum capacity of the completed Storage System, expressed in MW and calculated by dividing the MWhs of energy the Storage System is designed to store, divided by the number of hours the Storage System is designed to discharge at full output, when operated in compliance with the Interconnection Agreement and as designed by the manufacture, as measured at the Point of Delivery. The Storage System Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Energy Storage Capacity** MW.

"Storage System Operating Procedures" means those procedures applicable to the operation of the Storage System, as developed by the Operating Committee, in accordance with and subject to the Storage Requirements.

"Storage System Outage" means any period during which the capacity of the Storage System is unavailable for any reason as reported in accordance with the Operating Procedures.

"Storage System Planned Outage" means a planned removal from service of the Storage System, or some part thereof constituting not less than ten percent (10%) of the Storage System Nameplate Capacity, that is required for inspection, or routine, preventive or corrective maintenance; provided that Storage System Planned Outages during any Commercial Operation Year may not exceed **project specific** hours.

"Storage Requirements" means those requirements applicable to the Storage System and set forth in Exhibit M.

"Storage Test" shall have the meaning set forth in Exhibit N.

"Storage Unit" shall have the meaning set forth in the recitals to this PPA.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Tax Credit" means (i) [*wind only*-the Production Tax Credit][*solar only*- the tax credit for "energy property" under Section 48(a)(3)(A)(i) of the Internal Revenue Code of 1986 or any similar tax credits under Applicable Law, as it may be amended, supplemented, extended or replaced from time to time.], (ii) any other local, state or federal tax credits providing a tax benefit to Seller based on ownership of the Facility or energy production therefrom, and (iii) depreciation and other tax benefits arising from ownership or operation of the Facility.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2 and Section 9.11(A), which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services and all Environmental Attributes and delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.1(B).

"Test Energy Rate" means an amount equal to fifty percent (50%) of the Contract Energy Rate.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Tri-State's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"WREGIS" means the Western Renewable Energy Generation Information System, or any successor organization that Tri-State uses to track Environmental Attributes.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA

despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Energy is subject to PUC Approvals. Tri-State shall (i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of (i) _____ (__) _____ [wind turbines][solar panels] and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating** and (ii) _____ (__) _____ and associated equipment having a designed aggregate electric storage capacity of **Insert the Expected Energy Storage Capacity**. Exhibit B provides a detailed description of the Facility, including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Generating Units and Storage Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) [solar only- have suitable solar irradiation meters and other instrumentation necessary to measure the available resource and ambient temperature and to estimate the quantity of Contract Energy expected to be generated;]

(D) meet the Storage Requirements;

(E) include one full data circuit as required to transmit to Tri-State real-time weather data, including [wind speed, wind direction][solar irradiance], humidity and temperature collected by Seller's monitoring equipment on its meteorological data acquisition equipment located at the Facility; and

(F) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing, storing and delivering the Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days

of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW of nameplate capacity not installed, operating and capable of generating and storing Test Energy, as applicable, below the Expected Nameplate Capacity Rating and the Expected Energy Storage Capacity, as applicable, until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

(A) Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

(B) Within ten (10) Days after the Effective Date, Seller shall deliver to Tri-State a copy of any existing [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Generating Facility. Furthermore, promptly following its issuance to Seller or development by Seller, Seller shall deliver to Tri-State a copy of any new or updated [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Generating Facility.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within

twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20th) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery and storage of Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller has successfully completed a Storage Operation Test in accordance with Section 9.11(A) and Exhibit N;

(J) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility as a generating unit and itself as an account holder with WREGIS;

(6) Seller having successfully completed (i) Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating and the Storage Operation Test in accordance with Section 9.11;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated in a manner acceptable to the Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Generating Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC] and the Storage System Nameplate Capacity at the time of Commercial Operation is **Insert the Expected Energy Storage Capacity** MW; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase

all such Test Energy at the Test Energy Rate, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery and Metering

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-firm transmission service or network integration transmission service for the delivery of Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [Generating Unit][feeder breaker] trips and the causes of such trips, Generating Unit and Storage Unit failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering

Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller shall configure Electric Metering Devices in a manner that enables separate, bi-directional (as applicable) meter reading for all Energy transmitted between, or at, the following points as set forth in Exhibit B:

(1) Facility and the Point of Delivery

(2) To and from the Storage System Electric Metering Devices; and

(3) Generating Units and the Point of Delivery.

(C) Seller shall separately configure Electric Metering Devices, installed in accordance with the Local Provider's electric system and tariff requirements, as necessary, to separately account for all House Power.

(D) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(E) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(F) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 WREGIS Metering.

Seller shall cause the Facility to implement all necessary generation information communications required by WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility.

5.6 Charging Requirements

Tri-State shall be responsible for scheduling all of the Charging Energy for the Storage System in accordance with Section 6.9 and the Storage System Operating Procedures. Seller shall be responsible for delivering all Charging Energy from the Generating Facility to the Storage System. Seller shall be responsible for delivering all Discharging Energy up to and including delivery and receipt at the Point of Delivery. Tri-State shall be responsible for all Discharging Energy after delivery and receipt at the Point of Delivery. Seller shall take any and all action necessary to allow the delivery of Charging Energy to the Storage System in order to deliver Energy in accordance with the terms of this PPA, including maintenance, repair or replacement of equipment in Seller's possession or control used to deliver the Charging Energy to the Storage System and to delivery Discharging Energy at the Point of Delivery. Seller is responsible for any and all costs associated with charging the Storage System.

Article 6
Sale and Purchase of Contract Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Generating Facility, store in the Storage System, and deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Energy and other products and services required by this PPA; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any Energy that has not actually been generated by the Generating Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery except for payments of Curtailed Contract Energy as set

forth in Section 7.2 or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Right to Curtail Energy.

(A) Tri-State shall have the right at any time to notify Seller, by telephonic communication from the RDD or by the AGC system, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility to the Point of Delivery, and Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices. Tri-State may provide such notification for any reason and in its sole discretion. Any payments for such curtailed Contract Energy shall be in accordance with Section 7.2. Such curtailment rights do not provide Tri-State with any rights to direct the operation of the Facility.

(B) In the event the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority either directs Tri-State to notify Seller or notifies Seller directly, by any method established by such Person, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility, Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices.

(C) Seller shall be responsible for, and shall reimburse Tri-State to the extent Tri-State is charged and pays for any damages, fines or penalties as a result of Seller failing to comply with such curtailment instructions described in this Section 6.3.

6.4 Scheduling.

(A) Seller shall be responsible for providing the forecast of Contract Energy deliveries during the Term in accordance with the mutually-developed Operating Procedures described in Section 9.10(B).

(B) No later than ninety (90) Days before the start of Testing and by August 1 of each Year thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Month's average-day deliveries of Contract Energy, by hour, for the following Year.

(C) No later than thirty (30) Days before the start of Testing and at least ten (10) Business Days before the beginning of each Month thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Day's average deliveries of Contract Energy, by hour, for the following Month.

(D) Seller shall provide, or cause to be provided to Tri-State, by 6:00 a.m. MPT on each Day, in a format acceptable to Tri-State, a forecast of the hourly quantities of Contract Energy to be delivered to Tri-State for the immediately succeeding Day or for multiple Days as may be required by the parameters of the WECC prescheduling calendar.

(E) Seller shall provide, or cause to be provided to Tri-State, thirty (30) minutes before the start of every hour, in a format acceptable to Tri-State, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State for the next scheduling hour. As an example, Seller shall provide to Tri-State by 6:30 a.m. MPT, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State beginning 8:00 a.m. MPT and ending 9:00 a.m. MPT.

(F) If, at any time following submission of a forecast as described in Sections 6.4(B), (C), (D) and (E), Seller becomes aware of any change that alters the values previously provided to Tri-State, Seller shall promptly notify Tri-State no later than sixty (60) minutes before the next scheduling hour of such change or predicted change and if such change reduces the forecasted availability of the Facility more than ten (10) MW, such reduction shall be communicated to the RDD as soon as reasonably practicable, but within no more than ten (10) minutes.

(G) Tri-State and Seller shall agree upon reasonable changes to the requirements and procedures set forth above from time to time, as necessary to comply with changes to the Tariff or other requirements set forth by Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or an Organized Market, to accommodate changes to their respective generation technology and organizational structure and address changes in the operation and scheduling procedures of Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or the Organized Market, including more frequent reporting and automated forecast and outage submissions.

(H) Within fifteen (15) Days after the end of each quarter of the Year commencing with the first full quarter of the Year after the Commercial Operation Date, Seller shall calculate the aggregate MAPE for the prior quarter and provide such percentage, together with reasonable documentation supporting such calculation, to Tri-

State. Such percentage of MAPE amount is subject to verification by Tri-State. If the aggregate MAPE for any quarter exceeds [*wind only-* twelve percent (12%)][*solar only-* seven percent (7%)], Seller shall pay Tri-State, as liquidated damages and not a penalty, within ten (10) Days after delivering such calculation to Tri-State **Insert $2000*Expected Nameplate Capacity Rating** for each one percent (1.0%) above such amount, adjusted pro-rata for any partial percentage. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's forecasting inaccuracies would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.4(H) are a fair and reasonable calculation of such damages.

6.5 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Energy due to a Forced Outage, Storage System Forced Outage, or Emergency Condition resulting in a Generating Facility capacity reduction of more than ten (10) MW or Storage System capacity reduction of more than ten percent (10%) and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Storage System Forced Outage, Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Storage System Forced Outage, Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

6.6 *[wind only-*Cut-Out Events.

In the event of a Cut-Out Event, Seller shall coordinate with Tri-State's RDD the ramp-up rate of the Facility back to full production after such event.]

6.7 Guaranteed Energy Production.

(A) During each Commercial Operation Year, Seller is required to deliver to Tri-State at least the Guaranteed Energy Production; *provided* that the Facility shall be deemed to have generated Contract Energy during such Commercial Operation Year to the extent it was capable of delivering Contract Energy but failed to deliver such Contract Energy due to a (i) Delivery Excuse, (ii) Force Majeure Event, (iii) Emergency Condition, or (iv) a curtailment pursuant to Section 6.3 (except for a curtailment caused by a Forced Outage or otherwise covered by Section 7.2(B)(9) through (11)) with such deemed quantity to be determined using the factors set forth in Section 7.2(A).

(B) In the event Seller delivers less than the Guaranteed Energy Production in any Commercial Operation Year, Tri-State shall promptly invoice Seller for

an amount equal to the Shortfall MWh multiplied by the Contract Energy Rate during such Commercial Operation Year. Invoiced amounts shall be payable in accordance with Section 8.3(A); *provided* that this Section shall not limit Tri-State's rights and remedies under Article 12 with respect to Deficiency MWhs upon the occurrence of and during an Event of Default or Replacement Costs upon termination of this PPA. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's failure in achieving the Guaranteed Energy Production would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.7 are a fair and reasonable calculation of such damages and not a penalty.

6.8 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

6.9 Storage System Dispatch

(A) Every Storage Operating Day, Tri-State's RDD shall have the exclusive right to dispatch the Storage System, twenty-four (24) hours per Day, by communicating with Seller electronically in accordance to the requirements and limitations set forth in this PPA, including the Storage System Operating Procedures. Seller shall abide with all directives from Tri-State, subject only to Prudent Utility Practices.

(B) For each Storage Operating Day, Seller shall provide to Tri-State an hourly schedule of the expected availability of the Storage System for such Storage Operating Day, no later than two (2) Business Days before such Storage Operating Day (the "Availability Notice"). Seller must update Tri-State immediately, unless an event or circumstance makes it unsafe to do so, then as soon as practicable the availability of the Storage System for dispatch by Tri-State changes. Seller shall accommodate Tri-

State's reasonable requests for changes in the time or form of delivery of the Availability Notices.

Article 7
Payment Calculations

7.1 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for each Month (the "Contract Energy Payment") equal to the product of (i) the applicable Contract Energy Rate; and (ii) the aggregate amount of Contract Energy (other than Test Energy and Excess Contract Energy) delivered to Tri-State. The Contract Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(B) Test Energy Payment. Tri-State shall pay for all Test Energy at the Test Energy Rate. Test Energy Payments shall be equal to the product of (i) the Test Energy Rate; and (ii) the aggregate amount of Test Energy delivered by Seller to Tri-State during such Month. The Test Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(C) Excess Contract Energy Payment. Except as otherwise provided in this PPA, Tri-State shall pay for all Excess Contract Energy, if any, generated and delivered in each Commercial Operation Year, during the Term at the Excess Contract Energy Rate. Excess Contract Energy Payments shall be equal to the product of (i) the applicable Excess Contract Energy Rate for such Month, and (ii) the aggregate amount of Excess Contract Energy delivered by Seller to Tri-State. The Excess Contract Energy Payment, if any, for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

7.2 Curtailed Contract Energy Payment.

(A) Determination of Curtailed Contract Energy. On and after the Commercial Operation Date, if delivery of Contract Energy is curtailed by Tri-State pursuant to Section 6.3(A), then:

(1) The Parties shall determine the quantity of Contract Energy that would have been generated by the Facility and delivered to the Point of Delivery during the period of curtailment had its generation not been so curtailed by Tri-State ("Curtailed Contract Energy") by using the best available data obtained through commercially reasonable methods in accordance with the Operating Procedures; and shall be dependent upon measured [wind speed and wind direction][solar irradiance] gathered from appropriate [*wind only-* Generating Units anemometers][*solar only-* pyranometers] and meteorological towers at the Facility during those hours in which Tri-State curtailed its receipt of Contract Energy, as such process may be further described

in the Operating Procedures, and any other adjustments necessary to accurately reflect the Facility's capacity to generate and deliver Energy to the Point of Delivery including applicable losses and manufacturers' warranted power curves (a copy of which shall be provided to Tri-State) for all operational Generating Units whose output was curtailed. The methodology utilized to measure Curtailed Contract Energy shall be reviewed and adjusted, as necessary, by the Operating Committee, at least once every five (5) years after the Commercial Operation Date.

(2) Tri-State shall pay to Seller for such Curtailed Contract Energy all amounts that Seller would have received from Tri-State under this PPA for the corresponding Contract Energy had delivery not been so curtailed by Tri-State (and at the applicable rates set out in Section 7.1) [wind only -plus an amount per MWh that equals (a) the Production Tax Credit to the extent Seller would have been entitled to receive such Production Tax Credit plus (b) a gross up amount to take into account the federal, state and local income tax to Seller or its Affiliates or tax investors on such payment in lieu of the Production Tax Credit, calculated in accordance with the following formula] (the "Curtailed Contract Energy Payment"):

[wind only -

$$\text{Amount of Payment in lieu of Production Tax Credit} \times \frac{1}{\text{1-applicable aggregate tax rate}}$$

For the avoidance of doubt, Seller shall not be entitled to recover any of the above referenced tax benefits to the extent Seller would not have been entitled to receive the Production Tax Credit had the Curtailed Contract Energy actually been delivered.]

(3) In the event Tri-State is obligated to pay for Curtailed Contract Energy under this Section 7.2(A), Seller shall provide on the applicable monthly invoice detailed calculations of the Curtailed Contract Energy and the Curtailed Contract Energy Payment due Seller.

(B) Restriction on Curtailment Payments. Notwithstanding anything in this Section 7.2 to the contrary, no payment shall be due to Seller from Tri-State under paragraph (A) above for curtailments of delivery of Contract Energy resulting from:

(1) an Emergency Condition, Force Majeure Event, Storage System Forced Outage, or Forced Outage;

(2) the failure of Seller's Interconnection Facilities or any action taken by the Interconnection Provider in accordance with its rights under the Interconnection Agreement and not due to Seller's default;

(3) any restriction, reduction, or curtailment of firm transmission service or network integration transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery;

(4) any restriction, reduction, or curtailment of non-firm transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery to the extent such restriction, reduction, or curtailment would also have been imposed even if firm transmission service had been in place;

(5) maintenance outages, whether planned or unplanned, of any part of the Transmission System or any testing of the Transmission System;

(6) Allowable Curtailment;

(7) [*wind only-* Cut-Out Events; provided that Tri-State shall compensate Seller for any curtailment of Contract Energy up to one (1) hour for the first Cut-Out Event per quarter of any Year];

(8) any notification from the Balancing Authority requiring Seller to curtail or cease deliveries of Contract Energy to achieve load balancing in the Balancing Authority Area or any notifications from the Reliability Coordinator requiring Seller to curtail or cease deliveries of Contract Energy;

(9) any curtailment arising from Seller's failure to obtain and/or maintain in full force and effect any Governmental Approval or WREGIS registration, or failure to comply with applicable NERC reliability standards;

(10) any action taken by the Interconnection Provider pursuant to Seller's default under the Interconnection Agreement; or

(11) Seller fails or refuses to respond to AGC instructions from the SCADA system, Seller fails or refuses to respond, or Seller refuses or fails to respond to a curtailment instruction from Tri-State, the RDD, the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority pursuant to Section 6.3 including if the Interconnection Provider trips the breaker at the Electric Interconnection Point, due to Seller's failure or refusal.

7.3 Adjustments to Payments/Storage Payment.

[if any –project and payment formula specific]

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for Contract Energy delivered by Seller to Tri-State and the Curtailed Contract Energy, if any, determined pursuant to Section 7.2 for such Month. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street Journal* (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law

("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Energy or Curtailed Contract Energy within one hundred eighty (180) Days of delivery of such Contract Energy or curtailment of Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such Taxes, allowances and credits during the Term. If Tri-State is assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the

Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits or Additional Tax Benefits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price for Contract Energy.

(F) Additional Tax Benefits. From and after the Effective Date and throughout the Term, in the event that Seller or the Facility qualifies for and receives or is subject to Additional Tax Benefits, Seller and Tri-State shall share on a 50/50 basis the Additional Tax Benefit Amount associated with such Additional Tax Benefits by making an adjustment to the Contract Energy Rate for the Term of the PPA to account for such Additional Tax Benefit Amount. For the avoidance of doubt, Additional Tax Benefits may not result in an increase to the Contract Energy Rate. The Contract Energy Rate shall be adjusted in the first month following the effective date of the Applicable Law, which may be in the form of new or revised guidance or interpretations by a Governmental Authority having jurisdiction related to such Applicable Law, pursuant to which such Additional Tax Benefit is enacted. Seller shall at all times retain all right, title and interest in any Additional Tax Benefits. Seller shall provide Tri-State with written notice upon its receipt of Additional Tax Benefits, and along with such notice provide to Tri-State commercially reasonable documentation describing: (i) the Additional Tax Benefit Amount, (ii) the effective date of the Applicable Law, including guidance or interpretations by a Governmental Authority, (iii) reasonable accounting of

the Additional Tax Benefit Costs associated therewith, verified by an independent national accounting firm selected by Seller at Seller's expense, subject to further verification by Tri-State, and (iv) a calculation of the reduction to the Contract Energy Rate.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity or storage capacity of the Facility or the output of Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations and Prudent Utility Practices and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. Personnel (i) capable of remotely starting, operating and stopping the Facility shall be continuously available and reachable by phone, and (ii) shall be capable of being at the Facility on no more than sixty (60) minutes' notice, weather conditions permitting.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver and store Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State the projected schedule of Scheduled Maintenance Outages, for the subsequent Year or the remainder of the Term, whichever period of time is shorter. Seller shall notify Tri-State of a Scheduled Maintenance Outage and any changes to such no later than sixty (60) Days prior to the start date of a Scheduled Maintenance Outage. In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages and/or Additional Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Additional Maintenance Outages.

Before Seller conducts further maintenance on the Facility which would result in greater than ten (10) MW of the Nameplate Capacity Rating of the Generating Facility being taken out of service, greater than ten percent (10%) of the Storage System Nameplate Capacity Rating being taken out of service, or Seller's Interconnection Facilities being taken out of service in addition to the Scheduled Maintenance Outages conducted pursuant to Section 9.6 ("Additional Maintenance Outages"), Seller shall notify Tri-State of such required maintenance, together with proposed dates for carrying out such additional maintenance and the estimated duration of the work to be carried out. To the extent possible, such notification to Tri-State shall be provided no later than sixty (60) Days prior to the start date of an Additional Maintenance Outage. Unless deferral of such maintenance would cause an Emergency Condition, Seller and Tri-State shall negotiate in good faith a reasonable schedule during which such Additional Maintenance Outages shall take place. In the event an Additional Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Additional Maintenance Outage.

9.8 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any

way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.8 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.9 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with the Storage Requirements, Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.10 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list

for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; Contract Energy reports; measurement of Curtailed Contract Energy; unit operations log; charging and dispatch of the Storage System, and such other matters as may be mutually agreed upon by the Parties.

9.11 Storage System Testing

(A) Prior to the Commercial Operation Date, Seller shall schedule and successfully complete a "Storage Operation Test" in accordance with Exhibit N and provide the results of such to Tri-State.

(B) On an annual basis during Commercial Operation, upon seven (7) days prior notice to Tri-State, Seller shall schedule and complete a "Storage Periodic Test" in accordance with Exhibit N and provide the results of such to Tri-State. In addition, either Party shall have the right to require a retest at any time if such Party reasonably believes that the performance of the Storage System has varied materially from the results of the most recent Storage Test. Such retest shall be scheduled as soon as is reasonably practicable for the Parties consistent with Prudent Utility Practice.

(C) If Seller fails a Storage Periodic Test, then Seller shall be required to commence repairs in accordance with Section 9.12.

9.12 Storage System Repair Obligations

In the event that any equipment failure with respect to the Storage System results in the Storage System failing a Storage Test, then Seller shall repair the Storage System in accordance with Prudent Utility Practices. Within fourteen (14) Days of such failure, Seller shall demonstrate such remedy to Tri-State's satisfaction or present to Tri-State a description of the reason for the failure and a plan and schedule for the repair. Seller shall diligently and expeditiously implement such repair plan and repair the Storage System.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. Payment of each of the Contract Energy Rate, Test Energy Rate and the Excess Contract Energy Rate to Seller by Tri-State includes the consideration for the purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the generation of Contract Energy, Test Energy and Excess Contract Energy, respectively.

(B) Duration. Environmental Attributes associated with the Contract Energy are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or

otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Transfer of Title to Environmental Attributes; Documentation of Environmental Attributes Transfers.

(A) Title. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy at the Facility that gives rise to such Environmental Attributes.

(B) Bill of Sale. Upon request from Tri-State, Seller shall deliver to Tri-State an Attestation and Bill of Sale in the form attached as Exhibit J for all Environmental Attributes delivered to Tri-State during the time period requested by Tri-State.

(C) WREGIS Compliance. Seller shall, at its sole expense, use WREGIS to provide and convey to Tri-State the Environmental Attributes associated with the generation of Contract Energy. Such Environmental Attributes shall be conveyed in a manner consistent with the WREGIS provision below promptly upon WREGIS certificates relating to the Facility being credited to Seller's WREGIS account.

(D) WREGIS Account. Prior to Testing, Seller shall register the Facility with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain through the Term. Seller shall transfer the WREGIS certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Tri-State or the account(s) of a designee that Tri-State identifies by written notice ("Tri-State's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Facility with WREGIS, establishing and maintaining Seller's WREGIS Account, paying WREGIS certificate issuance and transfer fees, and transferring WREGIS certificates from Seller's WREGIS Account to Tri-State's WREGIS Account.

(E) Qualified Reporting Entity. Seller shall procure and maintain a Person to act as a qualified reporting entity and provide qualified reporting services for the Facility as required by WREGIS.

(F) Reporting Compliance. Seller, at its own cost and expense, shall comply with all reporting and other requirements of WREGIS relating to the Facility or Environmental Attributes.

(G) No Liens or Encumbrances. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(H) Additional Certification. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities

requested by Tri-State in order to qualify the Facility as a renewable resource or qualify the Contract Energy and/or Environmental Attributes with such Governmental Authority and maintain such registration/certification for the Term.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); provided that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by the Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars ($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000) for the period beginning with the Effective Date and continuing thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 6.4(H), Section 6.7 and Section 12.3, and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller starts-up, operates, charges, or discharges or permits or causes any third party (including Seller's designated operator) to start-up, operate, charge or discharge the Storage System other than as specifically permitted under this PPA;

(6) Seller intentionally or knowingly delivers, or attempts to deliver, Energy for sale under this PPA that was not associated with or stored by the Facility;

(7) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(8) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(9) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(10) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Seller's failure to deliver at least eighty percent (80%) of the Expected Contract Energy in a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that the Facility shall be deemed to have generated Contract Energy during such period as specified in Section 6.7 with such quantity to be determined using the factors set forth in Section 7.2(A); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the end of the energy deficient Commercial Operation Year, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the production of Contract Energy by the

Facility equals or exceeds ninety-five percent (95%) of the Expected Contract Energy for such period.

Subject at all times to the limitation set forth in Section 6.1, Seller shall be permitted to add and/or replace Generating Units if and to the extent reasonably required to cure Seller's default under this Section 12.1(D). Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the production of Contract Energy fails to equal or exceed ninety-five percent (95%) of the Expected Contract Energy for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

(E) Storage Unavailability. Seller's failure to maintain a Storage Availability of at least ninety percent (90%) on average for a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the Event of Default, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the Storage Availability equals or exceeds ninety percent (90%).

Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(E). If the Storage Availability fails to equal or exceed ninety percent (90%) for the Commercial Operation Year following the Event of Default as described in this Section 12.1(E), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include an amount calculated at the end of each Month during an Event of Default equal to the Deficiency MWhs multiplied by the applicable Contract Energy Rate during such Commercial Operation Year and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof,

upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs for the then remaining Term based upon, in the case of Energy, the amount of Expected Contract Energy that should have been delivered provided, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term (based upon, in the case of Energy, the amount of Expected Contract Energy) had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages, or the damages provided in Section 6.4(H), Section 6.7 and Section 12.3) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*(Expected Nameplate Capacity Rating in kw + Expected Energy Storage Capacity in kw)** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of

the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State under this PPA, including use, operation, charging or discharging of the Storage System, other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or

routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of energy production and storage (by individual block or Generating Unit and Storage Unit); changes in operating status; meteorological data;

maintenance; Storage System Forced Outage and Forced Outages (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

13.8 Provision of Real Time Data.

Seller shall, at least five (5) Business Days prior to the delivery of Test Energy and continuing through the Term, make the following data available to Tri-State on a real-time basis, at the Tri-State RTU:

(1) production of Energy in MW and MWh;

(2) [in-service status for each Generating Unit][feeder level breaker status] and Storage Unit;

(3) [Generating Unit MW output][inverter availability and generation in kW] and Storage Unit output;

(4) Storage Unit Energy available for discharge;

(5) [wind speed and direction at each Generating Unit][solar irradiance as measured by the pyranometers at the Facility];

(6) ambient temperature [solar only- and solar panel temperature];

(7) [solar only- stow indication][wind only- icing indication and overspeed indication for each Generating Unit];

(8) humidity; and

(9) barometric pressure.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written

notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure the Generating

Units, Storage Units, or any component parts therefor, or any associated equipment for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure the Generating Units, Storage Units or any component parts therefor, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit or Additional Tax Benefits, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; or (xi) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each

Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Article 7.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business in _____ and in each other jurisdiction where the failure to so qualify would have a

material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) That the Environmental Attributes, as to which right and title is to be transferred to Tri-State under this PPA are, or will be: (1) compliant with the definitions of local, state, or federal renewable portfolio standard rules and requirements, (2) free and clear of any liens, encumbrances and/or defects of title; and (3) shall not otherwise been, nor will be sold, retired, claimed, or represented as part of electricity output or sales, or used to satisfy obligations in any other jurisdiction.

(I) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the

creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration

date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the

Indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below, settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a

"Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Purchase Option

20.1 Right of First Offer of Sale of the Facility.

(A) Except for Transfers expressly permitted by Section 19.3(B) or Section 19.4(B), Seller shall not, and shall cause each direct and indirect owner of Seller not to, at any time during the Term, consummate or enter into any agreement for the consummation of any of the following (each, a "ROFO Transfer"):

(1) any Transfer by Seller of the Facility or any part of the Facility to one or more Persons that are not Affiliates of Seller; or

(2) any Transfer by any Person, in one or more transactions to one or more other Persons that are not Affiliates of such Person, of equity or other ownership interests in one or more Project Entities that (individually or in the aggregate) constitute a direct or indirect Controlling interest in Seller;

unless Seller has first offered to Transfer the Facility, or such direct or indirect owner has first offered to Transfer such direct or indirect equity interests in Seller, as applicable, to Tri-State pursuant to a written offer (in each case, an "Offered Assets Notice") and otherwise complies with this Section 20.1 and Article 19.

(B) Any Offered Assets Notice shall set forth in reasonable detail all material terms and conditions of the offer, including the minimum price and terms of payment, liabilities and obligations to be directly or indirectly assumed, all other financial terms, all material conditions to closing, a period of no less than 180 days

following execution of the purchase agreement for the parties to obtain any approvals or other authorizations of any Governmental Authority or third party that are required by such party in connection with such Transfer, and all material representations, warranties, rights to indemnification, limitations thereon, and credit support for any of the foregoing. Following Tri-State's receipt of the Offered Assets Notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller (i) shall promptly answer any questions that Tri-State may have concerning the Facility, any applicable liabilities and obligations, and the offered terms and conditions, (ii) shall meet with Tri-State to discuss the offer, and (iii) shall provide all documents and information requested by Tri-State that are reasonably available to Seller.

(C) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions to purchase the Facility or the specified equity interests (as applicable) within ninety (90) Days after receiving the Offered Assets Notice, Seller shall have the right to sell the Facility (or Seller's relevant parent shall have the right to sell the specified equity interests, as applicable) to a third party on terms and conditions that are not more favorable in the aggregate to the third party than those included in the Offered Assets Notice, at any time within the twelve-month period following issuance of the Offered Assets Notice, and to enter into any agreement therefor. If Seller or its relevant parent wishes to enter into an agreement for or consummate a ROFO Transfer with a third party on terms and conditions that in the aggregate are more favorable to the third party than those previously offered to Tri-State in the Offered Assets Notice, or on a date that is more than twelve months following delivery of the applicable Offered Assets Notice, such ROFO Transfer shall again be subject to this Section 20.1 and Seller or its relevant parent shall again first offer the revised terms and conditions to Tri-State pursuant to a new Offered Assets Notice.

(D) If Tri-State accepts an offer made by Seller under Section 20.1(B), the Parties shall within a further ninety (90) Days enter into a purchase agreement that, except to the extent otherwise agreement by Seller and Tri-State, incorporates the terms and conditions in the Offered Assets Notice.

20.2 Right of First Offer on Facility Expansion.

(A) If, at any time during the Term, Seller or any Affiliate of Seller intends to install or modify any energy generation or storage equipment on the Site or on any location within a five (5) mile radius of the boundary of the Site, the effect of which, if deemed part of the Facility, would be to increase the Nameplate Capacity Rating of the Generating Facility and/or Storage System Nameplate Capacity of the Storage System, Seller shall first offer the Energy (and Environmental Attributes) and/or storage capacity resulting from such installation or modification ("Expansion Right") to Tri-State. Such offer shall set forth in reasonable detail the proposed transaction and the terms and conditions of the offer, including the price. Following Tri-State's receipt of such notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller shall promptly answer any question that

Tri-State may have concerning the offered terms and conditions, shall meet with Tri-State to discuss the offer, and shall provide requested documents and information requested by Tri-State.

(B) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions within ninety (90) Days after receiving the offer, Seller or the Affiliate of Seller may enter into an agreement to sell the Expansion Right to a third party on terms and conditions no more favorable in the aggregate to the third party than those offered to Tri-State. If Seller or the Affiliate of Seller wishes to enter into an agreement with a third party on terms and conditions more favorable to the third party than those previously offered to Tri-State under Section 20.2(A), Seller or the Affiliate of Seller shall first offer such revised terms and conditions to Tri-State pursuant to Section 20.2(B).

(C) If Tri-State accepts an offer made by Seller under Section 20.2(A), the Parties shall within a further ninety (90) Days enter into an energy and storage purchase agreement in substantially the same form as this PPA for the purchase and sale of Expansion Right and associated Environmental Attributes (with the Security requirement set forth in Article 11, Contract Energy delivery requirements set forth in Section 6.1, the damage payment in Section 6.4(H) and Expected Contract Energy to be adjusted on a pro rata basis to account for the size of the proposed expansion relative to the Expected Nameplate Capacity Rating and/or Storage System Nameplate Capacity), but incorporating such changes as are expressly identified in the terms and conditions offered by Seller.

20.3 Option to Purchase.

(A) Seller hereby gives and grants to Tri-State the exclusive and irrevocable right and option to purchase the Facility Assets, at the times and upon the terms and conditions set forth in this Section 20.3, for a price equal to the Fair Market Value of the Facility, as determined pursuant to this Section 20.3 ("Purchase Option").

(B) As used herein, "Facility Assets" means the Facility, all interest of Seller or any of its Affiliates in, to or under this PPA, and any and all tangible or intangible assets that are reasonably necessary for the ownership, operation and maintenance of the Facility, including (i) all drawings, specifications, operations and maintenance records, and performance data of or related to the Facility; (ii) all warranties, equipment service and maintenance agreements, and similar agreements related to the Facility, any portion thereof, or any related equipment or facilities; (iii) non-exclusive, irrevocable and royalty-free licenses to use software and other intellectual property necessary for the ownership, operation or maintenance of the Facility; (iv) all Governmental Approvals related to the ownership, operation or maintenance of the Facility, to the extent assignable; (v) the Interconnection Agreement and utility services agreements, (vi) the Facility Site Documents, and all other interests or rights in real estate reasonably necessary for the operation and maintenance of the Facility, and (vii) all rights to future Energy, Environmental Attributes, and tax benefits.

(C) Facility Assets do not include (without limitation) (i) any liabilities of Seller or any of its Affiliates, contingent or otherwise, other than future performance obligations under contracts and Governmental Approvals that, in any case, are reasonably necessary for the ownership, operation or maintenance of the Facility and are assigned to Tri-State; (ii) any agreement or instrument evidencing indebtedness for borrowed money; (iii) any contracts or agreements for the sale of Energy, storage of Energy, Environmental Attributes, or other products, other than this PPA; or (iv) any contract or agreement for asset management, operations, or other services not specifically included in the Facility Assets.

(D) As a condition to any exercise of the Purchase Option, Tri-State must give non-binding written notice (a "Notice of Intent to Purchase") either (i) within ninety (90) days prior to any of [solar only: the sixth (6th) anniversary of the Commercial Operation Date,] the eleventh (11th) anniversary of the Commercial Operation Date, the fifteenth (15th) anniversary of the Commercial Operation Date, the twentieth (20th) anniversary of the Commercial Operation Date, or the expiration of the Term, or (ii) within ninety (90) days following any termination of this PPA by Tri-State, following the [solar: sixth (6th)][wind: fifteenth (15th)] anniversary of the Commercial Operation Date, due to an Event of Default by Seller.

(E) For a period of sixty (60) days following the date of the Notice of Intent to Purchase, the Parties will meet to discuss and negotiate in good faith to determine and agree upon the Fair Market Value, and shall use commercially reasonable efforts to agree upon the terms and conditions of a purchase and sale agreement with respect to the Facility Assets. For the avoidance of doubt, neither agreement upon Fair Market Value and such terms and conditions, nor execution of a purchase and sale agreement, shall be conditions to the closing of a purchase and sale of the Facility Assets pursuant to exercise of the Purchase Option.

(F) For purposes of this Section 20.3, "Fair Market Value" means the fair market value of the Facility Assets as agreed by the Parties; provided, however, that in the event the Parties cannot agree upon Fair Market Value within sixty (60) Days following the delivery of the Notice of Intent to Purchase, the Parties shall retain an independent nationally recognized appraiser experienced in appraising [wind][solar]-powered electric energy generation facilities and storage systems selected by Tri-State (and certified as so qualified by Seller), in which case Fair Market Value shall be as determined by such appraiser. The Parties shall share equally all fees and costs of the third appraiser, if required, retained to determine Fair Market Value.

(G) The appraiser shall consider the following factors in its determination of Fair Market Value:

(1) the expected annual generating output and storage capacity of the Facility over the remainder of its assumed useful life determined in a manner consistent with Prudent Utility Practices, taking into account the expected degradation of the Facility over such period;

(2) the net present value of the after-tax cash flows over the remainder of its assumed useful life (determined in a manner consistent with Prudent Utility Practices, and taking into account the expected degradation), applying a discount rate that is reasonable under then-current market conditions as agreed by the Parties, and if not so agreed within thirty (30) Days, then as determined by such appraiser;

(3) the general condition of the Facility at the time of the expected closing following exercise of the Purchase Option determined by inspection and, if applicable, testing;

(4) any restrictions on use of the Site or any portion thereof;

(5) any rights or obligations of Seller to dismantle and remove the Facility and restore the Site (whenever arising);

(6) any restrictions upon or obligations or liabilities associated with any of the Facility Assets or the operation of the Facility prior to the closing pursuant to the Purchase Option that could adversely affect the operation of the Facility, or for which Tri-State could be responsible or have any liability, following the closing pursuant to the Purchase Option, including due to any Environmental Contamination, any accrued liabilities (contingent or non-contingent) under the Interconnection Agreement, any Facility Site Documents, or any other contract included in the Facility Assets, any accrued and unpaid property tax liabilities, and any failure to comply with any Governmental Approval or Applicable Law;

(7) the terms and conditions of this PPA, including the encumbrance of any obligations and liabilities on an assignee thereof with respect to delivery of Contract Energy to Tri-State for the remainder of the Term, the expected market price of Energy following the expiration of this PPA, transmission costs and constraints and other limitations on the marketability of power generated from the Facility;

(8) any terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets;

(9) an appropriate discount to the extent that (i) Seller fails to provide to Tri-State and the appraiser any material information related to the Facility Assets or Site, or (ii) the representations, warranties, indemnification obligations and other terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets materially deviate from customary terms and conditions for the sale and purchase of facilities similar to the Facility; and

(10) such other factors as the independent appraiser deems relevant.

(H) Following delivery of a Notice of Intent to Purchase, Seller shall promptly provide to Tri-State (and, if applicable, the appraiser) all information regarding the Facility Assets and Site as may be requested thereby, that is reasonably available to Seller, and Tri-State (and, if applicable, the appraiser) shall be provided with access to the Site and Facility in order to conduct an inspection and witness any testing. All inspections and testing, and access to the Site and Facility, shall be conducted in accordance with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State (and, if applicable, the appraiser), and shall be conducted in a manner so as to minimize disruption in the operation and the maintenance of the Facility and in such a manner so as to avoid any adverse economic impacts to Seller under this PPA.

(I) To definitively exercise the Purchase Option, Tri-State must deliver written notice (a "Purchase Notice") to Seller within sixty (60) days following determination of Fair Market Value pursuant to this Section 20.3. Once the Purchase Notice has been delivered, the Purchase Option shall be irrevocable.

(J) The closing for purchase and sale of the Facility Assets shall occur on the later of the thirtieth (30th) day following the date of the Purchase Notice and the fifth (5th) Business Day after the receipt of all required consents and approvals of Governmental Authorities. At the closing:

(1) Seller shall convey to Tri-State good and marketable title to all of the Facility Assets, free and clear of all liens and encumbrances (other than those arising under the terms of the Facility Site Documents and Governmental Approvals), and with such other representations and warranties as may be agreed by the Parties; and

(2) Tri-State shall pay to Seller, in full consideration thereof, an amount in cash equal to the Fair Market Value.

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any

contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely

affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra.

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing

by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[_____]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[_____]	[*wind only-* Seller shall have provided Tri-State with copies of Determinations of No Hazard from the Federal Aviation Administration for the Generating Units.]
[_____]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[_____]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[_____]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[_____]	Delivery of major components to the Site shall have commenced.
[_____]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[_____]	The step-up transformer shall have been delivered to the Site.
[_____]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.

[_____] Start-up testing of the Generating Units and Storage Units shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Generating Units and Storage Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

CONTRACT ENERGY RATE

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	Minimum Limits of Coverage
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

EXHIBIT G

MONTHLY PRODUCTION PERCENTAGE OF EXPECTED CONTRACT ENERGY

Calendar Month	Monthly Production %
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF ATTESTATION AND BILL OF SALE

_____ ("Seller") hereby sells, transfers and delivers to Tri-State Generation and Transmission Association, Inc. ("Tri-State") the Environmental Attributes associated with the generation of Contract Energy, as detailed in the [Wind][Solar] and Storage Energy Purchase Agreement for the _____ Project between the Parties, dated _____ (the "Agreement"). Terms used, but not defined herein, shall have the meaning set forth in the Agreement.

_____
Name of Renewable Energy Facility

_____	_____	_____
Type/Resource	Nameplate Capacity Rating (MW)	Commercial Operation Date

_____ - _____ (from) (to)
Dates

_____
MWh generated

One (1) REC represents the REC and Environmental Attributes reporting rights associated with one (1) MWh generated from the Facility.

Seller further attests, warrants and represents as follows:

i) each REC and Environmental Attribute is free and clear of any liens, encumbrances and/or defects of title;

ii) none of the RECs or Environmental Attributes has been retired, claimed or represented as part of electricity output or sales by Seller, or used to satisfy obligations in any other jurisdiction;

iii) its sale to Tri-State is its one and only sale of the RECs and Environmental Attributes with respect to the Contract Energy referenced herein, after due inquiry, no third party has claimed nor can claim any interest in such RECs or Environmental Attributes;

iv) the Facility identified above produced the number of MWh above during the period indicated above;

v) Seller has title to and ownership of the RECs and Environmental Attributes sold hereunder; and

vi) Seller owns the _____.
Name of the Renewable Energy Facility

This serves as a bill of sale, transferring from Seller to Tri-State all of Seller's right, title and interest in and to the RECs and Environmental Attributes associated with the generation of the above referenced Contract Energy.

Contact Person: _____

phone: _____; fax: _____

[Seller]

Signed: _____

Name: _____

Title: _____

Date: _____

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN _____ AND STORAGE ENERGY PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH

THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

EXHIBIT L

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain [Wind][Solar] and Storage Energy Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____-powered electric energy generating facility having an Expected Nameplate Capacity Rating of _____ MW AC and energy storage facility having an Expected Energy Storage Capacity of _____ MW to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy and storage from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this

Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any

extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.

a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
c. any defense based upon an election of remedies by Company;
d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

EXHIBIT M

STORAGE REQUIREMENTS

TBD - generation technology and project specific

EXHIBIT N

STORAGE TEST

TBD - generation technology and project specific

Storage Operation Test

Storage Periodic Test

Attachment Vol II 7-5 Renewable PPA

Tri-State 11/19/2020
Model Renewable PPA
TS-XX-XXXX

[WIND] [SOLAR] ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT

BETWEEN

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

AND

_____

- [date] -

TS-XX-XXXX

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[WIND] [SOLAR] ENERGY PURCHASE AGREEMENT FOR THE _____ PROJECT
BETWEEN
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
AND
_____

This [Wind][Solar] Energy Purchase Agreement for the _____ Project (this "PPA") is made this ____ day of _____, 20__, by and between (i) _____ ("Seller"), a _____ and (ii) Tri-State Generation and Transmission Association, Inc. ("Tri-State"), a Colorado cooperative corporation. Seller and Tri-State are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, Seller desires to develop, design, construct, interconnect, own, operate, and maintain a _____ -powered electric energy generating facility consisting of _____(__) _____ [wind turbines][solar panels] (each, a "Unit" and collectively, the "Units") with an expected total nameplate capacity of ____ MW [*solar only-* AC] (the "Expected Nameplate Capacity Rating"), and which is further defined below as the "Facility"; and

WHEREAS, Seller has secured an approximately _____ (__,000) acre site in _____ County, _____ where it intends to locate the Facility and interconnect the Facility **[**to Interconnection Provider's existing _____ transmission line in the vicinity of the Site**][**at the Interconnection Provider's _____ Substation**]**; and

WHEREAS, Seller desires to sell and deliver to Tri-State at the Point of Delivery the electric energy produced by the Facility and all associated Environmental Attributes, and Tri-State desires to buy the same from Seller.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1
Definitions and Rules of Interpretation

1.1 Rules of Construction.

The capitalized terms used in this PPA shall have the meaning set forth in this Article 1 or as otherwise defined in this PPA, whether in the singular or the plural or in the present or past tense. Words not otherwise defined herein shall have meanings as commonly used in the English language and, where applicable, in Prudent Utility Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) References to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(B) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; *provided* that in the event of a conflict between the terms of any Exhibit and the terms of this PPA, the terms of this PPA shall take precedence.

(C) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(D) The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (i) where this PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (ii) wherever this PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(E) Use of the words "include" or "including" or similar words shall be interpreted as "including, but not limited to" or "including, without limitation."

(F) The words "hereof," "herein," and "hereunder" and words of similar import when used in this PPA shall refer to this PPA as a whole and not to any particular provision of this PPA.

(G) Numerical amounts will be rounded to the nearest cent with respect to Dollars, one (1) decimal point for MW and MWh, three (3) decimal points for percentages, which is to the nearest tenth of a percent, and otherwise to two (2) decimal points.

(H) Tri-State's technical review, comments or inspection of the Facility, any designs, testing procedures, reports, or other documents or monitoring of any events shall not be construed as endorsing such nor as any express or implied warranty of performance, safety, durability, or reliability of the Facility or waiver of its rights under this PPA.

1.2 Interpretation with Interconnection Agreement.

The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. The Parties acknowledge and agree that:

(A) the Interconnection Agreement shall be a separate and free-standing contract and that the terms of this PPA are not binding upon the Interconnection Provider.

(B) this PPA does not provide Seller authorization to interconnect the Facility to the Interconnection Provider or inject power into the Transmission System.

(C) notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement shall alter or modify Seller's or Tri-State's rights, duties and obligations under this PPA. This PPA shall not be construed to create any rights between Seller and the Interconnection Provider.

(D) for purposes of this PPA, the Interconnection Provider shall be deemed to be a separate entity and separate contracting party whether or not the Interconnection Agreement is entered into with Tri-State or an Affiliate of Tri-State.

1.3 Interpretation of Arrangements for Power Supply to the Facility.

This PPA does not provide for the supply of retail electric power to the Facility ("House Energy"). Seller shall arrange with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. Subject to Seller's right to self-generate and consume energy concurrently generated by the Facility, Seller shall obtain House Energy exclusively from the Local Provider.

1.4 Definitions.

The following terms shall have the meanings set forth herein:

"Abandonment" means (i) the relinquishment of all possession and control of the Facility by Seller, other than a transfer permitted under this PPA, or (ii) if prior to the Commercial Operation Date, complete cessation of the development, design, construction, testing or inspection of the Facility for thirty (30) consecutive Days by Seller and/or Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of, or requested by, Tri-State, or a Force Majeure Event.

[solar only- "AC" means alternating electric current.*]*

"Additional Tax Benefits" means any new Tax Benefits or changes to, extensions of, or qualification for existing Tax Benefits which become available to Seller or the Facility during the Term, from and after the Effective Date, and which provide an overall net increase in the Tax Benefits attributable to the Facility.

"Additional Tax Benefit Amount" means an amount equal to (i) the aggregate amount of all Tax Benefits received by or on behalf of Seller with respect to any Additional Tax Benefits, minus (ii) the aggregate amount of all Additional Tax Benefit Costs with respect to such Additional Tax Benefits. For the avoidance of doubt, if the Additional Tax Benefit Amount is a negative amount, it shall be deemed to be zero.

"Additional Tax Benefit Costs" means all additional costs, if any, incurred by Seller resulting directly from production, qualification, or verification of an Additional Tax Benefit.

"Additional Maintenance Outages" shall have the meaning set forth in Section 9.7.

"Affiliate" of any named Person means any other Person that Controls, is under the Control of, or is under common Control with, the named Person.

"AGC" means the equipment and capability of an electric generation facility to automatically adjust the generation quantity within the applicable Balancing Authority Area with the purpose of interchange balancing and specifically, the Facility's capability to accept an AGC Set-Point electronically, and the automatic adjustment and regulation of the Facility's energy production via the SCADA system.

"AGC Set-Point" means the Tri-State-generated analog or digital signal sent by the SCADA system to the Facility, representing the quantity of Contract Energy to be generated by the Facility. The RDD will communicate the AGC Set-Point to the Facility via the SCADA system.

"Allowable Curtailment" means the amount of otherwise compensable Curtailed Contract Energy in any Commercial Operation Year to be applied at the election of Tri-State at any time during a Commercial Operation Year, which amount equals (i) one percent (1%) in MWh of the Expected Contract Energy for that Commercial Operation Year plus (ii) any unused Allowable Curtailment from prior Commercial Operation Years. Any unused Allowable Curtailment from a Commercial Operation Year does not expire at the end of a Commercial Operation Year and is carried forward to future Commercial Operation Years.

"Applicable Law" means, collectively, all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction over the Parties or the Facility, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Back-Up Metering" shall have the meaning set forth in Section 5.3(B).

"Balancing Authority" means _____ or any successor entity or another responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission and loads within the metered boundaries of the Balancing Authority.

"Business Day" means any Day that is not a Saturday, a Sunday, or a NERC-holiday, or state- and/or federal-recognized holiday where banks in Denver, Colorado are required or authorized to close.

"Change of Control" of a specified Person means any sale or series of sales or other transactions, whether voluntary or by operation of law, following which the previously existing Ultimate Parent does not Control such Person.

"Commercial Operation" means the operation of the Facility beginning on the Commercial Operation Date and continuing through the Term of this PPA.

"Commercial Operation Date" or "COD" for the Facility means the date set forth in Seller's COD notice that Seller has satisfied all of the conditions for Commercial Operation listed in Section 4.9, subject to confirmation by Tri-State.

"Commercial Operation Milestone" means the milestone for Commercial Operation as set forth in Exhibit A.

"Commercial Operation Year" means, for the first Commercial Operation Year, the period starting at 12:01 a.m. MPT on the COD and ending at 11:59 p.m. MPT on the last Day of the Month in which the first anniversary of COD occurs, and each successive "Commercial Operation Year" shall mean the twelve (12) Month period following the prior Commercial Operation Year.

"Conditions" shall have the meaning set forth in Section 4.9.

"Construction Milestone" means the result specified by Seller as set forth in Exhibit A which Seller shall achieve by the Construction Milestone Date, including the Commercial Operation Milestone.

"Construction Milestone Date" means the date set forth in Exhibit A by which Seller shall achieve the corresponding result specified for such date, including the Commercial Operation Milestone.

"Contract Energy" means all net electric Energy including any and all associated capacity attributes, ancillary services, all associated Environmental Attributes, and any other attributes resulting from the generation or the output of the Facility or produced by the Facility and delivered to the Point of Delivery as measured by the Electric Metering Devices installed pursuant to Section 5.3. Contract Energy shall include any Test Energy and any Excess Contract Energy.

"Contract Energy Payment" means the payment specified in Section 7.1(A).

"Contract Energy Rate" means _____ and __/100 Dollars per MWh ($_____/MWh)**[**, escalating at a rate of ___ (__) percent per year on the anniversary of each Commercial Operation Year and as further set forth in Exhibit C**]**.

"Control" means the ownership of fifty percent (50%) or more of the voting interests of the entity, or the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of the entity, whether through ownership of voting securities, by contract or otherwise. "Controls," "Controlling," and "common Control" shall have correlative meanings when used in this PPA.

"Curtailed Contract Energy" shall have the meaning set forth in Section 7.2(A).

"Curtailed Contract Energy Payment" shall have the meaning set forth in Section 7.2(A).

[wind only - "Cut-Out Event" means the temporary shutting down of Units where the output from the Facility decreases by an aggregate of thirty (30) MW or greater during a five (5) minute interval due to wind speeds in excess of operating parameters specified by the Unit manufacturer.]

"Day" means a calendar day.

"Default Rate" shall have the meaning set forth in Section 8.3(C).

"Deficiency MWhs" means the amount of Energy in MWh, if a positive number, for any Month, equal to (i) ninety percent (90%) of the product of the Expected Contract Energy multiplied by the monthly production percentage for the applicable Month specified on Exhibit G less (ii) the actual amount of Contract Energy during the same period.

"Delay Damages" shall have the meaning set forth in Section 4.3(D).

"Delivery Excuse" means an event solely or substantially due to actions or omissions by Tri-State which prevents or delays delivery of Contract Energy.

"Designation Approval Date" shall have the meaning set forth in Section 2.2.

"Dispute Notice" shall have the meaning set forth in Section 13.9(A).

"Dollars" means the lawful currency of the United States of America.

"Effective Date" means the date first written above.

"Electric Interconnection Point" means the physical point at which electrical interconnection is made between the Interconnection Facilities and the Transmission System, pursuant to the Interconnection Agreement.

"Electric Metering Device(s)" means all metering and data processing equipment used to measure, record, or transmit data relating to the Energy produced by the Facility. Electric Metering Devices include the metering current transformers (CTs) and the metering voltage transformers (VTs).

"Emergency Condition" means any emergency condition or similar situation as defined under the Interconnection Agreement or any abnormal interconnection or system condition that requires automatic or immediate manual action to prevent or limit loss of load or generation supply (including Tri-State's load or generation), that could adversely affect the reliability of the interconnected system, or that could otherwise pose a threat to public safety.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"Environmental Attributes" means any and all present and future environmental benefits characteristics, or credits that are attributable to renewable energy, Contract Energy, or the Facility including credits towards achieving local, national or international emission reduction requirements or renewable portfolio standards; green tags, RECs; greenhouse gas or emissions reductions or avoidances, credits, offset, allowances or benefits; any avoided emissions of pollutants to the air, soil, or water, including sulfur oxides (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), carbon, volatile organic compounds (VOC), mercury (Hg), hydro fluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6), and other emissions avoided; and any and all other green energy or other environmental benefits associated with the generation of renewable energy (regardless of how any present or future law or regulation attributes or allocates such characteristics). Environmental Attributes do not include Tax Credits.

"Environmental Contamination" means the introduction or presence of Regulated Materials at the Site at such levels, quantities or location, or of such form or character, as to constitute a violation of Applicable Laws, or present a material risk under Applicable Laws that the Facility will not be available or usable, whether in whole or in part, to sell Contract Energy to Tri-State as contemplated by this PPA.

"EPC Contract" means the turnkey engineering, procurement and construction contract(s) to be entered into between Seller and the EPC Contractor in relation to the engineering, procurement and construction of the Facility.

"EPC Contractor" means the engineering, procurement and construction contractor(s) retained and paid for by Seller, which contractor(s) shall be acceptable to Tri-State.

"Equipment Supply Agreement" means the agreement under which Seller has purchased or has rights to purchase the Units and related equipment for the Facility.

"Event of Default" shall have the meaning set forth in Article 12.

"Excess Contract Energy" means that amount of Contract Energy in excess of one hundred ten percent (110%) of the Expected Contract Energy.

"Excess Contract Energy Payment" means the payment specified in Section 7.1(C).

"Excess Contract Energy Rate" means fifty percent (50%) of the Contract Energy Rate.

"Expansion Energy" shall have the meaning set forth in Section 20.2(A).

"Expected Contract Energy" means _____ MWh of Contract Energy in any given Commercial Operation Year.

"Expected Nameplate Capacity Rating" shall have the meaning set forth in the recitals to this PPA.

"Facility" means Seller's [wind][solar]-powered electric energy generating facility and Seller's Interconnection Facilities, as identified and described in Article 3 and Exhibit B, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Electric Interconnection Point: Seller's equipment, buildings, all of the generation facilities, including Units, step-up transformers, equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State, output breakers, monitoring hardware, weather station hardware, facilities necessary to connect to the Electric Interconnection Point, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of such [wind][solar]-powered electric energy generating facility.

"Facility Assets" shall have the meaning set forth in Section 20.3(B).

"Facility Site Documents" means the deeds, leases, easements, rights of way, land use agreement and other agreements or instruments reasonably necessary for the construction, operation and maintenance of the Facility and that evidence Seller's ownership or control of the Site.

"FERC" means the Federal Energy Regulatory Commission, or any successor agency.

"Financing" means the obligations of Seller or its Affiliates to any Financing Parties pursuant to the Financing Documents, including principal of and premium and interest on, indebtedness, fees, expenses or penalties, amounts due upon acceleration, prepayment or restructuring, swap or interest rate hedging breakage costs and any claims or interest due with respect to any of the foregoing.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, security agreements, lease financing agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements, equity purchase agreements, purchase option agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller subject to any required approvals, whether in this PPA, or otherwise, in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means, collectively, any lender(s), lessor(s) or tax equity investor(s) and other parties providing any Financing and any successor(s) or assigns thereto.

"Force Majeure Event" shall have the meaning set forth in Article 14.

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver, Energy that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure Event, (iii) a Delivery Excuse, (iv) an Emergency Condition, or (v) a curtailment as set forth in Section 6.3(A).

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of, or regulation by, any Governmental Authority relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility or to the execution, delivery or performance of this PPA.

"Governmental Authority" means any federal, state, tribal, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including a Reliability Coordinator, Balancing Authority or other governmental or quasi-governmental body administering energy, capacity, ancillary service, energy imbalance market or other Organized Markets, and PUC, FERC, NERC, WECC or other NERC regional entities; or any court or governmental tribunal.

"Guaranteed Energy Production" means that amount of Contract Energy equal to ninety percent (90%) of the Expected Contract Energy.

"Guaranty" means the payment and performance guaranty provided by a Qualified Guarantor or Superior Guarantor, as appropriate, to Tri-State in the form set forth in Exhibit L.

"House Energy" shall have the meaning set forth in Section 1.3.

"Independent Engineer" means an independent engineering firm of national repute and appropriate expertise in [wind][solar]-power electric generation relative to the configuration of the Facility under this PPA, appointed by Financing Parties under any Financing Documents, or if no such Financing Documents exist, by Seller after consultation with, and upon the prior written consent of, Tri-State.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Transmission System, as such agreement may be amended from time to time.

"Interconnection Facilities" means the facilities required to connect the Facility to the Transmission Provider's Transmission System and shall include the Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means _____ in its capacity as the owner of the Interconnection Provider's Interconnection Facilities, or any successor entity owner.

"Interconnection Provider's Interconnection Facilities" means the facilities necessary to connect Seller's Interconnection Facilities to the Transmission System at the Electric Interconnection Point as described in the Interconnection Agreement, including breakers, bus work, bus relays, and associated equipment installed by or for the Interconnection Provider for the direct purpose of interconnecting the Facility to the Transmission System at the Electric Interconnection Point, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Issuer" means a U.S. commercial bank or a licensed U.S. branch of a foreign bank, with such bank having an unsecured bond rating equivalent to A- or better as determined by at least two (2) rating agencies, one of which must be either Standard & Poor's or Moody's, and an asset value of at least thirty billion Dollars ($30,000,000,000), or a Person otherwise approved by Tri-State in its sole discretion. An Issuer cannot be an Affiliate of Seller.

"kW" means kilowatt.

"Letter(s) of Credit" means an unconditional, irrevocable, standby letter of credit from an Issuer in substantially the form set forth in Exhibit K, *provided, however,* that such form may be modified by the Issuer as long as such modifications are customary, commercially reasonable, and acceptable to Tri-State. Costs of a Letter of Credit shall be borne by Seller.

"Mean Absolute Percent Error" or "MAPE" equals:

$$\frac{1}{n}\sum_{t=1}^{n}\left|\frac{A_{t-}F_t}{NC}\right|$$

Where:

n = number of hours in the quarter of the Year;

A_t = actual value of Contract Energy deliveries in MWh for the forecast hour;

F_t = hour-ahead forecasted value in MWh for the forecast hour, as provided by Seller in accordance with Section 6.4(E); provided if no hour-ahead forecast was provided for such hour, the amount of the forecast for that hour will be zero; and

NC = Nameplate Capacity Rating.

"Month" means a calendar month.

"Moody's" means Moody's Investors Services, Inc., or any successor thereto.

"MPT" means, during any period of determination, the time in effect as of such period determination in the Mountain Time Zone of the United States of America, whether Mountain Standard Time or Mountain Daylight Savings Time.

"MW" means megawatt.

"MWh" means megawatt hours.

"Nameplate Capacity Rating" means the maximum installed instantaneous generation capacity of the completed Facility, expressed in MW [*solar only-* AC], when operated in compliance with the Interconnection Agreement and consistent with the Unit manufacturer's recommended power factor and operating parameters, as set forth in a notice from Seller to Tri-State delivered prior to or on the Commercial Operation Date (but shall be deemed to be zero (0) MW if no such notice is provided). The Nameplate Capacity Rating of the Facility shall not exceed **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC].

"NERC" means the North American Electric Reliability Corporation, or any successor organization.

"Notice of Intent to Purchase" shall have the meaning set forth in Section 20.3(D).

"O&M Records" shall have the meaning set forth in Section 13.7.

"Offered Assets Notice" shall have the meaning set forth in Section 20.1(A).

"Operating Committee" means one representative each from Tri-State and Seller, appointed pursuant to Section 9.10(A).

"Operating Procedures" means those procedures developed pursuant to Section 9.10(B).

"Operating Records" means all agreements, records and other data associated with the construction, operation or maintenance of the Facility, including O&M Records, Project Contracts, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility.

"Operation and Maintenance Agreement" means that certain operation and maintenance agreement between Seller and the Operation and Maintenance Contractor with respect to the Facility.

"Operation and Maintenance Contractor" means the operation and maintenance contractor retained and paid for by Seller, which contractor shall be a Qualified Operator and acceptable to Tri-State.

"Organized Market" means a regional transmission organization, independent system operator, energy imbalance market, or any other organized market.

"Party" and "Parties" shall have the meaning set forth in the recitals to this PPA.

"Party Representative" or "Parties' Representatives" shall have the meaning set forth in Section 13.9(A).

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Point of Delivery" means the electric system point at which Seller makes available to Tri-State the Contract Energy, which shall be on the high side of the step-up transformer **[**at the Electric Interconnection Point**]** and as specified in Exhibit B.

"PPA" means this Energy Purchase Agreement between Seller and Tri-State, including the Exhibits attached hereto, as the same may be amended from time to time in accordance with the provisions hereof.

[*wind only-* "Production Tax Credit" mean the production tax credits applicable to electricity produced from certain renewable resources under Section 45 of the Internal Revenue Code of 1986 or any substantially similar federal tax credits under Applicable Law that provides Seller with a tax credit based on energy production from the Facility.]

"Project Contracts" means the EPC Contract, the Equipment Supply Agreement, the Interconnection Agreement, the Facility Site Documents and the Operation and Maintenance Agreement, and any such other material agreements related to the development, construction, ownership, operation and maintenance of the Facility, a list of which agreements is set forth in Exhibit E.

"Project Entity" means (a) Seller, and (b) any entity that Controls Seller if the Facility and assets related thereto constitute all or substantially all of the assets of such entity (determined on a consolidated basis with all other Persons that are Controlled by such entity).

"Prudent Utility Practice(s)" means the practices, methods, standards, and acts of a significant portion of the electric power generation industry (including, where applicable, the practices, methods, standards, and acts engaged in or approved by a significant portion of the [wind][solar]-power electric generation industry operating facilities of a similar type, size and location in the United States of America), WECC and/or NERC, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Laws, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. With respect to the Facility, Prudent Utility Practice(s) includes taking reasonable steps to ensure that:

(A) equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;

(B) sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly, efficiently, and in coordination with Tri-State and are capable of responding to reasonably foreseeable Emergency Conditions;

(C) preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(D) appropriate monitoring and testing are performed to ensure equipment is functioning as designed;

(E) equipment is not operated in a reckless manner, in violation of manufacturers' guidelines or in a manner unsafe to workers, the general public, or the interconnected system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt-ampere reactive (VAR) loading, frequency, polarity, synchronization, and/or control system limits;

(F) equipment and components meet or exceed the standard of durability that is generally used for electric generation operations in the region and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Site under both normal and Emergency Conditions; and

(G) equipment, components, and processes are appropriately permitted with any Governmental Authority and are operated and maintained in accordance with Applicable Laws.

"PUC" means the _____ Commission, or any successor agency.

"PUC Approval" means any written order of the PUC necessary for Tri-State to effectuate the purposes of this PPA.

"Purchase Notice" shall have the meaning set forth in Section 20.3(I).

"Purchase Option" shall have the meaning set forth in Section 20.3(A).

"Qualified Guarantor" means a Person having an issuer credit rating of (A) Baa2 or higher by Moody's and (B) BBB or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Qualified Operator" means an operation and maintenance contractor that (i) has operated, for a period of at least five (5) years, multiple utility-scale [wind][solar]-powered electric energy generating facilities in North America having, collectively, an aggregate nameplate capacity of at least 500 MW, and (ii) maintains an operating staff consisting of personnel with comparable experience in the operation and maintenance of power generation facilities similar to the Facility.

"RDD" means Tri-State's resource dispatch desk representative(s) who are responsible for dispatch of generating units, including the Facility.

"Regulated Materials" means any substance, material, gas, or particulate matter that is regulated by any Governmental Authority, as an environmental pollutant or dangerous to public health, public welfare, or the natural environment, including protection of non-human forms of life, land, water, groundwater, and air, including any material or substance that is (i) defined as "toxic," "polluting," "hazardous waste," "hazardous material," "hazardous substance," "extremely hazardous waste," "solid waste" or "restricted hazardous waste" under any provision of local, state, or federal law; (ii) petroleum, including any fraction, derivative or additive; (iii) asbestos; (iv) polychlorinated biphenyls; (v) radioactive material; (vi) designated as a "hazardous substance" pursuant to the Clean Water Act, 33 U.S.C. §1251 *et seq.* (33 U.S.C. §1251); (vii) defined as a "hazardous waste" pursuant to the Resource Conservation and Recovery Act, 42 U.S.C. §6901 *et seq.* (42 U.S.C. §6901); (viii) defined as a "hazardous substance" pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act, 42 U.S.C. §9601 *et seq.* (42 U.S.C. §9601);

(ix) defined as a "chemical substance" under the Toxic Substances Control Act, 15 U.S.C. §2601 *et seq.* (15 U.S.C. §2601); or (x) defined as a "pesticide" under the Federal Insecticide, Fungicide, and Rodenticide Act, 7 U.S.C. §136 *et seq.* (7 U.S.C. §136).

"RECs" means renewable energy credits or certificates representing all right, title and interest in and to all Environmental Attributes associated with each MWh of energy from a generation facility in the specific period, including title to and claim over such Environmental Attributes, reporting and all other rights arising therefrom or connected therewith under Applicable Law.

"Reliability Coordinator" shall have the meaning as set forth in NERC's Glossary of Terms Used in NERC Reliability Standards as modified from time to time.

"Replacement Cost(s)" means the costs incurred and reasonably forecasted to be incurred by Tri-State for the Energy, ancillary services and Environmental Attributes which are necessary to replace that which Seller, in accordance with this PPA, is required to produce at the Facility and deliver to Tri-State, but will fail to so provide, less the sum of any payments from Tri-State to Seller, under this PPA, which are eliminated as a result of such failure. Replacement Costs include the amounts incurred and reasonably forecasted to be incurred by Tri-State for replacement renewable energy, ancillary services, transmission and directly associated transaction costs (including reasonable attorneys' fees suffered as result of Seller's failure to perform). Additional costs may include replacement capacity costs applicable to a [wind][solar] resource and any penalties incurred as a result of Seller's non-performance.

"ROFO Transfer" shall have the meaning set forth in Section 20.1(A).

"RTU" shall have the meaning set forth in Section 3.3(A).

"SCADA" means supervisory control and data acquisition.

"Scheduled Maintenance Outage" means a time period during which all or a portion of the Facility is shut down or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Tri-State.

"Security" shall have the meaning set forth in Article 11.

"Security Party" shall have the meaning set forth in Section 19.1(B).

"Seller" shall have the meaning set forth in the preamble to this PPA.

"Seller's Interconnection Facilities" means the facilities and equipment owned by Seller related to the interconnection of the Facility with the Interconnection Provider's Interconnection Facilities along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the

construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's metering, relays, and load control equipment as provided for in the Interconnection Agreement.

"Seller's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Shortfall MWh" means the amount of Energy in MWh, for any period of determination, equal to the Guaranteed Energy Production less the actual amount of Contract Energy during the same period.

"Site" means the parcel(s) of real property on which the Facility will be constructed and located, including any easements, rights of way, land use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility. The Site is more specifically described in Section 3.2 and Exhibit B.

"Standard & Poor's" means Standard & Poor's Global Ratings, or any successor thereto.

"Superior Guarantor" means any Person having an issuer credit rating of (A) Baa1 or higher by Moody's and (B) BBB+ or higher by Standard & Poor's, or a Person otherwise approved by Tri-State in its sole discretion.

"Tariff" shall have the meaning set forth in Section 5.1(B).

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth, together with any interest and penalties thereon.

"Tax Credit" means (i) [*wind only*-the Production Tax Credit][*solar only*- the tax credit for "energy property" under Section 48(a)(3)(A)(i) of the Internal Revenue Code of 1986 or any similar tax credits under Applicable Law, as it may be amended, supplemented, extended or replaced from time to time.], (ii) any other local, state or federal tax credits providing a tax benefit to Seller based on ownership of the Facility or energy production therefrom, and (iii) depreciation and other tax benefits arising from ownership or operation of the Facility.

"Term" means the period of time during which this PPA shall remain in full force and effect, and which is further defined in Section 2.1.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken in connection with preparing the Facility for Commercial Operation pursuant to Section 9.2, which shall include such tests as are consistent with Prudent Utility Practices.

"Test Date" means the date on which Seller shall commence Testing of the Facility and shall be the date falling at least sixty (60) Days prior to the Commercial Operation Milestone or such other date as Seller and Tri-State may agree in writing.

"Test Energy" means the net electric Energy that is produced by the Facility, including any and all associated ancillary services and all Environmental Attributes and delivered to Tri-State at the Point of Delivery, prior to Commercial Operation.

"Test Energy Payment" means the payment specified in Section 7.1(B).

"Test Energy Rate" means an amount equal to fifty percent (50%) of the Contract Energy Rate.

"TP Approvals" shall have the meaning set forth in Section 2.2.

"Transfer" means any sale, transfer or other disposition.

"Transmission Provider" means the owner or operator of the Transmission System responsible for providing transmission service.

"Transmission System" means the contiguously interconnected electric transmission and sub-transmission facilities over which the Transmission Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Electric Interconnection Point.

"Tri-State" shall have the meaning set forth in the preamble to this PPA.

"Tri-State's WREGIS Account" shall have the meaning set forth in Section 10.2(D).

"Ultimate Parent" means _____ or such other Person that Controls Seller and is not controlled by any other Person.

"Unit" shall have the meaning set forth in the recitals to this PPA.

"WECC" means the Western Electricity Coordinating Council, a NERC regional entity, or any successor organization.

"WREGIS" means the Western Renewable Energy Generation Information System, or any successor organization that Tri-State uses to track Environmental Attributes.

"Year" means a calendar year consisting of 365 Days (or 366 Days if a leap year), beginning on January 1 and ending on December 31.

Article 2
Term

2.1 PPA Term and Delivery Term.

This PPA shall become effective as of the Effective Date, and shall remain in full force and effect until 11:59 p.m. MPT on the last Day of the Month during which occurs the [___th] anniversary of the Commercial Operation Date, subject to early termination as set forth herein (the "Term").

2.2 Conditions Precedent.

(A) Network Resource. Tri-State's obligation to accept and pay for Contract Energy is subject to approval by the Transmission Providers of Tri-State's application for designation of the Facility as a network resource for Tri-State's native load customers and the associated reservation of firm network transmission service on the Transmission Provider's Transmission System, all without conditions materially unsatisfactory to Tri-State or requirements of material transmission upgrades (collectively, the "TP Approvals"). Tri-State shall (i) no later than fifteen (15) Business Days after the Effective Date, make a written request for all TP Approvals and (ii) thereafter use commercially reasonable efforts to obtain such TP Approvals from the Transmission Providers within one hundred fifty (150) Days from the Effective Date ("Designation Approval Date") and shall provide Seller prompt written notice upon receipt of all such TP Approvals. If any or all of the TP Approvals are not received by the Designation Approvals Date or any TP Approval would require conditions materially unsatisfactory to Tri-State or material transmission upgrades, (y) Tri-State shall promptly provide Seller written notice notifying Seller that Tri-State elects to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder, subject to Tri-State's obligation to return the Security to Seller in full, or (z) if no such notice is received by Seller within ten (10) Days following the Designation Approval Date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such TP Approvals, upon which the condition provided in this Section 2.2(A) shall be deemed to have been satisfied.

(B) PUC Approvals. Tri-State's obligation to accept and pay for Contract Energy is subject to PUC Approvals. Tri-State shall (i) no later than sixty (60) Days after the Effective Date apply to the PUC for any necessary PUC Approvals and (ii) thereafter use commercially reasonable efforts to obtain such PUC Approvals as soon as reasonably practicable. Seller shall cooperate with Tri-State's efforts to obtain PUC Approvals and provide such additional documentation and information as reasonably requested by Tri-State or the PUC. Tri-State shall have the right to terminate this PPA, upon which the Parties shall have no obligations or liabilities to each other hereunder as a result of such termination, by written notice to Seller: (a) at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approvals or granting PUC Approvals with conditions unacceptable to Tri-State in its sole discretion, (b) at any time between the 180th and 215th Day following Tri-State's

application for PUC Approval, if prior to the date of such termination the PUC has not issued the PUC Approvals, (c) at any time within 30 Days following timely request for reconsideration (in whole or in any material part) by any third party, of the PUC Approvals, and/or (d) at any time within thirty (30) Days following timely appeal by any party, of the PUC Approvals. If Tri-State elects to terminate this PPA, Tri-State shall return the Security to Seller in full. If Tri-State is eligible to terminate this PPA, but fails to terminate this PPA by the applicable date, Tri-State shall be deemed to have elected to proceed with this PPA despite not receiving such PUC Approvals, upon which the condition provided in this Section 2.2(B) shall be deemed to have been satisfied.

(C) Other Tri-State CPs. [if any].

(D) Seller CPs. [if any – project specific].

2.3 Survivability.

Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, and the indemnifications specified in this PPA. All remedies in this PPA shall survive termination or cancellation of this PPA.

Article 3
Facility Description

3.1 Summary Description.

Seller shall develop, design, construct, interconnect, own, operate, and maintain the Facility, which consists of _____ (__) _____ [wind turbines][solar panels] and associated equipment having a designed aggregate nameplate electric energy generating capacity of **Insert the Expected Nameplate Capacity Rating**. Exhibit B provides a detailed description of the Facility, including identification of the major equipment and components that will make up the Facility.

3.2 Location.

The Facility shall be located on the Site and shall be identified as the "**Insert Project Name**" or such other name as agreed to by the Parties. The latitude and longitude of the Site are _____. A scaled map that identifies the Site and the location of the Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities, is included in Exhibit B.

3.3 General Design of the Facility.

Seller shall develop, design and construct the Facility according to Prudent Utility Practice(s), this PPA and the Interconnection Agreement, as applicable. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times, and at Seller's expense:

(A) have the required electronic plant interfaces and communications interfaces for meter recording devices, 125vDC battery supplied voltage for meter recording devices, remote terminal unit ("RTU"), telemetering equipment and communications equipment. Seller is responsible for providing appropriate panel space and maintaining ambient conditions suitable for electronic equipment. Seller is responsible for establishing appropriate access control to the electronic equipment;

(B) use communication circuits from the Facility to Tri-State's RDD for the purpose of telemetering, supervisory control/data acquisition, voice communications as required by Tri-State, and dial-in access by Tri-State to remotely interrogate the Electric Metering Devices;

(C) [solar only- have suitable solar irradiation meters and other instrumentation necessary to measure the available resource and ambient temperature and to estimate the quantity of Contract Energy expected to be generated;]

(D) include one full data circuit as required to transmit to Tri-State real-time weather data, including [wind speed, wind direction][solar irradiance], humidity and temperature collected by Seller's monitoring equipment on its meteorological data acquisition equipment located at the Facility; and

(E) have the required equipment and software necessary to receive, accept and respond to an AGC Set-Point signal from Tri-State.

Article 4
Commercial Operation

4.1 Commercial Operation.

Seller shall cause the Facility to achieve Commercial Operation no later than the Commercial Operation Milestone. The Facility shall be fully capable of reliably producing and delivering the Contract Energy to be provided under this PPA to Tri-State at the Point of Delivery, no later than the Commercial Operation Milestone; provided, that Seller shall not be obligated to establish a Commercial Operation Date under this PPA that is earlier than the Commercial Operation Milestone, and Tri-State shall not be obligated to acknowledge a Commercial Operation Date under this PPA that is earlier than thirty (30) Days prior to the Commercial Operation Milestone.

4.2 Construction Milestone.

In order to achieve the Commercial Operation Date of the Facility by the Commercial Operation Milestone, Seller shall meet the Construction Milestones set forth in Exhibit A.

4.3 Delay Damages.

(A) If Seller fails to achieve any Construction Milestones (excluding the Commercial Operation Milestone) by the applicable Construction Milestone Date, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to maintain the overall construction and commercial operation schedule, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Thousand Five Hundred Dollars ($2,500) per Day for each Day following the Construction Milestone Date until the date the Construction Milestone is achieved; *provided, however,* that if Commercial Operation is achieved on or before the Commercial Operation Milestone, any liquidated damages amounts paid by, or on behalf of, Seller pursuant to this Section 4.3(A) shall be refunded by Tri-State to Seller without interest.

(B) If the Facility fails to achieve Commercial Operation by the Commercial Operation Milestone, (i) Seller shall provide Tri-State within ten (10) Days of the missed milestone with a detailed written report indicating the reason for such failure and Seller's proposed course of action to achieve Commercial Operation, including any required expediting actions, and (ii) Tri-State shall be entitled to delay damages, as liquidated damages and not a penalty, in an amount equal to Two Hundred Fifty Dollars ($250) per Day per MW for each MW [*solar only-* AC] of nameplate capacity not installed, operating and capable of generating Test Energy below the Expected Nameplate Capacity Rating until the earlier to occur of (x) the date Commercial Operation is achieved, and (y) the date, if any, on which this PPA is terminated by Tri-State as permitted hereunder.

(C) All Delay Damages shall begin to accrue on the Day after the applicable missed Construction Milestone and shall continue to accrue until the result specified for such Construction Milestone is achieved. Delay Damages shall be payable in lieu of actual damages accrued for the period during which Delay Damages are assessed; provided, that nothing in this Section shall be construed to preclude Tri-State from terminating this PPA for an Event of Default under Section 12.1 or Tri-State's entitlement to Replacement Costs upon termination of this PPA. All Delay Damages shall be cumulative.

(D) Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's delay or failure in achieving any Construction Milestone (collectively, "Delay Damages") would be difficult or impossible to predict with

certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties set forth herein are a fair and reasonable calculation of such damages.

(E) Following the end of the Month in which Delay Damages begin to accrue, Tri-State shall promptly deliver to Seller an invoice setting forth the amount due Tri-State in respect thereof for the preceding Month. The amount of Delay Damages shall be due and payable by Seller in accordance with Section 8.3(A).

4.4 Site Report.

(A) Within ninety (90) Days of the Effective Date, Seller shall conduct a Phase I environmental investigation of the Site and shall provide Tri-State with a copy of the report summarizing such investigation, together with any data or information generated pursuant to such investigation. To the extent the Phase I investigation identifies the need for further environmental audits or investigations, Seller shall also provide to Tri-State, any related further reports. Seller shall provide to Tri-State, with such report, confirmation from an environmental engineer that the Site has been inspected for Environmental Contamination and that the Site complies, in all respects, with all Applicable Law relating to environmental or occupational health and safety matters and Regulated Materials. Such report shall include a confirmation that, based upon such investigation and to the best of Seller's knowledge, no conditions involving Environmental Contamination exist at or under the Site.

(B) During the Term, Seller shall promptly:

(1) disclose to Tri-State and remediate, at Seller's sole cost and expense, any Environmental Contamination identified at the Site;

(2) provide to Tri-State copies of any reports summarizing any further environmental assessments or investigations, together with any data or information generated pursuant to such investigation; and

(3) disclose to Tri-State the existence of any enforcement, legal, or regulatory action or proceeding relating to any alleged presence of Environmental Contamination and/or the alleged violation of any Applicable Law related to the protection of endangered, migratory or other protected species.

4.5 Project Contracts.

(A) Promptly after the execution of each of the Project Contracts or amendment thereto, Seller shall deliver to Tri-State copies of each of the fully executed Project Contracts. Upon reasonable notice and request by Tri-State, Seller shall provide Tri-State with other Facility design and construction documents and drawings, including as-built and other major engineering drawings. Seller shall be permitted to redact from the copies of the Project Contracts provided to Tri-State any pricing information which Seller considers confidential.

(B) Within ten (10) Days after the Effective Date, Seller shall deliver to Tri-State a copy of any existing [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Facility. Furthermore, promptly following its issuance to Seller or development by Seller, Seller shall deliver to Tri-State a copy of any new or updated [wind][solar] energy or [wind][solar] resource assessment report related to the Site or the Facility.

4.6 Governmental Approvals.

Seller shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Seller required Governmental Approvals, and shall timely and properly pay its charges and fees in connection therewith. Tri-State shall have the right to inspect and obtain copies of all Seller required Governmental Approvals (and related applications) obtained or applied for by Seller. Exhibit F sets forth a list of Seller's required Governmental Approvals, which Seller shall update from time to time, as appropriate, to add additional Seller required Governmental Approvals prior to Commercial Operation.

4.7 Construction Progress Reports.

Seller shall provide Tri-State with written progress reports in a form reasonably acceptable to Tri-State: (A) on a quarterly basis commencing with the Effective Date and continuing until the commencement of physical construction of the Facility within twenty (20) Days following the end of each calendar quarter; and (B) on a monthly basis commencing on the commencement of physical construction of the Facility and continuing until Commercial Operation, on or before the twentieth (20^{th}) Day of each Month for the preceding Month. Such written progress reports shall evaluate the progress on development, design, and construction of the Facility, which reports shall include (i) a project master schedule, with appropriate bar charts and status reports; (ii) updated engineering and procurement schedules; (iii) an updated testing, commissioning and start-up schedule; and (iv) reports from engineers and other Persons involved in the engineering, procurement and construction of the Facility. Seller shall, from time to time, upon reasonable advance request from Tri-State, meet with Tri-State to discuss the progress of the construction of the Facility and make the EPC Contractor available to discuss and answer questions of Tri-State regarding the Facility and Construction Milestone progress in order to keep Tri-State informed on the status of the engineering, procurement and construction for the Facility and to consider Tri-State's comments in good faith. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13.

4.8 Tri-State's Rights During Construction.

Tri-State shall have the right to monitor the construction, start-up and Testing of the Facility, and Seller shall comply with all requests of Tri-State with respect to the monitoring of these events. Seller shall cooperate in such physical inspections of the

Facility as may be requested by Tri-State during and after completion of construction. All persons visiting the Facility on behalf of Tri-State shall comply with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State in writing prior to its visit.

4.9 Conditions to Commercial Operation.

Seller shall notify Tri-State in writing when Seller has satisfied all of the Conditions for Commercial Operation. Such notice shall specify the Commercial Operation Date. The Commercial Operation Date is contingent upon verification by Tri-State, including Seller providing evidence acceptable to Tri-State of the satisfaction or occurrence of all of the Conditions set forth below. Review and approval of such Conditions may occur on an ongoing and incremental basis, pending resolution of any dispute, as such Conditions are satisfied. Conditions shall be satisfied at Seller's sole cost and expense. Conditions to be fulfilled by Seller prior to Commercial Operation, to the satisfaction of, or waived in writing by, Tri-State are ("Conditions"):

(A) Seller having delivered to Tri-State copies of fully executed Project Contracts, pursuant to Section 4.5(A);

(B) if applicable, Seller having entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents;

(C) Seller having delivered to Tri-State (i) a copy of its constitutional documents (certified by the Secretary of State of the State of _____) and (ii) a copy of a resolution approving the terms of this PPA and authorizing one or more individuals to execute this PPA on its behalf (such copy to have been certified by its authorized officer as true, complete and current);

(D) the Facility having achieved initial synchronization with the Transmission System and having demonstrated the reliability of its communications systems and communications with Tri-State's RDD;

(E) the Independent Engineer having certified that the Facility has been completed in all material respects (excepting punch list items that do not adversely affect the ability of the Facility to operate as intended hereunder) and the Facility is ready for the delivery of Contract Energy and commencement of Commercial Operation;

(F) all arrangements for the supply of required House Energy to the Facility have been completed by Seller, are in effect, and are available for the supply of such House Energy to the Facility;

(G) the Security meeting the requirements set forth in Section 11.1 having been established in the amount required after the Commercial Operation Date pursuant to Section 11.1;

(H) certificates of insurance evidencing the coverages required in Exhibit D having been obtained and submitted to Tri-State;

(I) Seller having submitted to Tri-State a certificate of an officer of Seller familiar with the Facility after due inquiry stating that:

(1) all applicable Seller required Governmental Approvals (including those set forth in Exhibit F) have been obtained and are in full force and effect, except for minor Governmental Approvals that are expected by such officer to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility;

(2) Seller is in compliance with the terms and conditions of this PPA;

(3) the Facility is in compliance with all national and regional reliability standards, including standards set by WECC, NERC, FERC, the PUC and is compliance with all applicable terms and conditions of applicable Tariffs;

(4) Seller has good title to the Facility and all Facility Site Documents reasonably necessary for the operation and maintenance of the Facility are in full force and effect;

(5) Seller has registered (and attaching with such certificate documentation setting forth that it has registered) (i) with NERC as a generator owner and generator operator, and (ii) the Facility as a generating unit and itself as an account holder with WREGIS;

(6) Seller having successfully completed Testing of the Facility that may be required by the Financing Documents, applicable Seller required Governmental Approvals, any Project Contracts, manufacturers' specifications and warranties for the commencement of Commercial Operation, and in accordance with Section 9.2 at an installed capacity of the Expected Nameplate Capacity Rating;

(7) (i) Seller is in compliance with the Interconnection Agreement, (ii) the interconnection of the Facility to the Interconnection Provider's Interconnection Facilities has been completed in accordance with the Interconnection Agreement, (iii) the Facility has operated at a generation level acceptable to the Interconnection Provider, without experiencing any abnormal or unsafe operating conditions on any interconnected system, and (iv) any other testing of the Facility and/or Seller's interconnection Facilities required by the Interconnection Agreement to interconnect and deliver energy has been completed satisfactorily;

(8) the Nameplate Capacity Rating of the Facility at the time of Commercial Operation is **Insert the Expected Nameplate Capacity Rating** MW [*solar only-* AC]; and

(9) Seller shall have demonstrated that it is a Qualified Operator or that Seller has engaged a Qualified Operator to operate and maintain the Facility.

4.10 Financial Ability.

Within ninety (90) Days of the Effective Date, Seller shall provide to Tri-State copies of applicable funding agreements, financing documents or other documents and agreements, as such may be updated from time to time, which reasonably establish that Seller has or will have sufficient funding to complete the construction of the Facility and achieve Commercial Operation.

4.11 Test Energy.

Seller shall coordinate the production and delivery of Test Energy with Tri-State, with such prior notice as Tri-State may request. Tri-State shall cooperate with Seller to facilitate Testing, shall accept delivery of all Test Energy, and shall accept and purchase all such Test Energy at the Test Energy Rate, so long as the Facility is interconnected in accordance with the Interconnection Agreement and Seller is otherwise in compliance with this PPA.

Article 5
Delivery and Metering

5.1 Delivery Arrangements.

(A) Seller shall be responsible for all interconnection arrangements and costs required to deliver the Contract Energy. Seller shall execute, deliver, and perform its obligations under the Interconnection Agreement.

(B) Seller is solely responsible for meeting its obligations as an interconnection customer under the Interconnection Provider's open access transmission tariff (the "Tariff") and the requirements of the Balancing Authority. All costs and obligations associated with Interconnection Facilities required to accomplish and operate the Interconnection Facilities is the responsibility of Seller. Seller shall satisfy any concerns of Tri-State regarding viability of the interconnection (timing and status of the generator interconnection request); *provided, however,* that any and all costs associated with this Section 5.1(B) shall be at the sole cost and expense of Seller.

(C) Seller is responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy to Tri-State at the Point of Delivery.

(D) Tri-State shall be responsible for all electric losses, transmission and ancillary service arrangements and costs required to deliver Contract Energy beyond the Point of Delivery. Subject to the provisions of this PPA, Tri-State may elect, at Tri-State's sole option, whether to obtain and utilize firm transmission service, non-

firm transmission service or network integration transmission service for the delivery of Contract Energy from the Point of Delivery.

5.2 Availability Reporting.

Within thirty (30) Days after the end of each Commercial Operation Year, Seller shall provide Tri-State with an operating report detailing events such as maintenance outages, [Unit][feeder breaker] trips and the causes of such trips, Unit failures and the diagnosis of such failures, status of repairs as well as statistical performance summaries and operational trends for the previous Commercial Operation Year.

5.3 Electric Metering Devices.

(A) All Electric Metering Devices used to measure the Contract Energy and to monitor and coordinate operation of the Facility shall be owned, installed, and maintained in accordance with the Interconnection Agreement. If Electric Metering Devices are not installed at the Point of Delivery, meters or meter readings shall be adjusted to reflect losses from the Electric Metering Devices to the Point of Delivery. All Electric Metering Devices used to provide data for the computation of payments shall be sealed and only the Interconnection Provider shall break the seal when such Electric Metering Devices are to be inspected and tested or adjusted in accordance with this Article 5.

(B) Seller and/or Tri-State may elect to install and maintain, at its own expense, backup metering devices ("Back-Up Metering") in addition to those installed and maintained pursuant to the Interconnection Agreement, which installation and maintenance shall be performed in a manner acceptable to Tri-State. The Party installing the Back-Up Metering shall, at its own expense, inspect and test the Back-Up Metering upon installation and periodically thereafter. The Party installing the Back-Up Metering shall provide the other Party with reasonable advance notice of, and permit a representative of the other Party to witness and verify, such inspections and tests; provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. Upon request from the other Party, the Party installing the Back-Up Metering shall perform additional inspections or tests of its Back-Up Metering and shall permit a qualified representative of the other Party to inspect or witness the testing of the Back-Up Metering, provided, however, that the other Party shall not unreasonably interfere with or disrupt the activities of the Party installing the Back-Up Metering and shall comply with all of such Party's safety standards. The actual expense of any such requested additional inspection or testing by the non-installing Party shall be borne by the non-installing Party; *provided, however*, that the expense of the requested additional inspection or testing shall be borne by the Party installing if the Back-Up Metering is found to be inaccurate by more than the allowable limits established in this Article 5. If requested in writing, the Party installing the Back-Up Metering shall provide copies of any inspection or testing reports to other Party.

(C) If any Electric Metering Device, or Back-Up Metering, are found to be defective or inaccurate outside the bounds of the selected device's manufacturer's performance standards, they shall be adjusted, repaired, replaced, and/or recalibrated as near as practicable to a condition of zero error by the Party owning such defective or inaccurate device and at that Party's expense.

(D) Seller shall be responsible for the design, installation, operation and maintenance of site data historian systems at the Facility, which are linked on a real-time basis and interoperable with the RDD subject to prior written approval of such systems by Tri-State.

5.4 Adjustment for Inaccurate Meters.

If an Electric Metering Device, or Back-Up Metering, fails to register, or if the measurement made by an Electric Metering Device, or Back-Up Metering, is found upon testing to be inaccurate by more than one percent (1.0%), an adjustment shall be made correcting all measurements by the inaccurate or defective Electric Metering Device, or Back-Up Metering, for both the amount of the inaccuracy and the period of the inaccuracy, in the following manner:

(A) In the event that the Electric Metering Device is found to be defective or inaccurate, the Parties shall use Tri-State's Back-up Metering, if installed, to determine the amount of such inaccuracy; *provided,* however, that Tri-State's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Tri-State's Back-Up Metering is installed on the low side of Seller's step-up transformer, Tri-State's Back-Up Metering data shall be adjusted for losses. In the event that Tri-State did not install Back-Up Metering, or Tri-State's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall use Seller's Back-up Metering, if installed, to determine the amount of such inaccuracy; provided, however, that Seller's Back-Up Metering has been tested and maintained in accordance with the provisions of this Article 5. If Seller's Back-Up Metering is installed on the low side of Seller's step-up transformer, Seller's Back-Up Metering data shall be adjusted for losses. In the event that Seller did not install Back-Up Metering, or Seller's Back-Up Metering is also found to be inaccurate by more than one percent (1.0%), the Parties shall estimate the amount of the necessary adjustment on the basis of deliveries of Contract Energy during periods of similar operating conditions when the Electric Metering Device was registering accurately. The adjustment shall be made for the period during which inaccurate measurements were made.

(B) In the event that the Parties cannot agree on the actual period during which the inaccurate measurements were made, the period during which the measurements are to be adjusted shall be the shorter of (i) the last one-half of the period from the last previous test of the Electric Metering Device to the test that found the Electric Metering Device to be defective or inaccurate, or (ii) the one hundred eighty (180) Days immediately preceding the test that found the Electric Metering Device to be defective or inaccurate.

(C) To the extent that the adjustment period covers a period of deliveries for which payment has already been made by Tri-State, Tri-State shall use the corrected measurements as determined in accordance with this Article 5 to recompute the amount due for the period of the inaccuracy and shall subtract the previous payments by Tri-State for this period from such re-computed amount. If the difference is a positive number, the difference shall be paid by Tri-State to Seller; if the difference is a negative number, the difference shall be paid by Seller to Tri-State, or at the discretion of Tri-State, may take the form of an offset to payments due Seller by Tri-State. Payment of such difference by the owing Party shall be made not later than thirty (30) Days after the owing Party receives notice of the amount due, unless Tri-State elects payment via an offset.

5.5 WREGIS Metering.

Seller shall cause the Facility to implement all necessary generation information communications required by WREGIS, and report generation information to WREGIS pursuant to a WREGIS-approved meter that is dedicated to the Facility.

Article 6
Sale and Purchase of Contract Energy

6.1 Sale and Purchase.

Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Delivery, and sell to Tri-State, and Tri-State shall purchase from Seller, at the applicable price set forth in Article 7, all Contract Energy; *provided* that, notwithstanding anything in this PPA to the contrary, Tri-State shall have no obligation (i) to pay for any Energy that has not actually been generated by the Facility, measured by the Electric Metering Device(s), and delivered to Tri-State at the Point of Delivery except for payments of Curtailed Contract Energy as set forth in Section 7.2 or (ii) to pay for any Energy generated by the Facility to the extent the instantaneous output exceeds **Insert the Expected Nameplate Capacity Rating** MW. Seller shall be responsible for, and shall reimburse Tri-State for, any charges, fees, fines or penalties assessed to Tri-State by the Transmission Provider, Balancing Authority, or an Organized Market as a result of the instantaneous output exceeding **Insert the Expected Nameplate Capacity Rating** MW. Seller shall not curtail or interrupt deliveries of Contract Energy to Tri-State for economic reasons of any type.

6.2 Title and Risk of Loss.

As between Seller and Tri-State, Seller shall be deemed to be in control of the Contract Energy up to and including delivery and receipt at the Point of Delivery and Tri-State shall be deemed to be in control of Contract Energy after delivery and receipt at the Point of Delivery. Title and risk of loss related to the Contract Energy shall transfer from Seller to Tri-State at the Point of Delivery.

6.3 Right to Curtail Energy.

(A) Tri-State shall have the right at any time to notify Seller, by telephonic communication from the RDD or by the AGC system, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility to the Point of Delivery, and Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices. Tri-State may provide such notification for any reason and in its sole discretion. Any payments for such curtailed Contract Energy shall be in accordance with Section 7.2. Such curtailment rights do not provide Tri-State with any rights to direct the operation of the Facility.

(B) In the event the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized Market, NERC, WECC, FERC or any other Governmental Authority either directs Tri-State to notify Seller or notifies Seller directly, by any method established by such Person, to curtail the delivery of Contract Energy, in whole or in part, to Tri-State from the Facility, Seller shall as soon as reasonably practicable, but within no more than ten (10) minutes, comply with such notification consistent with Prudent Utility Practices.

(C) Seller shall be responsible for, and shall reimburse Tri-State to the extent Tri-State is charged and pays for any damages, fines or penalties as a result of Seller failing to comply with such curtailment instructions described in this Section 6.3.

6.4 Scheduling.

(A) Seller shall be responsible for providing the forecast of Contract Energy deliveries during the Term in accordance with the mutually-developed Operating Procedures described in Section 9.10(B).

(B) No later than ninety (90) Days before the start of Testing and by August 1 of each Year thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Month's average-day deliveries of Contract Energy, by hour, for the following Year.

(C) No later than thirty (30) Days before the start of Testing and at least ten (10) Business Days before the beginning of each Month thereafter, Seller shall provide, or cause to be provided, to Tri-State, in a format acceptable to Tri-State, a forecast of each Day's average deliveries of Contract Energy, by hour, for the following Month.

(D) Seller shall provide, or cause to be provided to Tri-State, by 6:00 a.m. MPT on each Day, in a format acceptable to Tri-State, a forecast of the hourly quantities of Contract Energy to be delivered to Tri-State for the immediately succeeding Day or for multiple Days as may be required by the parameters of the WECC prescheduling calendar.

(E) Seller shall provide, or cause to be provided to Tri-State, thirty (30) minutes before the start of every hour, in a format acceptable to Tri-State, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State for the next scheduling hour. As an example, Seller shall provide to Tri-State by 6:30 a.m. MPT, a forecast of the hourly quantity of Contract Energy to be delivered to Tri-State beginning 8:00 a.m. MPT and ending 9:00 a.m. MPT.

(F) If, at any time following submission of a forecast as described in Sections 6.4(B), (C), (D) and (E), Seller becomes aware of any change that alters the values previously provided to Tri-State, Seller shall promptly notify Tri-State no later than sixty (60) minutes before the next scheduling hour of such change or predicted change and if such change reduces the forecasted availability of the Facility more than ten (10) MW, such reduction shall be communicated to the RDD as soon as reasonably practicable, but within no more than ten (10) minutes.

(G) Tri-State and Seller shall agree upon reasonable changes to the requirements and procedures set forth above from time to time, as necessary to comply with changes to the Tariff or other requirements set forth by Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or an Organized Market, to accommodate changes to their respective generation technology and organizational structure and address changes in the operation and scheduling procedures of Tri-State, the Interconnection Provider, the Balancing Authority, the Transmission Provider, or the Organized Market, including more frequent reporting and automated forecast and outage submissions.

(H) Within fifteen (15) Days after the end of each quarter of the Year commencing with the first full quarter of the Year after the Commercial Operation Date, Seller shall calculate the aggregate MAPE for the prior quarter and provide such percentage, together with reasonable documentation supporting such calculation, to Tri-State. Such percentage of MAPE amount is subject to verification by Tri-State. If the aggregate MAPE for any quarter exceeds [*wind only-* twelve percent (12%)][*solar only-* seven percent (7%)], Seller shall pay Tri-State, as liquidated damages and not a penalty, within ten (10) Days after delivering such calculation to Tri-State **Insert $2000*Expected Nameplate Capacity Rating** for each one percent (1.0%) above such amount, adjusted pro-rata for any partial percentage. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's forecasting inaccuracies would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.4(H) are a fair and reasonable calculation of such damages.

6.5 Forced Outages and Emergency Conditions.

Seller shall notify the RDD by telephone call or other automated means acceptable to Tri-State as promptly as possible upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Contract Energy due to a

Forced Outage or Emergency Condition resulting in a capacity reduction of more than ten (10) MW and, as soon as reasonably practicable, but within no more than ten (10) minutes, following such discovery, shall notify the RDD of its best estimate of the expected duration of such Forced Outage or Emergency Condition. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Forced Outage or Emergency Condition, it shall as soon as reasonably practicable, but within no more than ten (10) minutes, of such change notify the RDD of the same.

6.6 *[wind only-*Cut-Out Events.

In the event of a Cut-Out Event, Seller shall coordinate with Tri-State's RDD the ramp-up rate of the Facility back to full production after such event.]

6.7 Guaranteed Energy Production.

(A) During each Commercial Operation Year, Seller is required to deliver to Tri-State at least the Guaranteed Energy Production; *provided* that the Facility shall be deemed to have generated Contract Energy during such Commercial Operation Year to the extent it was capable of delivering Contract Energy but failed to deliver such Contract Energy due to a (i) Delivery Excuse, (ii) Force Majeure Event, (iii) Emergency Condition, or (iv) a curtailment pursuant to Section 6.3 (except for a curtailment caused by a Forced Outage or otherwise covered by Section 7.2(B)(9) through (11)) with such deemed quantity to be determined using the factors set forth in Section 7.2(A).

(B) In the event Seller delivers less than the Guaranteed Energy Production in any Commercial Operation Year, Tri-State shall promptly invoice Seller for an amount equal to the Shortfall MWh multiplied by the Contract Energy Rate during such Commercial Operation Year. Invoiced amounts shall be payable in accordance with Section 8.3(A); *provided* that this Section shall not limit Tri-State's rights and remedies under Article 12 with respect to Deficiency MWhs upon the occurrence of and during an Event of Default or Replacement Costs upon termination of this PPA. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur due to Seller's failure in achieving the Guaranteed Energy Production would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 6.7 are a fair and reasonable calculation of such damages and not a penalty.

6.8 Organized Market.

(A) If at any time during the Term, the Interconnection Provider changes or the facilities at the Point of Delivery cease to be subject to the Interconnection Provider's Tariff, Tri-State and Seller shall cooperate and take all necessary actions to facilitate the delivery of Contract Energy from the Point of Delivery to Tri-State's load, at the least possible cost to the Parties, consistent with this PPA.

(B) If at any time during the Term, (i) the Interconnection Provider, the Transmission Provider, the Balancing Authority, or Tri-State elects to join or participate in an Organized Market, or (ii) WECC, NERC, FERC or any other Governmental Authority institutes an Organized Market and such action requires changes to this PPA or changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation and scheduling of the Facility and to amend this PPA to comply with such changes accordingly, at the least possible cost to the Parties, consistent with this PPA. The Parties shall negotiate and allocate the costs associated with these changes between the Parties in a fair and reasonable manner.

Article 7
Payment Calculations

7.1 Contract Energy Payment.

(A) Contract Energy Payment. Except as otherwise provided in this PPA, commencing on the Commercial Operation Date, Tri-State shall pay Seller an energy payment for each Month (the "Contract Energy Payment") equal to the product of (i) the applicable Contract Energy Rate; and (ii) the aggregate amount of Contract Energy (other than Test Energy and Excess Contract Energy) delivered to Tri-State. The Contract Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(B) Test Energy Payment. Tri-State shall pay for all Test Energy at the Test Energy Rate. Test Energy Payments shall be equal to the product of (i) the Test Energy Rate; and (ii) the aggregate amount of Test Energy delivered by Seller to Tri-State during such Month. The Test Energy Payment for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

(C) Excess Contract Energy Payment. Except as otherwise provided in this PPA, Tri-State shall pay for all Excess Contract Energy, if any, generated and delivered in each Commercial Operation Year, during the Term at the Excess Contract Energy Rate. Excess Contract Energy Payments shall be equal to the product of (i) the applicable Excess Contract Energy Rate for such Month, and (ii) the aggregate amount of Excess Contract Energy delivered by Seller to Tri-State. The Excess Contract Energy Payment, if any, for each Month during the Term shall be paid in accordance with the invoicing procedures set forth in Section 8.1.

7.2 Curtailed Contract Energy Payment.

(A) Determination of Curtailed Contract Energy. On and after the Commercial Operation Date, if delivery of Contract Energy is curtailed by Tri-State pursuant to Section 6.3(A), then:

(1) The Parties shall determine the quantity of Contract Energy that would have been generated by the Facility and delivered to the Point of Delivery during the period of curtailment had its generation not been so curtailed by Tri-State ("Curtailed Contract Energy") by using the best available data obtained through commercially reasonable methods in accordance with the Operating Procedures; and shall be dependent upon measured [wind speed and wind direction][solar irradiance] gathered from appropriate [*wind only-* Units anemometers][*solar only-* pyranometers] and meteorological towers at the Facility during those hours in which Tri-State curtailed its receipt of Contract Energy, as such process may be further described in the Operating Procedures, and any other adjustments necessary to accurately reflect the Facility's capacity to generate and deliver Energy to the Point of Delivery including applicable losses and manufacturers' warranted power curves (a copy of which shall be provided to Tri-State) for all operational Units whose output was curtailed. The methodology utilized to measure Curtailed Contract Energy shall be reviewed and adjusted, as necessary, by the Operating Committee, at least once every five (5) years after the Commercial Operation Date.

(2) Tri-State shall pay to Seller for such Curtailed Contract Energy all amounts that Seller would have received from Tri-State under this PPA for the corresponding Contract Energy had delivery not been so curtailed by Tri-State (and at the applicable rates set out in Section 7.1) [wind only -plus an amount per MWh that equals (a) the Production Tax Credit to the extent Seller would have been entitled to receive such Production Tax Credit plus (b) a gross up amount to take into account the federal, state and local income tax to Seller or its Affiliates or tax investors on such payment in lieu of the Production Tax Credit, calculated in accordance with the following formula] (the "Curtailed Contract Energy Payment"):

[wind only -

$$\text{Amount of Payment in lieu of Production Tax Credit} \times \frac{1}{1\text{-applicable aggregate tax rate}}$$

For the avoidance of doubt, Seller shall not be entitled to recover any of the above referenced tax benefits to the extent Seller would not have been entitled to receive the Production Tax Credit had the Curtailed Contract Energy actually been delivered.]

(3) In the event Tri-State is obligated to pay for Curtailed Contract Energy under this Section 7.2(A), Seller shall provide on the applicable monthly invoice detailed calculations of the Curtailed Contract Energy and the Curtailed Contract Energy Payment due Seller.

(B) Restriction on Curtailment Payments. Notwithstanding anything in this Section 7.2 to the contrary, no payment shall be due to Seller from Tri-State under paragraph (A) above for curtailments of delivery of Contract Energy resulting from:

(1) an Emergency Condition, Force Majeure Event, or Forced Outage;

(2) the failure of Seller's Interconnection Facilities or any action taken by the Interconnection Provider in accordance with its rights under the Interconnection Agreement and not due to Seller's default;

(3) any restriction, reduction, or curtailment of firm transmission service or network integration transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery;

(4) any restriction, reduction, or curtailment of non-firm transmission service by the applicable Transmission Provider, arranged by either Party, to provide transmission of Contract Energy to or from the Point of Delivery to the extent such restriction, reduction, or curtailment would also have been imposed even if firm transmission service had been in place;

(5) maintenance outages, whether planned or unplanned, of any part of the Transmission System or any testing of the Transmission System;

(6) Allowable Curtailment;

(7) [*wind only-* Cut-Out Events; provided that Tri-State shall compensate Seller for any curtailment of Contract Energy up to one (1) hour for the first Cut-Out Event per quarter of any Year];

(8) any notification from the Balancing Authority requiring Seller to curtail or cease deliveries of Contract Energy to achieve load balancing in the Balancing Authority Area or any notifications from the Reliability Coordinator requiring Seller to curtail or cease deliveries of Contract Energy;

(9) any curtailment arising from Seller's failure to obtain and/or maintain in full force and effect any Governmental Approval or WREGIS registration, or failure to comply with applicable NERC reliability standards;

(10) any action taken by the Interconnection Provider pursuant to Seller's default under the Interconnection Agreement; or

(11) Seller fails or refuses to respond to AGC instructions from the SCADA system, Seller fails or refuses to respond, or Seller refuses or fails to respond to a curtailment instruction from Tri-State, the RDD, the Transmission Provider, Interconnection Provider, Balancing Authority, Reliability Coordinator, an Organized

Market, NERC, WECC, FERC or any other Governmental Authority pursuant to Section 6.3 including if the Interconnection Provider trips the breaker at the Electric Interconnection Point, due to Seller's failure or refusal.

Article 8
Billing and Payment Procedures

8.1 Billing Invoices.

No later than ten (10) Business Days after the end of each Month, Seller shall provide to Tri-State an invoice for the amount due to Seller by Tri-State for Contract Energy delivered by Seller to Tri-State and the Curtailed Contract Energy, if any, determined pursuant to Section 7.2 for such Month. Seller's invoice shall show metered Energy from the Facility, all billing parameters, rates and factors, and any other data reasonably pertinent to the calculation of monthly payments due to Seller. If Tri-State disputes any portion of the invoice, Tri-State shall provide to Seller an explanation of the items in dispute. Billing disputes shall be resolved in accordance with Section 8.4.

8.2 Metered Billing Data.

All billing data based on metered deliveries to Tri-State shall be collected by the Electric Metering Device(s) in accordance with Article 5.

8.3 Payments and Late Payments.

(A) Payment Due to Tri-State. Unless otherwise specified herein, payments due to Tri-State under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Tri-State, on or before the fifth (5th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within three (3) Business Days after the date of written notice from Tri-State to Seller. This Section shall not limit Tri-State's right to draw any such amounts due from the Security in accordance with Section 11.1(E).

(B) Payments due to Seller. Unless otherwise specified herein, payments due to Seller under or in connection with this PPA shall be due and payable by electronic funds transfer, as designated by Seller, on or before the twentieth (20th) Business Day following receipt of the billing invoice. Any failure to make full payment within such time period shall constitute an Event of Default of Tri-State upon its occurrence but shall be subject to cure within ten (10) Business Days after the date of written notice from Seller to Tri-State.

(C) Late Payment Charges. If the undisputed amount due is not paid on or before the due date, a late payment charge shall be applied to the unpaid balance and shall be added to the next billing statement. Such late payment charge shall be calculated based on the lower of (i) an annual interest rate equal to two percent (2%) plus the prime interest rate, as published on the date of the invoice in *The Wall Street*

Journal (or, if *The Wall Street Journal* is not published on that Day, the next succeeding date of publication) and (ii) the maximum interest rate allowed by Applicable Law ("Default Rate"). If the due date occurs on Day that is not a Business Day, the late payment charge shall begin to accrue on the next succeeding Business Day.

(D) Offset. Tri-State at any time may offset against amounts owed to Seller, any liquidated amounts, accrued damages and other payments, and undisputed billing errors and adjustments, which are owed by Seller to Tri-State.

8.4 Billing Disputes.

Either Party may dispute invoiced amounts, but shall pay to the other Party at least the undisputed portion of invoiced amounts on or before the invoice due date. To resolve billing disputes, the Parties shall use the procedures set forth in Section 13.9(A). When the billing dispute is resolved, the Party owing shall pay the amount owed within five (5) Business Days of the date of such resolution, with late payment interest charges calculated on the amount owed in accordance with the provisions of Section 8.3 if payment is not received within the five (5) Business Days. Undisputed amounts invoiced under this PPA shall be paid on or before the due date or shall be subject to the late payment interest charges set forth in Section 8.3(C).

8.5 Statement Errors.

In the event that either Party becomes aware of any error in any statement, such Party shall, promptly upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether in the form of an underpayment or overpayment) within thirty (30) Days of such notification. If a Party does not notify the other Party of any error (regardless of actual knowledge of such error) within three hundred sixty five (365) Days of such error, any payment associated with such error older than three hundred sixty five (365) Days shall be waived. Except for adjustments in the billing and payment for defective or inaccurate Electric Metering Devices as provided in Section 5.4, if Seller fails to invoice for Contract Energy or Curtailed Contract Energy within one hundred eighty (180) Days of delivery of such Contract Energy or curtailment of Contract Energy, payment for such shall be waived.

8.6 Taxes.

(A) Tax Responsibility. Seller shall be responsible for, and shall pay when due, all income, gross receipts, sales, *ad valorem*, personal property or real property or other similar taxes and any and all franchise fees or similar fees assessed against Seller or the Facility due to generation of Energy from the Facility, the construction, ownership, leasing, operation or maintenance of the Facility, or any components or appurtenances thereof, including all taxes, fees, allowances, trading credits and other offsets and impositions for wastes and emissions (including carbon-based compounds, oxides of nitrogen and sulfur, mercury and other Regulated Materials) produced by the Facility. Seller's prices under Article 7 are inclusive of such

Taxes, allowances and credits during the Term. If Tri-State is assessed any Taxes or associated fees as a result of the improvement of the Site due to the existence of the Facility on the Site, Tri-State shall promptly notify Seller. Tri-State and Seller shall cooperate in contesting such assessment; *provided, however,* that Tri-State may pay such Taxes to avoid any penalties on such assessments subject to reimbursement by Seller. If, after resolution of the matter, Taxes are imposed on Tri-State as a result of the improvement of the Site due to the existence of the Facility on the Site, Seller shall reimburse Tri-State for such Taxes. Seller shall not be obligated to pay or reimburse Tri-State for Taxes imposed on or measured by the Tri-State's overall revenues or income.

(B) Reimbursement. If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other Party for such Taxes.

(C) Information. The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(D) Cooperation. Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; *provided, however,* that no Party shall be obligated to incur any extraordinary financial burden to reduce Taxes for which the other Party is responsible hereunder.

(E) Failure to Qualify for Tax Credits. Seller's failure to qualify for the Tax Credits or Additional Tax Benefits for any reason including Delivery Excuse, Force Majeure Event, the acts or inaction of the Interconnection Provider or of any third party, or any Event of Default, shall not release Seller of its obligations to comply with this PPA, give rise to any damages payable by Tri-State or an increase in the price for Contract Energy.

(F) Additional Tax Benefits. From and after the Effective Date and throughout the Term, in the event that Seller or the Facility qualifies for and receives or is subject to Additional Tax Benefits, Seller and Tri-State shall share on a 50/50 basis the Additional Tax Benefit Amount associated with such Additional Tax Benefits by making an adjustment to the Contract Energy Rate for the Term of the PPA to account for such Additional Tax Benefit Amount. For the avoidance of doubt, Additional Tax Benefits may not result in an increase to the Contract Energy Rate. The Contract Energy Rate shall be adjusted in the first month following the effective date of the Applicable Law, which may be in the form of new or revised guidance or interpretations by a Governmental Authority having jurisdiction related to such Applicable Law, pursuant to which such Additional Tax Benefit is enacted. Seller shall at all times retain all right, title and interest in any Additional Tax Benefits. Seller shall provide Tri-State with written notice upon its receipt of Additional Tax Benefits, and along with such notice provide to Tri-State commercially reasonable documentation describing: (i) the

Additional Tax Benefit Amount, (ii) the effective date of the Applicable Law, including guidance or interpretations by a Governmental Authority, (iii) reasonable accounting of the Additional Tax Benefit Costs associated therewith, verified by an independent national accounting firm selected by Seller at Seller's expense, subject to further verification by Tri-State, and (iv) a calculation of the reduction to the Contract Energy Rate.

Article 9
Testing, Operations and Maintenance

9.1 Modification of the Facility.

Seller shall not modify the Facility in any way that would increase or decrease the electric energy generating capacity of the Facility or the output of Contract Energy to be delivered to Tri-State under this PPA without Tri-State's prior written consent, which may be withheld in its sole discretion.

9.2 Facility Tests Prior to Commercial Operation.

Seller shall give Tri-State at least three (3) Months prior notice of (i) the approximate Test Date, (ii) the proposed Tests scheduled relating to the commissioning of the Facility, and (iii) a draft of the Testing procedures and requirements. Tri-State shall review and provide any comments on the Testing procedures and requirements within thirty (30) Days of receipt. Representatives of Tri-State shall have the right to be present at all such Testing. Seller shall promptly notify Tri-State of any changes to the Test Date or the date of any Tests relating to the Facility in order that Tri-State may arrange for its respective representatives to attend.

9.3 Operation and Maintenance of the Facility.

Seller shall staff, control, operate, maintain, and repair the Facility or cause the same to be staffed, controlled, operated, maintained, and repaired at all times in accordance with manufacturers' recommendations and Prudent Utility Practices and otherwise in accordance with this PPA. Seller shall procure and maintain a Qualified Operator to operate and maintain the Facility. Personnel (i) capable of remotely starting, operating and stopping the Facility shall be continuously available and reachable by phone, and (ii) shall be capable of being at the Facility on no more than sixty (60) minutes' notice, weather conditions permitting.

9.4 Replacement of Facility Equipment.

Seller shall, consistent with Prudent Utility Practices, repair and replace all necessary equipment at the Facility required to deliver Contract Energy for the Term.

9.5 Disposal of Facility Equipment.

Upon the cessation of operations or the replacement of equipment, Seller shall, at its sole expense and cost, dispose of all Facility equipment no longer in use in accordance with Applicable Law and Prudent Utility Practices, and all requirements under the Facility Site Documents.

9.6 Scheduled Maintenance.

Three (3) Months prior to the Commercial Operation Date and, thereafter, by August 1 of each Year, Seller shall deliver to Tri-State the projected schedule of Scheduled Maintenance Outages, for the subsequent Year or the remainder of the Term, whichever period of time is shorter. Seller shall notify Tri-State of a Scheduled Maintenance Outage and any changes to such no later than sixty (60) Days prior to the start date of a Scheduled Maintenance Outage. In the event a Scheduled Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Scheduled Maintenance Outage. Scheduled Maintenance Outages and/or Additional Maintenance Outages may not be scheduled during the Months of January, June, July, August, September, or December unless agreed to in writing by Tri-State at its sole discretion.

9.7 Additional Maintenance Outages.

Before Seller conducts further maintenance on the Facility which would result in greater than ten (10) MW of the Nameplate Capacity Rating of the Facility being taken out of service or Seller's Interconnection Facilities being taken out of service in addition to the Scheduled Maintenance Outages conducted pursuant to Section 9.6 ("Additional Maintenance Outages"), Seller shall notify Tri-State of such required maintenance, together with proposed dates for carrying out such additional maintenance and the estimated duration of the work to be carried out. To the extent possible, such notification to Tri-State shall be provided no later than sixty (60) Days prior to the start date of an Additional Maintenance Outage. Unless deferral of such maintenance would cause an Emergency Condition, Seller and Tri-State shall negotiate in good faith a reasonable schedule during which such Additional Maintenance Outages shall take place. In the event an Additional Maintenance Outage is extended, Seller shall notify Tri-State as soon as practicable of such extension and the expected end date of such Additional Maintenance Outage.

9.8 Access to and Inspection of Facility.

(A) Seller shall provide Tri-State and its authorized employees, agents and inspectors with reasonable access to the Facility (including Tri-State's equipment, if any) for the purposes set forth herein. Tri-State acknowledges that such access does not provide Tri-State with the right to direct or modify the operation of the Facility in any way and further acknowledges that any exercise by Tri-State of its rights under this Section 9.8 shall be at its own risk and expense.

(B) No inspections of the Facility, whether by Tri-State or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Utility Practices. In no event shall any statement, representation, or lack thereof by Tri-State, either express or implied, relieve Seller of its exclusive responsibility for the Facility.

9.9 Operating Parameters.

(A) Seller shall operate, maintain or procure the operation and maintenance of the Facility in accordance with Prudent Utility Practices and Applicable Law. Subject to compliance with Prudent Utility Practices and Applicable Law, Seller shall operate the Facility in such a manner that Contract Energy shall meet all requirements required by the Interconnection Provider and the Transmission Provider.

(B) Seller shall operate the Facility such that all system protective equipment is in service whenever the Facility is connected to, or is operated in parallel with, the Transmission System, except for normal testing and repair. Seller shall provide adequate system protection and control devices to ensure safe and protected operation of all energized equipment during normal testing and repair. The Facility's protective equipment shall meet Institute of Electrical and Electronic Engineers and all other applicable industry standards. Seller shall have qualified personnel test, calibrate and certify in writing the proper functioning of all protective equipment in accordance with the intervals and maintenance activities for each component as established by the appropriate reliability standards. All of the foregoing shall be conducted in accordance with Prudent Utility Practices.

9.10 Operating Committee and Operating Procedures.

(A) Representative. Tri-State and Seller shall each appoint one (1) representative and one (1) alternate representative to act in matters relating to the Parties' performance obligations under this PPA and to develop operating arrangements for the generation, delivery and receipt of Contract Energy hereunder. Such representatives shall constitute the Operating Committee, and shall be specified in Exhibit H. Each Party shall notify the other Party in writing of any changes to their representative and provide the other Party an updated Exhibit H. The Operating Committee shall have no authority to amend or waive any terms or conditions of this PPA.

(B) Operating Procedures. Prior to the Commercial Operation Date, the Operating Committee shall develop mutually agreeable written Operating Procedures which shall include methods of day-to-day communications; metering, telemetering, telecommunications, and data acquisition procedures; key personnel list for applicable Tri-State and Seller operating centers; operations and maintenance scheduling and reporting; Contract Energy reports; measurement of Curtailed Contract Energy; unit operations log; and such other matters as may be mutually agreed upon by the Parties.

Article 10
Environmental Attributes

10.1 Ownership of Environmental Attributes.

(A) Ownership of Environmental Attributes. Payment of each of the Contract Energy Rate, Test Energy Rate and the Excess Contract Energy Rate to Seller by Tri-State includes the consideration for the purchase and ownership of, and the right to market and sell, all Environmental Attributes associated with the generation of Contract Energy, Test Energy and Excess Contract Energy, respectively.

(B) Duration. Environmental Attributes associated with the Contract Energy are owned by Tri-State and Tri-State shall have the right to own and to use such Environmental Attributes for any purpose, including any Environmental Attributes that are reserved or "banked" during the Term of this PPA but not used, sold, assigned or otherwise transferred during the Term of this PPA. Tri-State may assign its rights, title and interest in and to any Environmental Attributes associated with Contract Energy to one or more third parties under any transaction.

10.2 Transfer of Title to Environmental Attributes; Documentation of Environmental Attributes Transfers.

(A) Title. Title to the Environmental Attributes shall irrevocably pass from Seller to Tri-State immediately upon the generation of Contract Energy at the Facility that gives rise to such Environmental Attributes.

(B) Bill of Sale. Upon request from Tri-State, Seller shall deliver to Tri-State an Attestation and Bill of Sale in the form attached as Exhibit J for all Environmental Attributes delivered to Tri-State during the time period requested by Tri-State.

(C) WREGIS Compliance. Seller shall, at its sole expense, use WREGIS to provide and convey to Tri-State the Environmental Attributes associated with the generation of Contract Energy. Such Environmental Attributes shall be conveyed in a manner consistent with the WREGIS provision below promptly upon WREGIS certificates relating to the Facility being credited to Seller's WREGIS account.

(D) WREGIS Account. Prior to Testing, Seller shall register the Facility with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain through the Term. Seller shall transfer the WREGIS certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Tri-State or the account(s) of a designee that Tri-State identifies by written notice ("Tri-State's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Facility with WREGIS, establishing and maintaining Seller's WREGIS

Account, paying WREGIS certificate issuance and transfer fees, and transferring WREGIS certificates from Seller's WREGIS Account to Tri-State's WREGIS Account.

(E) Qualified Reporting Entity. Seller shall procure and maintain a Person to act as a qualified reporting entity and provide qualified reporting services for the Facility as required by WREGIS.

(F) Reporting Compliance. Seller, at its own cost and expense, shall comply with all reporting and other requirements of WREGIS relating to the Facility or Environmental Attributes.

(G) No Liens or Encumbrances. Environmental Attributes shall be transferred to Tri-State free of all liens and encumbrances.

(H) Additional Certification. Upon request from Tri-State, Seller shall, at its expense, register and/or certify the Facility with Governmental Authorities requested by Tri-State in order to qualify the Facility as a renewable resource or qualify the Contract Energy and/or Environmental Attributes with such Governmental Authority and maintain such registration/certification for the Term.

Article 11
Security

11.1 Seller Security Form and Amount.

(A) Form. As security for its obligations hereunder, Seller shall, within ten (10) Days after the Effective Date, post and maintain in favor of Tri-State (i) one or more unconditional, irrevocable, standby Letter(s) of Credit from an Issuer, (ii) a cash escrow account established with an Issuer in favor of Tri-State pursuant to an escrow agreement acceptable to Tri-State, or (iii) any combination of the foregoing (i) and (ii) (the "Security"); provided that a Guaranty may be posted to satisfy part of or all of the Security amount set forth in Section 11.1(B) in lieu of Letter(s) of Credit or a cash escrow account, subject to the following conditions (x) any Guaranty provided by a Superior Guarantor shall not exceed Ten Million Dollars ($10,000,000), (y) any Guaranty provided by a Qualified Guarantor shall not exceed Five Million Dollars ($5,000,000), and (z) the total aggregate amount of guaranteed obligations of any such Guaranty and any other guaranties of payment or performance related to or provided by the Seller, the Qualified Guarantor, the Superior Guarantor or any of their Affiliates to Tri-State shall not exceed an aggregate of Five Million Dollars ($5,000,000) if provided by a Qualified Guarantor or Ten Million Dollars ($10,000,000) if provided by a Superior Guarantor, unless agreed to in writing by Tri-State at its sole discretion.

(B) Amount. The Security shall be in the amount of: (i) **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) for the period beginning with the Effective Date and continuing thereafter.

(C) Duration. The Security shall remain in place for the entire Term (except to the extent drawn upon as provided herein). To the extent the Security consists of Letter(s) of Credit expiring before the end of the Term, Seller shall cause their renewal or extension for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) no later than thirty (30) Days prior to each expiration date of such Letter(s) of Credit and written proof of such renewal shall be provided to Tri-State as soon as practicable thereafter, but in no event later than fifteen (15) Days prior to the expiration of the same. If the Letter of Credit(s) is not renewed or extended as required herein, Tri-State shall have the right to demand payment under the Guaranty or draw immediately upon the entire amount of the Letter of Credit and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute Letter of Credit(s) meeting the requirements of this Article 11.

(D) Downgrades. Upon the occurrence of a downgrade event, such that the Person providing the Security in the form of a Letter of Credit or Guaranty no longer meets the requirements of an Issuer, Qualified Guarantor, or Superior Guarantor, as applicable, Seller shall within three (3) Business Days of such downgrade event, provide replacement security satisfying the requirements of this Article 11. If such replacement security is not provided within three (3) Business Days, Tri-State shall have the right to draw immediately upon the entire amount of the Letter of Credit or demand payment under the Guaranty, as applicable, and to place the amounts so drawn, at Seller's cost and with Seller's funds, in an account controlled by Tri-State until and unless Seller provides a substitute security meeting the requirements of this Article 11. Except as provided in this Section 11.1(D), Seller may change the form of Security at any time and from time-to-time upon thirty (30) Days' prior written notice to Tri-State; *provided* that the Security shall satisfy the requirements of this Article 11 at all times.

(E) Draw on Security. Without notice to Seller, Tri-State may demand payment under or draw on the Security during the Term for Seller's failure to meet any of its obligations under this PPA, including Delay Damages, the damages provided in Section 6.4(H), Section 6.7 and Section 12.3, and Replacement Costs. Tri-State may draw or demand payment of all or any part of the appropriate amounts due to it from any form of Security to the extent available pursuant to this Article 11, and from all such forms, and in any sequence Tri-State may select; *provided* that any failure to draw upon the Security for any damages or other amounts due to Tri-State shall not prejudice Tri-State's rights to recover such damages or amounts in any other manner to the extent provided in this PPA. Tri-State shall notify Seller within five (5) Business Days following any draw on the Security by Tri-State, including the amount thereof and the basis therefor.

(F) Release of Security. Within thirty (30) Days following the expiration or termination of this PPA and the satisfaction of all of Seller's obligations hereunder, Tri-State shall release any remaining balance of the Security to Seller without interest.

(G) Replenishment. In the event Tri-State draws upon the Security pursuant to this Article 11, Seller shall replenish the Security to the amount required by Section 11.1 within ten (10) Days of such draw.

(H) Expenses. Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security under this Article 11.

Article 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Seller Defaults (No Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable unless otherwise stated:

(1) Seller's dissolution or liquidation;

(2) Seller makes a general assignment for the benefit of its creditors;

(3) Seller's authorization or filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(4) The sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State by Seller other than in mitigation of damages for any breach by Tri-State of this PPA;

(5) Seller's failure to establish, and maintain, the Security in accordance with Article 11;

(6) Seller's failure to achieve Commercial Operation by the date that is ninety (90) Days following the Commercial Operation Milestone;

(7) Seller's actual fraud or tampering with Tri-State owned facilities or other material misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility; and/or

(8) Seller's failure to make any payment due to Tri-State under this PPA in accordance with Article 8 (subject to cure by Seller as provided therein).

(B) Seller Defaults (30 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within thirty (30) Days after the date of written notice from Tri-State to Seller:

(1) Seller's Abandonment;

(2) Seller's failure to maintain in effect any agreements required to deliver Contract Energy to the Point of Delivery pursuant to Section 5.1, including the Interconnection Agreement;

(3) Seller's failure to comply with the requirements of Section 10.2;

(4) Seller's breach of or failure to perform or comply with any material term of this PPA not otherwise specified in this Section 12.1; and/or

(5) Seller's failure to achieve any Construction Milestone, excluding the Commercial Operation Milestone, by the date that is ninety (90) Days following the date specified for such milestone.

(C) Seller Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Tri-State to Seller:

(1) Seller's assignment of this PPA, or any Change of Control of Seller, or Seller's sale or transfer of its interest, or any part thereof, in the Facility, except as permitted in accordance with Article 19;

(2) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made; and/or

(3) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller.

(D) Seller Default (Delivery Shortfall). Seller's failure to deliver at least eighty percent (80%) of the Expected Contract Energy in a Commercial Operation Year shall constitute an Event of Default of Seller upon its occurrence; *provided* that the Facility shall be deemed to have generated Contract Energy during such period as specified in Section 6.7 with such quantity to be determined using the factors set forth in Section 7.2(A); *provided further* that this Event of Default shall be curable and deemed cured if (i) within thirty (30) Days following the end of the energy deficient Commercial Operation Year, Seller cures the reason(s) for such default (or, if such cure cannot reasonably be effected within thirty (30) Days, Seller commences to cure such default within thirty (30) Days and then diligently pursues such cure to completion as soon as practicable thereafter), and (ii) as a result of such efforts, during the next Commercial Operation Year subsequent to such Default, the production of Contract Energy by the

Facility equals or exceeds ninety-five percent (95%) of the Expected Contract Energy for such period.

Subject at all times to the limitation set forth in Section 6.1, Seller shall be permitted to add and/or replace Units if and to the extent reasonably required to cure Seller's default under this Section 12.1(D). Seller shall keep Tri-State apprised at least monthly of Seller's cure efforts under this Section 12.1(D). If the production of Contract Energy fails to equal or exceed ninety-five percent (95%) of the Expected Contract Energy for the Commercial Operation Year following the Event of Default as described in this Section 12.1(D), Tri-State shall have the right to terminate this PPA for default upon delivery of written notice.

12.2 Events of Default of Tri-State.

(A) Tri-State Defaults (No Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence and no cure period shall be applicable, unless otherwise stated:

(1) Tri-State's dissolution or liquidation, *provided, however,* that division of Tri-State into multiple entities shall not constitute dissolution or liquidation;

(2) Tri-State makes a general assignment for the benefit of creditors;

(3) Tri-State's authorization or filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or Tri-State voluntarily taking advantage of any such law by answer or otherwise; and/or

(4) Tri-State's failure to make any payment due to Seller under this PPA in accordance with Article 8 (subject to cure by Tri-State as provided therein).

(B) Tri-State Defaults (30 Day Cure). Tri-State's failure to comply with any material obligation under this PPA not otherwise specified in this Section 12.2 shall constitute an Event of Default of Tri-State if not cured within thirty (30) Days after the date of written notice from Seller to Tri-State.

(C) Tri-State Defaults (60 Day Cure). Any of the following shall constitute an Event of Default of Tri-State upon its occurrence but subject to cure sixty (60) Days after the date of written notice from Seller to Tri-State:

(1) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Tri-State;

(2) Tri-State's assignment of this PPA, except as permitted in accordance with Article 19; and/or

(3) Any representation or warranty made by Tri-State in this PPA shall prove to have been false or misleading in any material respect when made.

12.3 Damages Prior to Termination.

Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to collect damages accruing prior to the termination of this PPA from the defaulting Party as set forth below, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. For all Events of Default (including failure to achieve the Commercial Operation Milestone) the non-defaulting Party shall be entitled to receive from the defaulting Party all of the direct damages incurred by the non-defaulting Party in connection with such Event of Default. The Parties agree that the damages recoverable by Tri-State hereunder on account of an Event of Default of Seller prior to termination of this PPA shall include an amount calculated at the end of each Month during an Event of Default equal to the Deficiency MWhs multiplied by the applicable Contract Energy Rate during such Commercial Operation Year and Tri-State may draw the appropriate amounts from the Security. Each Party agrees and acknowledges that (i) the damages that Tri-State would incur at such time prior to termination of this PPA due to Seller's failure to perform would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the liquidated damages as agreed to by the Parties set forth in this Section 12.3 are a fair and reasonable calculation of such damages.

12.4 Termination.

Upon the occurrence of an Event of Default that has not been cured within the applicable time period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof, upon which this PPA shall terminate. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as otherwise may be explicitly provided for in this PPA. Upon the termination of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, all of the direct damages incurred by the non-defaulting Party related to such Event of Default, including, if Seller is the defaulting Party, the value of future Replacement Costs for the then remaining Term based upon the amount of Expected Contract Energy that should have been delivered provided, however, that, if the Replacement Costs amount is negative, the Replacement Costs shall be deemed to be zero.

12.5 Operation by Tri-State Following Event of Default of Seller.

(A) Subject to the rights of the Financing Parties, on occasion of an Event of Default and after the expiration of the cure period provided in respect thereof, if any, and prior to any termination of this PPA as a result thereof, Tri-State shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as

agent for Seller (in accordance with Seller's rights, obligations, and interest under this PPA) during the period provided for herein. Seller shall not grant any Person, other than the Financing Parties, a right to possess, assume control of, and operate the Facility that is equal to or superior to Tri-State's right under this Section 12.5.

(B) Tri-State shall give Seller and the Financing Parties ten (10) Days' prior notice of the contemplated exercise of Tri-State's rights under this Section 12.5. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Utility Practice, including all Operating Records. Upon such notice, Tri-State, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Site and Facility for the purpose of constructing and/or operating the Facility.

(C) Tri-State shall be entitled to immediately draw upon the Security to cover any expenses incurred by Tri-State in exercising its rights under this Section 12.5.

(D) During any period that Tri-State is in possession of and constructing and/or operating the Facility pursuant to this Section 12.5, Tri-State shall perform and comply with all of the obligations of Seller under this PPA and shall use the proceeds from the sale of electricity generated by the Facility to first, reimburse Tri-State for any and all expenses reasonably incurred by Tri-State in taking possession of and operating the Facility, and to second, remit any remaining proceeds to Seller.

(E) During any period that Tri-State is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and Tri-State shall assume possession, operation, and control solely as agent for Seller.

(1) In the event that Tri-State is in possession and control of the Facility for an interim period, Seller may resume operation and Tri-State shall relinquish its right to operate when Seller demonstrates to Tri-State's satisfaction that it will remove those grounds that originally gave rise to Tri-State's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this PPA, and (ii) has cured any Events of Default of Seller that allowed Tri-State to exercise its rights under this Section 12.5 (or, if the Event of Default is of such a nature that it cannot be cured by Seller without possession of the Facility, reasonable assurance that Seller will cure such Event of Default promptly following resumption of possession).

(2) In the event that Tri-State is in possession and control of the Facility for an interim period, the Financing Parties, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and Tri-State shall relinquish its right to operate when the Financing Parties or any nominee or transferee thereof, requests such relinquishment.

(F) Tri-State's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by Tri-State of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility Tri-State elects to return such possession and operation to Seller, Tri-State shall provide Seller with at least fifteen (15) Days' prior notice of the date Tri-State intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

(G) In the event Tri-State assumes operation of the Facility under this Section 12.5, Tri-State shall operate the Facility in accordance with Prudent Utility Practice.

12.6 Replacement Costs.

Upon termination for an Event of Default, subject to Section 12.11, Tri-State shall be entitled to Replacement Costs for the balance of the Term (based upon the amount of Expected Contract Energy) had this PPA not been terminated, and Tri-State may draw the appropriate amounts from the Security.

12.7 Specific Performance.

In addition to the other remedies specified in this Article 12, in the event that any Event of Default of Seller is not cured within the applicable cure period set forth herein, Tri-State shall have the right to specific performance. The Parties agree that in the event Tri-State seeks injunctive relief in connection with the foregoing, that such action may be taken without the necessity of posting of a bond or other security as would otherwise be required under Applicable Law.

12.8 Remedies Cumulative.

Each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.9 Forward Contracts.

The Parties agree that this PPA is a "forward contract" for purposes of the U. S. Bankruptcy Code; all payments made or to be made by one Party to the other Party pursuant to this PPA are "settlement payments" within the meaning of the U.S. Bankruptcy Code; and all transfers of Security by Seller to Tri-State under this PPA are "margin payments" within the meaning of the U.S. Bankruptcy Code.

12.10 Waiver and Exclusion of Other Damages.

NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES BY STATUTE, IN TORT OR CONTRACT (EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN); *PROVIDED* THAT IF EITHER PARTY IS HELD LIABLE TO A THIRD PARTY FOR SUCH DAMAGES AND THE PARTY HELD LIABLE FOR SUCH DAMAGES IS ENTITLED TO INDEMNIFICATION THEREFOR FROM THE OTHER PARTY, THE INDEMNIFYING PARTY SHALL BE LIABLE FOR, AND OBLIGATED TO REIMBURSE THE INDEMNIFIED PARTY FOR, SUCH DAMAGES, ALL IN ACCORDANCE WITH THE INDEMNIFICATION PROVISIONS OF ARTICLE 17.

12.11 Duty to Mitigate.

Each Party (i) has a general duty to mitigate all damages hereunder (other than Delay Damages, or the damages provided in Section 6.4(H), Section 6.7 and Section 12.3) and (ii) shall use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.12 Limitation of Liability.

Except as otherwise provided in this Section 12.12, Seller's aggregate financial liability to Tri-State for Delay Damages pursuant to Section 4.3, shall not exceed an amount equal to **Insert $100*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000) and Seller's aggregate financial liability to Tri-State for Replacement Costs and other damages, excluding Delay Damages, shall not exceed **Insert $250*Expected Nameplate Capacity Rating in kw** Dollars ($_____,000). If at any time during the Term, Tri-State incurs damages in excess of the limitations set forth above which Seller does not agree to pay when billed by Tri-State, Tri-State shall have the right to declare a termination of this PPA under Section 12.1, unless such damages are disputed in good faith. The limitations on damages set forth in this Section 12.12 shall not apply to damages arising out of any of the following events:

(A) damage or tampering with Tri-State owned facilities caused by negligence, breach of this PPA or other misconduct by Seller, its directors, officers, employees and agents;

(B) the sale by Seller to a third party, or diversion by Seller for any use, of Contract Energy committed to Tri-State under this PPA other than in mitigation of damages for any breach by Tri-State of this PPA;

(C) Seller's intentional misrepresentation or intentional misconduct in connection with this PPA or the operation of the Facility;

(D) Seller's failure (i) to maintain insurance coverages in the types and amounts required by this PPA or (ii) to apply any insurance proceeds to reconstruct the Facility following a casualty;

(E) any claim for indemnification herein;

(F) any Environmental Contamination; or

(G) damages incurred by Tri-State in connection with any bankruptcy or insolvency proceeding involving Seller, including Tri-State's loss of the benefit of its bargain due to rejection or other termination of this PPA in such proceeding.

Article 13
Contract Administration and Notices

13.1 Notices in Writing.

Notices required by this PPA shall be addressed to the other Party, including the other Party's representative on the Operating Committee, at the addresses specified in Exhibit I, as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall either be hand delivered or delivered by electronic mail with a copy mailed via overnight service with signature required upon receipt, to the representative of said other Party. Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section 13.1.

13.2 Representative for Notices.

Each Party shall maintain a designated representative to receive notices. Such representative may, at the option of each Party, be the same person as that Party's representative or alternate representative on the Operating Committee, or a different person. Either Party may, by written notice to the other Party, change the representative or the address to which such notices and communications are to be sent and shall provide the other Party an updated Exhibit I.

13.3 Authority of Representatives.

The Parties' designated representatives shall have authority to act for its respective principals in all technical matters relating to performance of this PPA and to attempt to resolve disputes or potential disputes. However, in their capacity as representatives, they shall not have the authority to amend or waive any provision of this PPA.

13.4 Operating Records.

Originals or copies of all Operating Records shall be maintained at the Facility or such other location in the State in which the Facility is located as may be specified by Seller from time to time. Tri-State may examine and make copies of such Operating Records from time to time upon request, during normal business hours.

13.5 Books and Records.

Seller and Tri-State shall each keep complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including metering, billing and payment records, and such records as may be required by Governmental Authorities in the prescribed format.

13.6 Audit Rights.

During the Term and for a period of three (3) years after the Term, Tri-State shall have the right, at its sole expense, with reasonable advance written notice and during normal working hours, to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this PPA.

13.7 Operating Log.

Seller shall maintain an accurate and up-to-date operating log, in electronic format, at the Facility with records of energy production (by individual block or Unit); changes in operating status; meteorological data; maintenance; and Forced Outages (the "O&M Records"). Within thirty (30) Days after the end of each quarter of the Year, Seller shall submit to Tri-State, in a mutually agreeable format, a copy of the O&M Records for the prior quarter.

13.8 Provision of Real Time Data.

Seller shall, at least five (5) Business Days prior to the delivery of Test Energy and continuing through the Term, make the following data available to Tri-State on a real-time basis, at the Tri-State RTU:

(1) production of Energy in MW and MWh;

(2) [in-service status for each Unit][feeder level breaker status];

(3) [Unit MW output][inverter availability and generation in kW];

(4) [wind speed and direction at each Unit][solar irradiance as measured by the pyranometers at the Facility];

(5) ambient temperature [solar only- and solar panel temperature];

(6) [solar only- stow indication][wind only- icing indication and overspeed indication for each Unit];

(7) humidity; and

(8) barometric pressure.

13.9 Dispute Resolution.

(A) The Parties agree that it is in the best interest of both Parties to attempt to resolve disputes that arise under this PPA in a quick and inexpensive manner. To that end, the Parties commit to use their best efforts to resolve disputes informally. For all disputes that arise pursuant to this PPA, the Parties immediately, through their designated representatives selected in the sole discretion of each Party (individually, the "Party Representative", together, the "Parties' Representatives"), shall negotiate with one another in good faith in order to reach resolution of the dispute. Such negotiation shall commence within fourteen (14) Days of the date of the letter from one Party Representative notifying the other Party Representative of the nature of the dispute. In the event that the Parties' Representatives cannot agree to a resolution of the dispute within thirty (30) Days after the commencement of negotiations, written notice of the dispute (the "Dispute Notice"), together with a statement describing the issues or claims, shall be delivered, within seventy-two (72) hours after the expiration of such thirty (30) Day period, by each of the Parties' Representatives to its respective senior manager or official (such senior manager or official to be selected by each of the Party Representatives in his or her sole discretion, *provided* such senior manager or official has authority to bind the respective Party). Within three (3) Business Days after receipt of the Dispute Notice, the senior manager or officials for both Parties shall negotiate in good faith to resolve the dispute. If the Parties are unable to resolve the dispute within fourteen (14) Days of receipt of the Dispute Notice by the senior manager or officials, either Party may seek available legal remedies.

(B) SELLER AND TRI-STATE EACH HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS PPA OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF SELLER AND TRI-STATE RELATED HERETO.

Article 14
Force Majeure

14.1 Definition of Force Majeure Event.

(A) A "Force Majeure Event" shall mean (i) an event or circumstance that is not reasonably foreseeable, (ii) is beyond the reasonable control of, and is not caused by, the negligence or lack of due diligence of the affected Party or its contractors or suppliers and (iii) adversely affects the performance by that Party of its obligations under or pursuant to this PPA. Such events or circumstances may include: actions or inactions of civil or military authority (including courts and governmental or administrative agencies), acts of God, war, riot or insurrection, terrorism, blockades, embargoes, sabotage (including arson and vandalism), epidemics, explosions and fires not originating in the Facility or caused by its operation, hurricanes, floods, strikes, lockouts or other labor disputes (not caused by the failure of the affected Party to comply with the terms of a collective bargaining agreement).

(B) The failure of a transmission line or element due to a Force Majeure Event that prevents Tri-State from delivering Contract Energy from the Point of Delivery is considered a Force Majeure Event.

(C) Equipment breakdown or the inability of Seller to use equipment due to its design, construction, operation, maintenance, the inability of Seller to meet regulatory standards, or failure by Seller to obtain on a timely basis and maintain a necessary permit or other regulatory approval, is not considered a Force Majeure Event.

(D) Notwithstanding the foregoing, the term "Force Majeure Event" does not include any of the following (i) inability by Seller to procure the Units or any component parts therefor, or any associated equipment for the Facility for any reason (the risk of which is assumed by Seller) or any increase in the price to procure the Units or any component parts therefor, including due to changes in any import or export duties or tariffs, (ii) any other acts or omissions of any third party, including any vendor, materialman, customer, or supplier of Seller, unless such acts or omissions are themselves excused by reason of a Force Majeure Event under Section 14.1(A); (iii) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishaps, events or conditions attributable to normal wear and tear or flaws, except as caused by a Force Majeure Event under Section 14.1(A), (iv) failure of Seller to abide by Prudent Utility Practices, (v) changes in market conditions that affect the cost of supplies, or that affect demand or price for power and/or Environmental Attributes; (vi) any labor strikes, slow downs or stoppages, or other labor disruptions against Seller's contractors, subcontractors, vendors, or suppliers; (vii) changes in Applicable Laws; (viii) failure of Seller or the Facility to qualify or be eligible for any Tax Credit or Additional Tax Benefits, including any federal, state, or local tax credits or exemptions; (ix) any delay or inability of Seller to construct or install any required interconnection or transmission facilities required to be constructed and installed in order for Seller to meet its

obligations hereunder, including any delays of the Interconnection Provider; (x) Seller's failure to timely apply for, or diligently pursue, any of the Governmental Approvals set forth in Exhibit F; or (xi) weather events or sudden actions of the natural elements within twenty (20) year normal weather patterns.

(E) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of sixty (60) Days from its inception, the Term of this PPA shall be extended on a day for day basis for the duration of the Force Majeure Event (including the initial sixty (60) Days from its inception) with a maximum extension of the Term of this PPA for all Force Majeure Events not to exceed four (4) years; *provided that* the Commercial Operation Year for purposes of determining the applicable Contract Energy Rate and Expected Contract Energy shall be tolled on a day for day basis for the duration of the Force Majeure Event.

(F) In the event that any delay or failure of performance (including a significant reduction in the delivery of Contract Energy) caused by a Force Majeure Event affecting Seller continues for an uninterrupted period of ninety (90) Days from its inception (with respect to a Force Majeure Event occurring prior to COD) or three hundred sixty-five (365) Days from its inception (with respect to a Force Majeure Event occurring after COD), the Party not claiming a Force Majeure Event may, at any time following the end of such period, terminate this PPA upon written notice to the affected Party, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(G) Except as otherwise provided in this PPA, and subject to compliance with the notice, mitigation and other requirements of this Article 14, each Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure Event but only and to the extent thereof.

14.2 Notification Obligations.

In the event of any delay or nonperformance resulting from a Force Majeure Event, the Party claiming that a Force Majeure Event has occurred shall notify the other Party immediately by telephonic communication and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure Event requires. A Party claiming that a Force Majeure Event has occurred shall not be entitled to any relief therefor unless and until confirming notice is provided. The Party claiming that a Force Majeure Event has occurred shall notify the other Party of the cessation of the Force Majeure Event or of the conclusion of the affected Party's cure for the Force Majeure Event, in either case within two (2) Business Days thereof.

14.3 Duty to Mitigate.

The Party claiming that a Force Majeure Event has occurred shall use commercially reasonable efforts to cure the cause(s) preventing its performance of this PPA; *provided, however,* that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.4 Delay Caused by Force Majeure Event.

Upon the occurrence and during the continuance of a Force Majeure Event and the effects thereof, to the extent that a Force Majeure Event affects the ability of Tri-State, Interconnection Provider or Transmission Provider to accept Energy from the Facility or to the extent that a Force Majeure Event affects the ability of Seller to Test pursuant to Section 9.2 or to deliver Energy from the Facility, then the hours during which the Force Majeure Event occurs shall be excluded from the payment calculations as set forth in Section 7.1.

Article 15
Representations and Warranties

15.1 Seller's Representations and Warranties.

Seller hereby represents and warrants as of the date hereof as follows:

(A) Seller is a _____, duly organized, validly existing and in good standing under the laws of the state of _____. Seller is qualified to do business in _____ and in each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller. Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Tri-State upon execution of this PPA);

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Seller's organizational documents or bylaws, or any indenture or loan or credit agreement, or

any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, or any judgment, order, statute, or regulation that is applicable to Seller or the Facility; or

(4) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Seller executing this PPA is authorized to do so and is authorized to bind Seller to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party.

(F) Except for those permits, consents, approvals, licenses and authorizations identified in Exhibit F, which Seller anticipates will be obtained by Seller in the ordinary course of business, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(G) That it has arranged for sufficient financing and other funding required to complete the construction of the Facility in accordance with this PPA and to achieve Commercial Operation on or before the Commercial Operation Milestone.

(H) That the Environmental Attributes, as to which right and title is to be transferred to Tri-State under this PPA are, or will be: (1) compliant with the definitions of local, state, or federal renewable portfolio standard rules and requirements, (2) free and clear of any liens, encumbrances and/or defects of title; and (3) shall not otherwise been, nor will be sold, retired, claimed, or represented as part of electricity output or sales, or used to satisfy obligations in any other jurisdiction.

(I) Within the meaning of the U.S. Bankruptcy Code, Seller is a "forward contract merchant."

15.2 Tri-State's Representations and Warranties.

Tri-State hereby represents and warrants as of the date hereof as follows:

(A) Tri-State is a cooperative corporation duly organized, validly existing and in good standing under the laws of the state of Colorado and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of Tri-State. Tri-State has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Tri-State have been duly authorized by all necessary corporate action, and do not and will not:

(1) require any consent or approval of Tri-State's members;

(2) violate any Applicable Law, the violation of which could have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA;

(3) result in a breach or constitute a default under Tri-State's corporate charter or bylaws, or under any agreement relating to the management or affairs of Tri-State, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Tri-State is a party or by which Tri-State or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA; or

(4) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Tri-State now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Tri-State to perform its obligations under this PPA.

(C) This PPA is a valid and binding obligation of Tri-State, enforceable against it in accordance with its terms, except as the enforceability hereof may be limited by general principles of equity or bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies.

(D) The individual of Tri-State executing this PPA is authorized to do so and is authorized to bind Tri-State to the obligations under this PPA.

(E) The execution and performance of this PPA shall not conflict with or constitute a breach or default under any contract or agreement of any kind to which Tri-State is a party or any judgment, order, statute, or regulation that is applicable to Tri-State.

(F) Within the meaning of the U.S. Bankruptcy Code, Tri-State is a "forward contract merchant."

Article 16
Insurance

16.1 Evidence of Insurance.

Seller shall, upon execution of this PPA and promptly after the renewal of each policy of insurance coverage required in Exhibit D, provide Tri-State with one copy of insurance certificates or other evidence in a form acceptable to Tri-State evidencing the insurance coverages required to be maintained in accordance with Exhibit D to this PPA. Such certificates shall (i) include Tri-State as an additional insured (except worker's compensation); (ii) provide that the applicable insurer shall endeavor to provide Tri-State with thirty (30) Days' prior written notice of non-renewal or cancellation of the policies required in Exhibit D (except that such notice shall be ten (10) Days for non-payment of premiums); and (iii) provide a waiver of any rights of subrogation against Tri-State, its Affiliates and their officers, directors, agents, subcontractors, and employees. Insurance carriers providing the coverages required in Exhibit D, must have a policy holders rating of "A-" or better, and a financial size of "Class VII" or better as published in the most recent edition of Best's Insurance Reports. Any policy of insurance furnished hereunder shall be written by an insurer authorized to write such coverage in the state where the Facility is located. All policies shall be written on an occurrence basis, except as provided in Section 16.2. All policies shall include language providing that Seller's policy shall be primary in all instances regardless of like coverages, if any, carried by Tri-State. Seller's liability under this PPA is not limited to the amount of insurance coverage required herein. Seller shall notify Tri-State immediately should the policies required in Exhibit D be cancelled before the expiration date, if the insureds receive a non-renewal notice from its carrier, or if there is any material adverse change of coverage.

16.2 Term and Modification of Insurance.

(A) All insurance required under this PPA shall cover occurrences during the Term and for a period of two (2) years after the Term. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the later of (i) the Effective Date, or (ii) the cancellation date of any occurrence basis policies that such insurance has replaced.

(B) Tri-State shall have the right to request modification of the insurance minimum limits specified in Exhibit D in order to maintain reasonable coverage amounts. Seller shall make all commercially reasonable efforts to comply with any such request. Tri-State shall reimburse Seller for all premium increases and other costs incurred by Seller in complying with any such Tri-State request for modification of the insurance minimum limits specified in Exhibit D.

16.3 Application of Proceeds.

Seller shall apply any insurance proceeds to reconstruction of the Facility following a casualty.

Article 17
Indemnity

17.1 Indemnification.

Each Party (the "Indemnifying Party") shall, to the extent permitted by Applicable Law, indemnify, pay, defend and hold harmless the other Party (the "Indemnified Party") and its officers, directors, employees, agents and contractors from and against any and all claims or demands of a third party, costs or expenses (including reasonable attorneys' fees) for loss, damages, or injury to persons or property of the Indemnified Party (or to third parties) (collectively, "Losses") caused by, arising out of, or resulting from:

(A) a breach by the Indemnifying Party of its covenants, representations, and warranties or obligations hereunder;

(B) a violation or alleged violation of Applicable Laws by the Indemnifying Party;

(C) any act or omission by the Indemnifying Party or its contractors, agents, servants or employees in connection with the installation, testing, inspection, or operation or maintenance of its respective facilities or equipment;

(D) any defect in, failure of, or fault related to, the Indemnifying Party's facilities or equipment; or

(E) the negligence or intentional acts or other misconduct of the Indemnifying Party or its contractors, agents, servants, employees or any authorized persons acting on behalf of such Indemnifying Party.

17.2 Indemnification for Fines and Penalties.

Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or other misconduct of the other Party) for non-compliance with any Applicable Laws shall be the sole responsibility of the non-complying Party.

17.3 Limitations

(A) The foregoing indemnification obligations shall apply notwithstanding any contributory misconduct of the Indemnified Party, but the Indemnifying Party's liability to indemnify the Indemnified Party shall be reduced in

proportion to the percentage by which the Indemnified Party's misconduct caused the damages.

(B) Neither Party shall be indemnified for Losses resulting from the sole negligence or intentional acts or misconduct of the directors, officers, employees, or agents of such Party

17.4 Notice of Proceedings.

Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification, but in any event no later than seven (7) Days after the receipt by the Party seeking indemnification of notice of the commencement of any action for which indemnity may be sought. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.4 to the other Party shall not release the other Party from any indemnification obligation which it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.5 Defense of Claims.

(A) Whether or not acknowledging in writing its obligation to indemnify an Indemnified Party to the extent required pursuant to this Section 17.5, the Indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party.

(B) Unless and until the Indemnifying Party acknowledges in writing its obligation to indemnify the Indemnified Party to the extent required pursuant to this Section 17.5 and assumes control of the defense of a claim, suit, action or proceeding in accordance with paragraph (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; *provided, however,* that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to paragraph (D) below,

settle or compromise any claim without the approval of such Indemnified Party. Except where such consent is unreasonably withheld, if an Indemnified Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to paragraph (A) above, the Indemnified Party shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the employment of counsel by the Indemnified Party has been authorized in writing by the Indemnifying Party; (ii) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party; or (iv) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party, or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnified Party beyond the scope of this PPA. If clause (ii), (iii) or (iv) of the preceding sentence shall be applicable, then counsel for the Indemnified Party shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnified Party and the reasonable fees and disbursements of such counsel shall constitute reimbursable legal or other expenses hereunder.

Article 18
Legal and Regulatory Compliance

18.1 Applicable Law.

Each Party shall at all times comply with all Applicable Law related to its obligations under this PPA, except for any non-compliance which, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on the business or financial condition of the Party or its ability to fulfill its commitments under this PPA. Seller shall promptly notify Tri-State of any investigation, notices or findings of violations of Applicable Law from any Governmental Authority, including any audit, notification, inspection or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law. Except as otherwise expressly provided herein, each Party assumes the risk of changes in Applicable Laws following the date hereof, that affect such Party's costs of ownership and operation of its assets, and its performance of this PPA, except as otherwise specifically set forth herein.

18.2 Compliance with Governmental Approvals.

Seller shall comply with and cause the Facility to comply with all applicable Governmental Approvals. Seller shall promptly notify Tri-State of any inspections by any Governmental Authority with respect to any material Governmental Approval and will promptly provide Tri-State with copies of any notices of violation or non-compliance with respect to any material Governmental Approval. Upon permanent cessation of generation of Energy from the Facility, Seller, at its sole cost and expense, shall decommission the Facility, dismantle the Facility, remediate the Site and submit and obtain any Governmental Approvals with respect thereto.

18.3 Compliance Information.

(A) Each Party shall, for the purpose of gathering information and/or providing verbal or written reports, testimony, affidavits or other submissions relevant to any Governmental Approvals, Applicable Laws or in connection with any litigation, arbitration or administrative proceeding before any authority of competent jurisdiction: (i) deliver or cause to be delivered to the other Party any necessary or required certificates of its officers, accountants, engineers or agents; and/or (ii) make available necessary personnel with knowledge as to such matters.

(B) To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Tri-State to contact and obtain information concerning the Facility and Interconnection Facilities directly from the Interconnection Provider and the Transmission Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider and the Transmission Provider confirming such authorization.

18.4 Reliability Standards.

In the event that new reliability standards are promulgated by WECC, NERC, FERC, or PUC, or any successor agencies, any and all costs incurred as a result of actions required for compliance with the new reliability standards shall be borne by Seller. To the extent that Seller contributes in whole or in part to actions which result in monetary penalties being assessed to Tri-State by WECC, NERC, FERC or PUC, or any successor agencies, for lack of compliance with reliability standards (except to the extent that Seller acted at the direction of Tri-State), Seller shall reimburse Tri-State for its share of such monetary penalties.

18.5 Financial Accounting Standards.

Under accounting principles generally accepted in the United States of America ("GAAP"), Tri-State may be required to consolidate an entity with which Tri-State has entered into a long-term power purchase agreement. Seller shall provide all information needed by Tri-State in order for Tri-State to determine whether or not Seller must be consolidated by Tri-State under GAAP. If Tri-State determines in its discretion that Tri-

State is required to consolidate Seller in its financial statements, Seller shall provide reasonable access to any records and personnel, as requested by Tri-State, in connection with such consolidation and also so that Tri-State's independent auditors can conduct financial statement audits in accordance with generally accepted audit standards, as well as internal controls review. Seller shall have adequate controls over financial information.

Article 19
Assignment and Other Transfer Restrictions

19.1 Assignment of PPA.

(A) Except as expressly permitted by this Section 19.1 or in connection with a Transfer of the Facility that is expressly permitted by Section 19.4, neither Party shall assign this PPA, or any portion thereof, without the prior written consent of the other Party. Any purported assignment of this PPA or any portion thereof in violation of the foregoing shall be null and void and shall constitute an Event of Default.

(B) Notwithstanding Section 19.1(A) but subject to Section 19.1(C), without the prior written consent of the other Party:

(1) Either Party shall have the right at any time and from time to time to mortgage, create or provide for a security interest in, convey in trust, or collaterally assign its respective rights, titles and interests in this PPA to any lender, collateral agent, mortgagee, or trustee as security for its present or future indebtedness (including, in the case of such an assignment by Seller, any Financing Party) (each, a "Security Party"), without such Security Party assuming or becoming in any respect obligated to perform any of the obligations of the Parties.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire all the rights, titles and interests of such Party in this PPA.

(3) Either Party may assign this PPA to any Affiliate thereof that has the financial capability to fulfill its obligations hereunder as demonstrated by a credit rating of equal to or better than the assigning Party.

(C) No assignment of or other succession to a Party's interest in this PPA shall be permitted pursuant to this PPA (other than Section 19.1(B)(1)) unless and until: (i) the successor assumes and agrees, in writing in form and substance reasonably acceptable to the other Party, to fully perform and discharge all of the obligations hereunder of such Party, and (ii) in the case of Seller's interest in this PPA, the successor (1) succeeds to and acquires all rights, title and interest of Seller in the Facility and (2) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Any successor to a Party's interest in this PPA shall notify the other Party promptly in writing of such succession, and shall furnish to the other Party evidence of such succession.

19.2 Change of Operator.

(A) Except as expressly permitted by this Section 19.2, Seller shall not replace the Operation and Maintenance Contractor (which for purposes of this Section 19.2 shall include replacement of any subcontractor or other Person providing operation management or other significant operation or maintenance services) without the prior written consent of Tri-State. The replacement of the Operation and Maintenance Contractor in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.2(A), Seller can replace the Operation and Maintenance Contractor without the prior written consent of Tri-State if:

(1) Seller provides to Tri-State reasonable advance written notice of such replacement (which, absent extraordinary circumstances affecting the safe and reliable operation of the Facility, shall not be less than ninety (90) Days prior to such replacement); and

(2) Seller reasonably demonstrates to Tri-State that the replacement operator is a Qualified Operator.

19.3 Change of Control.

(A) Except as expressly permitted by this Section 19.3, Seller shall not permit a Change of Control of Seller to occur without the prior written consent of Tri-State. The occurrence of a Change of Control of Seller in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.3(A) but subject to Section 19.3(C), without the prior written consent of Tri-State:

(1) Any direct or indirect owner of Seller shall have the right at any time and from time to time to mortgage, grant a security interest in, convey in trust, or pledge to any Security Party any equity or ownership interest in Seller or in any Person that Controls Seller.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire any such equity or ownership interests in Seller or in any Person that Controls Seller.

(C) No Change of Control of Seller shall be permitted under this PPA unless all obligations of Seller hereunder with respect to maintaining Security are satisfied immediately following such Change of Control.

(D) Seller shall notify Tri-State promptly in writing of any Change of Control of Seller.

19.4 Transfer of Facility.

(A) Except as expressly permitted by this Section 19.4, Seller shall not Transfer all or any portion of the Facility without the prior written consent of Tri-State. The Transfer of all or any portion of the Facility in violation of the foregoing shall constitute an Event of Default.

(B) Notwithstanding Section 19.4(A) but subject to Section 19.4(C), without the prior written consent of Tri-State:

(1) Seller shall have the right at any time and from time to time to mortgage, convey in trust, or grant to any Security Party a security interest in the Facility or any portion thereof.

(2) Any Security Party may foreclose upon or, in lieu thereof, otherwise succeed to and acquire the Facility or any portion thereof.

(3) Seller may, and shall be obligated to, Transfer the Facility to any Affiliate to which Seller assigns the PPA in compliance with the provisions of Section 19.1.

(C) No Transfer of the Facility or any portion thereof shall be permitted pursuant to this PPA (other than Section 19.4(B)(1)) unless and until the successor (i) succeeds to and acquires all rights, title and interest of Seller in this PPA, (ii) assumes and agrees in writing, in form and substance reasonably acceptable to Tri-State, to fully perform and discharge all of the obligations of Seller hereunder, and (iii) provides to Tri-State all Security then required to be maintained by Seller hereunder.

(D) Seller shall notify Tri-State promptly in writing of any Transfer of the Facility or any portion thereof, and shall furnish to Tri-State evidence of such Transfer.

19.5 Reimbursement of Tri-State's Costs.

In the event Seller proposes to or does assign or transfer an interest in the Facility or this PPA, undergo a Change of Control, or replace the Operation and Maintenance Contractor, as such transactions are described in this Article 19, Seller shall reimburse Tri-State for its expenses, including internal costs and expenses and reasonable attorneys' fees, incurred by Tri-State in connection with the evaluation of such proposed transaction and the preparation, negotiation, and execution of any consent and any other documents associated with such proposed transaction.

Article 20
Purchase Option

20.1 Right of First Offer of Sale of the Facility.

(A) Except for Transfers expressly permitted by Section 19.3(B) or Section 19.4(B), Seller shall not, and shall cause each direct and indirect owner of Seller not to, at any time during the Term, consummate or enter into any agreement for the consummation of any of the following (each, a "ROFO Transfer"):

(1) any Transfer by Seller of the Facility or any part of the Facility to one or more Persons that are not Affiliates of Seller; or

(2) any Transfer by any Person, in one or more transactions to one or more other Persons that are not Affiliates of such Person, of equity or other ownership interests in one or more Project Entities that (individually or in the aggregate) constitute a direct or indirect Controlling interest in Seller;

unless Seller has first offered to Transfer the Facility, or such direct or indirect owner has first offered to Transfer such direct or indirect equity interests in Seller, as applicable, to Tri-State pursuant to a written offer (in each case, an "Offered Assets Notice") and otherwise complies with this Section 20.1 and Article 19.

(B) Any Offered Assets Notice shall set forth in reasonable detail all material terms and conditions of the offer, including the minimum price and terms of payment, liabilities and obligations to be directly or indirectly assumed, all other financial terms, all material conditions to closing, a period of no less than 180 days following execution of the purchase agreement for the parties to obtain any approvals or other authorizations of any Governmental Authority or third party that are required by such party in connection with such Transfer, and all material representations, warranties, rights to indemnification, limitations thereon, and credit support for any of the foregoing. Following Tri-State's receipt of the Offered Assets Notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller (i) shall promptly answer any questions that Tri-State may have concerning the Facility, any applicable liabilities and obligations, and the offered terms and conditions, (ii) shall meet with Tri-State to discuss the offer, and (iii) shall provide all documents and information requested by Tri-State that are reasonably available to Seller.

(C) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions to purchase the Facility or the specified equity interests (as applicable) within ninety (90) Days after receiving the Offered Assets Notice, Seller shall have the right to sell the Facility (or Seller's relevant parent shall have the right to sell the specified equity interests, as applicable) to a third party on terms and conditions that are not more favorable in the aggregate to the third party than those included in the Offered Assets Notice, at any time within the twelve-month period following issuance of

the Offered Assets Notice, and to enter into any agreement therefor. If Seller or its relevant parent wishes to enter into an agreement for or consummate a ROFO Transfer with a third party on terms and conditions that in the aggregate are more favorable to the third party than those previously offered to Tri-State in the Offered Assets Notice, or on a date that is more than twelve months following delivery of the applicable Offered Assets Notice, such ROFO Transfer shall again be subject to this Section 20.1 and Seller or its relevant parent shall again first offer the revised terms and conditions to Tri-State pursuant to a new Offered Assets Notice.

(D) If Tri-State accepts an offer made by Seller under Section 20.1(B), the Parties shall within a further ninety (90) Days enter into a purchase agreement that, except to the extent otherwise agreement by Seller and Tri-State, incorporates the terms and conditions in the Offered Assets Notice.

20.2 Right of First Offer on Facility Expansion.

(A) If, at any time during the Term, Seller or any Affiliate of Seller intends to install or modify any energy generation or storage equipment on the Site or on any location within a five (5) mile radius of the boundary of the Site, the effect of which, if deemed part of the Facility, would be to increase the Nameplate Capacity Rating of the Facility, Seller shall first offer the Energy (and Environmental Attributes) resulting from such installation or modification ("Expansion Energy") to Tri-State. Such offer shall set forth in reasonable detail the proposed transaction and the terms and conditions of the offer, including the price. Following Tri-State's receipt of such notice, Tri-State shall have ninety (90) Days to investigate the proposed transaction and conduct due diligence. Seller shall promptly answer any question that Tri-State may have concerning the offered terms and conditions, shall meet with Tri-State to discuss the offer, and shall provide requested documents and information requested by Tri-State.

(B) If Tri-State does not provide Seller notice that it accepts the offered terms and conditions within ninety (90) Days after receiving the offer, Seller or the Affiliate of Seller may enter into an agreement to sell the Expansion Energy to a third party on terms and conditions no more favorable in the aggregate to the third party than those offered to Tri-State. If Seller or the Affiliate of Seller wishes to enter into an agreement with a third party on terms and conditions more favorable to the third party than those previously offered to Tri-State under Section 20.2(A), Seller or the Affiliate of Seller shall first offer such revised terms and conditions to Tri-State pursuant to Section 20.2(B).

(C) If Tri-State accepts an offer made by Seller under Section 20.2(A), the Parties shall within a further ninety (90) Days enter into an energy purchase agreement in substantially the same form as this PPA for the purchase and sale of Expansion Energy and associated Environmental Attributes (with the Security requirement set forth in Article 11, Contract Energy delivery requirements set forth in Section 6.1, the damage payment in Section 6.4(H) and Expected Contract Energy to

be adjusted on a pro rata basis to account for the size of the proposed expansion relative to the Expected Nameplate Capacity Rating), but incorporating such changes as are expressly identified in the terms and conditions offered by Seller.

20.3 Option to Purchase.

(A) Seller hereby gives and grants to Tri-State the exclusive and irrevocable right and option to purchase the Facility Assets, at the times and upon the terms and conditions set forth in this Section 20.3, for a price equal to the Fair Market Value of the Facility, as determined pursuant to this Section 20.3 ("Purchase Option").

(B) As used herein, "Facility Assets" means the Facility, all interest of Seller or any of its Affiliates in, to or under this PPA, and any and all tangible or intangible assets that are reasonably necessary for the ownership, operation and maintenance of the Facility, including (i) all drawings, specifications, operations and maintenance records, and performance data of or related to the Facility; (ii) all warranties, equipment service and maintenance agreements, and similar agreements related to the Facility, any portion thereof, or any related equipment or facilities; (iii) non-exclusive, irrevocable and royalty-free licenses to use software and other intellectual property necessary for the ownership, operation or maintenance of the Facility; (iv) all Governmental Approvals related to the ownership, operation or maintenance of the Facility, to the extent assignable; (v) the Interconnection Agreement and utility services agreements, (vi) the Facility Site Documents, and all other interests or rights in real estate reasonably necessary for the operation and maintenance of the Facility, and (vii) all rights to future Energy, Environmental Attributes, and tax benefits.

(C) Facility Assets do not include (without limitation) (i) any liabilities of Seller or any of its Affiliates, contingent or otherwise, other than future performance obligations under contracts and Governmental Approvals that, in any case, are reasonably necessary for the ownership, operation or maintenance of the Facility and are assigned to Tri-State; (ii) any agreement or instrument evidencing indebtedness for borrowed money; (iii) any contracts or agreements for the sale of Energy, Environmental Attributes, or other products, other than this PPA; or (iv) any contract or agreement for asset management, operations, or other services not specifically included in the Facility Assets.

(D) As a condition to any exercise of the Purchase Option, Tri-State must give non-binding written notice (a "Notice of Intent to Purchase") either (i) within ninety (90) days prior to any of [solar only: the sixth (6th) anniversary of the Commercial Operation Date,] the eleventh (11th) anniversary of the Commercial Operation Date, the fifteenth (15th) anniversary of the Commercial Operation Date, the twentieth (20th) anniversary of the Commercial Operation Date, or the expiration of the Term, or (ii) within ninety (90) days following any termination of this PPA by Tri-State, following the [solar: sixth (6th)][wind: fifteenth (15th)] anniversary of the Commercial Operation Date, due to an Event of Default by Seller.

(E) For a period of sixty (60) days following the date of the Notice of Intent to Purchase, the Parties will meet to discuss and negotiate in good faith to determine and agree upon the Fair Market Value, and shall use commercially reasonable efforts to agree upon the terms and conditions of a purchase and sale agreement with respect to the Facility Assets. For the avoidance of doubt, neither agreement upon Fair Market Value and such terms and conditions, nor execution of a purchase and sale agreement, shall be conditions to the closing of a purchase and sale of the Facility Assets pursuant to exercise of the Purchase Option.

(F) For purposes of this Section 20.3, "Fair Market Value" means the fair market value of the Facility Assets as agreed by the Parties; provided, however, that in the event the Parties cannot agree upon Fair Market Value within sixty (60) Days following the delivery of the Notice of Intent to Purchase, the Parties shall retain an independent nationally recognized appraiser experienced in appraising [wind][solar]-powered electric energy generation facilities selected by Tri-State (and certified as so qualified by Seller), in which case Fair Market Value shall be as determined by such appraiser. The Parties shall share equally all fees and costs of the third appraiser, if required, retained to determine Fair Market Value.

(G) The appraiser shall consider the following factors in its determination of Fair Market Value:

(1) the expected annual generating output of the Facility over the remainder of its assumed useful life determined in a manner consistent with Prudent Utility Practices, taking into account the expected degradation of the Facility over such period;

(2) the net present value of the after-tax cash flows over the remainder of its assumed useful life (determined in a manner consistent with Prudent Utility Practices, and taking into account the expected degradation), applying a discount rate that is reasonable under then-current market conditions as agreed by the Parties, and if not so agreed within thirty (30) Days, then as determined by such appraiser;

(3) the general condition of the Facility at the time of the expected closing following exercise of the Purchase Option determined by inspection and, if applicable, testing;

(4) any restrictions on use of the Site or any portion thereof;

(5) any rights or obligations of Seller to dismantle and remove the Facility and restore the Site (whenever arising);

(6) any restrictions upon or obligations or liabilities associated with any of the Facility Assets or the operation of the Facility prior to the closing pursuant to the Purchase Option that could adversely affect the operation of the

Facility, or for which Tri-State could be responsible or have any liability, following the closing pursuant to the Purchase Option, including due to any Environmental Contamination, any accrued liabilities (contingent or non-contingent) under the Interconnection Agreement, any Facility Site Documents, or any other contract included in the Facility Assets, any accrued and unpaid property tax liabilities, and any failure to comply with any Governmental Approval or Applicable Law;

(7) the terms and conditions of this PPA, including the encumbrance of any obligations and liabilities on an assignee thereof with respect to delivery of Contract Energy to Tri-State for the remainder of the Term, the expected market price of Energy following the expiration of this PPA, transmission costs and constraints and other limitations on the marketability of power generated from the Facility;

(8) any terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets;

(9) an appropriate discount to the extent that (i) Seller fails to provide to Tri-State and the appraiser any material information related to the Facility Assets or Site, or (ii) the representations, warranties, indemnification obligations and other terms and conditions (if any) that will apply to the sale and purchase of the Facility Assets materially deviate from customary terms and conditions for the sale and purchase of facilities similar to the Facility; and

(10) such other factors as the independent appraiser deems relevant.

(H) Following delivery of a Notice of Intent to Purchase, Seller shall promptly provide to Tri-State (and, if applicable, the appraiser) all information regarding the Facility Assets and Site as may be requested thereby, that is reasonably available to Seller, and Tri-State (and, if applicable, the appraiser) shall be provided with access to the Site and Facility in order to conduct an inspection and witness any testing. All inspections and testing, and access to the Site and Facility, shall be conducted in accordance with all of Seller's applicable reasonable safety and health rules and requirements that have been provided to Tri-State (and, if applicable, the appraiser), and shall be conducted in a manner so as to minimize disruption in the operation and the maintenance of the Facility and in such a manner so as to avoid any adverse economic impacts to Seller under this PPA.

(I) To definitively exercise the Purchase Option, Tri-State must deliver written notice (a "Purchase Notice") to Seller within sixty (60) days following determination of Fair Market Value pursuant to this Section 20.3. Once the Purchase Notice has been delivered, the Purchase Option shall be irrevocable.

(J) The closing for purchase and sale of the Facility Assets shall occur on the later of the thirtieth (30th) day following the date of the Purchase Notice and the

fifth (5th) Business Day after the receipt of all required consents and approvals of Governmental Authorities. At the closing:

(1) Seller shall convey to Tri-State good and marketable title to all of the Facility Assets, free and clear of all liens and encumbrances (other than those arising under the terms of the Facility Site Documents and Governmental Approvals), and with such other representations and warranties as may be agreed by the Parties; and

(2) Tri-State shall pay to Seller, in full consideration thereof, an amount in cash equal to the Fair Market Value.

Article 21
Miscellaneous

21.1 Waiver.

The delay or failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to exercise or take advantage of any of its rights, including any right to terminate this PPA, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

21.2 Fines and Penalties.

(A) Seller shall pay when due all fees, fines, penalties or costs incurred by Seller or its agents, employees or contractors for noncompliance by Seller or the Facility, its employees, or subcontractors with any provision of this PPA, or any contractual obligation, permit or requirements of Applicable Law except for such fines, penalties and costs that are being actively contested in good faith and with due diligence by Seller and for which adequate financial reserves have been set aside to pay such fines, penalties or costs in the event of an adverse determination.

(B) If fees, fines, liens, penalties, or costs are claimed or assessed against Tri-State by any Governmental Authority due to noncompliance by Seller or the Facility with this PPA, any requirements of Applicable Law, any permit or contractual obligation, or, if the work of Seller or any of its contractors or subcontractors is delayed or stopped by order of any Governmental Authority due to Seller's noncompliance with any requirements of Applicable Law, permit, or contractual obligation, Seller shall indemnify and hold Tri-State harmless against any and all losses, liabilities, damages, and claims suffered or incurred by Tri-State, including claims for indemnity or contribution made by third parties against Tri-State, except to the extent Tri-State recovers any such losses, liabilities or damages through other provisions of this PPA.

21.3 Disclaimer of Third Party Beneficiary Rights.

In executing this PPA, Tri-State does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

21.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Except as specifically provided in Section 12.5, neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Seller shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of Persons to perform Seller's obligations under this PPA, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the Persons employed by Seller shall be considered employees of Tri-State for any purpose; nor shall Seller represent to any Person that he or she is or shall become a Tri-State employee.

21.5 Severability.

In the event any of the terms, covenants, or conditions of this PPA, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of this PPA and their application not adversely affected thereby shall remain in force and effect; *provided, however,* that Tri-State and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

21.6 Complete Agreement; Amendments.

The terms and provisions contained in this PPA constitute the entire agreement between Tri-State and Seller with respect to the Facility and shall supersede all previous communications, representations, or agreements, either verbal or written, between Tri-State and Seller with respect to the sale of Contract Energy. This PPA may be amended, changed, modified, or altered, *provided* that such amendment, change, modification, or alteration shall be in writing and signed by both Parties.

21.7 Binding Effect.

This PPA, as it may be amended from time to time pursuant to this Article 21, shall be binding upon and inure to the benefit of the Parties and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

21.8 Headings.

The table of contents, captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

21.9 Counterparts.

This PPA may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

21.10 Governing Law.

The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the State of Colorado. The Parties hereby submit to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado.

21.11 Mobile-Sierra.

Notwithstanding any other provision of this PPA to the contrary, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this PPA through application or complaint to FERC pursuant to the provisions of Section 205, 206 or 306 of the Federal Power Act, or any other provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of service of this PPA proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as interpreted in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1,* 128 S. Ct. 2733 (2008). Changes proposed by a non-Party or FERC acting *sua sponte* shall be subject to the most stringent standard permissible under Applicable Law.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have executed this PPA as of the date first written above.

Seller:

_____

By: _____

Printed Name: _____

Title:_____

Tri-State:

Tri-State Generation and Transmission Association, Inc.

By: _____

Printed Name:

Title: Chief Executive Officer

EXHIBIT A

PROJECT MILESTONES

Date	**Construction Milestones**
10 Days after the Effective Date	Seller shall have established the Security in accordance with Article 11.
[_____]	Seller shall have delivered a fully executed EPC Contract to Tri-State.
[_____]	[*wind only-* Seller shall have provided Tri-State with copies of Determinations of No Hazard from the Federal Aviation Administration for the Units.]
[_____]	Seller shall have provided Tri-State with documentation that all Seller required Governmental Approvals have been obtained or will be obtained by the time needed to meet all Construction Milestones.
[_____]	Seller shall have entered into Financing Documents and having achieved or obtained waivers with respect to all conditions precedent to the initial availability for disbursement of funds under the Financing Documents.
[_____]	Seller shall have commenced construction of the Facility (all Seller required Governmental Approvals required to construct Facility shall have been obtained and are in full force and effect, except for minor Seller required Governmental Approvals that are expected to be obtained in the ordinary course, the failure of which to obtain would not adversely affect the construction and/or operation of the Facility).
[_____]	Delivery of major components to the Site shall have commenced.
[_____]	Seller shall have provided Tri-State with copies of the executed Operation and Maintenance Agreement, if applicable
[_____]	The step-up transformer shall have been delivered to the Site.
[_____]	Seller shall have completed construction of Seller's Interconnection Facilities and such facilities are capable of being energized.
[_____]	Start-up testing of the Units shall have commenced.

Commercial Operation Milestone

[_____] The Facility shall have achieved Commercial Operation.

EXHIBIT B

FACILITY DESCRIPTION AND SITE MAPS

Required Items:

Location of Electric Interconnection Point (see definition of Point of Delivery)

A detailed description of the Facility, including identification of the major equipment and components that will make up the Facility (see Section 3.1)

A scaled map that identifies the Site and the location of the Units on the Site and a drawing identifying the location of the Electric Interconnection Point, the Point of Delivery, important ancillary facilities and Interconnection Facilities (See Section 3.2)

EXHIBIT C

CONTRACT ENERGY RATE

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	Minimum Limits of Coverage
1. Commercial General Liability ("CGL") and commercial umbrella	$15,000,000 per occurrence and aggregate. If CGL insurance contains a general aggregate limit, it shall apply separately to the Facility.

CGL insurance shall be written on ISO occurrence form CG 00 01 01 96 (or a substitute form providing similar coverage) and shall cover liability arising from premises, operations, independent contractors, products/completed operations, contracts, property damage, personal injury and advertising injury, and liability assumed under an insured contract (including the tort liability of another assumed in a business contract). There shall be no endorsement or modification limiting coverage for liability assumed under an insured contract. There shall be no endorsement or modification of the CGL insurance limiting the scope of coverage for liability arising from explosion, collapse, or underground property damage.

Tri-State shall be included as an additional insured under the CGL policy, using ISO additional insured endorsement CG 20 10 (or a substitute providing similar coverage), and under the commercial umbrella insurance. The commercial umbrella insurance shall provide coverage over the top of the CGL insurance, the Business Automobile Liability insurance.

The CGL and commercial umbrella insurance to be obtained by or on behalf of Seller shall be:

primary as respects any claims, losses, damages, expenses, or liabilities arising out of this PPA.

2 Environmental/Pollution Liability insurance either stand alone or as part of the CGL/commercial umbrella	At least $5,000,000 each occurrence

Environmental/Pollution Liability insurance shall protect against bodily injury and property damage claims arising out of pollution. The policy through its language or by endorsement, shall include coverage for contractual liability.

3. Business Automobile Liability	$1,000,000 combined single limit (each accident), including Non-Owned and Hired Autos.

Business Automobile Liability insurance shall be written on ISO form CA 00 01, CA 00 05, CA 00 12, CA 00 20, or a substitute form providing similar liability coverage. If necessary, the policy shall be endorsed to provide contractual liability coverage equivalent to that provided in the 1990 and later editions of CA 00 01. If transporting hazardous waste/materials from the Site, an appropriate MCS-90 Endorsement must be attached with $10,000,000 limits of liability.

4. Workers' Compensation	Statutory Requirements. Seller may comply with these requirements through its project operator.

EXHIBIT D

INSURANCE COVERAGE

Type of Insurance	**Minimum Limits of Coverage**
5. Employers' Liability, if Seller maintains employees (or a certification from Seller that is maintains no employees)	Bodily Injury by Accident, $1,000,000 each accident Bodily Injury by Disease, $1,000,000 policy limit Bodily Injury by Disease, $1,000,000 each employee

6. Builders All Risk insurance coverage	For the full value of Facility.

Builders All Risk insurance shall include coverage carried by either Seller or the EPC Contractor, without limitation against the perils of fire and physical loss or damage including, without duplication of coverage, theft, vandalism, malicious mischief, collapse, water, falsework, testing and startup, for entire period of construction, which shall cover the interests of Indemnified Parties until the Commercial Operation Date, and insurance coverage as set forth in 7 below is provided. A certificate of Builders Risk insurance shall be provided to Tri-State regardless of who procures coverage.

7. All-Risk Property insurance covering physical loss or damage to the Facility	Full Replacement Value of the Facility. A deductible may be carried, which deductible shall be the absolute responsibility of Seller.

All-Risk Property insurance shall include: (i) coverage for fire, flood, wind and storm, tornado and earthquake; (ii) Boiler and Machinery insurance covering all objects customarily subject to such insurance, including boilers and engines, and (iii) business interruption to cover loss of providing Energy to Tri-State should Seller not be able to produce or provide electrical energy as agreed to herein. Tri-State shall be named as a loss payee as to its interests under this PPA.

Seller shall require its contractors and subcontractors to purchase and maintain commercial general liability including environmental coverage within or as a separate policy in an amount commensurate with type of work to be performed and automobile, workers' compensation and employers liability insurance of the types and amounts specified above. If requested by Tri-State, Seller shall furnish copies of certificates of insurance evidencing such coverage.

EXHIBIT E

PROJECT CONTRACTS

[Seller to Provide]

1. Generator Interconnection Agreement

2.

EXHIBIT F

SELLER'S REQUIRED GOVERNMENTAL APPROVALS

[Seller to Provide]

Tri-State 11/19/2020
Model Renewable PPA

EXHIBIT G

MONTHLY PRODUCTION PERCENTAGE OF EXPECTED CONTRACT ENERGY

Calendar Month	Monthly Production %
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

EXHIBIT H

OPERATING COMMITTEE REPRESENTATIVES

Tri-State	Seller
Primary Representative: Origination Manager Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Primary Representative:**
Alternative Representative: Senior Manager, Energy Resources Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Phone: (303) 254-_____ Email: _____@tristategt.org	**Alternative Representative:**

Tri-State 11/19/2020 Model Renewable PPA

TS-XX-XXXX

EXHIBIT I

NOTICE ADDRESSES

Tri-State	Seller
Notices: Chief Executive Officer Tri-State Generation and Transmission Association, Inc. 1100 W. 116th Avenue Westminster, CO 80234 Telephone: (303) 452-6111 with a copy to (at the same address): Senior Vice President and General Counsel	**Notice**:

EXHIBIT J

FORM OF ATTESTATION AND BILL OF SALE

_____ ("Seller") hereby sells, transfers and delivers to Tri-State Generation and Transmission Association, Inc. ("Tri-State") the Environmental Attributes associated with the generation of Contract Energy, as detailed in the Energy Purchase Agreement for the _____ Project between the Parties, dated _____ (the "Agreement"). Terms used, but not defined herein, shall have the meaning set forth in the Agreement.

_____
Name of Renewable Energy Facility

_____	_____	_____
Type/Resource	Nameplate Capacity Rating (MW)	Commercial Operation Date

_____ - _____ (from) (to)
Dates

_____
MWh generated

One (1) REC represents the REC and Environmental Attributes reporting rights associated with one (1) MWh generated from the Facility.

Seller further attests, warrants and represents as follows:

i) each REC and Environmental Attribute is free and clear of any liens, encumbrances and/or defects of title;

ii) none of the RECs or Environmental Attributes has been retired, claimed or represented as part of electricity output or sales by Seller, or used to satisfy obligations in any other jurisdiction;

iii) its sale to Tri-State is its one and only sale of the RECs and Environmental Attributes with respect to the Contract Energy referenced herein, after due inquiry, no third party has claimed nor can claim any interest in such RECs or Environmental Attributes;

iv) the Facility identified above produced the number of MWh above during the period indicated above;

v) Seller has title to and ownership of the RECs and Environmental Attributes sold hereunder; and

vi) Seller owns the _____.
Name of the Renewable Energy Facility

This serves as a bill of sale, transferring from Seller to Tri-State all of Seller's right, title and interest in and to the RECs and Environmental Attributes associated with the generation of the above referenced Contract Energy.

Contact Person: _____

phone: _____; fax: _____

[Seller]

Signed: _____

Name: _____

Title: _____

Date: _____

EXHIBIT K

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

IRREVOCABLE LETTER OF CREDIT NO _____

DATE OF ISSUANCE: _____

INITIAL EXPIRATION DATE: [Must be at least ONE YEAR after Date of Issuance]

BENEFICIARY:
TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

APPLICANT:
[NAME OF APPLICANT]

ATTN: CREDIT RISK ADMINISTRATOR
1100 W. 116TH AVENUE
WESTMINSTER, CO 80234

[APPLICANT ADDRESS]

1. AS THE ISSUING BANK ("ISSUER"), WE, [NAME OF ISSUING BANK], HEREBY ESTABLISH AND ISSUE THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. _____ IN FAVOR OF THE ABOVE-NAMED BENEFICIARY ("BENEFICIARY") FOR THE ACCOUNT OF THE ABOVE-NAMED APPLICANT ("APPLICANT") IN THE MAXIMUM AGGREGATE AMOUNT OF USD $_____ (_____ U.S. DOLLARS).

2. ISSUER UNDERTAKES TO BENEFICIARY TO PAY BENEFICIARY'S DEMAND FOR PAYMENT OF AN AMOUNT AVAILABLE UNDER THIS LETTER OF CREDIT, UPON PRESENTATION OF A DEMAND FOR PAYMENT SUBSTANTIALLY IN THE FORM OF EXHIBIT "A," ATTACHED HERETO, DULY COMPLETED AS INDICATED, AT THE FOLLOWING PLACE FOR PRESENTATION: [ADDRESS OF PLACE FOR PRESENTATION], AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE.

DEMAND FOR PAYMENT MAY ALSO BE PRESENTED BY FACSIMILE ("FAX") TO FAX NO._____ PROVIDED THAT SUCH FAX PRESENTATION IS MADE AT ANY TIME ON OR BEFORE 5:00 PM (_____ TIME) ON THE EXPIRATION DATE. ISSUER WILL ACKNOWLEDGE RECEIPT OF BENEFICIARY'S PRESENTMENT WITHIN FOUR (4) BUSINESS HOURS TO THE EMAIL ADDRESS PROVIDED TO ISSUER IN THE FAX DRAW CERTIFICATE.

IF THE AMOUNT IN THE DRAW CERTIFICATE EXCEEDS THE AMOUNT AVAILABLE, BUT THE PRESENTATION OTHERWISE COMPLIES, ISSUER UNDERTAKES TO PAY THE AMOUNT AVAILABLE.

NO OTHER DOCUMENTS WILL BE REQUIRED TO BE PRESENTED. PAYMENT MADE HEREUNDER SHALL BE MADE IN U.S. DOLLARS IN IMMEDIATELY AVAILABLE FUNDS.

3. PARTIAL AND MULTIPLE DRAWS AND PRESENTATIONS ARE PERMITTED, PROVIDED THAT THE AVAILABLE AMOUNT OF THIS LETTER OF CREDIT SHALL BE PERMANENTLY REDUCED BY THE AMOUNT OF EACH SUCH DRAW.

4. THIS LETTER OF CREDIT IS ISSUED PURSUANT TO THE PROVISIONS OF THAT CERTAIN ENERGY PURCHASE AGREEMENT BETWEEN THE BENEFICIARY AND THE APPLICANT DATED AS OF _____, 20__ (AS THE SAME MAY HAVE BEEN OR MAY BE AMENDED FROM TIME TO TIME, THE "PPA"). NOTWITHSTANDING ANY REFERENCE IN THIS LETTER OF CREDIT TO THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS, OR REFERENCES IN THE PPA OR ANY OTHER DOCUMENTS, INSTRUMENTS OR AGREEMENTS TO THIS LETTER OF CREDIT, THIS LETTER OF CREDIT CONTAINS THE ENTIRE AGREEMENT BETWEEN BENEFICIARY AND ISSUER RELATING TO THE OBLIGATIONS OF ISSUER HEREUNDER.

5. THIS LETTER OF CREDIT WILL BE AUTOMATICALLY EXTENDED EACH YEAR WITHOUT AMENDMENT FOR A PERIOD OF ONE YEAR FROM THE EXPIRATION DATE HEREOF, AS EXTENDED, UNLESS AT LEAST FORTY-FIVE (45) DAYS PRIOR TO THE EXPIRATION DATE, ISSUER NOTIFIES BENEFICIARY AND APPLICANT BY A NATIONALLY RECOGNIZED OVERNIGHT COURIER OR CERTIFIED MAIL THAT IT ELECTS NOT TO EXTEND THIS LETTER OF CREDIT FOR SUCH ADDITIONAL PERIOD (THE PRESENT OR ANY FUTURE EXPIRATION DATE AS AFORESAID IS REFERRED TO HEREIN AS THE "EXPIRATION DATE"). NOTICE OF NON-EXTENSION WILL BE GIVEN BY ISSUER TO BENEFICIARY AT BENEFICIARY'S ADDRESS SET FORTH HEREIN OR AT SUCH OTHER ADDRESS AS BENEFICIARY MAY DESIGNATE TO ISSUER IN WRITING AT ISSUER'S LETTERHEAD ADDRESS.

6. ISSUER UNDERTAKES TO MAKE PAYMENT AGAINST A COMPLYING PRESENTATION WITHIN THREE BUSINESS DAYS AFTER PRESENTATION. THE BENEFICIARY SHALL RECEIVE PAYMENT BY WIRE TRANSFER TO A BANK ACCOUNT OF THE BENEFICIARY. FOR THE PURPOSES HEREOF, "BUSINESS DAY" SHALL MEAN ANY DAY ON WHICH COMMERCIAL BANKS IN COLORADO ARE NOT AUTHORIZED OR REQUIRED TO CLOSE.

7. THIS LETTER OF CREDIT IS FREELY TRANSFERABLE TO AN ASSIGNEE AND THE NUMBER OF TRANSFERS IS UNLIMITED. SUBJECT TO COMPLIANCE WITH APPLICABLE LAWS, ISSUER AGREES THAT IT WILL EFFECT ANY TRANSFERS IMMEDIATELY UPON PRESENTATION TO ISSUER OF THIS LETTER OF CREDIT AND A COMPLETED WRITTEN TRANSFER REQUEST SUBSTANTIALLY IN THE FORM OF EXHIBIT "B," ATTACHED HERETO, DULY COMPLETED AS INDICATED. SUCH TRANSFER WILL BE EFFECTED AT NO COST TO BENEFICIARY. ANY TRANSFER FEES ASSESSED BY ISSUER WILL BE PAYABLE SOLELY BY APPLICANT, AND THE PAYMENT OF ANY TRANSFER FEES WILL NOT BE A CONDITION TO THE VALIDITY OR EFFECTIVENESS OF THE TRANSFER OR THIS LETTER OF CREDIT.

8. THIS LETTER OF CREDIT IS SUBJECT TO THE INTERNATIONAL STANDBY PRACTICES 1998 ("ISP98") (INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP98. AS TO MATTERS NOT COVERED BY THE ISP98, THIS LETTER OF CREDIT SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH

THE LAWS OF THE STATE OF COLORADO, WITHOUT REGARD FOR THE PRINCIPLES OF CONFLICTS OF LAWS THEREUNDER.

9. ISSUER'S CHARGES AND FEES FOR ISSUING, AMENDING, OR HONORING THIS LETTER OF CREDIT ARE FOR APPLICANT'S ACCOUNT AND SHALL NOT BE DEDUCTED FROM ANY PAYMENT ISSUER MAKES UNDER THIS LETTER OF CREDIT.

ISSUER:

By: _____
AUTHORIZED SIGNATURE
Its:_____

EXHIBIT "A"
(TO LETTER OF CREDIT)

FORM OF DEMAND FOR PAYMENT

[ISSUING BANK NAME] DATE:
[ISSUING BANK ADDRESS]

LADIES AND GENTLEMEN:

THIS DEMAND FOR PAYMENT IS PRESENTED BY THE UNDERSIGNED BENEFICIARY UNDER THE IRREVOCABLE LETTER OF CREDIT NO. _____, DATED _____ (THE "LETTER OF CREDIT"), ISSUED BY _____ ("ISSUER") FOR THE AMOUNT OF U.S. DOLLARS _____ AND ____/100THS (U.S.$_____), WHICH CONSTITUTES A PAYMENT OF THE FUNDS AVAILABLE TO THE BENEFICIARY UNDER THE LETTER OF CREDIT.

1. UNDER THIS DEMAND FOR PAYMENT, THE BENEFICIARY STATES [CHECK APPLICABLE]:

   [___] BENEFICIARY IS OWED BY APPLICANT THE AMOUNT DEMANDED UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____, WHICH AMOUNT REMAINS DUE AS OF THE DATE OF THIS DEMAND FOR PAYMENT.

   [___] THE ISSUER HAS GIVEN WRITTEN NOTICE PURSUANT TO THE LETTER OF CREDIT OF ITS INTENT NOT TO EXTEND THE LETTER OF CREDIT FOLLOWING THE PRESENT EXPIRATION DATE THEREOF AND THE CURRENT EXPIRY DATE OF THIS LETTER OF CREDIT IS WITHIN THIRTY (30) DAYS AND THE AMOUNT DEMANDED IS REQUIRED TO SECURE THE OBLIGATIONS OF APPLICANT UNDER THE AGREEMENT BETWEEN BENEFICIARY AND APPLICANT TITLED _____ AND DATED _____.

2. BENEFICIARY REQUESTS THE AMOUNT DEMANDED HEREUNDER BE TRANSFERRED TO BENEFICIARY BY WIRE TRANSFER TO THE FOLLOWING BANK ACCOUNT OF THE BENEFICIARY:

   _____
   _____
   _____

[3. ISSUER ACKNOWLEDGEMENT OF BENEFICIARY'S PRESENTMENT BY FAX SHALL BE SENT TO BENEFICIARY AT _____@TRISTATEGT.ORG.]

BENEFICIARY:

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

BY: _____
NAME: _____
TITLE: _____

EXHIBIT "B"
(TO LETTER OF CREDIT)

FORM OF TRANSFER REQUEST

IRREVOCABLE LETTER OF CREDIT NO: _____

CURRENT BENEFICIARY:

APPLICANT:

TO: [NAME OF ISSUING BANK]

THE UNDERSIGNED, AS THE CURRENT "BENEFICIARY" OF THE ABOVE REFERENCED LETTER OF CREDIT, HEREBY REQUESTS THAT YOU REISSUE THE LETTER OF CREDIT IN FAVOR OF THE TRANSFEREE NAMED BELOW [INSERT TRANSFEREE NAME AND ADDRESS BELOW]:

FROM AND AFTER THE DATE THIS TRANSFER REQUEST IS DELIVERED TO THE ISSUER, THE TRANSFEREE SHALL BE THE "BENEFICIARY" UNDER THE LETTER OF CREDIT FOR ALL PURPOSES AND SHALL BE ENTITLED TO EXERCISE AND ENJOY ALL OF THE RIGHTS, PRIVILEGES AND BENEFITS THEREOF.

DATED: _____

[NAME OF BENEFICIARY]

By:
Name:
Title:

EXHIBIT L

FORM OF GUARANTY

This Guaranty is executed and delivered as of this _____ day of _____, 20__ by _____, a _____ ("Guarantor"), in favor of Tri-State Generation and Transmission Association, Inc. ("Company"), in connection with the performance by _____, a _____ _____ ("Seller") of that certain Energy Purchase Agreement for the _____, dated _____, 20__, TS-__-____, by and between Seller and Company (the "PPA"). Capitalized terms used but not defined herein shall have the meanings set forth in the PPA.

RECITALS

A. Seller is planning to develop, design, construct, own, operate, and maintain a _____-powered electric energy generating facility having an Expected Nameplate Capacity Rating of _____ MW AC to be located in _____ County, _____ (the "Facility").

B. Seller and Company have entered into the PPA for the purchase and sale of capacity and electrical energy from the Facility on the terms and conditions set forth therein.

C. This Guaranty is delivered to the Company pursuant to Section 11.1(A) of the PPA.

D. To induce Company to enter into the PPA and consummate the purchase and sale of electrical energy contemplated by the PPA, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing and for good and valuable consideration, Guarantor hereby agrees as follows:

AGREEMENT

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the PPA, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this

Guaranty. In furtherance of the foregoing and without limiting the generality thereof, Guarantor agrees as follows:

a. The liability of Guarantor under this Guaranty is not conditional or contingent upon the genuineness, validity, regularity or enforceability of the PPA or the pursuit by Company of any remedies which it now has or may hereafter have under the PPA;
b. Company may enforce this Guaranty upon the occurrence of a default by Seller under the PPA notwithstanding the existence of a dispute between Company and Seller with respect to the existence of the default;
c. The obligations of Guarantor under this Guaranty are independent of the obligations of Seller under the PPA and a separate action or actions may be brought and prosecuted against Guarantor whether or not any action is brought against Seller or any other guarantors and whether or not Seller is joined in any such action or actions;
d. Company may, at its election, foreclose on any security held by Company, or exercise any other right or remedy available to Company without affecting or impairing in any way the liability of Guarantor under this Guaranty, except to the extent the amount(s) owed to Company by Seller have been paid;
e. Guarantor shall continue to be liable under this Guaranty and the provisions hereof shall remain in full force and effect notwithstanding: (i) any modification, amendment, supplement, extension, agreement or stipulation between Seller and Company or their respective successors and assigns, with respect to the PPA or the obligations encompassed thereby; (ii) Company's waiver of or failure to enforce any of the terms, covenants or conditions contained in the PPA; (iii) any release of Seller or any other guarantor from any liability with respect to the Obligations or any portion thereof; (iv) any release, compromise or subordination of any real or personal property then held by Company as security for the performance of the Obligations or any portion thereof, or any substitution with respect thereto; (v) without in any way limiting the generality of the foregoing, if Company is awarded a judgment in any suit brought to enforce a portion of the Obligations, such judgment is not deemed to release Guarantor from its covenant to pay that portion of the Obligations which is not the subject of such suit; (vi) Company's acceptance and/or enforcement of, or failure to enforce, any other guaranties or any portion of this Guaranty; (vii) Company's exercise of any other rights available to it under the PPA; (viii) Company's consent to the change, reorganization or termination of the corporate structure or existence of the Seller and to any corresponding restructuring of the Obligations; (ix) any failure to perfect or continue perfection of a security interest in any collateral that secures the Obligations; and (x) any other act or thing or omission, or delay to do any other act or thing that might in any manner or to any

extent vary the risk of Guarantor as an obligor with respect to the Obligations; and

f. Guarantor agrees that upon a demand for payment under this Guaranty, Guarantor shall pay such Obligations as are included in such demand notwithstanding any defenses, setoffs or counterclaims that Seller may allege or assert against Company with respect to the Obligations, including, without limitation, statute of frauds and accord and satisfaction; provided that Guarantor reserves the right to assert any defenses, setoffs or counterclaims that Seller may allege or assert against Company (except for such defenses, setoffs or counterclaims as are expressly waived under other provisions of this Guaranty) in a subsequent action for recoupment, restitution or reimbursement.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ ($_____), plus costs of collection with respect to any valid claim(s) made by Company hereunder that are incurred in the enforcement or protection of the rights of Company.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

   a. to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the PPA;
   b. to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and
   c. to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance; Payment. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the PPA has expired ("Default"), Guarantor shall immediately (but in no event later than three (3) Business Days) upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct. All sums payable by Guarantor hereunder shall be made in immediately available funds in U.S. Dollars.

5. Term; Satisfaction.

a. This Guaranty shall continue in full force and effect until the earlier to occur of: (i) the substitution of an alternative form of Security in accordance with the PPA; (ii) the satisfaction of all Obligations of Seller under the PPA; or (iii) the payment by Guarantor, without reservation of rights, of an aggregate amount equal to the maximum liability set forth in Section 2, together with any other amounts required to be paid by Guarantor pursuant to Section 10 hereof.
b. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full.

6. Bankruptcy. So long as any Obligations remain outstanding, Guarantor may not, without the prior written consent of Company, commence or join with any other person in commencing any bankruptcy, reorganization or insolvency proceedings of or against Seller. The obligations of Guarantor under this Guaranty may not be reduced, limited, impaired, discharged, deferred, suspended or terminated by any proceeding, voluntary or involuntary, involving the bankruptcy, insolvency, receivership, reorganization, liquidation or arrangement of the Seller or by any defense which Seller may have by reason of the order, decree or decision of any court or administrative body resulting from any such proceeding. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

a. all set-offs, counterclaims, withholdings or deductions and all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;
b. any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;
c. any defense based upon an election of remedies by Company;
d. any duty of Company to protect or not impair any security for the Obligations;

e. any defense based upon promptness, diligence, and any requirement that Company protect, secure, perfect or insure any security interest or lien or any property subject thereto;
f. the benefit of any laws limiting the liability of a surety or any other circumstance that limits the liability of or exonerates a guarantor generally or provides any legal or equitable discharge of Guarantor's obligations hereunder;
g. other than demand for payment, any requirement of notices between Company and Seller including, without limitation, with respect to the PPA and this Guaranty, notice of acceptance of this Guaranty, any notice of credits extended and sales made by Seller to Company, any information regarding Seller's financial condition, and all other notices whatsoever;
h. any duty of Company to disclose to Guarantor any facts concerning Seller, the PPA or the Facility, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and
i. until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the PPA. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

a. Guarantor is a [corporation], duly organized, validly existing, and in good standing under the laws of the state of its [incorporation]. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.
b. The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency . This Guaranty has been duly and validly executed and delivered by Guarantor

and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor hereby agrees to pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor. Guarantor shall have no right to assign this Guaranty or its obligations hereunder without the prior written consent of Company, which consent may be withheld in its sole discretion. Company shall have the right to assign this Guaranty to any person or entity without the prior written consent of Guarantor; *provided*, *however*, that no such assignment shall be binding upon Guarantor until it receives written notice of such assignment from Company.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of Colorado without regard to the principles of conflicts of law thereof. Guarantor hereby submits to the exclusive jurisdiction in the federal and state courts of the State of Colorado, and venue is hereby stipulated as Denver, Colorado. Guarantor waives any claim or defense that such action or proceeding brought in any such court is an inconvenient forum, any objection to venue with respect to such action or proceeding, and any right of jurisdiction on the account of the place of residence or domicile of the Guarantor.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the PPA, addressed as follows:

if to Company: Tri-State Generation and Transmission Association, Inc.
1100 W. 116th Avenue
Westminster, CO 80234
Attn: Senior Vice President and Chief Financial Officer
Phone: (303) 452-6111

if to Guarantor: _____
_____
_____
Attn:
Phone: (___) _____

or to such other address(es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20__, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires:_____.

_____
Notary Public

(S E A L)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit FF: PRPA, *Craig Units 1&2 (Yampa Project)* (2026)

Craig units 1 & 2 (Yampa Project)

Fuel type: coal
Net capacity: 151 MW
Commercial operation: Unit 1—1980; Unit 2—1979
Operations: baseload

Operations

- Platte River's ownership of Craig 1 and 2 is 18%
- Operated by Tri-State Generation and Transmission
- Co-owners include Tri-State Generation and Transmission, Salt River Project, PacifiCorp and Xcel Energy
- Craig Unit 1 to be removed from Platte River's mix by Dec. 31, 2025
- Craig Unit 2 to be removed from Platte River's mix by Sept. 30, 2028

Financials

- Platte River's second-lowest operating cost resource
- Fuel prices are based on production costs and not subject to market price volatility
- No debt service
- Fuel cost volatility mitigated by management of mine production levels and costs through an ownership share of Trapper Mine (27.14%), located adjacent to Craig units 1 and 2

Environmental

- Upgraded technology to reduce sulfur and particulate emissions
- Maintains full compliance with strict environmental laws and regulations

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit G: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1
(Tri-State, *Responsible Energy Plan* (Jan. 2020)

Released January 2020

TRI-STATE

RESPONSIBLE ENERGY PLAN

RESPONSIBLE TO OUR EMPLOYEES, OUR MEMBERS, OUR COMMUNITIES, AND OUR ENVIRONMENT

Cooperative power. Transformed.

Colorado PUC E-Filings System

To learn more about our Responsible Energy Plan, visit **www.tristate.coop**

A Touchstone Energy® Cooperative

TRI-STATE

Tri-State Generation and Transmission Association Responsible Energy Plan

Responsible to our employees, our members, our communities, and our environment

At Tri-State, we're implementing a clean energy transition that will expand renewable generation and reduce greenhouse gas emissions while ensuring reliable, affordable, responsible electricity for our member cooperatives and public power districts, and for the communities they serve. Our Responsible Energy Plan (REP) is based on a vision for the future in which the benefits of an economy-wide energy transition – from cleaner air to economic opportunity to a greener grid – are shared with everyone.

As a cooperative, we're owned and governed by our members, and we're accountable to them and their retail consumers. Our member-comprised board of directors established in July 2019 that our cooperative would pursue a transition to a cleaner energy portfolio by developing a Responsible Energy Plan. The board set a goal for our cooperative to comply with all applicable environmental and renewable energy requirements while striving to reduce members' rates, preserve electricity reliability and affordability, and maintain financial strength. We've been working together since then to develop a REP that reflects this direction. Our plan is also informed by input from a collaboration with an external advisory group – convened and facilitated by Colorado Governor Bill Ritter and the Center for the New Energy Economy – composed of stakeholders gathered from across the region and across interests.

Our Responsible Energy Plan allows Tri-State to work toward the commitments and goals that follow and be responsible to our employees, our members, our communities, and our environment.

While this energy transition comes with challenges, we are confident that by working together and maintaining our commitment to our mission — to provide reliable, affordable, responsible power to our members — we can make it a success.

Tri-State's Responsible Energy Plan outlines an energy transition that makes it possible for us to deliver on our mission while achieving compliance with state and federal regulations. It will ensure significant emission reductions while maintaining our strong financial position and competitive rates in all four states we serve. As a cooperative wholesale electricity provider serving, owned by and governed by members in Colorado, Nebraska, New Mexico, and Wyoming, this regional view was a key consideration as we developed this plan and determined how we would accomplish the commitments and goals we identified.

REDUCING EMISSIONS

We're eliminating 100% of emissions from our New Mexico coal facilities by closing Escalante Station by the end of 2020, and we're eliminating 100% of emissions from our Colorado coal facilities by closing Craig Station and the Colowyo Mine by 2030.

INCREASING CLEAN ENERGY

By 2024, we're bringing over 1 gigawatt of wind and solar resources online, meaning 50% of the energy our cooperative consumes will come from renewables.

INCREASING MEMBER FLEXIBILITY

Our members are working together to increase contract flexibility and options to develop more local renewable generation.

EXTENDING THE BENEFITS OF A CLEAN GRID

We're helping consumers save money and reduce emissions.

COMMITTING TO COMMUNITY AND EMPLOYEES

We're committed to supporting employee and community transition.

LOOKING FORWARD TO A BRIGHTER FUTURE

We're working together to bring this bright future and clean grid in reach.

Tri-State Generation and Transmission Association is a not-for-profit wholesale electric cooperative association of 45 members, including 42 electric distribution cooperatives and public power districts across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State and our members power more than a million predominantly rural consumers across nearly 200,000 square miles of the West — an area greater than California.

Our mission is to provide our member systems a reliable, affordable and responsible supply of electricity in accordance with cooperative principles.

REDUCING EMISSIONS

In New Mexico, we're committing to a 100% reduction in emissions from coal generation by closing Escalante Station by the end of 2020, in support of New Mexico's SB19-489 zero carbon by 2050 goal

In Colorado, we're committing to a 100% reduction in emissions from coal generation by closing Craig Station and the Colowyo Mine by 2030, in support of Colorado's HB19-1261 emission reduction goals

In Colorado, we anticipate working with the General Assembly to achieve, by 2030 and relative to 2005 levels:

- **A 90% reduction in CO_2 emissions across the generation facilities we own or operate in Colorado, and**
- **A 70% reduction in CO_2 emissions associated with Colorado wholesale electric sales**

We're committing not to add more coal to our system

Our cooperative is working to shift our generation portfolio to cleaner energy sources to meet member demand, comply with environmental regulations in Colorado and New Mexico, and in response to a changing energy landscape. We believe it is possible to provide reliable, affordable, responsible power to our members while implementing these emission reduction steps to meet broader public policy goals. With engagement and support from partners like the Colorado General Assembly and other natural resource stakeholders, we can achieve an efficient, cost-effective and equitable transition.

KEY STEPS:

- **Retire Escalante Generating Station by the end of 2020**
- **Retire Craig Station Unit 1 by the end of 2025**
- **Retire Craig Station Units 2 & 3 and the Colowyo Mine by 2030**
- **Cancel the Holcomb Station coal expansion project**

ADVISORY GROUP

To develop our REP commitments, we collaborated with a diverse advisory group, facilitated by Colorado State University's Center for the New Energy Economy (CNEE) and Colorado Governor Bill Ritter, on key elements regarding emission reductions. This group included representatives from across the states Tri-State serves from academic, agricultural, cooperative, electric industry, environmental, rural, and state and local government groups. These advisors gathered to learn with us, share with us, challenge us, and roll up their sleeves to work with us on some of the details that will make our energy transition vision a reality. We are grateful to Governor Ritter and the CNEE advisory group participants for their good-faith contributions and efforts to find common ground in the pursuit of ambitious but actionable commitments and challenging but attainable goals, as reflected here.

CNEE ADVISORY GROUP INVITEES

- Dan Arvizu, New Mexico State University
- Kim Christiansen, Nebraska Rural Electric Association
- Bob Easton, Western Area Power Administration (retired)
- Howard Geller, Southwest Energy Efficiency Project
- Megan Gilman, Holy Cross Energy Board
- Keven Groenewold, New Mexico Rural Electric Cooperative Association
- Renny MacKay, Wyoming Governor's Office
- Jim Macy, Nebraska Department of Environment & Energy
- John Nielsen, Western Resource Advocates
- Sarah Cottrell Propst, New Mexico Department of Energy, Minerals & Natural Resources
- John Putnam, Colorado Department of Public Health & Environment
- Kent Singer, Colorado Rural Electric Association
- John Stulp, Agriculture & Rural Communities Representative
- John Swartout, Colorado Counties, Inc.
- Shawn Taylor, Wyoming Rural Electric Association
- Will Toor, Colorado Energy Office
- Colorado Public Utilities Commission (PUC) observed

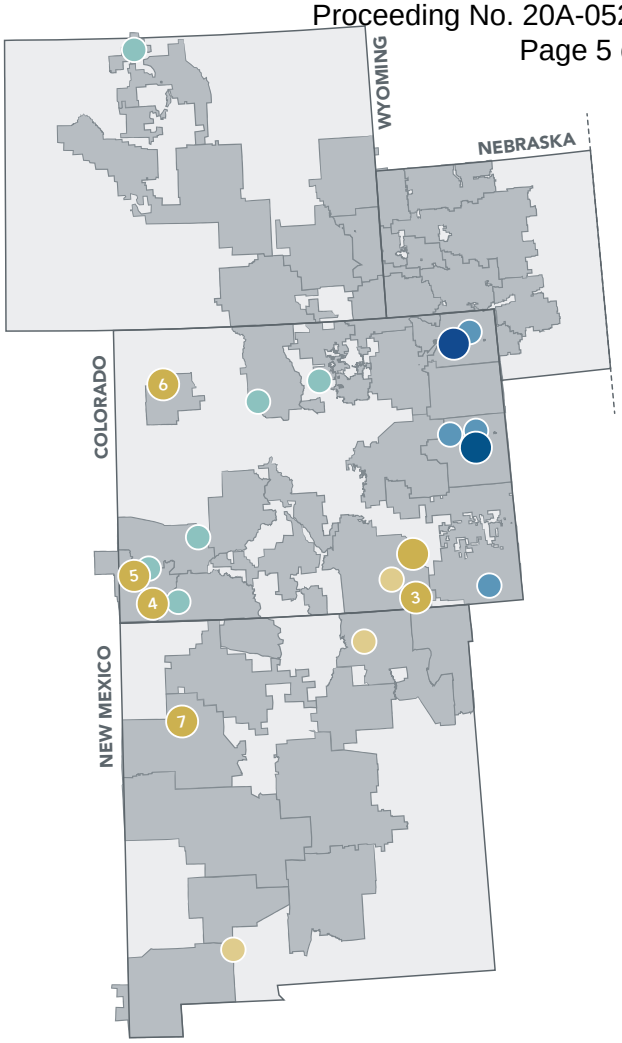
INCREASING CLEAN ENERGY

By 2024, 50% of the energy our cooperative consumes will come from renewable resources

Our members have asked for more renewable resources, so as we accelerate retirement of our coal generation, we're replacing it with clean energy in locations across our members' service territories. To start, we're adding six utility-scale solar projects and two utility-scale wind projects, bringing our system up to over 2 gigawatts of renewables by 2024. This will include the most solar of any cooperative in the nation.

KEY STEPS

- **Bring over 1 gigawatt of additional utility-scale renewable wind and solar projects online by 2024 in seven of our members' service territories — enough to power nearly 850,000 homes**



Projects coming online by 2024

1. Niyol Wind, 200 MW
2. Crossing Trails Wind, 104 MW
3. Spanish Peaks II Solar, 40 MW
4. Coyote Gulch Solar, 120 MW
5. Dolores Canyon Solar, 110 MW
6. Axial Basin Solar, 145 MW
7. Escalante Solar, 200 MW
8. Spanish Peaks Solar, 100 MW

Existing Wind
367 MW total

Existing Solar
85 MW total

Existing Hydro
26.56 MW small hydro total, plus WAPA allocations

INCREASING MEMBER FLEXIBILITY

Our members are working together to develop a more flexible contract structure so they can self-generate more renewable energy than ever before

We're making it more affordable for members that choose to self-generate to take advantage of that opportunity

In April 2019, our members voted to pursue changes to their contracts with Tri-State and each other to make it possible to locally generate more than 5% of their energy, as previously agreed. By the end of 2019, we implemented a provision so members have the option to build community solar to serve an additional 2 megawatts or 2% of their consumption.

In April 2020, we expect the member-comprised contract committee that has been reviewing flexible contract and self-generation options to make their recommendations to the Tri-State Board of Directors so they can vote on their preferred changes and we can implement those adjustments.

KEY STEPS

- **Implement the board's decision regarding partial-requirements contracts and additional self-generation**
- **Partner with a solar and energy services provider to make local renewables easier and more affordable to build**

EXTENDING THE BENEFITS OF A CLEAN GRID

We're committing nearly $2 million to extend the electric vehicle (EV) charging network across our members' service territories and are otherwise promoting EVs and EV solutions in rural areas

We're expanding programs to help consumers save money and energy while cutting emissions through energy efficiency (EE), beneficial electrification (BE) and other initiatives

As we rapidly transition to power the grid with clean energy, there are more and more opportunities to power products with low-cost, reduced-emission electricity. These are some of the exciting benefits of the energy transition, but not all of them are readily available to the rural communities we serve. An electric vehicle (EV), for example, will only take you as far as there's a place to charge it, and there aren't any charging stations in a lot of rural areas. That's why we're working with our members to expand the regional EV charging network by allocating each member $45,000 to install charging stations in their service territories. Access to these charging facilities will give rural consumers the option to choose EVs the next time they buy vehicles by making charging available in their communities. It will also substantially expand the regional and state EV charging networks for everyone to use.

We're committing to expand more of the benefits of a clean grid than just access to EVs and charging. We know beneficial electrification (BE) can save consumers money at the same time that it lowers emissions. We know energy efficiency (EE) can lower energy bills and energy use, and demand-side management (DSM) can lower the total amount of energy we all use so we don't need as many resources to meet our

combined power needs. Together, this suite of tools can make it possible for all of us to enjoy energy savings – on our power bills through lower costs and out on the grid through lower demand and emissions. Tri-State is studying how much those savings might be, and how we can share more of them.

KEY STEPS

- **Allocate $45,000 per member — nearly $2 million in total — to install EV charging stations in their service territories, and promote solutions to increase rural EV usage and equity**
- **Promote BE, EE and DSM and study opportunities to bolster programs, like through support of the Beneficial Electrification League of Colorado and other state chapters**
- **In Colorado, study potential emissions reductions associated with BE**

COMMITTING TO COMMUNITY AND EMPLOYEES

We're providing retraining and transition support for employees affected by these changes

We're committed to working with impacted communities to find meaningful economic development opportunities

We're working with local, state and federal leaders to support a truly just transition from coal

Our REP will change Tri-State as a cooperative, including by directly impacting nearly half of our employees and many of the communities in which they live and work. After their commitment to keeping the lights on for all of us, Tri-State is committing to help them better-manage the challenges of the transition.

KEY STEPS

- For Escalante employees, offer generous severance packages, options to apply to positions at other Tri-State facilities, assistance for financial planning and education, and supplemental funding for health benefits
- For the Escalante area, contribute a $5 million financial package to invest in community development and execute a new $200 million solar project on Escalante Station property
- For Craig Station, the Colowyo Mine and the surrounding areas, work with employees and community members to develop and begin to implement economic development, retraining and other strategies to ease the transition over time, including executing a new solar project on the Colowyo Mine property
- Work with local, state, federal, and industry leaders to develop, fund and implement retraining, educational and economic development solutions in addition to those we provide

LOOKING FORWARD TO A BRIGHTER FUTURE

We're striving for 100% clean energy in Colorado by 2040, and will outline steps for 2030-2040 reflecting our effort to achieve that goal in our 2024 resource plan for the Colorado PUC

We're striving to maintain or reduce rates for members in all states we serve as we implement the REP

We're promoting a western Regional Transmission Organization (RTO) to efficiently and cost-effectively integrate more renewables into the grid

Our REP, like the broader energy transition, is dynamic. Expectations and goals, not to mention technologies and costs, are always changing, and we expect that our REP will change, too. While we work to accomplish the initiatives outlined here, we know we will add more in our pursuit of delivering on our mission: to provide reliable, affordable and responsible power to our members.

We all use electricity, and we are all part of the energy transition. How we all work together to achieve this transition is what will make the difference to the people who provide electricity for us all to use. We will all enjoy the benefits of this energy transition. Imagine what we can accomplish if we all work together to lessen its negative impacts.

We are energized by the potential of this transition, even as we work to manage the challenges that remain. To be able to efficiently, cost-effectively and equitably implement this REP and a broader energy transition, there's an immediate need to work together on solutions that achieve:

- **Dedicated and meaningful support for transitioning communities,** so communities that lose employment, tax and royalty payments, and other benefits associated with existing generation and production facilities don't have to carry the weight of the transition alone.
- **Treatment for cooperative debt and stranded assets,** so cooperative associations can retire coal generation and add renewables in accordance with state regulations without endangering financial stability.
- **The formation of an RTO,** to secure electricity reliability and affordability while transitioning to a clean grid in a cost-effective and efficient manner.
- **Streamlined siting and permitting for necessary infrastructure,** to be able to build transmission and generation infrastructure that meets the time and cost expectations of the clean energy transition.

The REP will have regional impacts, and consideration of these impacts is paramount to Tri-State because our 42 utility members serve more than a million consumers across four states, and this plan changes our cooperative. It will directly impact almost half of our employees. It will require significant investment and disinvestment decisions. If we work together it will also ensure significant emission reductions, a strong financial position, predictable flat to reduced member rates in all states, and create as much time as possible for us, our employees and communities to plan for the future.

Balancing these impacts will not be an easy task, but it is a necessary one, and Tri-State is committed to working with our employees, their communities and others across the region to smooth the effects of this transition. As a cooperative, we believe that if we work together, a bright future and clean grid is in reach.

Cooperative power. Transformed.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit GG: PacifiCorp, *Utah Integrated Resource Plan Volume I* (Mar. 31, 2025)

UTAH 2025
Integrated Resource Plan

Volume I - March 31, 2025

PacifiCorp

This 2025 Integrated Resource Plan is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
irp@pacificorp.com
www.pacificorp.com

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CHAPTER 13 – UTAH ACTION PLAN

CHAPTER 1 – EXECUTIVE SUMMARY

Maintaining customer focus

Our 2025 Integrated Resource Plan (IRP) is a roadmap for continual progress in safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.

- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

New Resources

- The following resources are added in the 2025 IRP:
  - 3,782 megawatts of new wind resources
  - 7,524 megawatts of storage resources, including four-hour, and 100-hour durations
  - 5,912 megawatts of new solar resources, including utility-scale and small-scale
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,255 megawatts of capacity saved through energy efficiency programs
- 769 megawatts of capacity saved through direct load control programs

Transmission

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Yakima substation near Yakima, Washington
- Various upgrades that increase transfer capability between the Summer Lake substation in Oregon and the Hemingway substation in Idaho

- New transmission, including a 110-mile line from Summer Lake to Burns, Oregon, and an 88-mile line from Summer Lake to the planned Full Circle substation in Central Oregon. These near-term upgrades connect with a later upgrade a new transmission line connecting Walla Walla to the Full Circle substation, expected in 2039.
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

Key Thermal Outcomes

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030 to comply with Wyoming's low carbon portfolio standard
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Initiate the process of coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are situs-allocated and deliverable to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[1] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements were represented:

- Utah, Idaho, Wyoming, and California (UIWC)[2]
  - Cost-effective resources
  - Includes WRAP compliance constraints for UIWC load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Includes WRAP compliance constraints for Oregon load
  - Includes small-scale renewable capacity requirement
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and assumed to be situs to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of this draft necessitated that coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off,

[1] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[2] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

PacifiCorp hosted stakeholders in nine online public input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 1.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2025 IRP Approach

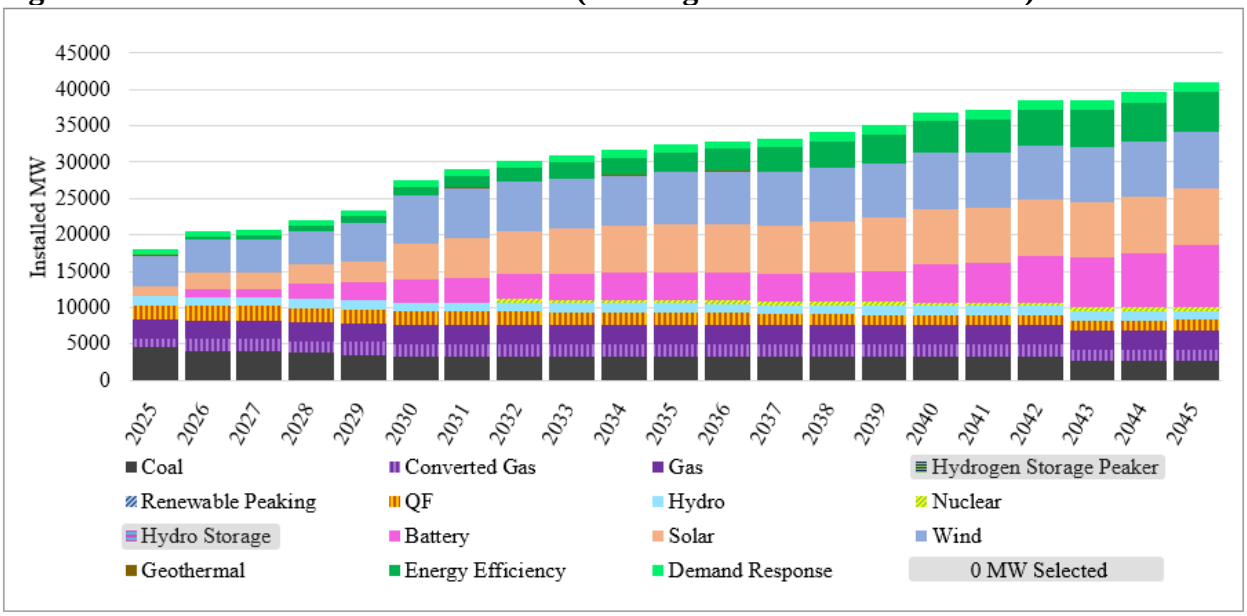
Preferred Portfolio Highlights

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and renewable peaking resources facilitated by incremental transmission investments.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the fall of 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912MW of new solar.

Figure 1.2 – 2025 IRP Preferred Portfolio (Existing and Planned Resources)*



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The 2025 IRP preferred portfolio includes several transmission upgrades which increase transfer capability between southern Utah and the Wasatch Front and between Walla Walla and Yakima in Washington, as well as a series of upgrades that increase transfer capability between the Hemingway substation in Idaho, the Summer Lake Substation in southern Oregon, the planned Full Circle substation in Deschutes County, Oregon, and eventually connecting from Full Circle to Walla Walla in Washington. Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 1.1 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio. Currently, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 1.1 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
	Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
	Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 2 Area 19: Summer Lake to Central Oregon 500 k	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032	Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total		**4,250**	**4,250**	**5,404**	**4,169**			

[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

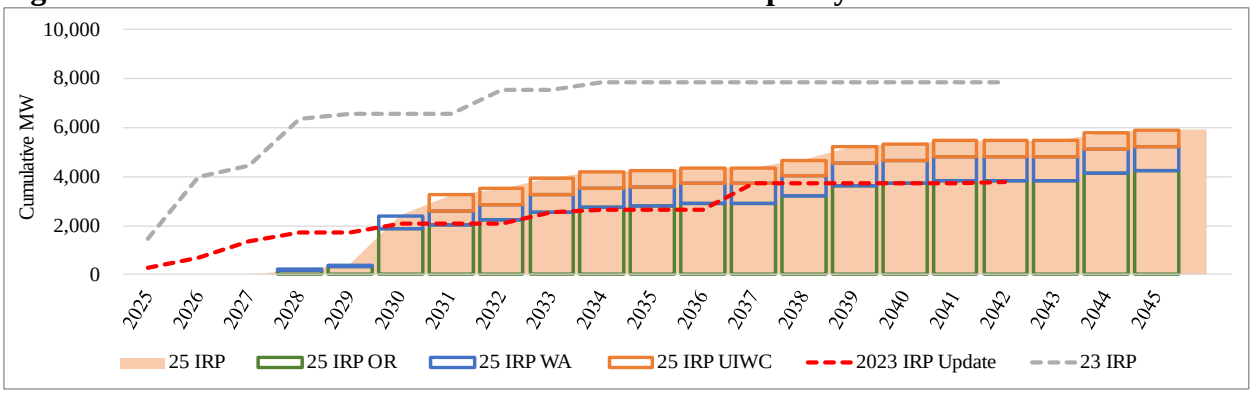
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

In Chapter 9 (Modeling and Portfolio Selection Results), a sensitivity analysis evaluates the impacts of significant new data center loads coming online in the 2027-2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 1.3.

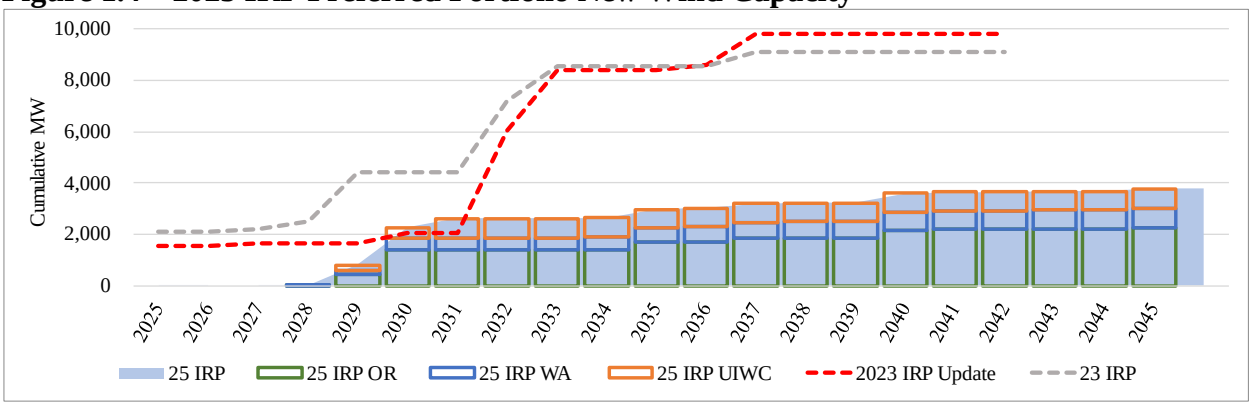
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

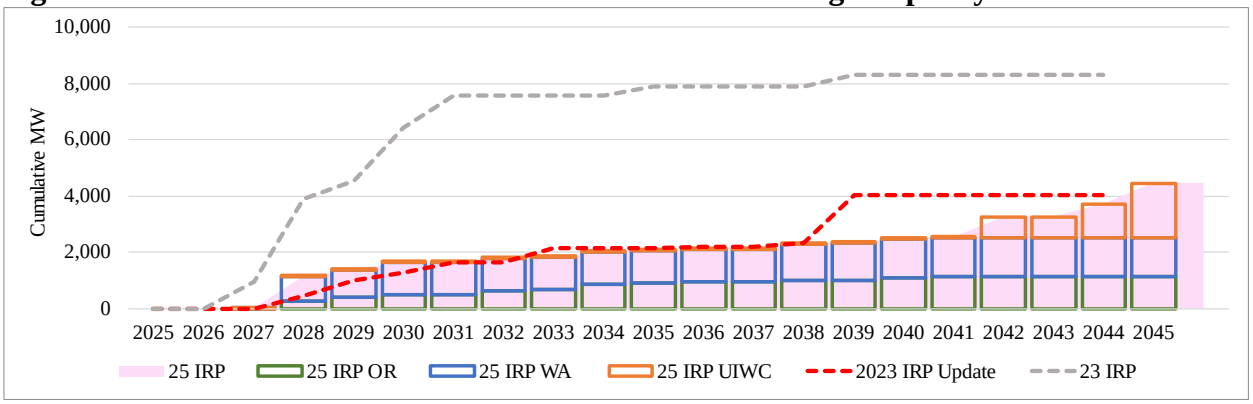
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

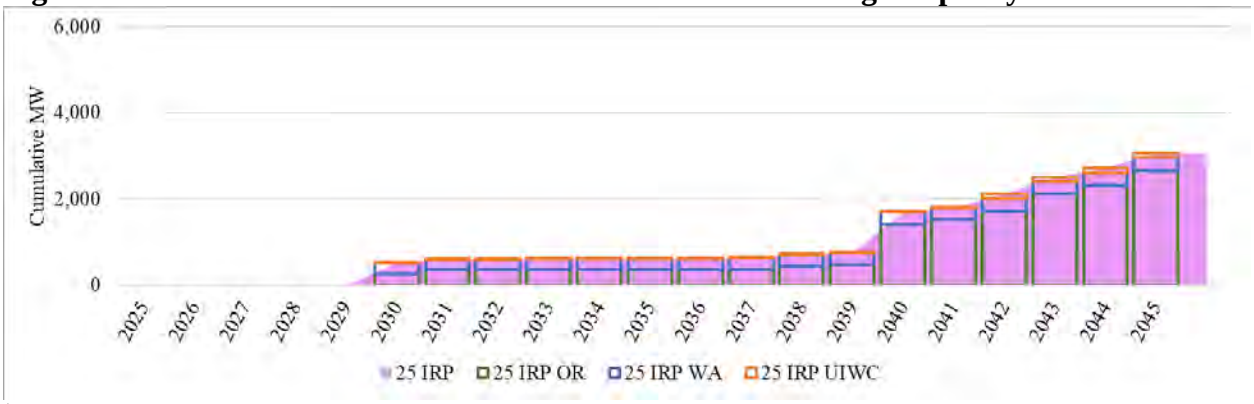
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of 100-hour iron air storage by the end of 2030, 616 MW by 2035 and 3,073 MW by 2045. Total storage selections, inclusive of both 4-hour and 100-hour resources, include a total of 7,524 MW of new storage.

Figure 1.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 1.5 include a minimal amount of intermediate duration storage.

Figure 1.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]

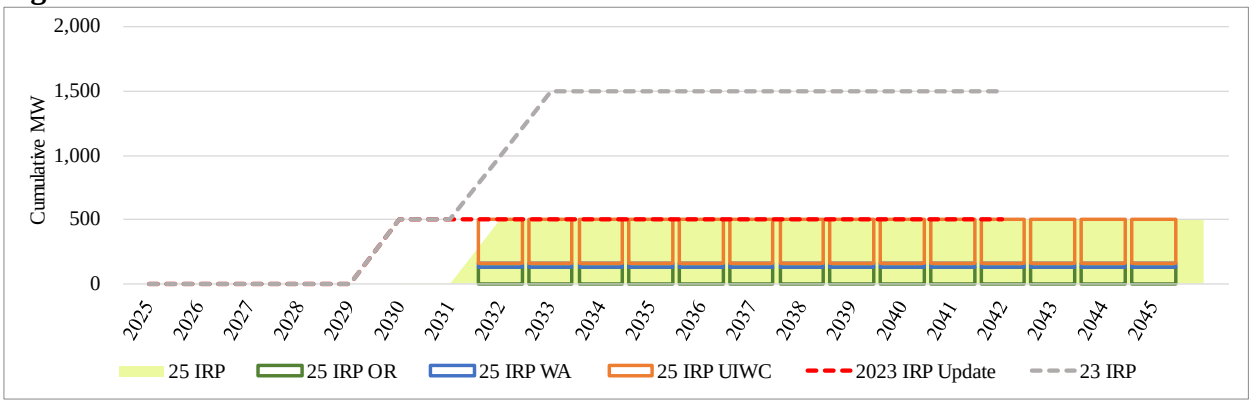


[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7 , the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031.

Figure 1. – 2025 IRP New Nuclear[1]



[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

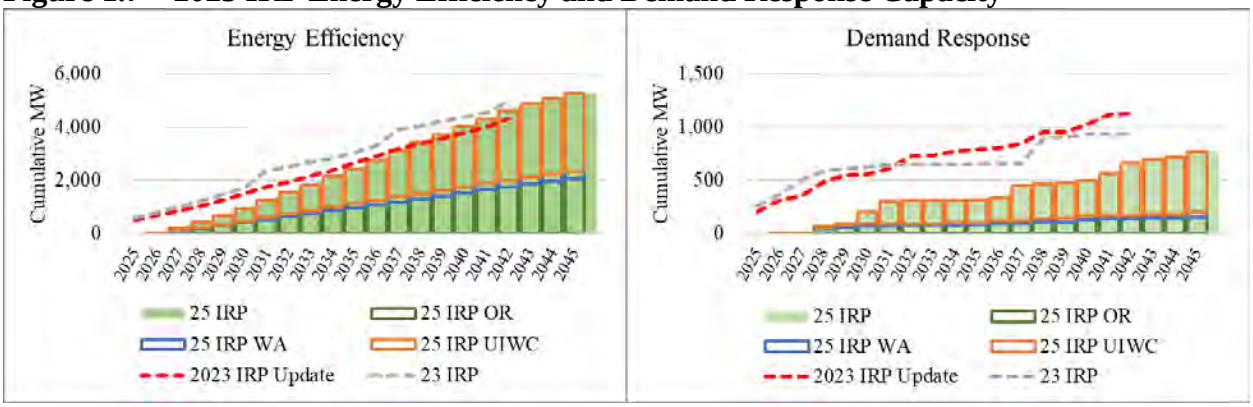
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

and forecasted coincident system peak is down 5.3 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.28 percent for load and 1.18 percent for peak. Changes to PacifiCorp's load forecast are driven by a shift in the 2025 IRP in which demand from new large customers is no longer included in the load forecast as those customers are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits. As shown in Figure 1.8, both energy efficiency and demand response show a lower trajectory in the latest forecast, however the trajectories continue to trend upward across the long-term planning horizon.

- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
  - 610 megawatts of energy efficiency from 2025 through 2028
  - 83 megawatts of demand response from 2025 through 2028

Figure 1.7 – 2025 IRP Energy Efficiency and Demand Response Capacity

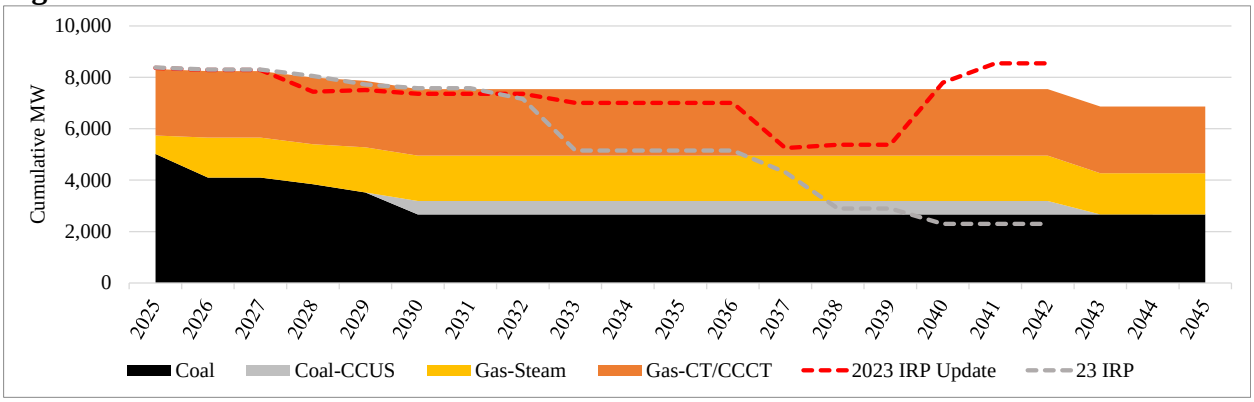


Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled the company to reduce fuel consumption and associated costs and emissions and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 1.9, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, exits PacifiCorp's share in 386

MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 1. – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP preferred portfolio is shown in Table 1.2. Also shown in Table 1.2 are the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

Table 1.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

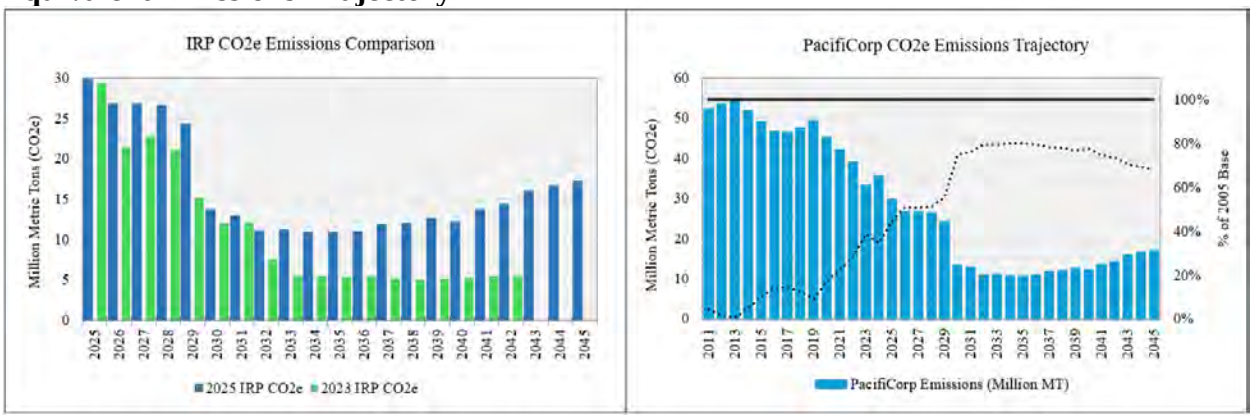
Carbon Dioxide Emissions

The 2025 IRP preferred portfolio demonstrates PacifiCorp's ongoing commitment to providing cost-effective clean energy solutions for its customers, continuing a trend of declining carbon dioxide (CO_2) and CO_2 equivalent (CO_2e) emissions over the next decade. Key drivers of this decline include PacifiCorp's participation in the Energy Imbalance Market (EIM), the ongoing transition to clean energy resources such as renewables, advanced nuclear, battery storage, and transmission, as well as compliance with Regional Haze regulations.

The chart on the left in Figure 1.10 compares projected annual CO_2e emissions between the 2025 IRP and 2023 IRP preferred portfolios. While the 2025 IRP emissions are projected to be slightly higher than those in the 2023 IRP, this difference stems from updates to modeling assumptions. The expected price-policy scenario in the 2025 IRP does not include a CO_2 price or the Ozone Transport Rule, both of which were included in the 2023 IRP. Increased emissions also result from higher unspecified market purchases, assigned a default emissions factor, although market-wide emissions are expected to decline with further renewable energy adoption. PacifiCorp is working with regulators to adjust this factor to reflect the evolving energy market landscape.

The chart on the right in Figure 1.10 presents historical emissions data, assigning emissions to unspecified market purchases, and indicates a long-term decline in system-wide CO2e emissions compared to the company's baseline, with a slight increase toward the end of the planning horizon due to the factors discussed in more detail in Chapter 9.

Figure 1.8 – 2025 IRP Preferred Portfolio CO_2 Equivalent Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed.

Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 1.3 details specific 2025 IRP action items by resource category.

Table 1.3 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**Regional Haze Compliance:** Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

1f	**Natrium™ Demonstration Project:** By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	**Ozone Transport Rule Compliance:** EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process. Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.

PacifiCorp will pursue cost-effective energy efficiency resources.

Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)
2025	595	92
2026	573	89
2027	597	209
2028	648	220

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

Year	Annual Incremental Capacity (MW)
2025	18
2026	2
2027	0
2028	63

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

Action Item	5. Market Purchases
5a	**Market Purchases:** PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

CHAPTER HIGHLIGHTS

- PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California.
- This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest.
- Regulatory staff, advocacy groups, and other interested parties influence the development of the IRP through a collaborative public input process.
- As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are made by PacifiCorp with respect to its obligations to customers, regulators, and shareholders.

INTRODUCTION

In recent integrated resource planning cycles, there has been increased focus on individual state jurisdictional outcomes aligned with both stakeholder and regulatory interest, and state legislation and rulemaking. To recognize and respect this trend, PacifiCorp's 2025 IRP enhances jurisdictional portfolio development and reporting leading to the integration of results into the preferred portfolio. Chapter 8 (Modeling and Portfolio Evaluation) describes the fundamental methodologies used to arrive at state-level initial portfolios and how they are subsequently integrated to form a single coherent plan.

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Chapter 9 (Modeling and Portfolio Selection Results), shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources (including iron-air technology with 100- hour storage duration), and advanced nuclear.[1]

The 2025 IRP preferred portfolio is in addition to contracted resources, many of which are in Utah. The 100 MW Hornshadow I Solar and 200 MW Hornshadow Solar II facilities are set to come online in 2025, while two facilities combining solar and storage are set to come online in 2025 and 2026: Faraday with 525 MW solar and 150 MW storage and Green River with 400 MW solar and 400 MW storage. Finally, Oregon's Community Solar Program has ten small-scale solar facilities scheduled to come online in 2025 and 2026, totaling approximately 18 MW.

The 2025 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 5,492 MW of new solar and 7,668 MW of new storage resources.

New storage includes five battery facilities totaling 520 MW are projected to come online ahead of the peak summer season in 2026: Dominguez BESS (200 MW), Enterprise BESS (80 MW),

[1] See Chapter 7 (Resource Options)

Escalante BESS (80 MW), Granite Mountain BESS (80 MW) and Iron Springs BESS (80 MW). These signed battery storage contracts were committed since the filing of the 2023 IRP update.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission projects which are described in Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant analysis to support the 2025 IRP includes:

- An updated demand-side management resource conservation potential assessment
- A distributed generation study for PacifiCorp's service territory
- A flexible reserve study
- An updated plant water consumption study
- An energy storage potential evaluation
- An assessment of grid enhancement technologies
- Historic weather years
- An updated load and resource balance

This chapter outlines the components of the 2025 IRP, summarizes the role of the IRP, and provides an overview of the public input process.

2025 Integrated Resource Plan Components

The basic components of PacifiCorp's 2025 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities; Volume I, Chapter 4 (Transmission)
- Regional resource adequacy assessments, wildfire mitigation planning and the role of transmission in system reliability and incident recovery; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance)
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options)
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results)
- Presentation of PacifiCorp's 2025 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan)

The IRP appendices, included as Volume II, contain the items listed below:

- Load Forecast (Volume II, Appendix A)
- Regulatory Compliance (Volume II, Appendix B)
- Public Input Process (Volume II, Appendix C)
- Demand-Side Management (Volume II, Appendix D)
- Grid Enhancement (Volume II, Appendix E)
- Flexible Reserve Study (Volume II, Appendix F)
- Plant Water Consumption Study (Volume II, Appendix G)
- Stochastics (Volume II, Appendix H)
- Capacity Expansion Results (Volume II, Appendix I)
- Capacity Contribution (Volume II, Appendix K)
- Distributed Generation Study (Volume II, Appendix L)
- Stakeholder Feedback Forms (Volume II, Appendix M)
- Washington Clean Energy Action Plan (Volume II, Appendix O)
- Oregon Clean Energy Update (Volume II, Appendix P)
- Renewable Portfolio Implementation Plan (Volume II, Appendix R)
- Acronyms (Volume II, Appendix Z)

PacifiCorp is also providing supporting workpapers for the 2025 IRP. These electronically provided materials support and provide additional details for the analysis described within the document. Supporting workpapers are generated for public, confidential, and highly confidential data to be provided as appropriate to each recipient. Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. The "Highly Confidential" workpaper category, adopted in the prior 2023 IRP planning cycle, allows the company to provide the maximum amount of access to parties who are not participants in commercial developments or otherwise have direct conflicts of interest regarding commercially sensitive information.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP establishes a proxy resource plan capable delivering adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[2] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

[2] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long-run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Public Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized held nine public input meetings, spanning one or two days each, to facilitate information sharing, collaboration, and expectations for the 2025 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage is accessible using the following link:

www.pacificorp.com/energy/integrated-resource-plan.html

Messages relevant to PacifiCorp's IRP can sent to the following email address:

irp@pacificorp.com

Additionally, a stakeholder feedback form provides opportunities for stakeholders to submit additional input and ask questions throughout the 2025 IRP public input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website:

www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summaries of stakeholder feedback forms received, and company responses were provided throughout the public input meeting series and are also available in Appendix M (Stakeholder Feedback Forms). In the 2025 IRP, links to stakeholder feedback forms are provided in footnotes to further tie together stakeholder feedback with the development of the filed IRP. Appendix C (Public Input Process) reports additional details regarding engagement for the 2025 IRP.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. Flexible generation, transmission, new storage technologies, and market design changes will need to better integrate these resources into the grid.
- The federal Inflation Reduction Act (IRA) was enacted on August 16, 2022,, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2025 IRP studies. As of December 2024, the future of some provisions of the IRA remains unknown under the new administration.
- 2024 saw significant new environmental regulation with potential impacts to PacifiCorp's generation resources. These included Greenhouse Gas (GHG) emission standards for existing coal-fired and new gas-fired plants, Mercury and Air Toxics Standards (MATS) revisions, Effluent Limitations Guidelines revisions, Coal Combustion Residuals legacy rule, and the NEPA Phase 2 rule.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of retail electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its inaugural Clean Energy Implementation Plan (CEIP) in December 2021, and expects to file its second CEIP in October 2025, detailing the company's action plan for the next four-year period.
- In 2021, Washington passed the Climate Commitment Act, which established a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2025 IRP includes modeling to support House Bill 2021 which will be expanded upon in PacifiCorp's Oregon Clean Energy Plan submission to be filed within 180 days of the 2025 IRP.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM's footprint has grown significantly, generating $3.4 billion in monetary benefits to customers of participating entities. ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing

authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

Introduction

This chapter profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the role of emerging technologies, and the net costs of renewables and battery technologies also factor into the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system operates in conjunction with a multifaceted market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers' expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits and improved technology performance have continued to place wind and solar energy generators "in the money" in areas of high resource potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, evolving storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These transmission lines ultimately connect areas of high renewable energy potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project, brought in-service in late 2024. These transmission projects will provide greater system-wide flexibility transferring energy from Wyoming to load centers located in Utah.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. As of 2022, nine states had implemented energy storage targets or mandates, with action being considered in at least one other.[1] In California, the Elkhorn Battery project became fully operational for Pacific Gas & Electric (PG&E) in April of 2022. The Moss Landing project in Monterey County includes 182.5 MW of Tesla Megapack energy storage.[2] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Utah, Hawaii, Arizona, Nevada, California, and Texas.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[3]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barriers to the participation of electric storage resources in certain organized wholesale markets. PacifiCorp continues to evaluate the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance Market (EIM). The EIM became operational November 1, 2014, and since that time has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho

[1] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.
[2] In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; PG&E ushers in landmark Tesla battery energy storage system at Moss Landing (mercurynews.com)
[3] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico, Avista Utilities, Tucson Electric Power, Turlock Irrigation District, Tacoma Power, Bonneville Power Administration, Avangrid Renewables, El Paso Electric, and Western Area Power Administration join the EIM. Black Hills Power plans to join the EIM in 2026. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Extended Day-Ahead Market (EDAM), which is currently in the phase of implementation activities and expected to onboard participants in 2026.

As with all markets, electricity markets face a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented 24.1% decline in marketed natural gas production in Texas, a drop of 186.7 billion cubic feet (Bcf) compared to the previous month. This decline contributed to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

The Western United States experienced an excessive heat event during the first week of September 2022. As a result, record temperatures were recorded on September 4th through September 7th, reaching as high as 114º F in Sacramento, California, 110º F in Burbank, California, and 107º F in Salt Lake City, Utah. With these record setting temperatures, the West saw a widespread surge in electricity demand and correspondingly tight supply conditions. Maintaining reliability across the region during this period was a testament to the benefits of energy markets, geographic diversity across the West, and conservation efforts during extreme heat events.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability, and any number of data services are available that track the status of new resource additions[4]. In NERC's latest release, the WECC region was classified as "elevated risk", in which shortfalls may occur in extreme conditions.

The Western Resource Adequacy Program (WRAP)[5] will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

[4] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment
[5] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan's decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon because of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2025 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies which drive additional costs and restrictions of emissions. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

Power Market Prices

Mild weather, strong production, and limited exports caused high storage levels in the fossil gas market, resulting in low gas prices throughout 2024. Low fuel prices coupled with mild demand led to an annually averaged 34% decrease in on-peak spot prices across the Non-CAISO WECC trading hubs in 2024, as seen in Table 3.1.

Table 3.1 - 2023 and 2024 Monthly Average On-Peak Spot Prices ($/MWh)

Month	2023	2024	Difference	Percent
Jan	135.23	137.27	2.05	2%
Feb	84.41	41.95	-42.46	-50%
Mar	76.51	25.05	-51.46	-67%
Apr	79.53	18.57	-60.97	-77%
May	21.60	20.48	-1.13	-5%
Jun	38.87	31.13	-7.74	-20%
Jul	93.02	67.88	-25.13	-27%
Aug	88.59	48.50	-40.09	-45%
Sep	51.76	52.55	0.78	2%
Oct	78.57	46.24	-32.33	-41%
Nov	70.90	35.19	-35.71	-50%
Dec	52.12	47.50	-4.62	-9%
Annual	**72.59**	**47.69**	**-24.90**	**-34%**

**As of December 16, 2024*

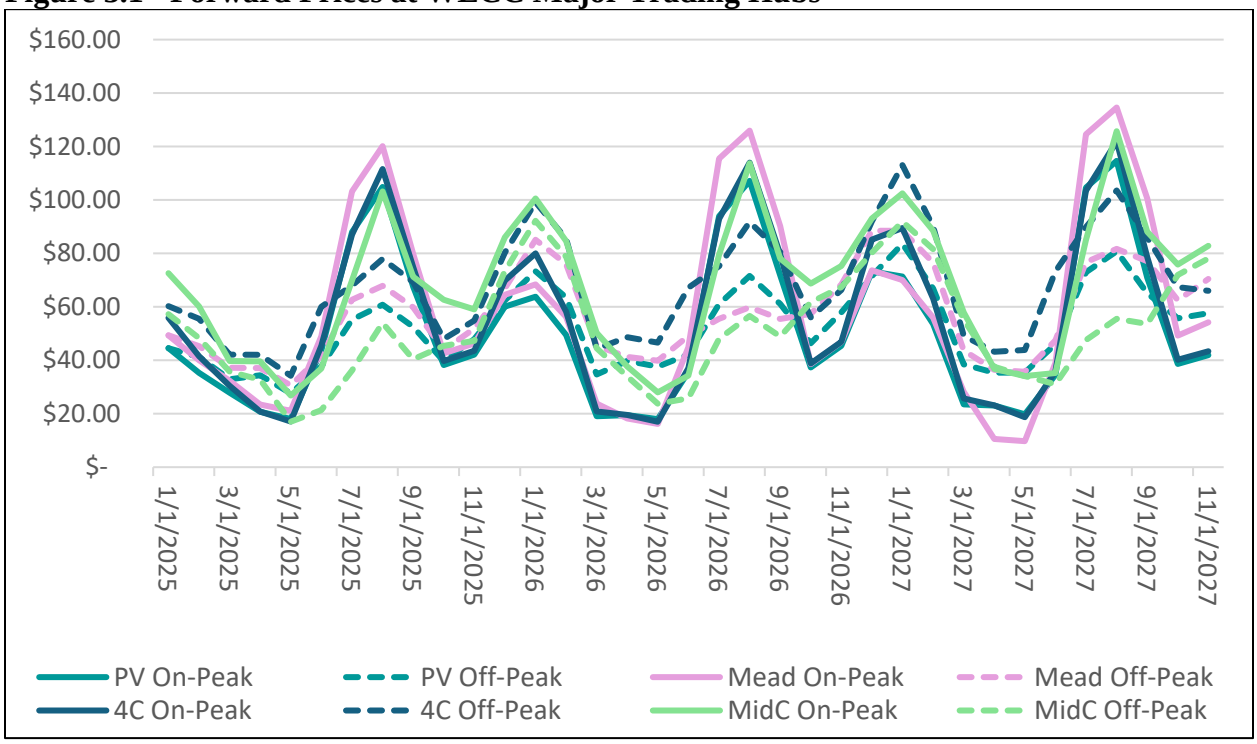
Source: SNL

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to increase slightly relative to 2024 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August

[6] California and Washington carbon allowance price forecasts are applied when appropriate. Washington allowance prices assumed the forecast published by Vivid Economics, commissioned by Washington Department of Ecology as part of its CCA Regulatory Impact Analysis for WAC 173-446, which was the best available information at the time of modeling. Available at https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

2025 On-Peak power prices at Palo Verde, Mead, Four Corners, and Mid-Columbia are all trading around $105-$120 per MWh.

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

Table 3.2 reports the quarterly on-peak and off-peak price spread across the major WECC hubs, driving the peaks and valleys observed in Figure 3.1 above.

Table 3.2 - 2025-2027 Forward Price Spread ($/MWh)

	Palo Verde		Mead		4 Corners		Mid-Columbia	
Date	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
1/1/2025	$ 44.57	$ 44.53	$ 49.32	$ 49.35	$ 55.87	$ 60.23	$ 72.60	$ 57.25
5/1/2025	$ 18.04	$ 27.62	$ 21.12	$ 30.62	$ 17.05	$ 34.20	$ 26.81	$ 17.02
8/1/2025	$104.89	$ 60.81	$120.14	$ 67.85	$111.56	$ 77.93	$103.20	$ 53.99
11/1/2025	$ 42.14	$ 47.94	$ 46.28	$ 51.86	$ 43.55	$ 54.89	$ 59.08	$ 47.28
1/1/2026	$ 63.81	$ 73.32	$ 68.41	$ 85.12	$ 79.99	$ 99.17	$100.52	$ 92.19
5/1/2026	$ 17.98	$ 37.62	$ 16.18	$ 39.84	$ 17.00	$ 46.59	$ 27.99	$ 23.71
8/1/2026	$107.13	$ 71.57	$125.96	$ 59.86	$113.94	$ 91.72	$113.74	$ 56.61
11/1/2026	$ 45.38	$ 57.92	$ 46.83	$ 68.32	$ 46.89	$ 66.32	$ 75.27	$ 67.37
1/1/2027	$ 71.36	$ 83.56	$ 70.01	$ 88.44	$ 89.44	$113.02	$102.48	$ 91.87
5/1/2027	$ 19.80	$ 35.40	$ 9.73	$ 35.70	$ 18.71	$ 43.83	$ 34.07	$ 34.10
8/1/2027	$114.63	$ 80.80	$134.58	$ 81.71	$121.91	$103.55	$125.72	$ 55.51
11/1/2027	$ 41.95	$ 57.62	$ 54.19	$ 70.41	$ 43.35	$ 65.97	$ 82.83	$ 78.10

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

The generation mix in the non-CAISO WECC region reflects the influence of state RPS (renewable portfolio standard) and emissions policies. In 2023, natural gas resources provided about 31% of generated energy followed by hydro at 22%, coal at 18%, and wind at 12%. Natural gas and coal share is expected to decrease slightly, with non-hydro renewables expected to replace this energy throughout 2030.

Figure 3.2 - National RPS Targets

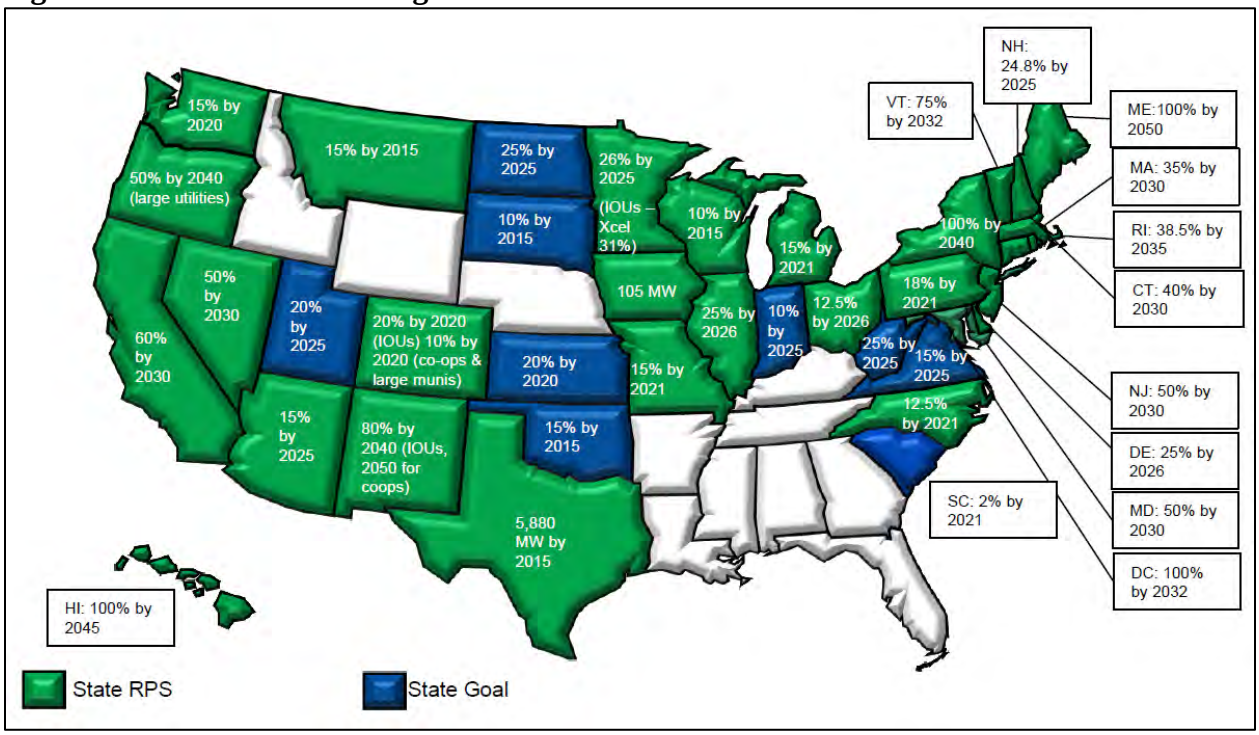
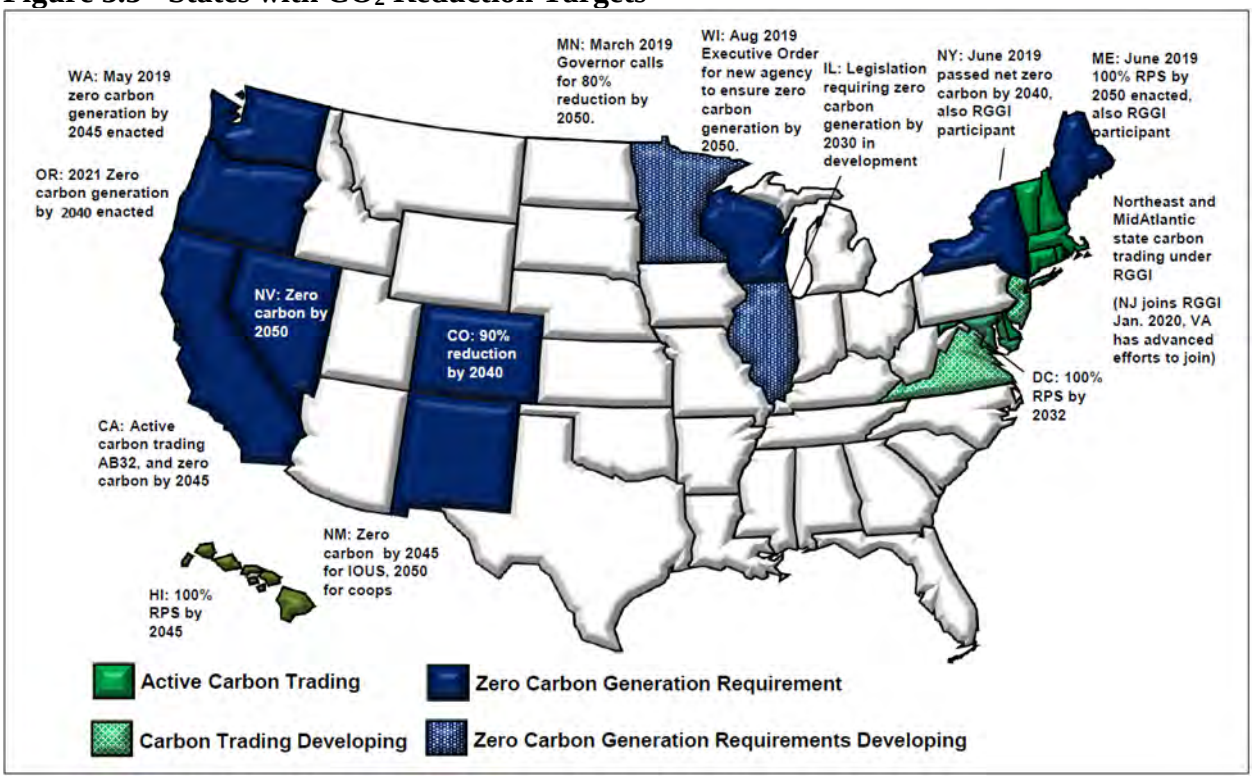
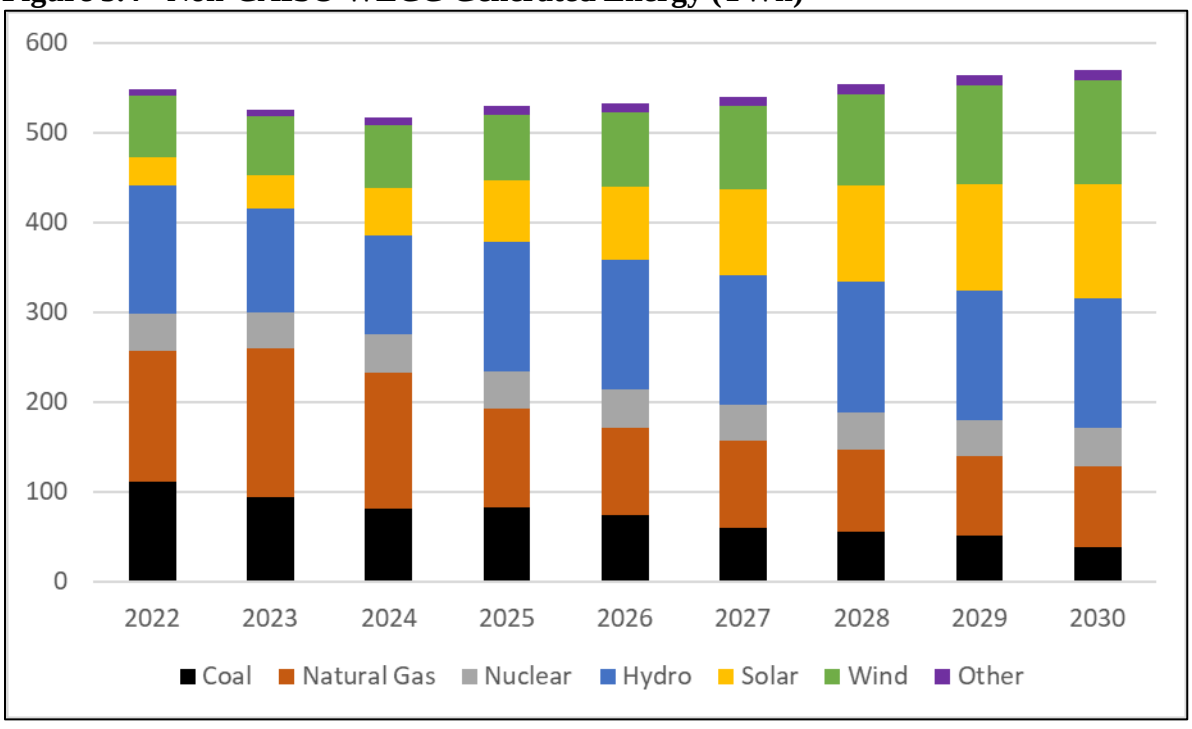


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

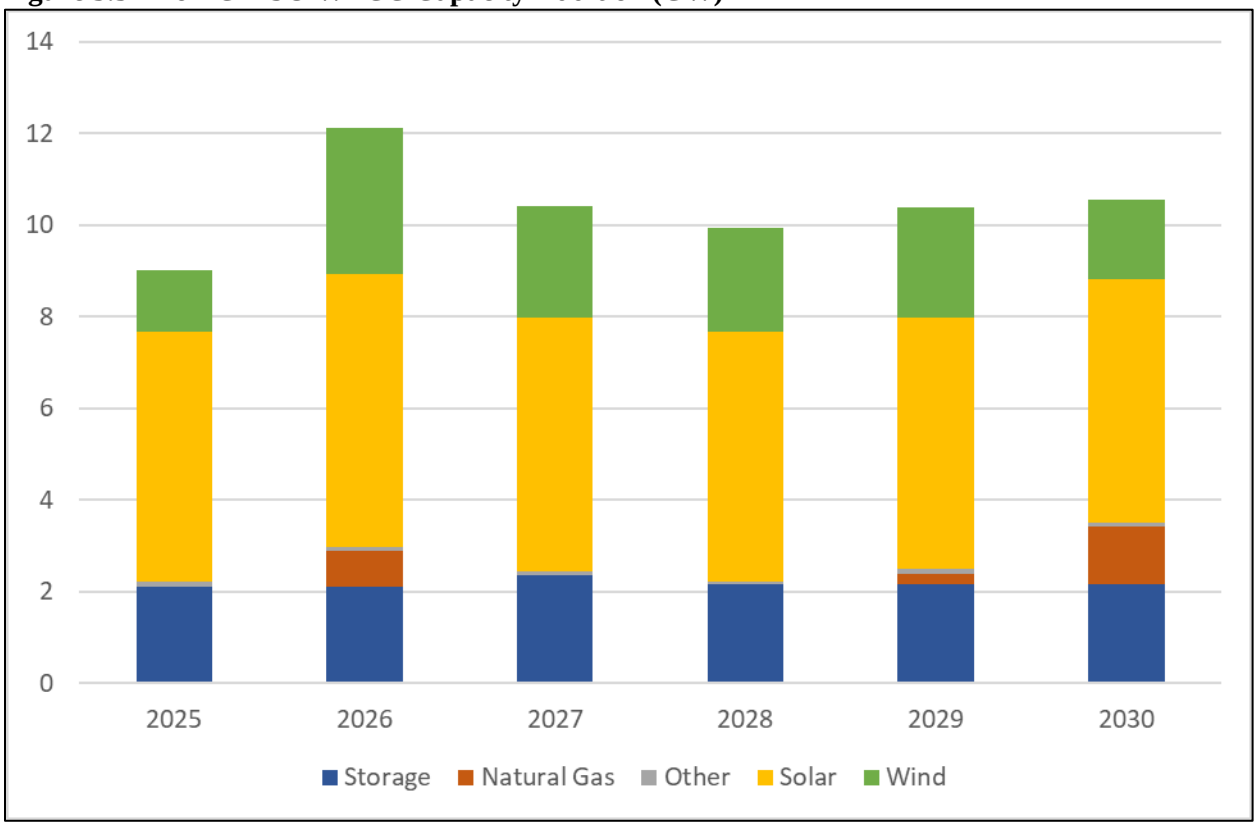
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

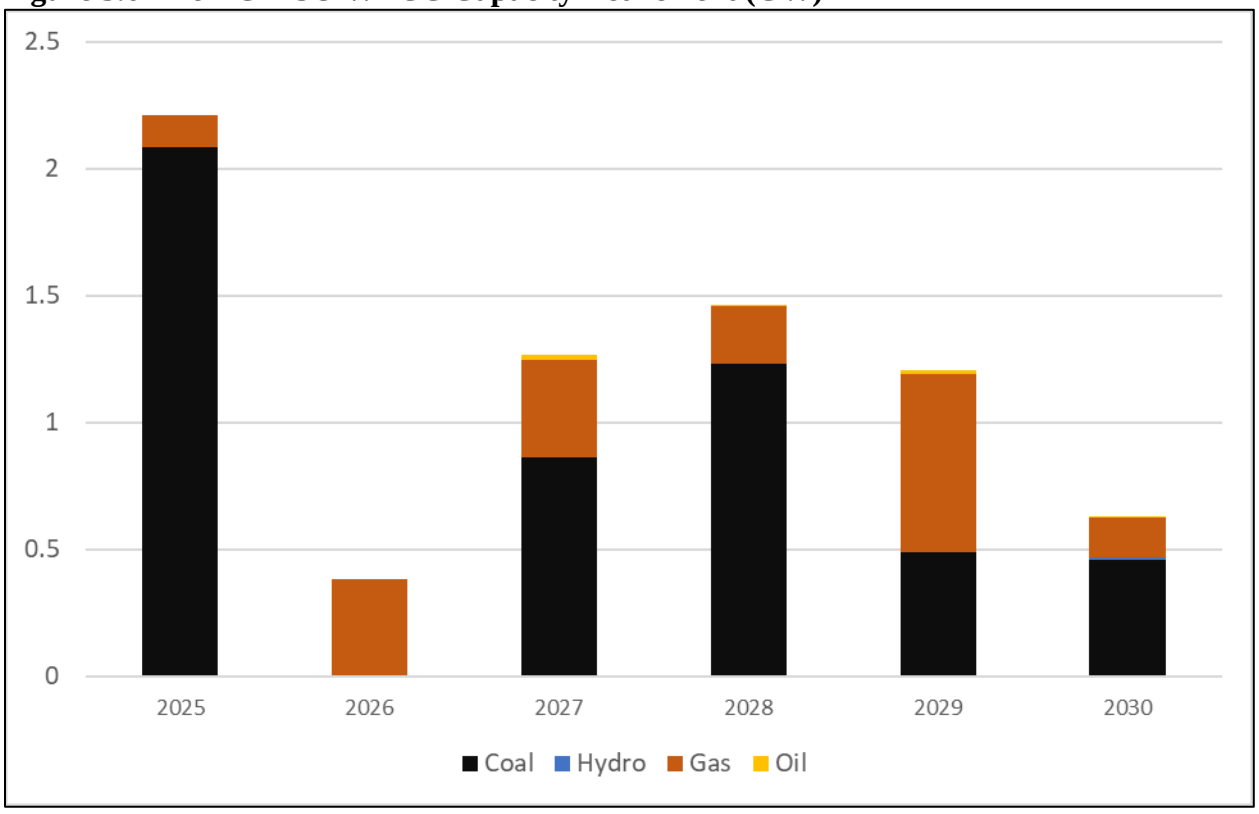
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage capacity additions have also been significant, with 1.4 GW of storage capacity brought online in 2022 and 1.9 GW online through October 2024. Minimal fossil fuel capacity came online in 2023, and that trend may continue through 2030 if carbon reduction goals continue to drive renewable additions.

Figure 3.5 - Non-CAISO WECC Capacity Addition (GW)



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement (GW)



Source: IHS Markit, SNL, Siemens PTI

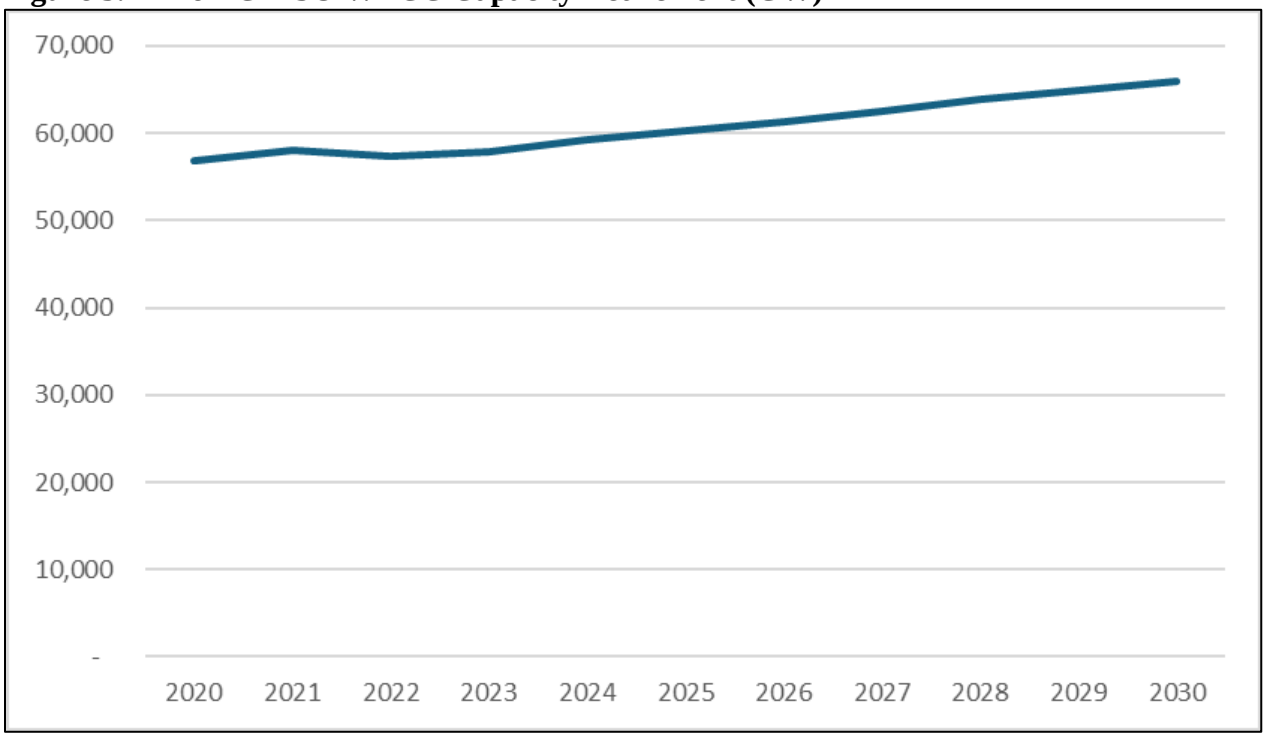
Emissions and Environment

Cool weather and low natural gas prices in 2023 led to decreased emissions and low demand for allowances. In addition, the finalization of the Good Neighbor Plan in March 2023 contributed to an 18% NOx emission reduction within the ten implemented states. On April 25, 2024, the U.S. Environmental Protection Agency (EPA) unveiled its final rule to regulate greenhouse gas (GHG) emissions from power plants under Section 111 of the Clean Air Act. The updated rule mandates that coal-fired baseload units achieve 90% carbon capture and storage (CCS) by 2032. It also provides an option for plants scheduled for retirement by 2039 to co-fire up to 40% natural gas as a transitional measure to reduce emissions.

Non-CAISO WECC Demand Forecast

After years of relatively stagnant demand nationwide, recent additions of loads—such as data centers, manufacturing facilities, and electrification initiatives—have caused load forecast projections to surge. According to regional outlooks, the non-CAISO WECC region is anticipated to experience a compound annual growth rate (CAGR) of 1.8% from 2024 to 2030. Recent Integrated Resource Plans (IRPs) from utilities across the region, including Nevada Energy, Arizona Public Service, show higher-than-usual load growth expectations, largely due to significant new load additions expected to come online in the coming years.

Figure 3.7 - Non-CAISO WECC Capacity Retirement (GW)



Source: Siemens PTI

Forward Influence of the IRA

In August 2022, the US Congress Passed the Inflation Reduction Act ("IRA"). The notable near-term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits or investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative attempt to avoid losing production tax credits.

As of November 2024, the future of some provisions of the IRA remains uncertain under the new administration. While a repeal of the IRA is unlikely as that would require congressional approval, the Trump administration could slow the payment of grants and loans or rescind or modify regulations and guidance issued to date on how to implement provisions of the IRA. This action would make it difficult for companies and individuals to plan with certainty with respect to claiming tax credits for investments in new renewable and non-emitting technologies including EVs and offshore wind. A US policy movement away from federal climate initiatives could also enhance China's global dominance in clean energy industries such as solar panels and EVs, while potential new import tariffs could hinder the deployment of energy generation and other technologies supported by the IRA.

Natural Gas Prices

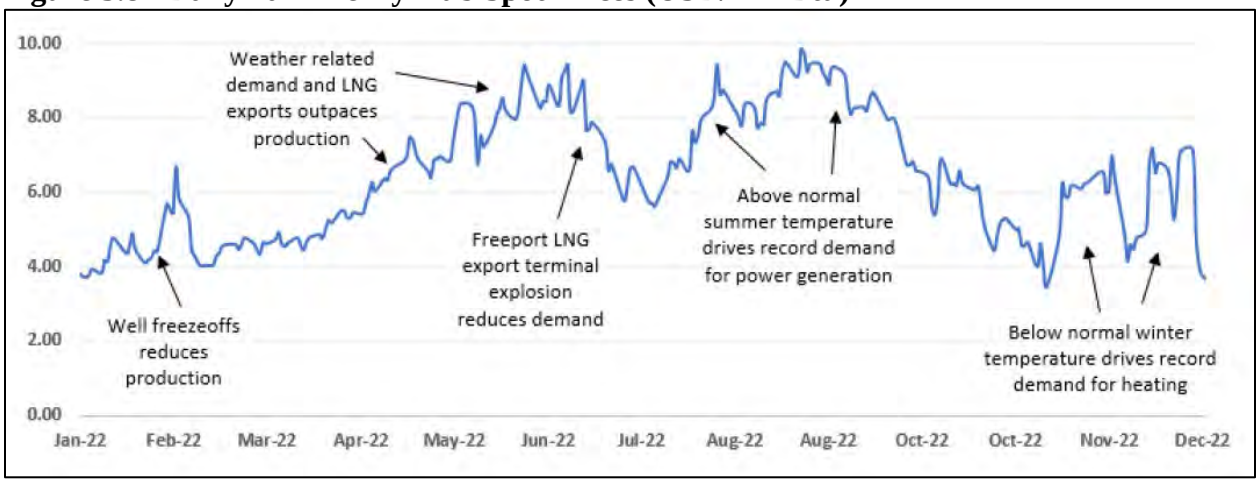
2022 Summary

In the first quarter of 2022, demand for natural gas surpassed production in the US due to well freeze-offs in January and February. High withdrawals of natural gas from storage during this time

caused prices to increase. Continued demand for U.S. liquified natural gas (LNG) exports into Europe due to Russia's war on Ukraine, as well as increasing weather-driven demand, caused upward price pressure.

In the second quarter, starting in May, weather-related demand for natural gas for electric generation as well as uncertainty around storage injections led to an increase in natural gas prices. The Henry Hub spot prices, as you can see in Figure 3.8, rose to over $9/MMBtu. However, in late June, the second largest LNG export terminal in the US, accounting for 17% of total LNG export capacity, suffered a tragic explosion which took it offline. As such prices fell to below $6/MMBtu. For the first half of 2022, the U.S. was the largest exporter of LNG in the world, and over two-thirds of the cargoes headed to Europe.

Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

The price of natural gas quickly rebounded in July and August, because of a heat wave in many parts of The U.S., which resulted in record high demand for power generation. The Western States of the U.S. were particularly affected by this not only due to higher demand for power but also from reduced supply of hydro resources due to continuing drought.

Despite these challenges, US Lower 48 supply surpassed pre-pandemic levels in the first half of 2022, led by gas production growth as higher prices spurred increased rig activity. Rig activity was more pronounced in low-cost basins such as Permian (Texas/New Mexico) and Haynesville (Louisiana) as they have better infrastructure to access demand areas.

Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

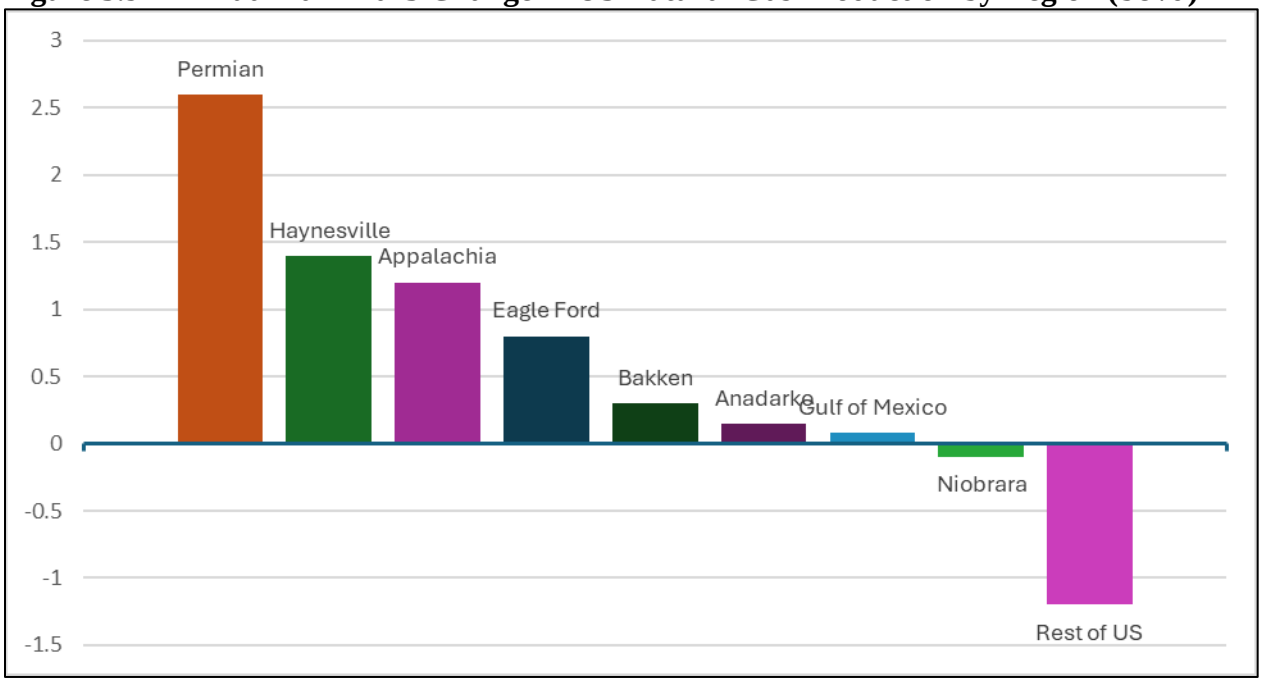
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

demand for natural gas. This higher demand, the constraint on pipelines, and reduce storage levels contributed to significantly higher prices that the west is currently experiencing.

2023 Summary

In 2023, U.S. natural gas prices saw a significant drop compared to the previous year, with the benchmark Henry Hub price averaging $2.57 per million British thermal units (MMBtu), a steep 62% decline from 2022. This price decline was largely driven by record-high production levels, which reached an average of 104 billion cubic feet per day (Bcf/d), 4% higher than the previous year. This production increase was particularly notable in key regions like the Permian, Haynesville, and Appalachia, where technological advancements and strong oil prices supported higher outputs.

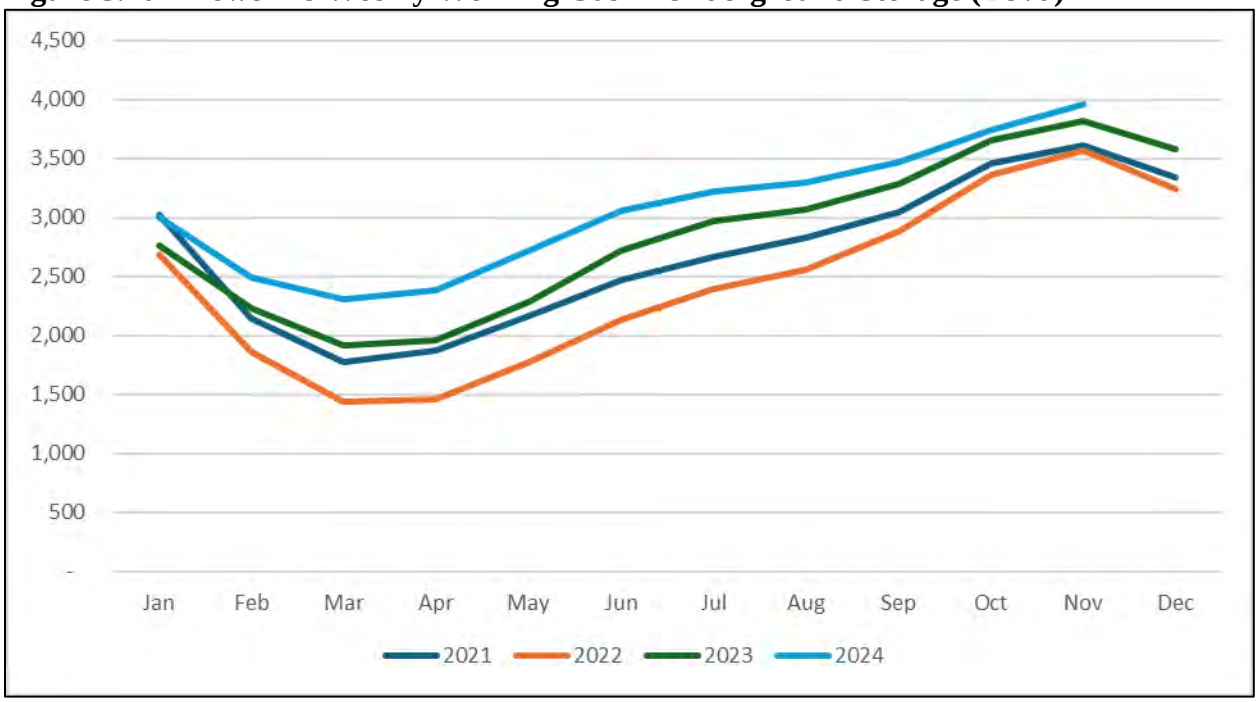
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



Source: EIA, Siemens PTI

Weather played a critical role in shaping the market. Warmer-than-average winter temperatures in January and February significantly reduced demand for natural gas in residential and commercial heating, particularly in the Midwest and Northeast, where natural gas is a primary heating source for most households. These mild conditions led to the lowest winter consumption levels in seven years and kept storage inventories above the five-year average for much of the year, further pressuring prices downward.

Figure 3.10 – Lower 48 Weekly Working Gas in Underground Storage (Bcf/d)



Source: EIA, Siemens PTI

On the West Coast, natural gas prices were influenced by unique regional factors. Severe winter storms early in the year disrupted supply chains and increased demand for heating in California and surrounding areas, creating temporary price spikes in localized markets. However, as weather conditions stabilized and milder temperatures returned, these pressures eased, and West Coast prices aligned more closely with the broader national trend of declining natural gas costs.

While domestic demand for natural gas remained relatively flat overall, there were notable increases in liquefied natural gas (LNG) exports, which rose by 12%, and pipeline exports, which increased by 9%. These exports helped offset some of the impact of reduced residential and commercial consumption. Despite this, the overall supply-demand balance remained tilted toward oversupply, with storage levels high and production continuing at record rates.

Adding to the dynamics was the gradual recovery of the Freeport LNG facility, which had been offline due to an outage in 2022 and returned to full operation in 2023. While this increased export capacity, it did not significantly alter the broader market trajectory, as domestic production remained the dominant factor. Prices remained under $3.00/MMBtu for most of the year, with May marking the lowest monthly average at $2.19/MMBtu, illustrating how robust supply and subdued demand combined to create one of the least volatile years for natural gas in recent history.

2024 Summary

In 2024, U.S. natural gas prices remained relatively low, with the Henry Hub averaging under $3.00 per MMBtu through November. Production levels, while slightly reduced compared to the previous year, remained robust at an average of 103.3 Bcf/d according to EIA. This marked the first annual production decline since 2020, driven by lower drilling activity because of subdued spot prices. Despite this, overall supply continued to outpace domestic demand, keeping inventories above the five-year average.

In the Permian Basin of western Texas and southeastern New Mexico, natural gas production, primarily as associated gas from oil wells, increased this year alongside rising oil production driven by oil prices, with expanding pipeline takeaway capacity, such as the Matterhorn pipeline, continuing to support higher production levels despite some volatility caused by periodic pipeline maintenance affecting Permian supply

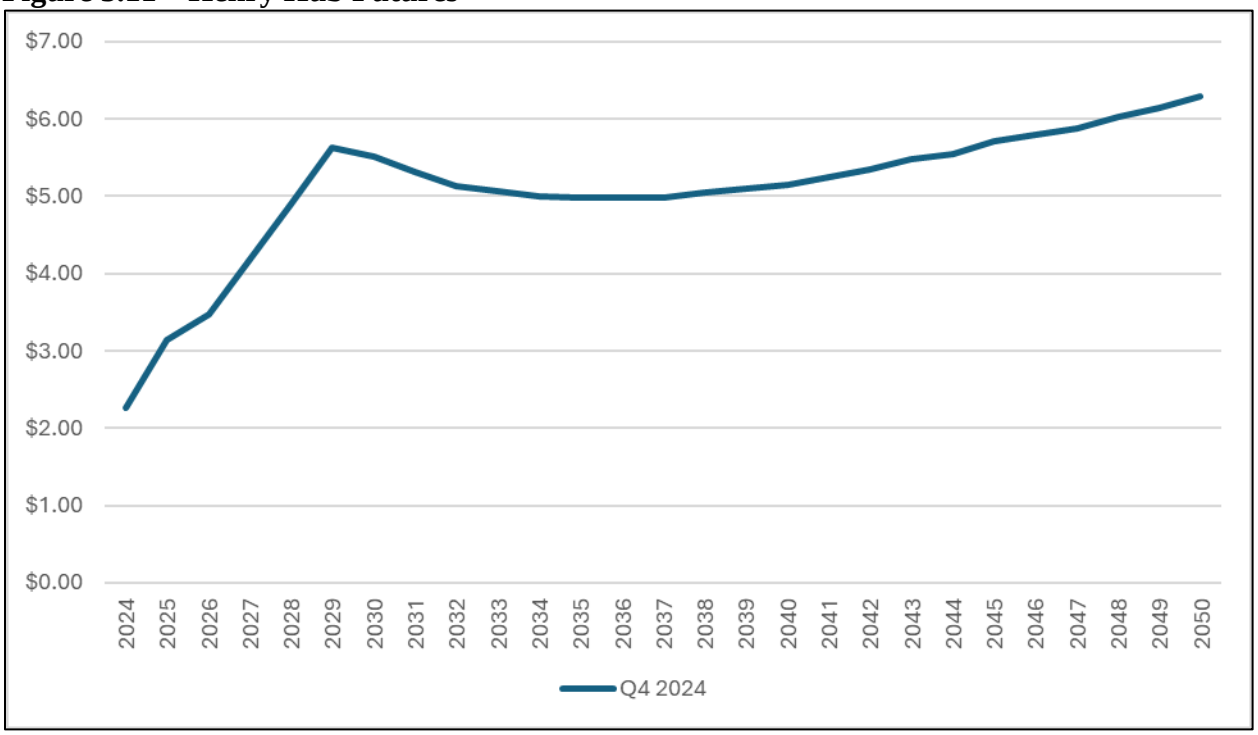
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts to diversify energy sources remained a priority. However, higher exports were offset by stable industrial demand and moderate consumption for power generation, resulting in a balanced domestic market. Regional pricing saw temporary variations, particularly in the West, where localized weather events, including early-season storms, increased heating demand briefly. Despite these regional factors, the national market reflected a stable supply-demand balance with minimal volatility. This relative stability was further supported by the continued high storage levels, maintaining downward pressure on prices throughout the year.

2025-2032 Forward View

As we consider the 2025 to 2030 timeframe, our fundamental forecast for natural gas spot prices at Henry Hub indicates a steady upward trend, with prices expected to average in the mid-$4/MMBtu range in real terms by 2027. Total natural gas demand is projected to reach 122 Bcf/d by 2029, a 13% increase from 2023 levels, driven primarily by rising LNG exports and pipeline deliveries to Mexico. LNG exports are anticipated to double by 2027, as several terminals reach final investment decisions and expand capacity. Similarly, pipeline exports to Mexico are expected to grow significantly, fueled by increased demand for power generation and industrial use.

To meet this growing demand, U.S. natural gas production is expected to expand significantly, particularly from low-cost basins such as the Permian, Eagle Ford, and Haynesville. These regions are well-positioned to serve both domestic and export markets, benefiting from their proximity to demand centers and the development of new takeaway capacity through ongoing pipeline expansion projects. While the market may experience tightness through the middle of the decade due to accelerating LNG export growth, the combination of increased production and strategic infrastructure investments is expected to stabilize supply and support a balanced market by 2032.

Figure 3.11 – Henry Hub Futures



Source: Siemens PTI, GPCM

Conclusion

In summary, the natural gas market is poised for significant growth through the 2025–2030 timeframe, driven by surging export demand and supported by robust production from key basins and expanding infrastructure. While domestic demand shifts modestly, the market's stability will hinge on the alignment of production growth with expanding export capacity. Despite periods of tightness mid-decade, strategic investments and rising supply will position the market for long-term equilibrium, with Henry Hub prices reflecting this balance.

PacifiCorp's Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to over 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative multi-state process (MSP) has been used to develop an allocation methodology. This collaborative process has led to the development and adoption of PacifiCorp's current inter-jurisdictional cost-allocation method.

The underlying principle of each of the historical inter-jurisdictional cost-allocation methods has been the use of PacifiCorp's system as a single whole. Except for distribution, all states are served from a common portfolio of generation and transmission assets, which enables the company to leverage economies of scale and take advantage of load diversity to plan and operate in a way that results in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the

costs and benefits of coal-fired generation while other states are not. Similarly, diverging state polices related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol had been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system.

In 2024, PacifiCorp determined that a negotiated agreement was unlikely given the differences in state energy policies and data limitations for parties to compare alternatives. PacifiCorp will file a new allocation methodology for approval by all six state commissions in 2025 for implementation in 2026 and beyond. PacifiCorp's guiding principles in the development of the new allocation methodology will continue to be:

1. Provide a long-term, durable solution
2. Follow cost-causation principles
3. Minimize rate impacts at implementation
4. Allow for state autonomy for new resource portfolio selection
5. Maintain and optimize system-wide benefits and joint dispatch to the extent possible
6. Enable compliance with state policies
7. Ensure credit-supportive financial outcome
8. Provide the company with a reasonable opportunity to recover its costs

Environmental Regulation

The upcoming administration change featuring Republican control of the House, Senate, and presidency, sets the stage for significant shifts in federal energy policy that could influence PacifiCorp's portfolio selection process used in the development of future IRPs. PacifiCorp recognizes the potential for new legislative and regulatory priorities to impact the energy sector and resource planning. The company actively monitors federal legislative and regulatory developments and participates in rulemaking processes by submitting comments, engaging in hearings, and providing policy assessments to ensure alignment with evolving requirements.

Suggested upcoming legislative priorities under the new administration include changes to the Inflation Reduction Act and a reconciliation bill with energy as a focal point that could directly impact PacifiCorp's existing and potential generation portfolio.

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

$5 billion FY 2022-2026

The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

- The acquisition, installation, and network connection of EV charging stations to facilitate data collection, access, and reliability
- Proper operation and maintenance of EV charging stations
- Long-term EV charging station data sharing

On February 6, 2025, the FHWA released a letter suspending approval of state electric vehicle infrastructure deployment plans pending review of the policies underlying the implementation of the NEVI Formula Program. The FHWA aims to have updated draft NEVI Formula Guidance published for public comment in the spring. After the public comment period has closed, FHWA will publish updated final NEVI Formula Guidance that responds to the comments received.

Section 11401 Grants for Charging and Fueling Infrastructure

$2.5 billion for FY 2022 – 2026

Competitive grant program to strategically deploy publicly accessible electric vehicle charging infrastructure and other alternative fueling infrastructure along designated alternative fuel corridors. At least 50 percent of this funding must be used for a community grant program where priority is given to projects that expand access to EV charging and alternative fueling infrastructure within rural areas, low- and moderate-income neighborhoods, and communities with a low ratio of private parking spaces. Opportunity to obtain funding through this grant closed on September 11, 2024.

New Credits and Considerations for Non-emitting Resources – Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation signed into law in August 2022 by President Biden. Substantive details of how the legislation will be implemented are still being fleshed out in the form or regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand, such as tax credits for electric vehicles.

Features of the IRA include:

- The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting

economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.

- Key Energy Provisions:
  - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
  - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
  - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2025 IRP, resources in designated areas are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

New Credits and Considerations for Customer Resources–Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income.

Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a $3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

The IRA also extends the federal Investment Tax Credit (ITC) for small scale solar systems through 2034 and expands the credit to include standalone energy storage systems as well. Since the passage of the IRA, the ITC has been extended beyond its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC is set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of $0.50–5.00 per square foot (/sf) of floor area to owners of new and

improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than $25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, IRA increases the credit to 30% of cost, with an annual cap of $1,200 along with smaller limits for most items, but it also allows up to $2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of $500).

New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in April 2024, EPA finalized new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units (Clean Air Act Section 111(d) rule).

For new combustion turbines, the final rule establishes three subcategories based on operating intensity as measured by capacity factor.

1. Base load turbines (operating above 40% of maximum annual capacity factor) must initially meet a standard reflective of an efficient combined cycle design and achieve 90% carbon capture by January 1, 2032.
2. Intermediate load turbines (operating between 20% and 40% of capacity factor) must meet a standard reflective of an efficient simple cycle design.
3. Low load turbines (operating below 20% capacity factor) must meet a standard based on using low-emitting fuels.

For existing coal-fired electric generating units (EGUs), the final rule subcategorizes plants based on the units intended operational timeline.

1. Long-term units (operating beyond January 1, 2039) must meet emission limits based on 90% carbon capture and storage (CCS) by January 1, 2032.
2. Medium-term units (retiring by January 1, 2039) must meet limits by January 1, 2030, using 40% natural gas co-firing.
3. Near-term units (closing before January 1, 2032) have no emission reduction obligations.

For existing gas- or oil-fueled steam units, the final rule subcategories units based on capacity factor.

1. Base load units (annual capacity factor greater than or equal to 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,400 lb/MWh)
2. Intermediate load units (annual capacity factor between 8% and 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,600 lb/MWh)
3. Low load units (annual capacity factor less than 8%) must meet a standard based on using low-emitting fuels.

States are required to submit implementation plans within two years of the rule's publication. These plans must show meaningful engagement with stakeholders, including affected communities and reliability authorities. States also have flexibility to consider factors like Remaining Useful Life, allow for emissions trading and averaging, and provide one-year compliance extensions for delays beyond an operator's control.

The rule has been challenged by multiple parties and is currently awaiting a decision from the D.C. Circuit Court of Appeals.

Credit for Carbon Oxide Sequestration – Internal Revenue Service § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[7] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[8] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024, to January 1, 2026.

The Inflation Reduction Act made considerable changes to the 45Q tax credit in 2022. The tax credit amount increased to $60/tonne (use) and $85/tonne (storage), the construction window was extended to January 1, 2033, the minimum capture thresholds were lowered (18,750 tonnes per year for electric generating facilities) and the Act now requires 75% of a generating units CO_2 production to be captured, among other requirements.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NOX), particulate matter (PM), and sulfur dioxide (SO_2). The primary standards are set at a level that protects public health with an adequate margin of safety. The secondary standards are set to protect the public welfare from adverse effects including those related to effects on soils, water, crops, vegetation, anthropogenic materials, among other impacts. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan (SIP) to bring that area into compliance, and that plan must be approved by

[7] Before February 9, 2018, the tax credit was strictly for CO_2.
[8] The tax credit reaches $35/tonne and $50/tonne in 2026.

EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

Ozone NAAQS

In October 2015, EPA issued a final rule modifying both the primary and secondary 8-hour ozone from 75 parts per billion (ppb) to 70 ppb. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its "Good Neighbor Rule" for the 2015 ozone NAAQS (the "Ozone Transport Rule" or "OTR"), which proposed a federal implementation plan (FIP) to eliminate interstate transport of ozone precursors from states that EPA identified as significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The proposed rule covered 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and California. Specifically, EPA proposed in that action to implement emissions reductions by requiring some sources within these states to participate in revised provisions of the Cross-State Air Pollution Rule (CSAPR). EPA applied the interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NOx emissions from electric generating unit (EGU) sources within the borders of 25 states during the ozone season and to limit ozone season NOx emissions from non-EGU sources in 23 states to reduce interstate ozone transport.

On February 13, 2023, EPA finalized disapproval of interstate ozone transport SIP submissions for the 2015 8-hour ozone NAAQS for multiple states and issued a partial disapproval for two additional states. This included the SIP for Wyoming. In the same action, EPA deferred final action on its proposed disapproval for Wyoming. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a 1% threshold instead of the one ppb threshold despite EPA previously recognizing, in an August 2018 memorandum, that state may establish an alternative contribution threshold of 1 ppb. States, like Utah, for which EPA issued disapproval actions of their interstate ozone transport SIPs were required to comply with the interstate ozone transport FIP for the 2015 ozone standard upon finalization of that action on March 2023. Due to EPA's delayed final action on Wyoming's SIP submission, Wyoming was not required to comply with the final interstate ozone transport FIP for the 2015 8-hour ozone NAAQS.

Numerous states and industries, including PacifiCorp, challenged certain provisions of the ozone interstate transport SIP disapprovals and FIP for the 2015 ozone standard. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA's denial of the Utah SIP with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the interstate transport FIP for the 2015 ozone NAAQS while the stay remains in place. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been stayed.

The EPA finalized approval of Wyoming's interstate ozone transport SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the interstate ozone transport FIP. Given the court stay of EPA's disapproval of Utah's SIP, PacifiCorp

was not subject to the interstate ozone FIP requirements for the 2015 ozone NAAQS during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication on the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of the litigation.

In addition to litigation over SIP disapprovals, numerous appeals of, and motions to stay, the interstate ozone FIP were filed in four different circuit courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the interstate ozone transport FIP for the 2015 ozone standard that was filed by several state and industry parties. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the interstate ozone transport FIP with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement, and other industries affected by the rule, filed supportive requests for a stay on the same day. The U.S. Supreme Court granted a stay of the FIP on June 27, 2024. Accordingly, states are not required to comply with the ozone transport FIP pending the stay.

On December 9, 2024, EPA signed a final rule to reclassify the Northern Wasatch front, which includes Salt Lake County, from moderate to serious nonattainment for the 2015 Ozone NAAQS. PacifiCorp's Gadsby facility is in the Northern Wasatch Front area and was previously identified as a major source subject to Utah's moderate nonattainment area SIP for Ozone. In anticipation of EPA's decision, the Utah Department of Environmental Quality (DEQ) requested that PacifiCorp submit a reasonably available control technology (RACT) analysis to the Utah DEQ's Division of Air Quality. PacifiCorp submitted the RACT analysis on January 9, 2024, and followed the top down RACT analysis process for each nitrogen oxide and volatile organic carbon emission source at the at the Gadsby plant. Plant emissions from 2017 were utilized to prepare cost effectiveness analyses for add-on controls; these analyses demonstrated that no additional controls are cost effective at this time.

Particulate Matter NAAQS

On October 17, 2006, EPA revised the level of the 24-hour $PM_{2.5}$ NAAQS from 65 micrograms per cubic ($\mu g/m^3$) meter to 35 $\mu g/m^3$. On May 10, 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ nonattainment areas from moderate to serious for the 2006 24-hour $PM_{2.5}$ NAAQS. PacifiCorp's Lake Side and Gadsby facilities were subject to major source requirements due to their emissions of PM2.5. On April 27, 2017, PacifiCorp submitted a Best Available Control Technology (BACT) determination for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices for the Lake Side and Gadsby facilities in the SIP.

On November 17, 2020, EPA finalized redesignation of the Salt Lake City and Provo nonattainment areas to attainment for the 2006 24-hour $PM_{2.5}$ NAAQS. On April 6, 2021, EPA reopened the comment period after adding supplemental information to the proposal. Re-designation to attainment would have no effect on current emissions and operating limits for the Lake Side and Gadsby facilities.

On March 6, 2024, EPA revised the primary annual $PM_{2.5}$ NAAQS from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$. EPA has not yet designated areas as attainment, nonattainment, unclassifiable/attainment, or unclassifiable under this new standard.

Regional Haze

Clean Air Act (CAA) Section 169A includes a program for protecting visibility in the nation's mandatory Class I Federal areas, which include national parks and wilderness areas. The CAA directs EPA to promulgate regulations to assure reasonable progress toward meeting the goal of protecting visibility. In 1990, CAA section 169B was added to further address visibility impairment, specifically, impairment from regional haze. EPA promulgated the Regional Haze Rule in 1999, which requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado, and Montana). The states are required to update their regional haze rule plans generally every ten years, with second planning period revisions due in August of 2023. Litigation over the first planning period requirements for both Utah and Wyoming are mostly concluded.

On July 6, 2005, EPA published final amendments to its regional haze rule to require emission controls known as Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include PM, NOx, SO_2, certain VOCs, and ammonia. The 2005 amendments included BART guidelines for states to use in determining which facilities must install controls and presumptive controls for certain sources subject to BART. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities.

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the regional haze program. EPA issued additional guidance on July 8, 2021, that discusses source selection, characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, consideration of visibility in making control determinations, and the consideration of five additional factors, among other topics.

Utah Regional Haze

In May 2011, the state of Utah submitted to EPA a regional haze SIP for the first planning period requiring the installation of SO_2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NOx and PM portions for Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's approval of the SO_2 SIP was appealed by environmental groups to the Tenth Circuit. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the SIP on the basis that the NOx and PM BART determinations for the sources did not comply with the Regional Haze rules. PacifiCorp and the state's appeals were dismissed as was the appeal filed by environmental groups in the Tenth Circuit. In June 2015, Utah submitted a revised SIP to EPA for approval which included an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2 and crediting NOx emission reductions from Hunter Units 1, 2, and 3 and Huntington Units 1 and 2. On July 5, 2016, EPA published a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a FIP. The FIP established NOx emission limitations on Hunter Units 1 and 2 and Huntington Units 1 and 2 that are reflective of Selective Catalytic Reduction (SCR) and Low-NOx Burners (LNB) and Separated Overfire Air (SOFA). On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative

and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP as well as the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the court.

Utah and PacifiCorp worked with EPA to develop a revised Utah regional haze SIP, based on new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA that would require reporting of all deviations from compliance with the applicable requirements under BART and the BART Alternative, including the emission limits for Hunter and Huntington.

On January 22, 2020, EPA published its proposed approval of the Utah SIP revision and withdrawal of the FIP requirements that would have required emissions limitations for the Hunter and Huntington plants equivalent to SCR plus upgraded combustion controls (LNB/SOFA). EPA subsequently finalized approval of the SIP and withdrawal of the FIP as proposed on November 27, 2020. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp and EPA's motion to dismiss the Utah regional haze petitions.

Environmental groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to EPA's approval of Utah's regional haze SIP for the first planning period. After holding the case in abeyance at EPA's request, the Tenth Circuit lifted the abeyance and granted PacifiCorp and Hunter co-owners and Utah's pending motions to intervene. On August 14, 2023, the Tenth Circuit determined EPA properly approved the Utah regional haze SIP for the first planning period and denied environmental groups' petition.

On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the state as part of its second planning period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO_2 at the Hunter and Huntington units to meet second planning period requirements.

The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022, and submitted the SIP to EPA on August 2, 2022. The SIP differs from PacifiCorp's Reasonable Progress Analysis and requires updated mass-based NOx limits. The SIP also concluded that existing SO_2 limits in Hunter and Huntington's title V permits were necessary to make reasonable progress but required no further SO_2 emission limits for the plants.

On December 2, 2024, EPA finalized a final partial approval and partial disapproval for Utah's regional haze state implementation plan for the second planning period without simultaneously

finalizing a federal implementation plan. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management (FLM) consultation components of the SIP. EPA's disapproval of Utah's long-term strategy is based, in part, on EPA's rejection of Utah's finding that installation of SCR or other physical NOx pollution controls for Hunter and Huntington is not necessary to achieve reasonable progress. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously finalized FIP. PacifiCorp filed a petition for reconsideration on EPA's disapproval action on January 30, 2025, and filed a petition for review in the Tenth Circuit the next day.

Wyoming Regional Haze

On January 30, 2014, EPA published a final rule partially approving and partially disapproving the Wyoming regional haze SIP for the first planning period and promulgating a FIP to address the deficiencies EPA found in the Wyoming SIP submission. As a result of the 2014 final rule and FIP, the following controls were required at PacifiCorp facilities for the regional haze first planning period:

- Naughton Units 1 and 2: LNB/OFA, with an emission limit of 0.28 lbs/MMBtu for each unit
- Naughton Unit 3 by December 31, 2014: SCR + LNB/SOFA, 0.07 lb/MMBtu (30-day rolling average).
- Jim Bridger Unit 3 by December 31, 2015: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 4 by December 31, 2016: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 2 by December 31, 2021: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 4, 2015
- Jim Bridger Unit 1 by December 31, 2022: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 3, 2015
- Dave Johnston Unit 3: Either a commitment to retire by 2027 and LNB/OFA, with an emission limit of 0.28 lbs/ MMBtu (30-day rolling average) or SCR + LNB/OFA, with an emission limit of 0.07 lbs/ MMBtu (30-day rolling average)
  Wyodak Unit 1: SCR+ LNB/SOFA, with an emission limit of 0.07 lb/ MMBtu (30-day rolling average)

Naughton – In its 2014 rule, EPA approved Wyoming's determination that NOx BART for Units 1 and 2 was LNB and OFA. While EPA approved Wyoming's NOx BART determination of SCR and LNB/OFA, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) for Naughton Unit 3, EPA stated that it would approve limitations that reflect the conversion of Unit 3 to natural gas once Wyoming submitted the requisite SIP revision. On November 28, 2017, Wyoming submitted to EPA a source-specific revision to its regional haze SIP for the first planning period for the Naughton Unit 3 conversion. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed Unit 3 to operate on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approving Wyoming's SIP revision for Naughton Unit 3's gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as NOx BART for Units 1 and 2 in the Tenth Circuit. On August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied

environmental groups' petition.

Jim Bridger – In its 2014 rule, EPA approved Wyoming's determination that Jim Bridger Units 1 and 2 meet an emission limit of 0.07 lb/MMBtu (30-day rolling average) by 2022 and 2021, respectively. EPA also approved Wyoming's NOx BART determination that required Jim Bridger Units 1 and 2 to meet a NOx emission limit of 0.26 lb/MMBtu (30-day rolling average) by March 4, 2019. For Jim Bridger Units 3 and 4, EPA approved Wyoming's determination that the appropriate level of NO_X control for Units 3 and 4 for purposes of reasonable progress is the SCR-based emission limit in the SIP of 0.07 lb/MMBtu, with compliance dates of December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. Accordingly, SCR was installed on Jim Bridger Units 3 and 4 by the dates required by the Wyoming SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an air permit application for monthly average plant-wide NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. PacifiCorp proposed that the plantwide limits were more cost effective while leading to better modeled visibility than SCR installations on Units 1 and 2. Wyoming submitted a regional haze SIP revision to the EPA on May 14, 2020, that incorporated PacifiCorp's proposed emission limits in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2. While EPA communicated that it would issue a proposed approval of Wyoming's Jim Bridger SIP, the proposal was not issued before the administration change in 2021.

When EPA failed to issue a determination by the statutory deadline in November 2021, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, using authority granted by the Clean Air Act, suspending the existing SIP requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for four months due to the EPA's failure to act on the SIP revision submitted by Wyoming in 2020. EPA published a proposed disapproval of the Jim Bridger SIP revision on January 18, 2022. However, PacifiCorp negotiated a consent decree with Wyoming and an administrative consent order with EPA and the disapproval was not finalized. Under the Wyoming consent decree and EPA administrative consent order, PacifiCorp is required to comply with a compliance plan that allows continued operation of Jim Bridger Units 1 and 2 under the emission limits established by Wyoming in 2020 until they are converted to natural gas in 2024. The consent decree committed Wyoming to processing a SIP revision requiring the conversion and imposing post-conversion emission limits.

On December 30, 2022, Wyoming submitted to EPA for approval a revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming issued to PacifiCorp an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. PacifiCorp completed the conversion. On April 10, 2024, EPA proposed to approve Wyoming's December 2022 SIP revision for Jim Bridger Units 1 and 2. The SIP includes enforceable emissions and heat input limits at Jim Bridger Units 1 and 2, consistent with the conversion of those units to natural gas. EPA accepted comments on the proposed approval through May 10, 2024, but has not yet finalized the approval.

Dave Johnston – EPA's January 20, 2014, FIP action required either the installation of SCR on Dave Johnston Unit 3 or that the unit retire by the end of 2027. PacifiCorp opted not to install SCR. EPA approved Wyoming's NOx BART determination for Dave Johnston Unit 4 of an emission limit of 0.15 lb/MMBtu (30-day rolling average). EPA also approved Wyoming's NOx

reasonable progress determinations for Dave Johnston Units 1 and 2 that no controls were necessary.

Wyodak – EPA's January 20, 2014, FIP action determined SCR + LNB/SOFA to be NOx BACT. PacifiCorp and Wyoming petitioned EPA's FIP that would require SCR at Wyodak in the Tenth Circuit. On September 9, 2014, the Tenth Circuit stayed the NOx emission limits for Wyodak Unit 1 in the regional haze FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. EPA, Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. On January 4, 2021, EPA published the proposed settlement agreement in the Federal Register, requesting public comment. PacifiCorp submitted comments to EPA on March 5, 2021, in support of the Wyodak proposed settlement agreement. However, EPA did not proceed with final approval of the proposed settlement agreement but rather re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit. Litigation for the Wyodak case challenging EPA's denial of the Wyoming SIP and finalization of a FIP recommenced when the mediation process was not successful. On August 15, 2023, the Tenth Circuit found EPA's disapproval of Wyoming's SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act.

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. Wyoming incorporated the four-factor analyses in its SIP for the regional haze second planning period. Wyoming determined that emission limits and planned unit retirements met the reasonable progress goals for Regional Haze. Wyoming submitted the state's regional haze SIP for the second planning period to EPA on August 10, 2022.

On December 2, 2024, EPA finalized partial approval and partial disapproval of Wyoming's regional haze SIP for the second planning period. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA's disapproval of Wyoming's long-term strategy is based in part on the state's decision to forego a full four-factor analysis for units at Jim Bridger, Naughton, Dave Johnston, and Wyodak. There are no new compliance obligations for PacifiCorp at this time, as the disapproval action did not include a simultaneously finalized FIP. On January 30, 2025, the state of Wyoming submitted an "open letter" to EPA stating its concerns about the agency's disapproval of the regional haze second planning period plan for the state. On January 31, 2025, the state also filed a petition for review in the Tenth Circuit. PacifiCorp filed a petition for reconsideration with the agency on January 30, 2025, and petition for review in the Tenth Circuit the next day.

Colorado Regional Haze

Craig- The Colorado regional haze SIP for the first planning period established SO_2 BART emission limits on Craig Units 1 and 2 of 0.11 lb/MMBtu (30-day rolling average). Colorado incorporated NOx emission limits of 0.28 lb/MMBtu (30-day rolling average) for Craig Unit 1 and 0.08 lb/MMBtu (30-day rolling average) for Craig Unit 2 in the SIP. Although the state determined that SNCR was reasonable for BART for both Units 1 and 2, Tri-State and Colorado agreed to a NOx emission control plan for Unit 2 that reflected SCR and was therefore more stringent than the BART determination. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) at Craig Units 1 and 2, which could be met through the operation of the existing fabric filter baghouses.

Hayden- In its regional haze SIP for the first planning period, Colorado determined that the SO_2 BART emission limit for Hayden Unit 1 is 0.13 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.13 lb/MMBtu (30-day rolling average). These limits are met with the operation of the existing controls. For NOx, Colorado determined that the NO_X BART emission limit for Hayden Unit 1 is 0.08 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.07 lb/MMBtu (30-day rolling average). These BART emission limits could be met through the installation and operation of SCR. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) for Hayden Unit 1 and Unit 2. These PM emission limits can be met through the operation of the current fabric filter baghouses.

EPA found Colorado's determinations for the Craig and Hayden units to be approvable and finalized approval of the Colorado regional haze SIP for the first planning period on December 31, 2012. Environmental groups appealed EPA's action in February 2013, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment, with a NOx BART emission limit for Craig Unit 1 is 0.07 lb/MMBtu, calculated on a 30 boiler-operating-day rolling average at Craig Unit 1 by August 31, 2021, 2021.

On May 26, 2017, Colorado submitted a SIP amendment to EPA that reflected further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements The revised SIP required Craig Unit 1 to meet an annual NO_X emission limit of 4,065 tons per year by December 31, 2019. The SIP revision also required the unit to either convert to natural gas by August 31, 2023, and if converting to natural gas, comply with a NO_X emission limit of 0.07 lb/MMBtu (30-day rolling average) beginning August 31, 2021, or shut down by December 31, 2025. EPA approved the SIP on July 5, 2018.

Colorado Regional Haze Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units 1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA on March 22, 2021. However, EPA has not yet acted on the Colorado regional haze SIP for the second planning period. The Colorado SIP is part of the deadline suit filed by environmental groups in the federal D.C. District Court.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that coal- and oil-fired facilities achieve emission standards for mercury, acid gas hazardous air pollutants (HAPs), non-mercury HAP metals, and organic HAPs. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, in response to a Supreme Court decision requiring consideration of costs, EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate coal- and oil-fired EGUs under the Clean Air Act.

On February 7, 2019, EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate HAPs, reversing the Agency's

prior determination. On May 22, 2020, EPA published a reconsideration of its 2016 supplemental finding. In the reconsideration action, EPA determined that it is not appropriate and necessary to regulate HAP emissions from coal- and oil-fired EGUs. The rule was effective May 22, 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting EPA's decision to rescind the appropriate and necessary finding. The court granted EPA's motion to hold the cases in abeyance while the agency reviewed the 2020 repeal. On March 6, 2023, EPA finalized a rule rescinding the 2020 revocation of the appropriate and necessary finding. The rule therefore reinstated the finding. Because PacifiCorp plants are in compliance with the MATS standards, the reinstatement of the finding has immediate impact on PacifiCorp's operations.

On April 25, 2024, EPA finalized revisions to the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The final rule, effective July 8, 2024, tightens the standard for emissions of mercury from existing lignite-fired units by 70 percent and sets a more stringent standard for emissions of filterable particulate matter from existing coal-fired power plants. The rule also requires that continuous emissions monitoring be used to demonstrate compliance with the filterable PM standard.

Coal Combustion Residuals

On April 17, 2015, EPA finalized a rule to regulate the management and disposal of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The rule establishes minimum nationwide standards for new and existing CCR landfills and surface impoundments as well as all lateral expansions consistent of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, recordkeeping, notification, and internet posting requirements. In addition to other requirements, the rule requires existing unlined CCR surface impoundment that is contaminating groundwater to stop receiving CCR and either retrofit or close, except in limited circumstances. The rule also requires the closure of certain landfills and CCR impoundments. The first of these reports was posted to PacifiCorp's CCR compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR and hence are not subject to the final rule.

On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions in the 2015 CCR rule which would have allowed inactive CCR surface impoundment units that had closed by a certain date to forgo groundwater monitoring or other requirements. In response to this decision, EPA published a direct final rule on August 5, 2016, to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under RCRA.

On July 30, 2018, in response to further legal challenge, EPA finalized a rule to establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by EPA. The rule also revised groundwater protection standards for certain constituents. In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, EPA extended the deadline by which facilities must

cease the placement of waste in CCR units closing for cause in certain instances. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule").

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") on August 28, 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which unlined surface impoundments that failed aquifer location restriction must initiate closure. In addition, the rule revised the alternative closure provisions to grant facilities additional time to develop alternative capacity to manage both CCR and/or non-CCR wastewater streams before they must stop receiving waste and initiate closure of their surface impoundments. Finally, the rule revised certain requirements related to the annual groundwater monitoring and corrective action report and the requirements for publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 was placed into service. EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

On November 12, 2020, EPA published the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process that allows facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. EPA proposed these options as part of a subsequent proposal on March 3, 2020. On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program in accordance with the requirements of the Water Infrastructure Improvements for the Nation (WIIN) Act. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 15, 2017, EPA published a request for comment on its proposed permitting guidance which describes EPA’s interpretation of the WIIN Act provisions and how EPA will review states' CCR permit programs The state of Utah adopted the federal final rule in September 2016 and issued the final permit for Huntington Power Plant CCR Landfill on March 21, 2023, and for Hunter Power Plant CCR Landfill on May 15, 2024. It is anticipated that Utah will submit an application to EPA for approval, but the timing of the submission remains uncertain. EPA rejected Wyoming’s application due to concerns about the state’s ability to meet federal standards for the safe management of coal ash.

On May 8, 2024, EPA finalized the legacy surface impoundments rule to (1) extend federal CCR regulatory requirements to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land (CCR management units or CCRMUs) and (2) allow for alternative closure provisions that allow a facility to complete the closure by removal in two stages. The final rule, which became effective on November 8, 2024, includes exemptions and establishes new categories

where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. Affected facilities must conduct a facility evaluation and report to determine the presence of CCRMUs and/or legacy surface impoundments. The first phase of such a report is due February 2026. Because the facility evaluation and report requirement will determine the magnitude of compliance obligations, PacifiCorp cannot assess the full impacts of the rule at this time.

On August 5, 2024, Utah, Wyoming and other Republican-led states filed a petition for review in the D.C. Circuit on EPA's May 2024 legacy rule, arguing that EPA acted arbitrarily and beyond its authority when enacting the new rule. On February 3, 2025, these same petitioners as well as power companies, utilities and trade groups filed their opening brief in a consolidated case contesting the rule in the D.C. Circuit.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act (Clean Water Act) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to, and withdrawals from, waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact." In August 2014, EPA published a final rule, effective October 2014, under section 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule establishes requirements that apply to existing power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from Waters of the United States (WOTUS) and use at least 25 percent of the withdrawn water exclusively for cooling purposes. The rule includes standards to address impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility). The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from WOTUS for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million, but less than 125 million, gallons of water per day.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards. Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs.

Effluent Limit Guidelines

In November 2015, EPA published final effluent limitation guidelines and standards (ELG) for the steam electric power generating sector which, among other things, regulate the discharge of bottom

ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System (NPDES) permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018, and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with EPA. EPA granted the request for reconsideration and extended certain compliance dates for FGD wastewater and bottom ash transport water limits until November 1, 2020. On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing FGD wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on FGD wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet FGD wastewater requirements and includes additional subcategories to both wastewater categories.

On May 9, 2024, EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule), which includes a new subcategory for EGUs permanently ceasing coal combustion by 2034. The 2024 ELG Rule also imposes a zero liquid discharge requirement at coal-based generating units for bottom ash transport water, flue gas desulfurization wastewater, and coal combustion residual leachate. The rule also eliminates 2020 ELG Rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The rule maintains, however, the 2020 ELG Rule subcategory for EGUs permanently ceasing the combustion of coal by 2028 and oil-fired and small (50 megawatts (MW) or less) EGUs established in the 2015 rule. The rule finalizes additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

Most of the issues raised by the 2024 ELG Rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. In October 2021, the Dave Johnston plant submitted a notice of planned participation in subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream. The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys,

monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands or that receive federal funding are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects (TB Flats, Ekola Flats, and Cedar Springs) constructed as part of PacifiCorp's Energy Vision 2020 initiative, for example, were required to obtain permits from the State of Wyoming's Industrial Siting Division, which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. CARB's 2022 Scoping Plan was

adopted laying out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279, passed in 2022.

CARB adopted the Advanced Clean Cars II Rule in August of 2022. The rulemaking establishes that by 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded several times since its inception. In September 2018, Governor Brown signed into law Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045. The California Energy Commission, California Public Utilities Commission, and California Air Resources Board have not introduced rules on if and how electric utilities will demonstrate compliance with SB 100. Interim targets for the carbon-free target were subsequently adopted by SB 1020 in 2022.

Idaho

In 2007, Idaho released its State Energy Plan, focusing on developing of a broad range of power generation options, improving energy efficiency, diversifying the state's energy portfolio, and reducing dependency on fossil fuels. The plan outlined strategies for energy conservation, the development of renewable energy sources, and improvements to transmission infrastructure within the state, aiming to balance growth with environmental stewardship and promote both economic development and sustainable energy practices.

In 2012, Idaho updated its 2007 plan to address new energy challenges and opportunities, emphasizing five core objectives: 1) a secure and stable energy system for Idaho's citizens and businesses, 2) maintaining Idaho's low-cost energy supply, 3) protecting public health and conserving natural resources, 4) promoting economic growth, job creation, and rural economic development, and 5) ensuring Idaho's energy policy can adapt to changing circumstances.

In October of 2020, Governor Brad Little issued Executive Order 2020-17, continuing the role of the Office of Energy and Mineral Resources (OEMR) as the central coordinator for Idaho's energy policy. The OEMR manages energy production, conservation, and policy alignment, ensuring the state's energy resources remain stable and cost-effective.

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of

Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

In 2007, Oregon enacted Senate Bill (SB) 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged as follows: 27 percent for 2025-2029, 35 percent for 2030-2034, 45 percent for 2035-2039, and 50 percent for 2040 and every subsequent year thereafter. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp filed its first Clean Energy Plan (CEP) on May 31, 2023, which included possible pathways towards compliance with HB 2021 emissions reduction goals, inclusive of the Small-Scale Renewable (SSR) targets and with emphasis on community-based actions. As also directed by HB 2021, PacifiCorp convened a Community Benefits and Impacts Advisory Group in the fall of 2022. An Oregon Tribal Nations Clean Energy-specific engagement series was started in March of 2023 after six months of direct outreach. The engagement series was formatted by informed feedback from outreach to Oregon Tribal Nations members with whom PacifiCorp had an existing relationship, and through new Tribal Nations relationship building.

In December 2022, Oregon Department of Environmental Quality adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. In Jan of 2022, HB 2165 passed requiring that all electricity companies (with ≥25,000 retail customers) recover the cost of prudent infrastructure investments in transportation electrification. Furthermore, in November 2021, Oregon adopted California's emission standards for HMDV via

the Advanced Clean Truck Rules 2021, paving the way for Oregon to adopt a target of 100% of new MHDV sales being ZEVs by 2050.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020 and every year thereafter. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In 2019, the Washington Legislature passed the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its retail electricity sales be supplied from renewable and non-emitting resources by 2045. PacifiCorp submitted its inaugural Clean Energy Implementation Plan (CEIP) on December 30, 2023, establishing a trajectory towards CETA compliance both for the current CEIP period, 2022 – 2025, and across the next two decades.

In 2021, Washington Legislature passed the Climate Commitment Act, which establishes a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with serving Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

- Improving the efficiency of their fuel production processes
- Producing and/or blending low-carbon biofuels into the fuel they sell
- Purchasing credits generated by low-carbon fuel providers, including electric vehicle charging providers

Utah[9]

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, which allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, which enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved the Electric Vehicle Infrastructure Program on December 20, 2021, for implementation on January 1, 2022. The program construct will undergo regulatory review every three years through 2032.

In March 2024, the Utah Legislature passed SB 224, Energy Independence Amendments, that modifies the factors the Public Service Commission must consider when evaluating certain proposed energy resource decisions, establishes parameters for an affected electrical utility's recovery of costs associated with proven dispatchable generation resources located within the state, and encourages the commission to evaluate the purchase of excess proven dispatchable generation capacity.

In March 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, which requires the Public Service Commission to act in accordance with the state energy policy and make certain determinations before authorizing the early retirement of an electrical generation facility.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility;

[9] Significant Utah legislative activity gathered interest in the 2025 IRP public input meeting series and stakeholder feedback. Regarding Utah SB-224, see Appendix M, stakeholder feedback form #13 (Emma Verhamme). Portfolio planning is currently not directly impacted by Utah SB-224, however variant and sensitivity studies may reflect this potential, such as the Low-Cost Renewables case and the No Coal 2032 case. Additional discussion of Utah activity is addressed in Appendix M, stakeholder feedback form #37 (Utah Citizens Advocating Renewable Energy).

requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. During the 2024 legislative session the Reliable and Dispatchable Low-Carbon Energy Standard statute was amended through SF 42, which extended the deadline for compliance with the Low-Carbon Energy Standards from July 1, 2030, to July 1, 2033.

In 2024, the Wyoming legislature passed SF 0023 Public Utilities-Energy Resource Procurement (SF 23) and SF 0024 Public Service Commission-Integrated Resource Plans (SF 24). SF 23 requires public utilities to conduct a solicitation process that is approved by the Wyoming Public Service Commission to acquire or construct a significant energy resource after July 1, 2024. A significant energy resource consists of 100 megawatts or more of new utility-owned generating capacity or utility-contracted generating capacity that has a dependable life or contract term of 10 or more years. SF 24 requires the Wyoming Public Service Commission to engage in long-range planning regarding public utility regulatory policy to facilitate the well-planned development and conservation of utility resources and requires the Commission to adopt rules providing a process for the review and acknowledgement of an action plan within an IRP.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. Effective February 2025, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 876 lb GHG/MWh.

PacifiCorp purchased Chehalis in 2008 and this change in ownership is the act that triggered the applicability of the standard. Because the EPS was 1,100 lb GHG/MWh during the time of triggered applicability, that is the standard that Chehalis complies with. It isn't until Chehalis undergoes a change in ownership, upgrade, or new or renewed long-term financial commitment with anyone other than Bonneville Power Administration that applicability to the lowered standard would be triggered.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.3, with additional discussion below.

Table 3.3 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[10] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[11] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[12] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.4 below.

[10] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.
[11] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[12] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

Table 3.4 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.75% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.25% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(46.67% * 2025 Retail Sales) + (49.33% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.67% * 2028 Retail Sales) + (57.33% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

SB 2 (1X) established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or
>
> Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[13]

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.5.

[13] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.

Table 3.5 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC, and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources, or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites. Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

In June of 2007, Oregon established a comprehensive renewable energy policy, including RPS, with the passage of SB 838, the Oregon Renewable Energy Act. [14] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[15] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are set at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.

[14] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[15] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[16]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

PacifiCorp files an annual RPS compliance report by June 1 of every year. In addition, after the passage of Oregon House Bill 3161, effective January 1, 2024, ORS 469A.075 now aligns the filing of a renewable plan (formally called the Renewable Portfolio Implementation Plan or RPIP) with the filing of the IRP. Please see Appendix R for detailed information on PacifiCorp's 2025

[16] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

RPS Renewable Plan, including annual targets, list of resources, applicable requirements, and assumptions and methodologies. These RPS compliance reports and plans are available on PacifiCorp's website.[17]

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative, later codified in Utah Code Title 54 Chapter 17.[18] This law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 29, 2023. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.0 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

[17] www.pacificpower.net/ORrps
[18] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[19] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[20]

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states. One exception to REC sales is a special contract for one industrial customer where the customer foregoes REC sales revenue in exchange for a REC retirement to maintain renewable claims for corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming.

[19] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[20] www.pacificpower.net/report

Clean Energy Standards

Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act (CETA). Under the law, Washington utilities are required to be carbon neutral by January 1, 2030, and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030, and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric sales over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Oregon

As noted under State Policy Updates, above, in July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

California

In 2018, California passed Senate Bill 100 – known as the "100 percent Clean Energy Act of 2018," which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state's Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California's electricity is renewable.

In 2022, California passed Senate Bill 1020, the Clean Energy, Jobs, and Affordability Act of 2022. This bill established interim targets to the previously established SB 100. It requires that eligible renewable energy resources and zero-carbon resources supply:

- 90% of all retail sales of electricity to California end-use customers by December 31, 2035
- 95% of all retail sales of electricity to California end-use customers by December 31, 2040
- 100% of all retail sales of electricity to California end-use customers by December 31, 2045
- 100% of electricity procured to serve all state agencies by December 31, 2030

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. In February 2025, the Commission adopted final rules that exempted multijurisdictional electric companies with 60,000 or fewer customers in California from compliance with the hourly reporting requirement.

Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The Company requested an extension and filed the final plan on March 29, 2024 that included a proposal to: conduct additional technical and economic analyses for an Allam Fetvedt Cycle Project at either the Dave Johnston or Wyodak facilities by conducting a pre-FEED study in conjunction with SK and 8 Rivers; conduct additional technical and economic analyses by conducting a front-end engineering and design (FEED) study at the Jim Bridger facility; and no determination of a low-carbon portfolio standard at this time since CCUS continues to be evaluated for its technical and economic feasibility. The Commission approved the Company's final plan in public deliberations held on September 19, 2024. The statute also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

Transportation Electrification

The electric transportation market continues to strengthen since 2022. Overall, light duty battery electric vehicle sales have grown since 2022 resulting in a market share of about 9% in the United States[21]. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind[22]. By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales[23]. EV sales still comprise a small portion of overall sales, however this will shift as medium-duty/heavy-duty (MD/HD) customers continue to expand. PacifiCorp also hosts major interstates and traffic corridors that will see continued electrification through policies discussed above. Furthermore, many businesses are moving to electrify their fleets from port authorities, transit agencies, etc. which will increase load over time.

This rapidly evolving market represents a potential driver of future load growth, and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation could improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (MD/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV

[21] October 2024 auto sales volume to hold steady in the US | S&P Global
[22] Electric vehicle market and policy developments in U.S. states, 2023 - International Council on Clean Transportation
[23] Electric Vehicle Sales and the Charging Infrastructure Required Through 2035

forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop commercial and residential charging programs, research new rate designs and implement time-of-use pricing programs and managed charging pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities.

In California, Pacific Power's Electric Vehicle Infrastructure Rule 24 will pay for and coordinate the design and deployment of service extensions from our electrical distribution line facilities to the service delivery point for separately metered electric vehicle charging stations.[24] Pacific Power continues to provide programs funded by the Oregon Clean Fuels program as well as the recent HB 2165 legislation passed that created a transportation electrification benefits charge to support infrastructure development in the state of Oregon. As of November 2022, the Washington Utility and Transportation Commission approved Pacific Power's Transportation Electrification Plan which sets out an estimated spend of $3.5 million over the next five years to support TE in Washington state.

In Utah, PacifiCorp is implementing the $50 million Electric Vehicle Infrastructure Program that has four core components: Company-owned public fast chargers, customer incentives, innovative projects, and outreach and education efforts. In June 2024, the first four locations with Company-owned public direct current fast chargers (DCFC) became operational. It is anticipated that there will be roughly 20 locations with an estimated 100 DCFC stations throughout Utah by the end of the program. As of the end of 2023, PacifiCorp had supported installation of over 4,800 EV ports throughout the territory.

Electric vehicle load is reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles.

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation

[24] California Electric Vehicle Infrastructure Line Extensions (pacificpower.net)

does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

As of December 31, 2024, PacifiCorp has 15 FERC licensed hydroelectric projects. Each license may contain a single or multiple hydro developments (e.g., dams and powerhouses). PacifiCorp is currently seeking new licenses for the Cutler (30 MW) and Ashton (7.85 MW) hydroelectric projects. A new license for Cutler is expected in 2025, and a new license for Ashton in 2027. The next project to undergo the FERC relicensing process is the Bear River hydroelectric project (77 MW). That project's FERC license expires in 2033.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Tribal and interested party consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies could place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad involvement or that incorporate measures agreed upon through multi- party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2023, PacifiCorp had incurred approximately $33 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on

PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing implementation and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 7.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting Tribal, agency and others' interests through creative solutions, is the best way to achieve environmental and social improvements while balancing customer costs and risks. PacifiCorp also has reached agreements to decommission projects where that has been the most cost-effective outcome for customers.

Rate Design

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No 20-035-04 The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has several rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings All other remaining costs are recovered through volumetric- based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-

day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of December 2023, less than one percent of customers have opted to participate in the time-of-day rate option.

As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers an optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage,

Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

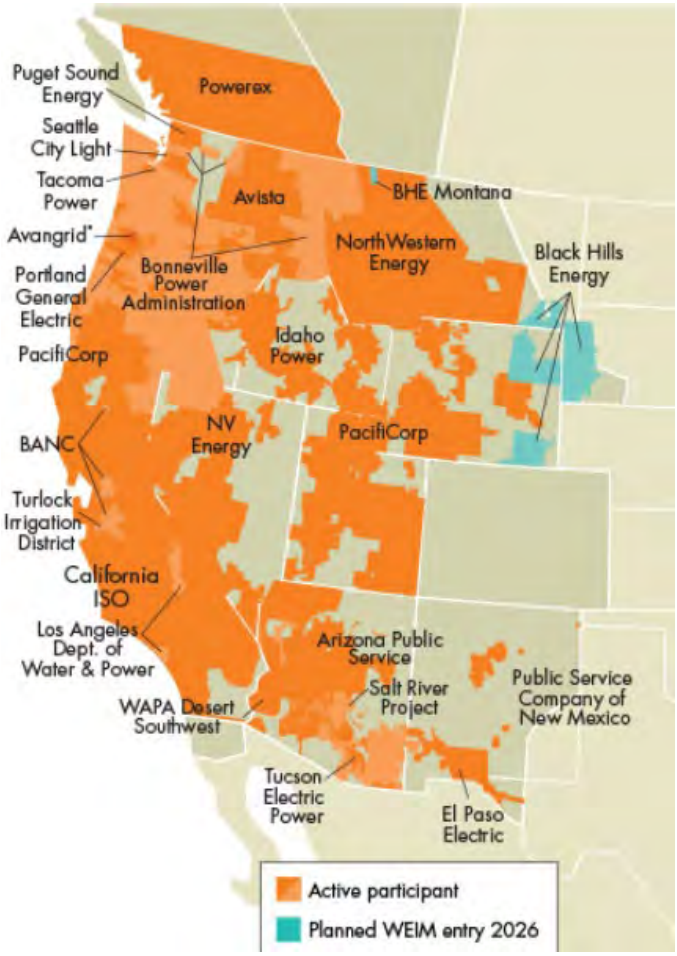
Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service

(APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. El Paso Electric (EPE), Western Area Power Administration Desert Southwest (WAPA DSW) and Avangrid (AVR) entered in April 2023. In 2026, Black Hills Montana and Berkshire Hathaway Energy Montana (BHE Montana) have planned entry into the WEIM.

The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Texas, New Mexico, Utah, Washington, Wyoming, and British Columbia which make up almost eighty percent of the Western Energy Coordinating Council (WECC) load and will expand to include Montana in 2026. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.12 – Western Energy Imbalance Market Expansion



The WEIM has produced approximately $5.85B in monetary benefits since inception for participating utilities, quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every fifteen and five minutes within and across the WEIM footprint based on the most economical solution; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexible reserves in all WEIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the WEIM footprint.

A significant contributor to WEIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations that exist in states with a price on carbon (i.e., California and Washington). Generally, transfer quantities are based on transmission and interchange rights between participating balancing authority areas.

After development and expansion of the WEIM in the west, a natural next question was – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of WEIM but short of a full regional transmission organization? PacifiCorp believes the answer is 'yes'.

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023 and received FERC approval on December 28, 2023. EDAM is scheduled to go live on May 1, 2026, and to date, PacifiCorp and Portland General Electric have signed their EDAM implementation agreements.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint as stakeholders who want to participate in Markets+ would need to exit WEIM. In addition to a smaller WEIM footprint, day-ahead markets with different design elements and requirements for participation exacerbate the seams issue which already exist throughout the west. SPP and stakeholders filed their tariff with FERC on March 29, 2024, and received a deficiency letter on July 31, 2024, that SPP is currently working through to remedy FERC's clarification and additional information request due at the end of November 2024. SPP does not believe the SPP Markets+ timeline will be impacted for their projected spring 2027 go-live target and stakeholders must be vigilant to ensure the markets work as cohesively as possible.

Recent Resource Procurement Activities

PacifiCorp's past procurement efforts have resulted in a number of contracts for new resources that have recently come online or are projected to come online through 2026 as summarized in Table 3.6.[25] These resources are also included in the resource tables presented in Chapter 6.

[25] See Appendix M, stakeholder feedback form #59 (Renewable Northwest)

Table 3.6 – PacifiCorp's Recent and Upcoming New Resource Additions

Resource	Type	Resource Capacity (MW)	Storage Capacity (MW)	Year contracted	Commercial operation	Source
Appaloosa Solar	Solar	200	n/a	2020	Jan 2024	Customer program: UT Sch 34
Rocket Solar	Solar	80	n/a	2020	Feb 2024	Customer program: UT Sch 34
Castle Solar	Solar	40	n/a	2020	Apr 2024	Customer program: UT Sch 32
Horseshoe Solar	Solar	75	n/a	2020	Apr 2024	Customer program: UT Sch 34
Elektron Solar	Solar	80	n/a	2020	Apr 2024	Customer program: UT Sch 34
Oregon Institute of Tech. BESS	Battery Storage	n/a	2	n/a (owned)	Mar 2025	OR HB 2193 (2015)
Rock River Wind	Wind	50	n/a	n/a (owned)	Sep 2024	Repowering of existing site
Cedar Creek Wind	Wind	151.8	n/a	2022	Mar 2024	2020 AS RFP
Anticline Wind	Wind	190	n/a	2022	Dec 2024	2020 AS RFP
Boswell Wind	Wind	100.5	n/a	2022	Dec 2024	2020 AS RFP
Cedar Springs Wind IV	Wind	320	n/a	2022	Jan 2025	2020 AS RFP
Rock Creek Wind I	Wind	350.4	n/a	n/a (owned)	Dec 2024	2020 AS RFP
Rock Creek Wind II	Wind	400	n/a	n/a (owned)	Sep 2025	2020 AS RFP
Green River Energy Center	Solar + Battery	400	400	2022	May 2026	2020 AS RFP: amended to increase storage capacity in 2023
Faraday Solar and Storage	Solar + Battery	525	150	2023	Sep 2025	Customer program: UT Sch 34
Hornshadow Solar	Solar	300	n/a	2023	Jun 2025	Customer program: OR Sch 272
Dominguez Grid	Battery Storage	n/a	200	2024	Jun 2026	Negotiated after 2022 AS RFP
Enterprise Storage	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Escalante BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Granite Mountain BESS East	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Iron Springs BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Oregon Comm. Solar (aggregate)	Solar	38.8	n/a	various	various	Oregon Community Solar Program
Total		**3,301**	**1,072**			

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.7 summarizes recent RFP activities.

Table 3.7 – PacifiCorp's Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
Renewable energy credits (Purchase)	Excess system RECs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2024 Utah Renewables Community RFP	Seeking resources consistent to the Community Clean Energy Act (Utah Code 54-17-901 to -909)	Ongoing	Expected November 2024	Expected October 2025

2022 All-Source RFP

On April 1, 2024, PacifiCorp published the company's 2023 Integrated Resource Plan Update. The 2023 IRP Update preferred portfolio demonstrated that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is material customer benefit to scaling down and delaying resource acquisition until after 2030. As such, the 2022 All-Source Request for Proposals was terminated. PacifiCorp's 2025 IRP will inform the next steps for incremental resource acquisition.

2024 Utah Renewables Community RFP

The 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP) is administered by the Community Renewable Energy Agency (Agency) on behalf of customers that participate in the Community Clean Energy Program (Program). The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

2025 All-Source RFP

PacifiCorp will seek to file the 2025 All Source RFP ("2025AS RFP") based on results identified in the 2025 IRP preferred portfolio. Further updates on the status and schedule of the 2025AS RFP will be provided as they become available.

Recent Resource Procurement/DSM Procurement

In 2023, PacifiCorp issued a Request for Proposals to re-procure program delivery services for the Home Energy Savings and Wattsmart Business energy efficiency programs in Washington and California. As a result of the re-procurement, new contracts for Washington and California were signed in 2024. For Washington specifically, PacifiCorp followed its Competitive Procurement Framework,[26] including seeking Washington DSM Advisory Group input and posting a notice on the Company website prior to releasing the Request for Proposals. In 2024, PacifiCorp issued a Request for Proposals to re-procure program delivery services for Wattsmart Business in Utah, Idaho and Wyoming, and contracting is underway.

In 2024, PacifiCorp also issued an RFP for energy efficiency implementation services for a commercial new construction program in its Utah service area. The procurement and subsequent contracting steps are still underway.

[26] 2022-2023 Biennial Conservation Plan, Appendix 6 (Docket UE-201830)
The current Competitive Procurement Framework for Washington Conservation and Efficiency Resources is available in Appendix 6 to the 2024-2025 Biennial Conservation Plan (Docket UE-230904).

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2025 IRP preferred portfolio includes the following notable transmission upgrades:[1]
    - A series of upgrades to increase transfer capability between southern Utah and the Wasatch Front, projected to come online between 2026 and 2036.
    - New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington, projected to come online in 2031.
    - 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon, projected to come online in 2032.
    - New transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.
    - A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2), projected to come online in 2036.
- Further, the 2025 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp's transmission system including investment in infrastructure in Oregon, Utah, and Washington that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp's customers.

Introduction

PacifiCorp's bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

[1] Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP base modeling:

- The Energy Gateway South transmission line - a new 416-mile, high-voltage 500 –kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in Q4-2024.
- The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in Q4-2024.

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, considering scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a carbon free energy future.
4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Resiliency to protect against system and market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which

supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on this data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[2] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC reliability coordinator. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to always meet aggregate electrical demand for customers. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

[2] For example, PacifiCorp's application to begin the Environmental Impact Statement process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

Generation Interconnection Study Methodology Changes

In 2022 PacifiCorp filed a request with FERC to modify its large generator interconnection procedure to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions were implemented into generation interconnection studies starting with Cluster 2. The new operating assumptions have allowed PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2023 FERC released Order 2023 which required modifications of all transmission provider's including PacifiCorp's, generator interconnection procedures. Several notable changes were included in Order 2023. First, FERC required all transmission providers to move to a first ready, first serve cluster study process which PacifiCorp had already transitioned to in 2020. Second, FERC required all transmission providers to use a distribution factor analysis to assign cost responsibility to specific interconnection customer requests driving the need for network upgrades. This change to PacifiCorp's procedures will allow for projects sited in locations that have smaller impacts on the transmission system, avoiding cost responsibility for upgrades in the region that its project does not cause. Other aspects of the Order 2023 include requiring 100 percent of site control for proposed generating facilities with the initial application and substantial withdrawal penalties at the facilities study stage both of which should disincentivize speculative projects. PacifiCorp will implement a transition process in which existing interconnection requests that have not yet proceeded far enough in the study process will have the opportunity to be studied in a transition cluster study or be withdrawn. PacifiCorp's next application window for new generation interconnection requests will open in 2026.

Aeolus to Mona/Clover (Gateway South – Segment F)

The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled to come online by the end of 2024.

Windstar-Populus (Gateway West – Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

Figure 4.1 - Segment D

- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming.
- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020.
- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

Figure 4.2 - Segment E

The Gateway West Segment E project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The record of decision (ROD) and right-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management (BLM) to review progress.

Boardman-Hemingway (Segment H)

Boardman-to-Hemingway (B2H) is an approximately 290-mile high-voltage 500-kV transmission line capable of coming online in 2027. PacifiCorp is continuing to coordinate with regional transmission providers and retail customers to evaluate options for this project.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power's 2023 IRP identified the B2H as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2027 or beyond.

The BLM released its record of decision ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the

B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018, for lands administered by the USFS based on the analysis in the final environmental impact statement. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019, in support of construction of a portion of the B2H project on 7.1-miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

On September 27, 2022, Oregon's Energy Facility Siting Council approved the Oregon site certificate completing Oregon's permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, BPA and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville's exit of the project with Idaho Power acquiring Bonneville's share responsibility of the project. This will provide Idaho Power with a 45 percent share of the project and retain PacifiCorp's 55 percent share. Additional terms under negotiations include changes in transmission service between PacifiCorp and BPA, between BPA and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to BPA customers in southeast Idaho via the B2H line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power's transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023.

Idaho Power has applied for Certificates of Public Convenance and Necessity (CPCN) in Oregon and Idaho. Issuance of both certificates were received in June of 2023. PacifiCorp received a CPCN in Idaho in June 2023 and in Wyoming in August 2023.

The current project schedule includes projected completion in 2027.

At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Spanish Fork – Mercer 345-kV line

The 2025 preferred portfolio includes the construction of a new, approximately 50-mile, 345-kV transmission line between Spanish Fork Substation and Mercer substation in Utah, with an identified in-service date of 2036, based on projected interconnection requirements. Load-service and reliability requirements may bring this date forward, as could accelerated generator

interconnection demand. PacifiCorp has begun the permitting process for this new transmission line and is currently targeting an in-service date of 2027 for the line.

Other Transmission System Improvements

The 2025 IRP preferred portfolio also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

Energy Gateway Transmission Expansion Plan

Introduction

Given the long–lead time required to successfully site, permit, and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements and other state-specific policy goals. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy

groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

- **Rocky Mountain Area Transmission Study**
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion is like Gateway West.
  - Southeast Idaho to southwest Utah expansion akin to Gateway Central, Segment B, Segment C and Sigurd to Red Butte (in service 2015).
  - Improved east-west connectivity like Energy Gateway Segment H alternatives.

> "The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices."

- **Western Governors' Association Transmission Task Force Report**
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high conventional resource scenarios. Again, for PacifiCorp's system, the transmission expansion that supported these scenarios closely resembled Energy Gateway's configuration.

> "The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location."

- **NorthernGrid Regional Transmission Plan Reports**
  In the 2020-2021 NorthernGrid Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study: the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

> "After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

The NorthernGrid 2022-2023 Regional Transmission Plan identified the regional combination consisting of Gateway West (Segment D.3 and Segment E) and B2H as the most efficient and cost-effective set of projects for the NorthernGrid 10-year planning horizon. Gateway South was considered as an in-service project in all cases, including the selected regional combination.

- **WECC/Reliability Assessment Committee (RAC) Annual Reports and Western Interconnection Transmission Path Utilization Studies**
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

> "Path 19 [Bridger] is the most heavily loaded WECC path in the study…. Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

Energy Gateway Configuration

To address constraints identified on PacifiCorp's transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington. This plan contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was formally a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[3]

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to

[3] http://www.oatioasis.com/ppw/index.html

establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received more than 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway (B2H) project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing

authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500 kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the B2H Permitting Agreement with Idaho Power Company and BPA that provides for PacifiCorp's participation through the permitting phase of the project. The B2H project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the B2H project, and PacifiCorp continues to support these activities under the conditions of the B2H Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed and placed in service the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In October 2020, Segment D2 of Gateway West, from Aeolus to Jim Bridger was placed into service which included a new 500 kV substation at Aeolus, and a new 345 kV substation at Anticline.

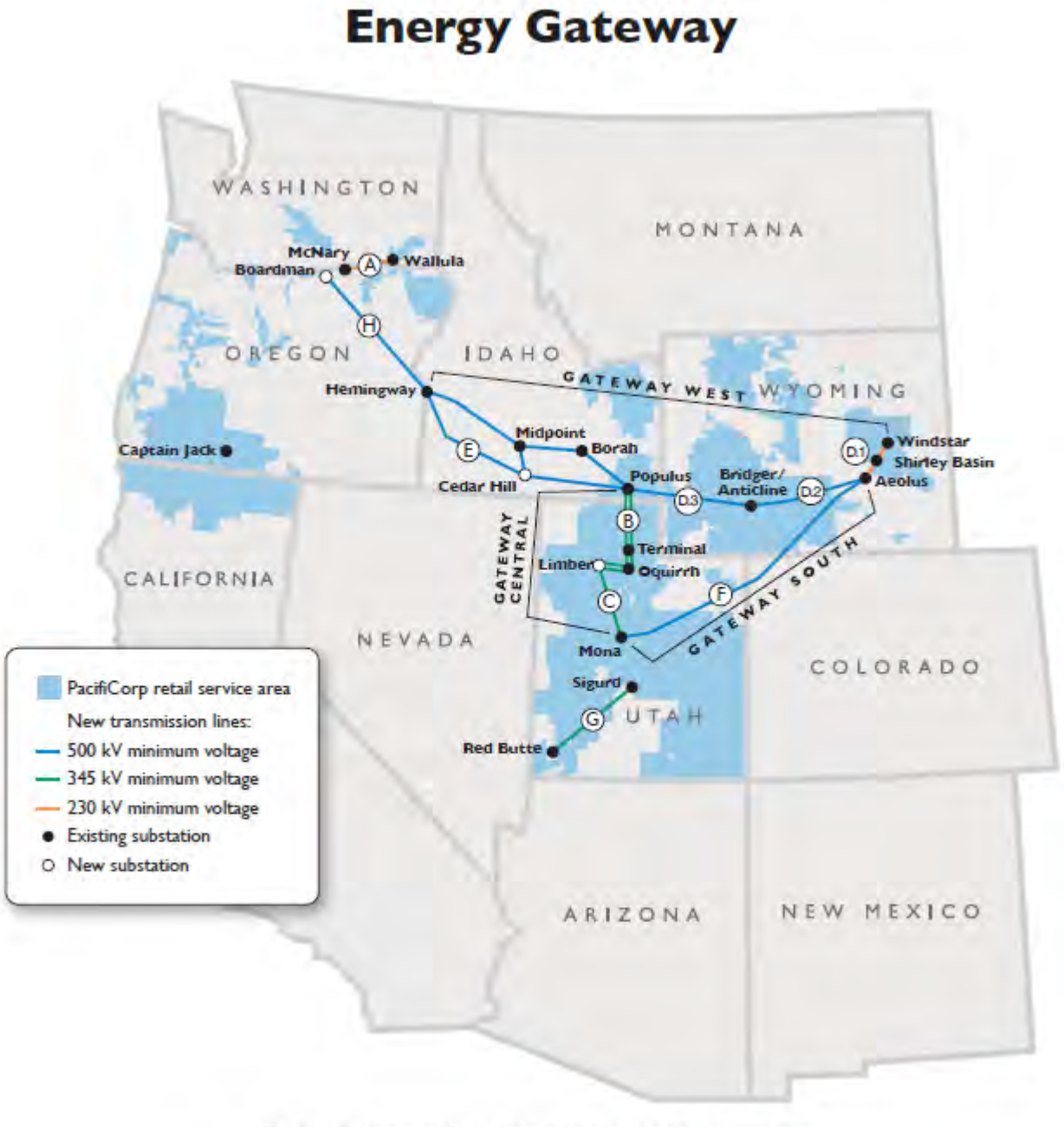
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 230 kV line between Shirley Basin and Dave Johnston substations is under construction with an expected completion date of both lines in December 2024.

Gateway Segment F, referred to as Gateway South, a 416-mile 500 kV line from Aeolus substation in Wyoming to Mona/Clover substation in central Utah is under construction with an expected completion date of December 2024.

Other Gateway segments, including Gateway West Segment D3 from Bridger substation in Wyoming to Populus substation in Idaho and Gateway West Segment E from Populus to Hemingway, in Idaho, are in pre-construction activities to address requirements as defined in their permitting Record of Decision and right-of-way grants issued by the BLM.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

Figure 4.3 – Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: right-of-way acquisition underway • Scheduled in-service: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2034 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2036 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pre-construction activities in progress • Scheduled in-service: 2027

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 20 remedial action schemes (RAS) to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market (EIM) since November 2014. As of April 2023, 22 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system can identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being

developed by the California Independent System Operator (CAISO).[4] While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

Transmission System Improvements Placed In-Service Since the 2023 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Installs a 345 kV, 200-MVAr switched shunt reactor at Mona substation:
        - Project driver was to address the high voltage conditions experienced during steady state operations under light load and light transfer conditions.
        - Benefits include more effective high voltage control and safe and more reliable power for the Utah area by reducing lines taken out of service and preservation of substation equipment life, particularly circuit breakers which are exposed to frequent switching, reduced probability of mis operation and increased maintenance costs.
2. Northern Utah/Southeast Idaho Area
    - Constructed a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Looped in the existing Populus – Terminal 345 kV line into Bridgerland and Ben Lomond substations:
        - Project driver was to resolve System Operating Limit on Path C.
        - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.
3. Salt Lake City Utah area
    - Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line:
        - Project driver was to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
        - Benefits included mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability.
4. Southern Utah area
    - Reconductor 2.57-miles of the St. George-Purgatory Flat 138 kV transmission line:
        - Project driver was to increase the thermal rating of the line which loaded to 95 percent of its continuous summer thermal rating summer 2022.
        - Benefits included the increases of the transmission line summer continuous rating by 63 MVA.

[4] http://www.caiso.com/Documents/EDAM-Fact-Sheet.pdf

PacifiCorp West (PACW) Control Area

1. Klamath Falls Oregon Area
    - Constructed a second 230 kV transmission line from Snow Goose to Klamath Falls substation:
        - Project driver was to resolve NERC Standard TPL-001-5 Category P6 (N-1-1) for a double contingencies on the 230-kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
        - Benefits included reinforcing 230 kV system between in Klamath Falls area to cover TPL-001-5 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.
2. Prineville Oregon Area
    - Construct a second 115 kV line between Houston Lake and Ponderosa substations:
        - Project driver was to eliminates potential N-1 overloads of the Prineville 115 kV system associated with increased load, changing generation mix, and grid flow conditions in the area.
        - Benefits included the elimination of a NERC Standard TPL-001-5 Category P1 contingency event for a fault on the 115 kV line between Baldwin Road and Ponderosa substation or a fault on the 115 kV line between Houston Lake and Stearns Butte.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area
    - Upgrade the 345-138 kV 167-MVA transformer at Camp Williams substation to a 345-138 kV 700-MVA transformer:
        - Project driver is to correct NERC Standard TPL-001-5 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
        - Benefits include mitigating the NERC Standard TPL-001-5 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability.
    - Install a second 345-138 kV 700 MVA transformer at Oquirrh substation:
        - Project driver is to correct N-1 contingency overload issues in the South Jordan area.

- Benefits include increasing capacity on the 138 kV network serving the Salt Lake Valley.

- Construct a new 345 kV line between Spanish Fork and Mercer 345 kV substations:
  - Project driver is to eliminate the need for the Lakeside II Remedial Action Scheme (RAS) and prevent generation shedding during contingencies. Once flows across the Wasatch Front South boundary exceed 5,562 MW, the Lakeside RAS is no longer effective and cannot be modified to accommodate more flow.
  - Benefits include the increase of path limit to 6,300 MW and allow 1,000 MW additional generation to be interconnected in southern Utah.

2. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers:
   - Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming:
     - Project driver was to correct NERC Standard TPL-001-5 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 12 substations to be addressed as required per R2.8.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-5 Requirement R2.3 deficiencies and as required per R2.8.
3. Salt Lake City, Utah Area:
   - Convert North Salt Lake Substation to 138-kV:
     - Project driver is to correct N-1 contingency overload issues in the North Salt Lake area.
     - Converting to 138 kV at North Salt Lake substation increases the capacity in the area while mitigating the contingency overloads, reduces the burden on the 46 kV system, and brings better reliability to the customers in the area.
   - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard:
     - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
     - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45-MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
   - Construct a new 230-46 kV substation near Eden, Utah:
     - Project driver is to provide a transmission loop to the area to facilitate a line rebuild through Ogden Canyon.
     - Benefits include improved future reliability and area capacity.
4. Southeast Idaho Area:
   - Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation:
     - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.

- Benefits include resolving the NERC Standard TPL-001-5 Category P1 voltage issues.

PacifiCorp West (PACW) Control Area

1. Eastern Oregon Area
   - Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers:
     - Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
     - Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.
2. Portland Oregon Area
   - Reconfigure and convert the existing Bonneville Power Administration's (BPA) St. Johns – Columbia and PacifiCorp's (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV:
     - Project driver is to correct NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies for load loss of up to 62-MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
     - Benefits include resolution of NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.
3. Roseburg Oregon Area
   - Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and construct a new 115 kV tie from Roberts Creek to the converted Green substation:
     - Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
     - Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3 percent per year rate.
   - Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer:
     - Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4 percent above nominal in the North Umpqua Hydroelectric System and is nearly 8.7 percent above nominal at Dixonville substation.
     - Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North

Umpqua areas extending the life of the transformers as well as all the downstream equipment.

4. Medford Oregon Area

- Construct a 230-kV transmission line between Lone Pine and Whetstone substations:
  - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230-kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230-kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230-kV line or Dixonville-Grants Pass 230-kV line.
  - Benefits include resolving the NERC Standard TPL-001-5 Category P1 and P6 issues as well as preventing reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
- Construct one new 500-230 kV substation called Sams Valley:
  - Project driver is to correct NERC Standard TPL-001-5 deficiencies for the loss of a single 230 kV line and for N-1-1 and N-2 outages to 230 kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500 kV source to address load growth in the Southern Oregon region.
  - Benefits include adding a second source of 500 kV capacity, adding a new 230-kV line, improving reliability of the 230 kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-5 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2025 IRP preferred portfolio includes the Energy Gateway South (GWS) and Energy Gateway West segment D.1, which are currently operational. The preferred portfolio also includes future transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of low-cost resource options and relieves stress on current assets.

Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong history of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp's resource planning and energy supply teams work closely with regional partners and ensure that there is sufficient supply to serve customers, while transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west to ensure that PacifiCorp can deliver power safely to customers now and in the future.

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2025 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information.

In December 2024 the Western Electricity Coordinating Council (WECC) published the Western Assessment of Resource Adequacy (WARA), which serves as an interconnection-wide assessment of resource adequacy as discussed below. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC WARA was published in December 2024 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years.[1] The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. A key driver of the results is the forecasted growth in load across the west, which is projected to increase by over 20.4% in the next ten years (on an energy basis), more than double the 9.6% growth forecast from the 2022 WARA. PacifiCorp's loads are located in the NW-Northwest and NW-Central regions evaluated as part of the WARA. Peak demand in the NW-Northwest region is forecasted to grow by 13.5% in the next ten years, while the NW-Central region is forecasted to grow by 8.5% over the same time. While significant, these are both lower than the growth of the Western Interconnection as whole, where growth is projected at 17.2%, driven by increases in California and the Desert Southwest.

Resource plans have identified a vast quantity of resources to meet this demand, 172 GW of new generation resources, which is more than double the generation capacity added in the last ten years. Plans include 68 GW of solar capacity additions in the next ten years, while will nearly triple the 35 GW in operation in 2023, plus 40 GW of wind capacity additions in the next ten years, relative to 37 GW in operation in 2023. Similarly, battery storage is projected to grow by 37 GW. The WARA highlights concerns that planned resources will not be brought online in a timely manner and includes four scenarios evaluating various levels of resource build out.

In the "All Additions" scenario, which includes all planned resources, the WARA identifies risks in the NW-Northwest region, primarily in the winter, and primarily in 2029 and later. Risks increase and appear in other regions if lower levels of planned resources are achieved, as summarized in Table 5.1.

Table 5.1 – WARA Demand-at-Risk Summary[2]

	Month											
	55% Resource Additions Scenario											
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	Medium	Medium	Low	-	-	-
NW-Northwest	High	High	Medium	Low	-	-	Low	Medium	Medium	High	High	High
NW-Northeast	-	Low	-	-	-	-	Low	Medium	-	-	-	-
NW-Central	-	-	-	-	-	Low	Medium	Medium	Medium	-	-	-
	Month											
	85% Resource Additions Scenario											
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	-	-	-	-	-	-
NW-Northwest	Medium	Medium	-	-	-	-	-	Low	-	Medium	Low	Medium
NW-Northeast	-	Low	-	-	-	-	-	Low	-	-	-	-
NW-Central	-	-	-	-	-	Low	Low	Low	Medium	-	-	-

Risk reflects the count of hours in each month that exceed a one-day-in-ten-years threshold by 2034.

High >50 hours Medium 10-49 hours Low <10 hours

[1] WECC. Western Assessment of Resource Adequacy 2024. Available online: https://feature.wecc.org/wara/ (accessed 12/18/2024)

[2] WECC. WARA 2024 Demand-at-Risk Hours by Subregion. Available online at: https://www.wecc.org/wecc-document/17071 (Accessed 12/18/2024)

The NW-Northwest and NW-Central regions which include PacifiCorp's load both have hours at risk. In the NW-Northwest region, significant risk exists in both the summer and winter seasons. While PacifiCorp has significant transfer capability into the NW-Northwest and proportionately lower dependence on hydropower than the NW-Northwest region as a whole, regional capacity limitations would result in less margin for error. In the NW-Central region, risks are somewhat lower, and concentrated in the summer, but still indicate that incremental resources are necessary to serve growing loads. The results shown assume import capability between sub-regions – in the absence of imports, risks are high in the NW-Northwest and NW-Central regions even if all planned new resources are built.

The WARA characterizes four risks that impact planned resource additions: supply chain disruptions, interconnection queue, siting delays, and increased costs. Some of the impacts are reduced because of PacifiCorp's particular circumstances. PacifiCorp's relatively large portfolio and geographic footprint create a wider range of opportunities than are available to many other utilities, increasing the likelihood that some new projects will be able to proceed. This is bolstered by PacifiCorp's implementation of a cluster study interconnection process in 2020, which has enabled large numbers of interconnection requests to be processed more quickly than was possible in the past, increasing the likelihood that projects will be available in desired timeframes. After cost-effective projects are identified, PacifiCorp's relatively large demand allows it to contract with multiple developers for multiple sites, reducing the impact if any single developer or site falls through or is delayed. That said, substantial risks remain for any resource additions.

The WARA also characterizes risks associated with other factors: resource variability, transmission considerations, energy policy, and extreme weather. The limitations of wind, solar, and energy-limited resources like energy storage are different from those of baseload or dispatchable resources, and those limitations become more restrictive as the share of these resources increases. Given the expected tripling of solar capacity and doubling of wind capacity, variability is expected to increase significantly. The variability and operational requirements of that future resource mix is not fully characterized and could be impacted further by extreme weather events. The other risk factors cover a range of planning and policy considerations, and the process through which resource and transmission build outs are implemented. Utility planning and procurement takes time, and the build out of resources and transmission is reliant upon a range of state and federal processes and requirements.

NERC Long-Term Reliability Assessment (LTRA)

Resources

As part of the regional reliability assessment to support the 2025 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2024.[3] The NERC LTRA organizes prospective resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

- Tier 1: resources under construction, or with signed contracts.
- Tier 2: resources with completed interconnection studies.
- Tier 3: resources in an interconnection queue that do not meet the Tier 2 requirement.

Planning Reserve Margin

The LTRA defines "planning reserve margin" as the difference between resources and demand, divided by demand, expressed as a percentile.

Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- High Risk: shortfalls may occur at normal peak conditions.
- Elevated Risk: shortfalls may occur in extreme conditions.
- Normal Risk: low likelihood of electricity supply shortfall.

WECC Subregions

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peak
NW	The rest of WECC, beyond the exceptions listed below	United States	Summer
SW	Primarily Arizona and New Mexico	United States	Summer
CA/MX	California / Mexico	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 presents the WECC LTRA assessments for the three WECC subregions that include the United States. Anticipated Reserve Margin is based on existing resources, firm transfers, and Tier 1 additions, less confirmed retirements. Prospective Reserve Margin adds existing resources without firm transmission, or with other potential limitations, likely transfers, and Tier 2 capacity additions, less unconfirmed retirements. Values that fall below the reference margin level (i.e. planning target) are highlighted.

[3] NERC. 2024 Long-Term Reliability Assessment. December 2024. Available online at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed 12/18/2024)

Table 5.3 – NERC LTRA for Selected WECC Subregions

WECC-NW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	*16.3%*	*15.8%*	*15.9%*	*15.4%*	*14.7%*	*14.5%*	*14.3%*	*14.2%*	*14.4%*	*13.8%*

WECC-SW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	*11.0%*	*10.8%*	*12.0%*	*11.7%*	*10.2%*	*10.1%*	*9.9%*	*9.7%*	*10.8%*	*9.4%*

WECC-CA/MX

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	*17.4%*	*17.4%*	*16.4%*	*17.4%*	*16.6%*	*16.4%*	*16.1%*	*16.3%*	*14.9%*	*15.3%*

As shown, the WECC-NW subregion that includes PacifiCorp's load meets the reference margin with anticipated resources through 2030, and with prospective resources through the ten-year horizon. The WECC-SW subregion also meets the reference margin with anticipated resources through 2030 but only has sufficient prospective resources through 2031. The WECC-CA/MX region meets the reference margin with anticipated resources through 2033, and with prospective resources through the ten-year horizon. While this presents a relatively favorable view of supply and demand, the LTRA definition of Tier 1 resources includes everything with an interconnection agreement and/or power purchase agreement. Not all such resources will ultimately be brought online in a timely manner. The factors identified the WECC WARA (supply chain disruptions, interconnection queue, siting delays, and increased costs) can all derail projects that are otherwise feasible.

Pacific Northwest Power Supply Adequacy Assessment

The Northwest Power and Conservation Council released its 2029 Adequacy Assessment in August 2024.[4] Starting in 2011, an annual loss-of-load-probability of up to five percent was deemed adequate. Starting with the 2023 assessment a multi-metric framework of shortfall frequency, duration, and magnitude was used. These metrics include:

- **Loss of load events (LOLEV):** limits the expected frequency of shortfall events to protect against frequent use of emergency measures.
- **Duration Value at Risk**: limits shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
- **Peak Value at Risk**: limits maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
- **Energy Value at Risk**: limits total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

An adequate system must meet all these metrics. The 2029 Adequacy Assessment is based on the 2021 Northwest Power Plan, discussed below, with updates for expected changes through 2029, including load growth, resource development, and transmission. Based on updated results for adequacy in year 2029, the 2029 Adequacy Assessment concludes that power supply would be

[4] Northwest Power and Conservation Council. Pacific Northwest Power Supply Adequacy Assessment for 2029. August 2024. Available online at: https://www.nwcouncil.org/fs/18853/2024-4.pdf (accessed 12/18/2024)

adequate under reference conditions. This conclusion is in part based on coal plants changing to natural gas, rather than retiring (including Jim Bridger 1 and 2, which were converted in 2024). The 2029 Adequacy Assessment identifies two scenarios that could lead to reliability shortfalls. First, if energy efficiency savings only meet the low end of the targeted quantity, shortfall risks increase in the winter. Second, higher data center loads in the absence of commensurate resource supply could lead to reliability shortfalls in both the winter and the summer. An additional potential risk is related to the Boardman-to-Hemingway project which the 2029 Adequacy Assessment assumes is operational by 2029, increasing transfer capability between Idaho and the Pacific Northwest, as this upgrade is not part of PacifiCorp's 2025 IRP preferred portfolio. The metric results from the 2029 Adequacy Assessment are provided in Table 5.4, with shortfalls highlighted in orange.

Table 5.4 – Northwest Power and Conservation Council 2029 Adequacy Assessment

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.35	1.294
Frequency	Summer LOLEV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9600 MWh	0	4,196	196,324

Western Resource Adequacy Program (WRAP)

The WRAP is a regional reliability planning and compliance program, intended to help facilitate region-wide resource adequacy, and initiated on behalf of the utilities that are part of the Western Power Pool (formerly the Northwest Power Pool). WRAP allows for coordination and visibility of resource needs and supply among the participants, taking advantage of the diversity and sharing from pooling resources.

WRAP begins with regional analysis, as the program sets regional reliability metrics for upcoming seasons, including planning reserve margins that are applied to loads and qualifying capacity contributions that apply to resources. With those values in hand, utilities must secure resources and, seven months prior to the start of a winter or summer season, must submit a forward showing demonstrating they have resources and transmission to cover their load and planning reserve margin requirements. Time is provided to cover shortfalls before the season begins. Within the season, an operational component allows those participants with a day-ahead resource shortfall to call upon the program and receive incremental resources from participants who have a surplus.

WRAP is based on two seasons: summer (June through September) and winter (November through March). Planning reserve margins vary by month, and by region, as WRAP covers two regions: the Pacific Northwest (primarily Oregon and Washington and British Columbia, with parts of northern Idaho and Montana) and the Desert Southwest, including the remainder of Idaho, Utah, Wyoming, Colorado, Nevada, and Arizona. Similarly, monthly qualifying capacity contributions are calculated for each resource, and capture technology type, regional variations, and resource-specific performance. For example, wind and solar contributions incorporate a resource's output

during capacity critical hours (the highest load hours after netting out wind, solar, and run of river hydro generation).

As of September 2024, the Western Power Pool Board of Directors has approved updates to the WRAP tariff along with seven business practice manuals detailing of the program will operate. WRAP is currently operational with non-binding requirements and has plans in place to enable fully binding operations in Summer 2027 for participants that provide notice of their intent by January 2026. All participants will be binding for Winter 2027-2028 (i.e. starting November 2027). If a WRAP Participant chooses to exit the program, a two-year exit period applies. Current WRAP Participants have until October 31st, 2025, to exit the program without being subject to a financially binding season.

PacifiCorp is currently participating in WRAP and is working with the Western Power Pool to address outstanding issues, including the interaction between WRAP and the CAISO's Enhanced Day-Ahead Market (EDAM) and complexity from PacifiCorp's footprint spanning both WRAP regions. While issues remain, PacifiCorp's 2025 IRP includes modeling to capture WRAP compliance requirements starting in 2028 and continuing through the study horizon. While proxy resource selections within the 2025 IRP can only begin on January 1st of each year, actual resource procurement could be targeted to the November 2027 start date to the extent necessary, or short-term products could be used to address unmet requirements, if any.

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp previous IRP modeling has included front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions. However, market transactions that are not based on a specified source do not provide qualifying capacity for WRAP compliance. While other short-term products exist, such as slices of hydropower projects on the Mid-Columbia or tolling agreements for merchant-owned natural gas plants, there are relatively few such opportunities and there may be significant competition for such products given rising demand and stricter resource adequacy requirements under WRAP. With that in mind, for the 2025 IRP, PacifiCorp is not including short-term market products as options for WRAP compliance.

WRAP compliance does not guarantee reliability, in particular a monthly qualifying capacity contribution value does not ensure resources will be available to meet hourly requirements such as the hourly balancing test in the EDAM. At the same time, PacifiCorp recognizes that increasing coordination of spot market transactions through EIM, EDAM, and WRAP is likely to provide significant economic benefits. To balance the limitations of market transactions for capacity and reliability requirements and the benefits of market transactions for regional dispatch, the 2025 IRP does not allow market purchases in certain key periods, but otherwise allows market purchases up to transmission limits. During the summer WRAP season (June through September), market purchases are not allowed from 4:00 p.m. to 12:00 a.m. on PacifiCorp's top five load days in each month. Similarly, in the winter WRAP season (November through March), market purchases are

not allowed from 4:00 a.m. to 8:00 a.m. as well as 4:00 p.m. to 12:00 a.m., again on PacifiCorp's top five load days in each month. For the 2025 IRP, PacifiCorp is also differentiating market prices within each month, to reflect historical patterns on the days used to derive the chaotic normal load forecast and reflecting the same weather conditions used to develop wind and solar generation profiles. In general, market prices are higher when load is high and wind and solar output is relatively low, though market prices reflect region-wide conditions of PacifiCorp's supply and demand is only a part. Market prices in EIM and EDAM will reflect the balance of supply-and-demand, and surplus supply from PacifiCorp is likely to result in lower market clearing prices. While this effect is not captured in PacifiCorp's hourly market price forecast, market sales for the 2025 IRP have been capped at historical average levels, since large surpluses would impact pricing.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, the company will continue to refine its assessments of market depth and liquidity for transactions to quantify the risk associated with the level of market reliance. Additional description is provided in Volume I, Chapter 7 (Resource Options); also, see the sensitivities discussion in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2025 IRP to assess the ways in which climate change may impact planning assumptions.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2004 through 2023. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. These temperature changes lead to higher summer peaks and lower winter peaks, with increasing impacts across the study horizon. See Appendix A for additional detail regarding how climate change is incorporated into the load forecast.

Weather-Related Impacts to Variable Generation

New for the 2025 IRP, all wind and solar generation profiles are based on historical weather conditions on the same historical day underlying the load forecast. This captures the relationship between load, wind, and solar that happened in recent history. Each month of the Company's chaotic normal load forecast reflects the range of weather conditions experienced in the most typical month from 2013-2022, while stochastic analysis for the 2025 IRP will reflect the range of weather conditions experienced in every year from 2006-2023. The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios. For the 2025 IRP, PacifiCorp is not projecting specific climate impacts on wind and solar generation but notes that recent history

may be more representative of future conditions than earlier conditions. As a result, reliability and system cost risks identified using inputs derived from recent historical years may be of greater concern as an indicator of future risk.

Wildfire Impacts

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to

modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

Impacts on Wind and Solar Energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[5] Some broad impacts anticipated from climate change are noted below:[6]

Wind Energy

- Changes to wind speed: could impact energy assessments.
- Changes in temperature: with increased temperatures the air density could reduce energy outputs.
- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand.

[5] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.

[6] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Rising sea levels: could damage offshore wind farm infrastructure.

Solar Energy

- Changes in mean temperatures: increased global temperatures could reduce cell efficiency.
- Changes in solar irradiation, dirt, snow, precipitation: increase in these variables could reduce energy output.

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

Wildfire Risk Mitigation

PacifiCorp's Wildfire Mitigation Plans (WMPs) are designed to meet regulatory requirements while delivering safe and reliable power. These plans focus on enhancing situational awareness, implementing robust operational practices, and hardening the power system to mitigate wildfire risks while balancing customer and community impacts.[7]

PacifiCorp Wildfire Mitigation Plan Regulatory Compliance

PacifiCorp meets regulatory requirements through the submittal of Wildfire Mitigation Plans (WMPs) with the specific regulatory alignments for each state stated below:

1. **California**: The WMP complies with California Senate Bill 901 and the California Public Utilities Commission (CPUC) provisions under Section 8386.
2. **Idaho**: The WMP was submitted in accordance with Idaho Public Utilities Commission Order No. 36045.
3. **Utah**: The WMP adheres to Utah Administrative Code R746-315-2, effective June 1, 2023, and complies with Subsection 54-24-201.
4. **Oregon**: The WMP meets the requirements set forth in Oregon Administrative Rule 860-300-0040.
5. **Washington**: The WMP was submitted on October 31, 2024, and compliance with statutory requirements was confirmed by the Washington Utilities and Transportation Commission as complying with the Revised Code of Washington (RCW) 80.28.440.

Although Wyoming does not have regulatory requirements for a wildfire mitigation plan, PacifiCorp has proactively filed one in conjunction with the general rate case.

Core Principles

All WMPs are publicly accessible via the PacifiCorp Wildfire Mitigation Plan website (linked here). These plans detail the investments and strategies for constructing, maintaining, and operating electrical lines and equipment for wildfire mitigation projects and programs. While there

[7] Wildfire mitigation and impacts were discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

are state-specific requirements, the core strategy across all six states remains consistent, guided by the following principles:

- **Situational Awareness and Operational Readiness**: Implementing systems that enhance situational awareness, and operational readiness is crucial for mitigating fire risks and their impacts.
- **Operational Practices**: Minimizing the impact of fault events through rapid isolation using advanced equipment and trained personnel.
- **System Hardening**: Reducing the frequency of ignition events by engineering more resilient systems that experience fewer faults.

Balancing Mitigation and Community Impact

PacifiCorp is committed to balancing wildfire risk mitigation with the needs of customers and communities. Adjustments to power system operations, such as modifying protective device settings and testing protocols, are carefully considered to reduce wildfire risks. These measures are applied selectively to avoid unnecessary disruptions to the power supply.

The wildfire mitigation program approach includes deploying advanced technologies like fault indicators and assessing outages to inform short-term mitigation projects. These efforts are designed to enhance safety while maintaining reliable service.

PacifiCorp's Wildfire Mitigation Plans (WMPs) reflect the Company's dedication to balancing costs, benefits, operational impacts, and risk mitigation with the goal to provide safe, reliable, and affordable electric service, prioritizing the well-being of customers and communities.

Transmission-Based Reliability

PacifiCorp is required to meet mandatory FERC, NERC, and WECC reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generating resources for reserve capacity to comply with mandatory reliability standards.

Federal Reliability Standards

The Energy Policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in short-term (1-2 years), medium term (5 years) and long-term (10-20 years) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 as detailed in Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produce a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers. In 2024, FERC issued Order 1920 which will further expand regional planning processes, including a requirement for a long-term (20 year) regional plan. PacifiCorp is working with NorthernGrid members to draft tariff revisions to outline the expanded process in preparation for the FERC required compliance filing in August 2025.

Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study if the study determines that mitigations are required due to retirement.

Past studies have found that several factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit designation/retirement is received, all such coal retirement analysis is considered preliminary.

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- New for the 2025 IRP, PacifiCorp is calculating its capacity position based on Western Resource Adequacy Program (WRAP) compliance requirements, with binding operations under the program expected to begin by 2028. WRAP participants with projected resource shortfalls on a day-ahead basis will be able to purchase from WRAP participants with excess supply.
- Every resource has a qualifying capacity contribution (QCC) for each month of the summer (June-September) and winter (November-March) seasons. These values are calculated by WRAP based on resource-specific historical performance and are based on the loads and resource mix of the regional participants. These values are updated by WRAP ahead of each compliance season.
- Seven months prior to the start of each season, WRAP participants must make a forward showing, demonstrating that the QCC for their resources is sufficient to meet their peak load plus a monthly planning reserve margin determined by WRAP.
- While WRAP is projected to enhance reliability by providing priority access to supply from other participants, the monthly QCC values do not ensure a utility will be reliable or have sufficient resources to meet its requirements from hour to hour, so hourly analysis of the load and resource balance is also necessary.
- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements.
- The company's load obligation is calculated based on projected load less distributed generation, energy efficiency savings, and demand response, including interruptible load.
- A distributed generation study prepared by DNV produced estimates on distributed generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2025 IRP load and resource balance reflects base case distributed generation penetration levels as a reduction in load.
- Relative to WRAP compliance requirements, PacifiCorp's system is capacity deficient (before adding proxy resources other than energy efficiency, and without considering short-term capacity procurement, i.e. market purchases) in the summer beginning in 2026, and the winter peaks throughout the planning horizon.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. PacifiCorp's 2025 IRP reflects renewable resource generation profiles based on the same patterns of historical weather conditions used to develop its load forecasts, both on a normalized basis and for stochastic analysis. While adjustments to account for climate change are included in the base forecast, customer demand may be further influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Appendix A (Load Forecast). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2025 IRP relies on PacifiCorp's May 2024 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency. The system summer peak load grows at a compound annual growth rate (CAGR) of 1.67 percent over the period 2025 through 2044.

Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System	11,318	11,270	11,425	11,553	11,690	11,844	12,104	12,193	12,363	12,575
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
System	12,819	13,134	13,404	13,693	13,978	14,279	14,581	15,008	15,237	15,518

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "End of Coal-fired Operation" reflects the year a resource must retire or converts to natural gas (if option is available) as reflected in modeling inputs.

Table 6.2 – Coal-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)	End of Coal-fired Operation
Colstrip 3	10	Montana	74	2025 (Transfer capacity to unit 4)
Colstrip 4	10*	Montana	74	2029 (PacifiCorp exit)
Craig 1	19	Colorado	82	2025 (Assumed end of life)
Craig 2	19	Colorado	79	2028 (Assumed end of life)
Dave Johnston 1	100	Wyoming	99	2028 (Gas conversion option)
Dave Johnston 2	100	Wyoming	106	2028 (Gas conversion option)
Dave Johnston 3	100	Wyoming	220	2027 (Retire: Clean air compliance)
Dave Johnston 4	100	Wyoming	330	
Hayden 1	24	Colorado	44	2028 (Assumed end of life)
Hayden 2	13	Colorado	33	2027 (Assumed end of life)
Hunter 1	94	Utah	418	
Hunter 2	60	Utah	269	
Hunter 3	100	Utah	471	
Huntington 1	100	Utah	459	
Huntington 2	100	Utah	450	
Jim Bridger 3	67	Wyoming	349	
Jim Bridger 4	67	Wyoming	351	
Naughton 1	100	Wyoming	156	2025 (Gas conversion option)
Naughton 2	100	Wyoming	201	2025 (Gas conversion option)
Wyodak	80	Wyoming	268	
TOTAL – Coal			**4,533**	

*PacifiCorp's share of Colstrip 4 is projected to include its current ownership of Colstrip 3 starting in 2026.

Table 6.3 – Natural Gas-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)
Chehalis	100	Washington	500
Currant Creek	100	Utah	540
Gadsby 1	100	Utah	64
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	40
Gadsby 5	100	Utah	40
Gadsby 6	100	Utah	40
Hermiston	100	Oregon	237
Jim Bridger 1	67	Wyoming	354
Jim Bridger 2	67	Wyoming	359
Lake Side	100	Utah	580
Lake Side 2	100	Utah	677
Naughton 3	100	Wyoming	247
TOTAL – Natural Gas			**3,852**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 5,154 MW of wind resources. Table 6.4 shows existing (or under construction) wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Goodnoe Hills East	WA	94
Leaning Juniper	WA	101
Marengo I	WA	156
Marengo II	WA	78
Cedar Springs 2	WY	199
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
High Plains	WY	99
McFadden Ridge 1	WY	29
Pryor Mountain	WY	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats 1-2	WY	500
Foote Creek II-IV	WY	43
Rock Creek I	WY	190
Rock Creek II	WY	400
Rock River	WY	50
TOTAL – Owned Wind		**2,937**

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements	State	PPA or QF	Capacity (MW)
Wolverine Creek	ID	PPA	65
Chopin-Schumann	WA	QF	8
Cedar Springs I	WY	PPA	199
Cedar Springs III	WY	PPA	133
Three Buttes Power	WY	PPA	99
Top of the World	WY	PPA	200
Meadow Creek Project Five Pine	ID	QF	40
Meadow Creek Project North Point	ID	QF	80
Latigo	UT	QF	60
Mountain Wind I	UT	QF	61
Mountain Wind II	UT	QF	80
Power County Park North	UT	QF	23
Power County Park South	UT	QF	23
Spanish Fork Park 2	UT	QF	19

Tooele 1 and 2	UT	QF	3
Big Top	WA	QF	2
Butter Creek Power	WA	QF	5
Chopin	WA	QF	10
Four Corners	WA	QF	8
Four Mile Canyon	WA	QF	10
Orchard 1	WA	QF	10
Orchard 2	WA	QF	10
Orchard 3	WA	QF	10
Orchard 4	WA	QF	10
Oregon Trail	WA	QF	10
Pacific Canyon	WA	QF	8
Sand Ranch	WA	QF	10
Three Mile Canyon	WA	QF	8
Wagon Trail	WA	QF	3
Ward Butte	WA	QF	7
BLM Rawlins	WY	QF	0.1
Pioneer Park I	WY	QF	80
Cedar Creek	ID	PPA	152
Anticline	WY	PPA	101
Boswell	WY	PPA	320
Cedar Springs IV	WY	PPA	350
TOTAL – Purchased Wind			**2217**

Solar

PacifiCorp has a total of 97 solar projects under contract representing 3,615 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 550 MW of battery storage. Table 6.6 list solar power purchase agreements, and through Table 6.7 through Table 6.9 list solar qualifying facilities for each relevant state.

Table 6.6 – Solar Power Purchase Agreements

Power Purchase Agreements			
Resource	**State**	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Black Cap	OR	2	-
Millican	OR	60	-
Old Mill	OR	5	-
Oregon Solar Incentive Project	OR	9	-
Prineville	OR	40	-
Appaloosa Solar IA	UT	120	-
Appaloosa Solar IB	UT	80	-
Castle Solar (Retail 1)	UT	20	-
Castle Solar (Retail 2)	UT	20	-
Cove Mountain	UT	58	-
Cove Mountain II	UT	122	-
Elektron Solar 20Yr	UT	10	-
Elektron Solar 25Yr	UT	70	-
Faraday	UT	525	150
Graphite	UT	80	-
Green River	UT	400	400
Hornshadow Solar I	UT	100	-
Hornshadow Solar II	UT	200	-
Horseshoe	UT	75	-
Hunter	UT	100	-
Milford	UT	99	-
Pavant III	UT	20	-
Rocket	UT	80	-
Sigurd	UT	80	-
TOTAL – Power Purchase Agreements		**2375**	**550**

Table 6.7 – Solar Qualifying Facilities, Oregon

Oregon Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
7 Mile Solar	1	-
Adams	10	-
Antelope Creek Solar	2	-
Bear Creek	10	-
Black Cap II	8	-
Blackwell Creek Solar*	1	-
Bly	8	-
Buckaroo Solar 1*	3	-
Buckaroo Solar 2*	3	-
Canyonville Solar 1*	1	-
Canyonville Solar 2*	2	-
Chapman Creek Solar*	3	-
Cherry Creek Solar*	0.4	-
Chiloquin Solar	10	-
Elbe	10	-
Goodling Community Solar*	1	-
Green Solar*	3	-
Hay Creek Solar*	0.6	-
Klamath Falls Solar 1	0.8	-
Klamath Falls Solar 2	3	-
Linkville Solar*	3	-
Merrill	10	-
Norwest Energy 2 (Neff)	10	-
Norwest Energy 4 (Bonanza)	6	-
Norwest Energy 7 (Eagle Point)	10	-
Norwest Energy 9 Pendleton	6	-
OR Solar 2, LLC (Agate Bay)	10	-
OR Solar 3, LLC (Turkey Hill)	10	-
OR Solar 6, LLC (Lakeview)	10	-
OR Solar 8, LLC (Dairy)	10	-
Orchard Knob Solar	2	-
OSLH Collier	10	-
Pilot Rock Solar 1*	3	-
Pilot Rock Solar 2*	3	-
Pine Grove Solar	1	-
Round Lake Solar	1	-
Skysol	55	-
Solorize Rogue*	0.1	-
Sunset Ridge Solar	2	-
Tumbleweed	10	-
Tutuilla Solar*	2	-
Wallowa County*	0.4	-
Whisky Creek Solar*	0.2	-
Wocus Marsh Solar*	0.9	-
Wood River Solar*	0.4	-
Woodline Solar	8	-
TOTAL – Oregon Solar QF Resources	**264**	**0**

*New project added in 2025 IRP

Table 6.8 – Solar Qualifying Facilities, Utah

Utah Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Beryl	3	-
Buckhorn	3	-
CedarValley	3	-
Enterprise	80	-
Escalante I	80	-
Escalante II	80	-
Escalante III	80	-
Ewauna	1	-
Ewauna II	3	-
Granite Mountain - East	80	-
Granite Mountain - West	50	-
GranitePeak	3	-
Greenville	2	-
Iron Springs	80	-
Laho	3	-
Milford 2	3	-
Milford Flat	3	-
Pavant	50	-
Pavant II	50	-
Quichapa I	3	-
Quichapa II	3	-
Quichapa III	3	-
Red Hill	80	-
South Milford	3	-
SunE1	3	-
SunE2	3	-
SunE3	3	-
Three Peaks	80	-
TOTAL – Utah Solar QF Resources	**838**	**0**

Table 6.9 – Solar Qualifying Facilities, Wyoming

Wyoming Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Sage I	20	-
Sage II	20	-
Sage III	18	-
Sweetwater	80	-
TOTAL – Wyoming Solar QF Resources	**138**	**0**

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW,

was completed at the end of 2007. The Oregon Institute of Technology has a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

Distributed Generation Resources

Table 6.10 provides a breakdown of distributed generation capacity and customer counts from data collected as of March 31, 2024. In addition to resources, PacifiCorp's customers also have over 60 MW of battery storage capacity. For forecasted growth in distributed generation and storage, please refer to Appendix L (Distributed Generation Study).

Table 6.10 – Distributed generation Customers and Capacity

Fuel	Solar	Wind	Gas[1]	Hydro	Mixed[2]
Nameplate (kW)	772,160	847	784	965	1,233
Capacity (percentage of total)	99.51%	0.11%	0.10%	0.12%	0.16%
Number of customers	86,449	192	3	21	63
Customer (percentage of total)	99.68%	0.22%	0.00%	0.02%	0.07%

[1] Gas includes: biofuel, waste gas, and fuel cells

[2] Mixed includes projects with multiple technologies, one project is solar and biogas, and the others are solar and wind

Energy Storage

In addition to the battery storage contracted with solar resources listed in Table 6.6 PacifiCorp has existing or committed battery storage projects totaling approximately 523 MW of nameplate capacity, as shown in Table 6.11.

Table 6.11 – Storage Resources

Power Purchase Agreements / Exchanges	State	Technology	Capacity (MW)
Dominguez Storage*	UT	Battery	200
Enterprise*	UT	Battery	80
Escalante*	UT	Battery	80
Granite Mountain*	UT	Battery	80
Iron Springs*	UT	Battery	80
Panguitch	UT	Battery	1
Oregon Institute of Technology (OIT)	OR	Battery	2
TOTAL – Purchased Battery			**523**

*New project added in 2025 IRP

Hydroelectric Generation

PacifiCorp owns or purchases over 1,200 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that

can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity available from hydroelectric plants is dependent upon several factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control.

Table 6.12 – PacifiCorp Hydroelectric Generation Facilities

Plant	River System	State	Capacity (MW)
East - Owned			
Cutler	Bear	UT	29
Grace	Bear	UT	33
Oneida	Bear	UT	27.9
Soda	Bear	UT	14
Small East [1/]	Other	UT	20.5
West - Owned			
Bend	Other	OR	1
Big Fork	Other	MT	4.6
Swift 1 [2/]	Lewis	WA	263.6
Yale	Lewis	WA	163.6
Merwin	Lewis	WA	151
Clearwater 1	N. Umpqua	OR	17.9
Clearwater 2	N. Umpqua	OR	31
Fish Creek	N. Umpqua	OR	10.4
Lemolo 1	N. Umpqua	OR	32
Lemolo 2	N. Umpqua	OR	38.5
Slide Creek	N. Umpqua	OR	18
Soda Springs	N. Umpqua	OR	11.6
Toketee	N. Umpqua	OR	45
Eagle Point	Rogue	OR	2.8
Prospect 1	Rogue	OR	4.6
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7.7
Prospect 4	Rogue	OR	0.9
Fall Creek	Other	OR	2
Wallowa Falls	Other	OR	1.1
		Total Owned	**968**
Qualifying Facilities (QF)			
QF	Various	CA	9.4
QF	Various	ID	22.7
QF	Various	OR	40
QF	Various	UT	2.2
QF	Various	WA	2.9
Mid-Columbia	Columbia	WA	170
		Total QF	**247**
Total Hydroelectric			**1215**

[1/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.

[2/] Cowlitz County PUD owns Swift No. 2 and is operated in coordination with other Lewis River projects by PacifiCorp.

Demand-Side Management/Distributed Generation

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories, or "classes." These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Modeling includes program drop-out rate and event non-performance rate assumptions to account for program parameters. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program. These are considered Class 1 DSM resources.

- **Energy Efficiency—Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at businesses. The savings are considered firm over the life of the improvement or customer action. These are considered Class 2 DSM resources.

- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. These are considered Class 3 DSM resources.

- **Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Like price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs. These are considered Class 4 DSM resources.

PacifiCorp has been operating successful DSM programs since the late 1970s. Over time, PacifiCorp's DSM acquisition has grown in investment levels, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 6.13 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.13 is shown as having zero MW.[1] Similarly, demand response resources available to the preferred portfolio, are characterized as incremental to Table 6.13. For a summary of current DSM program offerings in each state, refer to Appendix D (Demand-Side Management Resources).

[1] The historical effects of previous energy efficiency savings are captured in the load forecast before the modeling for new energy efficiency.

Table 6.13 – Existing DSM Resource Summary

Program	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2025-2045 Period
Demand Response	Residential/small commercial air conditioner load control	135 MW summer[1/]	Yes.
	Irrigation load management	200 MW summer	Yes.
	Interruptible contracts	136 MW summer	Yes.
	Wattsmart® Batteries	32 MW summer	Yes.
	Wattsmart® Business	45 MW summer	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW	No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Price Response and Load Shifting	Time-based pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education and Information	Energy education	Energy and capacity impacts are not available/measured.	No. Historical savings from customer participation are reflected in the load forecast.

[1/] A/C load control is based on long duration event characterization which assumes 50% cycling of ACs. A faster event (<1 hr) is characterized as 270 MW within the model.

Distributed Generation Forecast

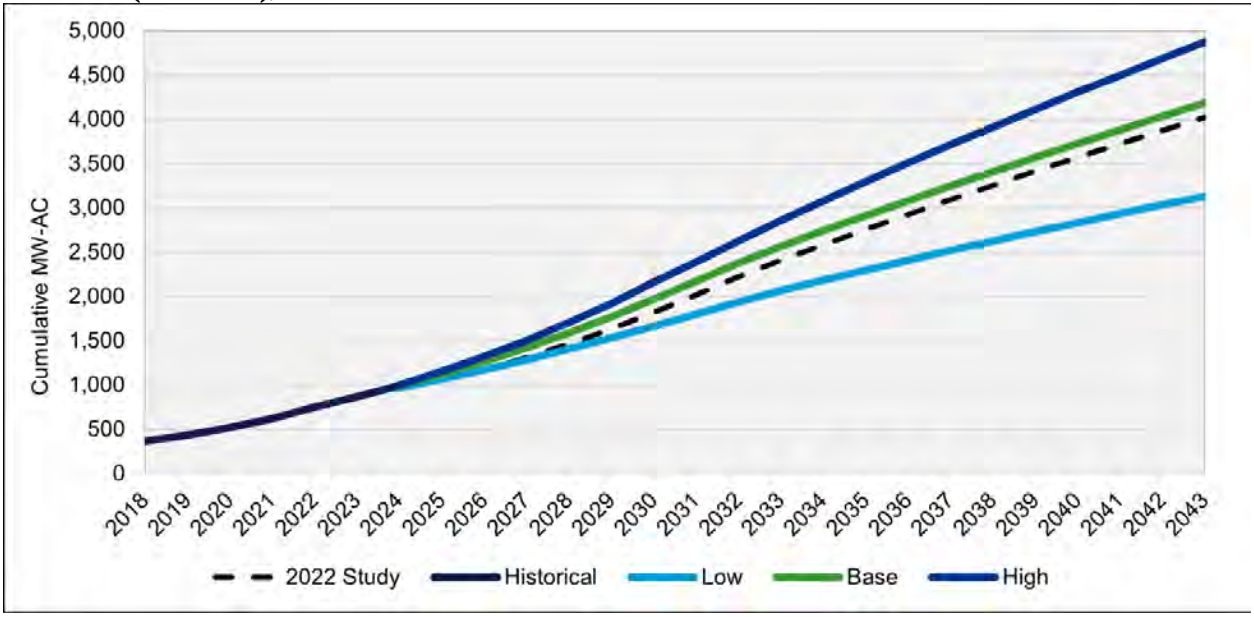
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

[2] In the 2023 IRP, this study was referred to as the "Private Generation" assessment.
[3] See Appendix L (Distributed Generation Study).
[4] PacifiCorp's and DNV's decisions in the development of the DG study were topics of discussion in the 2025 IRP public input meeting series and stakeholder feedback.
See Appendix M, stakeholder feedback form #6 (Renewable Northwest).
See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon).
See Appendix M, stakeholder feedback form #26 (Vote Solar).

DNV estimates approximately 4.18 gigawatts (GW) of DG capacity will be installed in PacifiCorp's service area by 2043 in the base case scenario. As shown in Figure 6.1, the low and high scenarios project a cumulative installed capacity of 3.12 GW and 4.87 GW by 2043, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for distributed generation that creates favorable economics for adoption and is incorporated into each case. The DNV study identifies expected levels of customer-sited DG, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

See Appendix L for the full DNV Distributed Generation report.

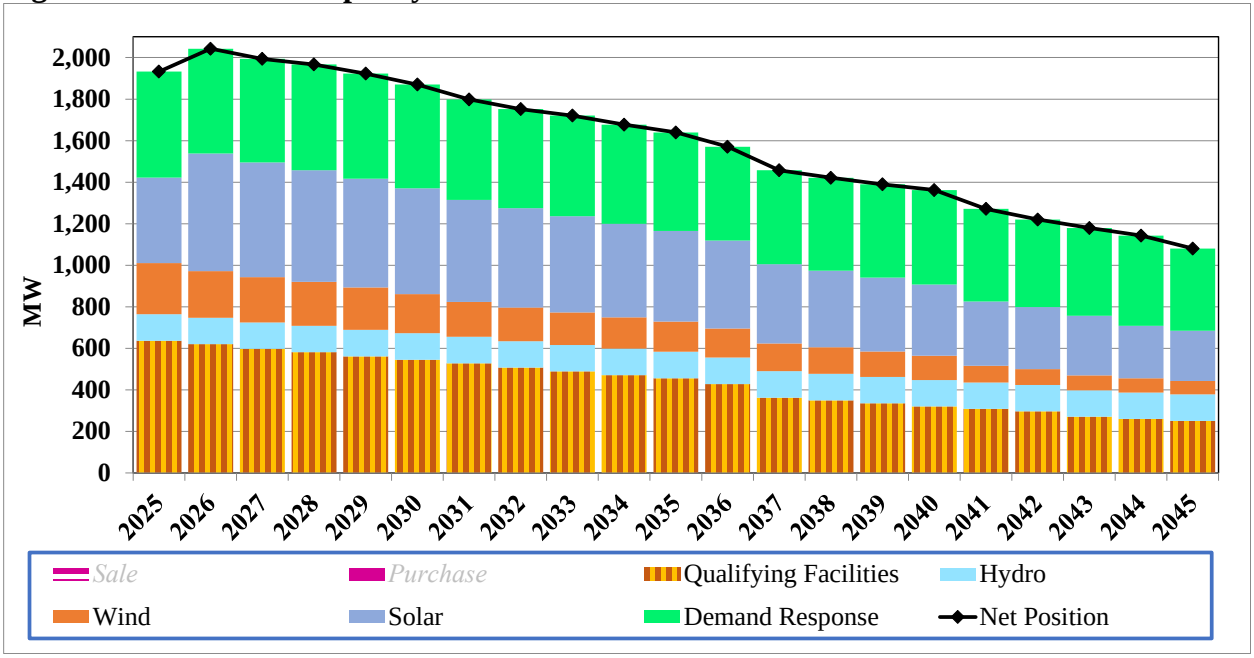
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



Power-Purchase Agreements

PacifiCorp also meets capacity and energy requirements through long-term firm contracts. Figure 6.2 presents the contract capacity in place for 2025 through 2045. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. After their current contract terms, QF contracts are extended at a reduced level that reflects the historical renewal rate of 75%. All contracts are shown at their peak capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2025 IRP Summer Load and Resource Balance



Capacity Load and Resource Balance

Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations to the annual capability of PacifiCorp's existing resources after retirements and future energy efficiency savings from the 2025 IRP preferred portfolio, and without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP, the load and resource balance use values from the Western Resource Adequacy Program (WRAP). WRAP calculates project-specific qualifying capacity contribution values for all existing and contracted resources, and those values are used where data is available. WRAP also provides the average contribution for wind, solar, energy storage and run of river hydro in different geographic areas, and these estimates are used for proxy resources in the 2025 IRP. WRAP will update the capacity contributions for resources ahead of each season, reflecting the current resource mix of the WRAP footprint through time. WRAP has also provided projections for future years and different resource penetration levels – as the penetration of wind, solar, and storage increases, contributions are expected to decline. Significant uncertainty remains, due to resource mix and timing, along with indirect factors like climate impacts on load and hydro. To better reflect future WRAP compliance requirements, PacifiCorp used the projections provided by WRAP to estimate contributions in 2045 based on the regional resource mix developed as part of the forward price curve used in the 2025 IRP. Because PacifiCorp is a relatively small portion of the regional resource mix, the calculation is static and does not vary with PacifiCorp's specific portfolio selections. WRAP contributions fall linearly from the current values for 2025 to the projected values for 2045. Additional detail is provided in Appendix K (Capacity Contribution).

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly distributed generation projections to determine the net

system coincident peak load for each of the first ten years (2025-2034) of the planning horizon. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are included as part of the existing resources. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (14.4% for the 2025 IRP, reflecting the WRAP value for the month of July) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The main component categories consist of the following: resources, obligation, reserves, position, and available market purchases.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—coal, gas, hydroelectric, wind, solar, other renewables, storage, QFs, demand response, and purchases. Categories in the obligation section include load, distributed generation, and energy efficiency from the preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a resource. Under WRAP, demand response must be designated as either a load reduction, where any impacts are captured in peak loads, or as a resource, based on its availability and duration during peak conditions. For the 2025 IRP, demand response is used for operating reserves and dispatched within the PLEXOS model based on economic need and is not targeted to reduce summer-time peak loads which often occur during solar generation hours when net demand is lower. As a result, treatment as a resource provides a larger capacity benefit currently. PacifiCorp expects to continue evaluating this as the WRAP gets underway, as some demand response programs may be suitable for peak load reduction. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less distributed generation and energy efficiency from the preferred portfolio. The following are descriptions of each of these components:

Load Net of Distributed generation

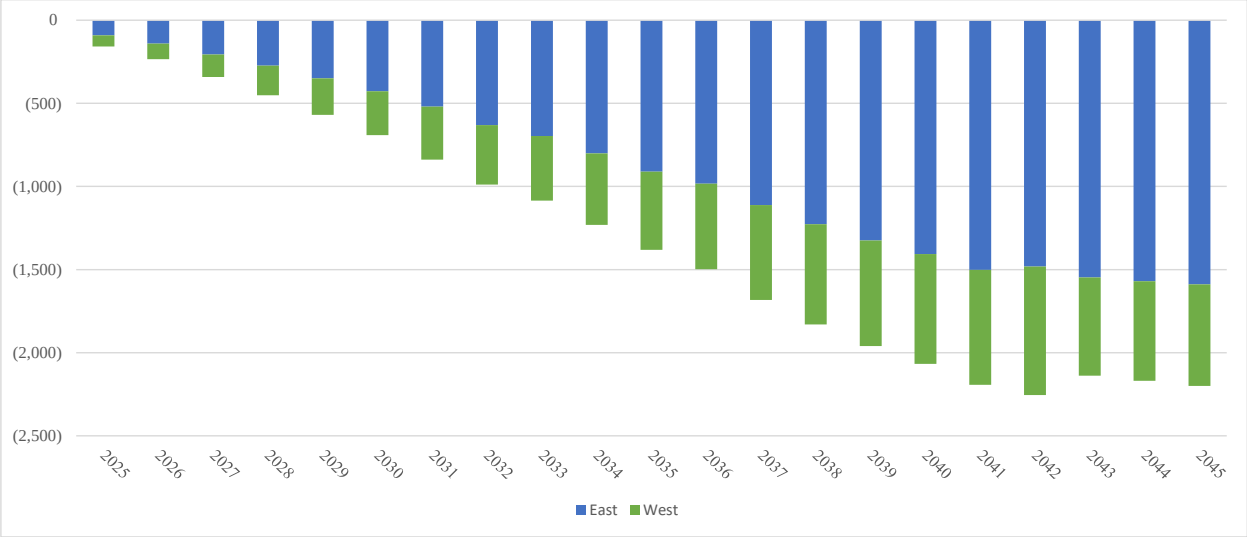
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2024 energy efficiency that is not incorporated in the forecast. The 2024 energy efficiency forecast has been added to the energy efficiency line along with the energy efficiency selected in the 2025 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2025 IRP preferred portfolio.

Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)



Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

Position

The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

Existing Resources = Coal + Gas + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities + Demand Response

The peak load, distributed generation, energy efficiency (from the preferred portfolio) are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

Obligation = Load – Distributed generation – Energy Efficiency

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 14.4 percent PRM for July and 16.8 percent PRM for December adopted from WRAP for the 2025 IRP. The formula for this calculation is:

Planning Reserves = Obligation x PRM

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, including available Market purchases, as shown in the following formula:

Capacity Position = (Existing Resources + Available Market purchases) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 6.14 and Table 6.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 14.4 percent in the summer and 16.8 percent in the winter to calculate the planning reserve amount.[5] Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis up to the limits of the transfer capability between the two areas. Also note that QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewable, or other line items.

[5] PacifiCorp acknowledged errors in its 2023 IRP load and resource balance, which have been addressed in the 2025 IRP. See Appendix M, stakeholder feedback form #12 (Utah Association of Energy Users).

Table 6.14 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(274)	(1,440)	(1,361)	(1,096)	(902)	(631)	(476)	(421)	(380)	(277)
East Existing Resources	**8,578**	**8,433**	**8,452**	**8,479**	**8,504**	**8,540**	**8,611**	**8,603**	**8,592**	**8,632**
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	**7,498**	**7,372**	**7,388**	**7,412**	**7,433**	**7,465**	**7,527**	**7,520**	**7,511**	**7,545**
Planning Reserve Margin (14.4%)	1,080	1,062	1,064	1,067	1,070	1,075	1,084	1,083	1,082	1,087
East Obligation + Reserves	8,578	8,433	8,452	8,479	8,504	8,540	8,611	8,603	8,592	8,632
East Position	0	0	0	0	0	0	0	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	274	1,440	1,361	1,096	902	631	476	421	380	277
West Existing Resources	**2,271**	**3,426**	**3,330**	**3,054**	**2,846**	**2,431**	**2,260**	**2,192**	**2,141**	**2,028**
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	**3,662**	**3,664**	**3,695**	**3,690**	**3,688**	**3,688**	**3,738**	**3,684**	**3,767**	**3,798**
Planning Reserve Margin (14.4%)	527	528	532	531	531	531	538	530	542	547
West Obligation + Reserves	4,189	4,192	4,227	4,222	4,219	4,219	4,277	4,214	4,309	4,345
West Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	10,849	11,859	11,782	11,533	11,349	10,971	10,871	10,795	10,734	10,660
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	1,918	766	898	0	0	0	0	0	0	0
Net Surplus/(Deficit)	0	0	0	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)

Table 6.14 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(161)	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,690**	**8,763**	**8,643**	**8,569**	**8,519**	**8,472**	**8,383**	**8,310**	**7,622**	**7,564**	**7,472**
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	**7,596**	**7,752**	**7,792**	**7,865**	**7,946**	**8,057**	**8,156**	**8,413**	**8,536**	**8,686**	**8,848**
Planning Reserve Margin (14.4%)	1,094	1,116	1,122	1,133	1,144	1,160	1,174	1,211	1,229	1,251	1,274
East Obligation + Reserves	8,690	8,869	8,914	8,998	9,090	9,217	9,330	9,624	9,766	9,937	10,123
East Position	0	(105)	(271)	(429)	(571)	(745)	(947)	(1,314)	(2,144)	(2,373)	(2,650)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	161	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,902**	**1,731**	**1,708**	**1,700**	**1,689**	**1,681**	**1,651**	**1,644**	**1,621**	**1,613**	**1,608**
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
New Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	**3,841**	**3,885**	**3,929**	**3,998**	**4,073**	**4,154**	**4,233**	**4,340**	**4,562**	**4,663**	**4,764**
Planning Reserve Margin (14.4%)	553	559	566	576	586	598	609	625	657	671	686
West Obligation + Reserves	4,394	4,444	4,495	4,574	4,659	4,752	4,842	4,965	5,219	5,334	5,450
West Position	(2,492)	(2,713)	(2,787)	(2,874)	(2,970)	(3,072)	(3,191)	(3,321)	(3,598)	(3,721)	(3,842)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,592	10,494	10,351	10,269	10,209	10,152	10,034	9,954	9,243	9,178	9,080
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)

Table 6.15 – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,585)	(1,353)	(1,118)
East Existing Resources	**7,804**	**8,523**	**8,433**	**8,120**	**7,911**	**7,608**	**7,442**	**7,369**	**7,522**	**7,662**
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	**5,821**	**5,790**	**5,876**	**5,963**	**6,033**	**6,119**	**6,231**	**6,309**	**6,440**	**6,560**
Planning Reserve Margin (16.8%)	978	973	987	1,002	1,014	1,028	1,047	1,060	1,082	1,102
East Obligation + Reserves	6,799	6,763	6,863	6,964	7,047	7,147	7,278	7,369	7,522	7,662
East Position	1,005	1,760	1,570	1,156	864	461	164	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,585	1,353	1,118
West Existing Resources	**3,345**	**3,342**	**3,333**	**3,330**	**3,325**	**3,174**	**3,171**	**3,153**	**2,919**	**2,679**
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	**3,459**	**3,506**	**3,521**	**3,527**	**3,511**	**3,517**	**3,558**	**3,578**	**3,609**	**3,647**
Planning Reserve Margin (16.8%)	581	589	591	593	590	591	598	601	606	613
West Obligation + Reserves	4,041	4,095	4,112	4,120	4,101	4,108	4,156	4,180	4,215	4,259
West Position	(696)	(753)	(780)	(790)	(776)	(934)	(985)	(1,027)	(1,297)	(1,581)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	11,149	11,865	11,766	11,450	11,235	10,783	10,613	10,522	10,441	10,341
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,336	1,339	1,353	1,367	1,374	1,388	1,410	1,424	1,447	1,470
Obligation + Reserves	10,617	10,635	10,750	10,857	10,918	11,024	11,199	11,312	11,497	11,677
System Position	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)

Table 6.15 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(919)	(674)	(414)	(137)	0	0	0	0	0	0	0
East Existing Resources	**7,778**	**7,925**	**8,097**	**8,275**	**8,336**	**8,262**	**8,096**	**8,008**	**7,276**	**7,204**	**7,101**
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	**6,659**	**6,786**	**6,932**	**7,084**	**7,248**	**7,387**	**7,498**	**7,717**	**7,872**	**8,070**	**8,131**
Planning Reserve Margin (16.8%)	959	977	998	1,020	1,044	1,064	1,080	1,111	1,134	1,162	1,171
East Obligation + Reserves	7,618	7,763	7,931	8,105	8,292	8,451	8,578	8,828	9,005	9,232	9,302
East Position	160	163	166	170	44	(189)	(482)	(820)	(1,729)	(2,028)	(2,201)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	919	674	414	137	0	0	0	0	0	0	0
West Existing Resources	**2,478**	**2,229**	**1,967**	**1,687**	**1,546**	**1,544**	**1,541**	**1,539**	**1,536**	**1,534**	**1,531**
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	**3,662**	**3,707**	**3,800**	**3,888**	**3,957**	**4,010**	**4,097**	**4,239**	**4,463**	**4,567**	**4,535**
Planning Reserve Margin (16.8%)	615	623	638	653	665	674	688	712	750	767	762
West Obligation + Reserves	4,277	4,330	4,438	4,541	4,622	4,684	4,786	4,952	5,212	5,334	5,297
West Position	(1,799)	(2,100)	(2,471)	(2,854)	(3,075)	(3,140)	(3,245)	(3,413)	(3,676)	(3,801)	(3,766)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,255	10,155	10,064	9,962	9,882	9,806	9,637	9,547	8,812	8,737	8,632
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used

to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7 (Resource Options).

Figure 6.4 – Summer System Capacity Position Trend

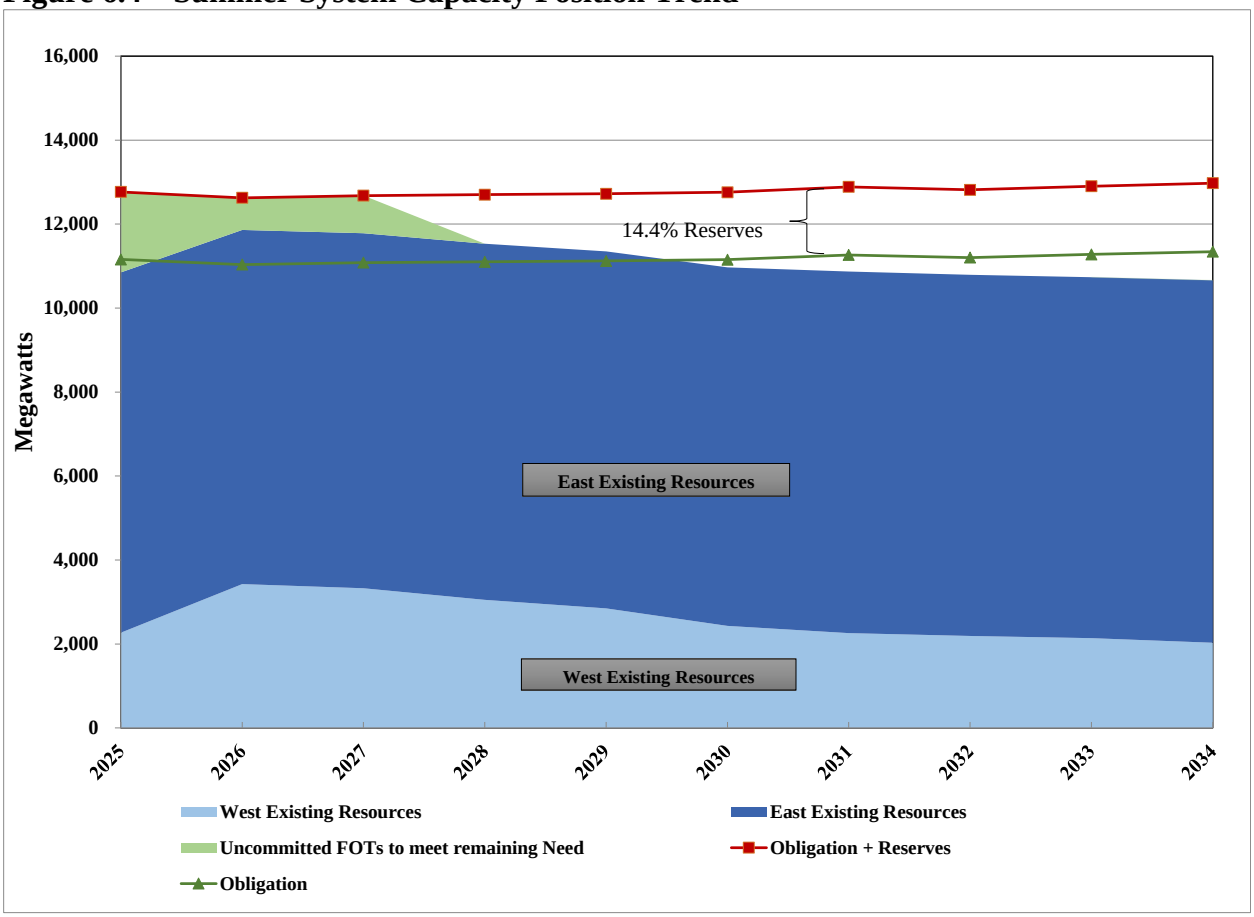


Figure 6.5 – Winter System Capacity Position Trend

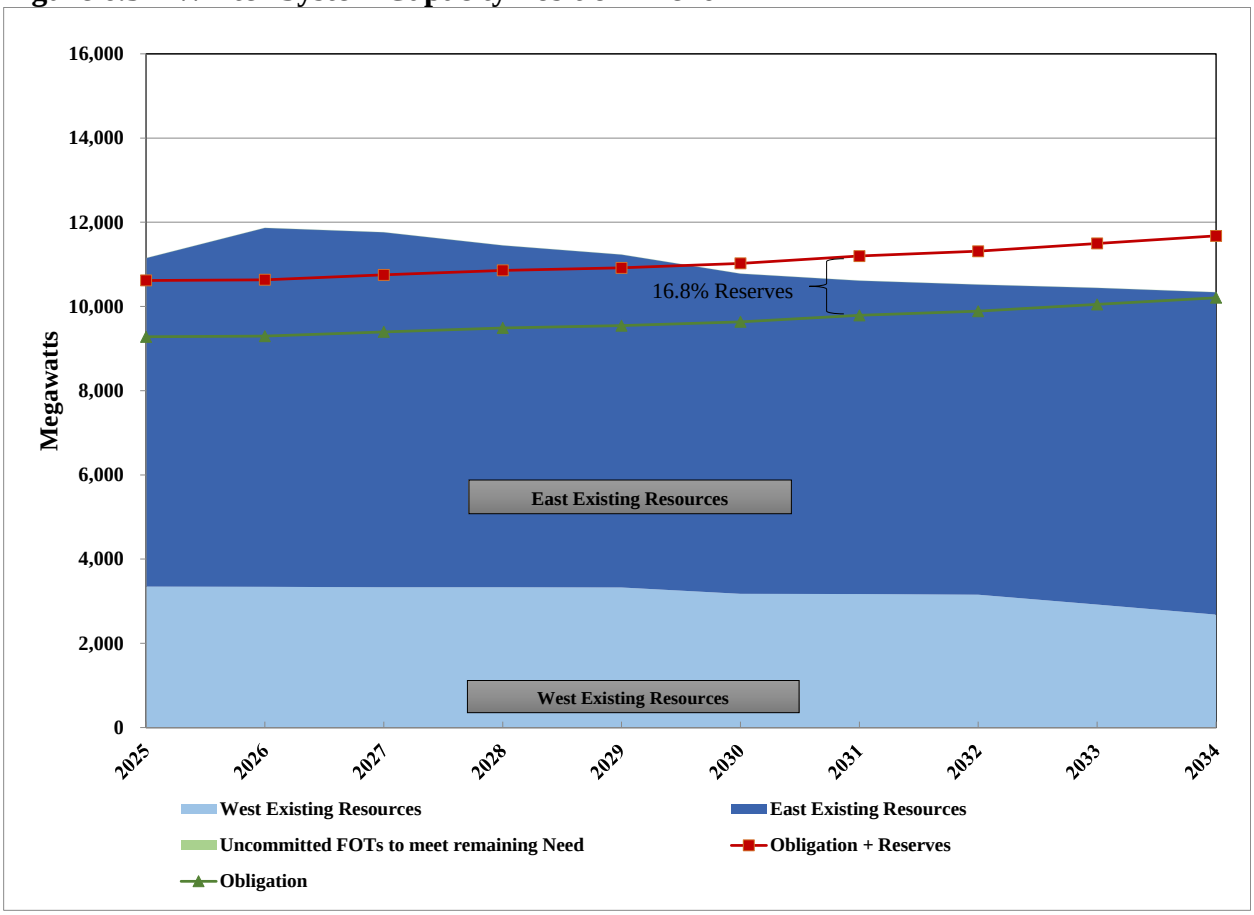


Figure 6.6 – East Summer Capacity Position Trend

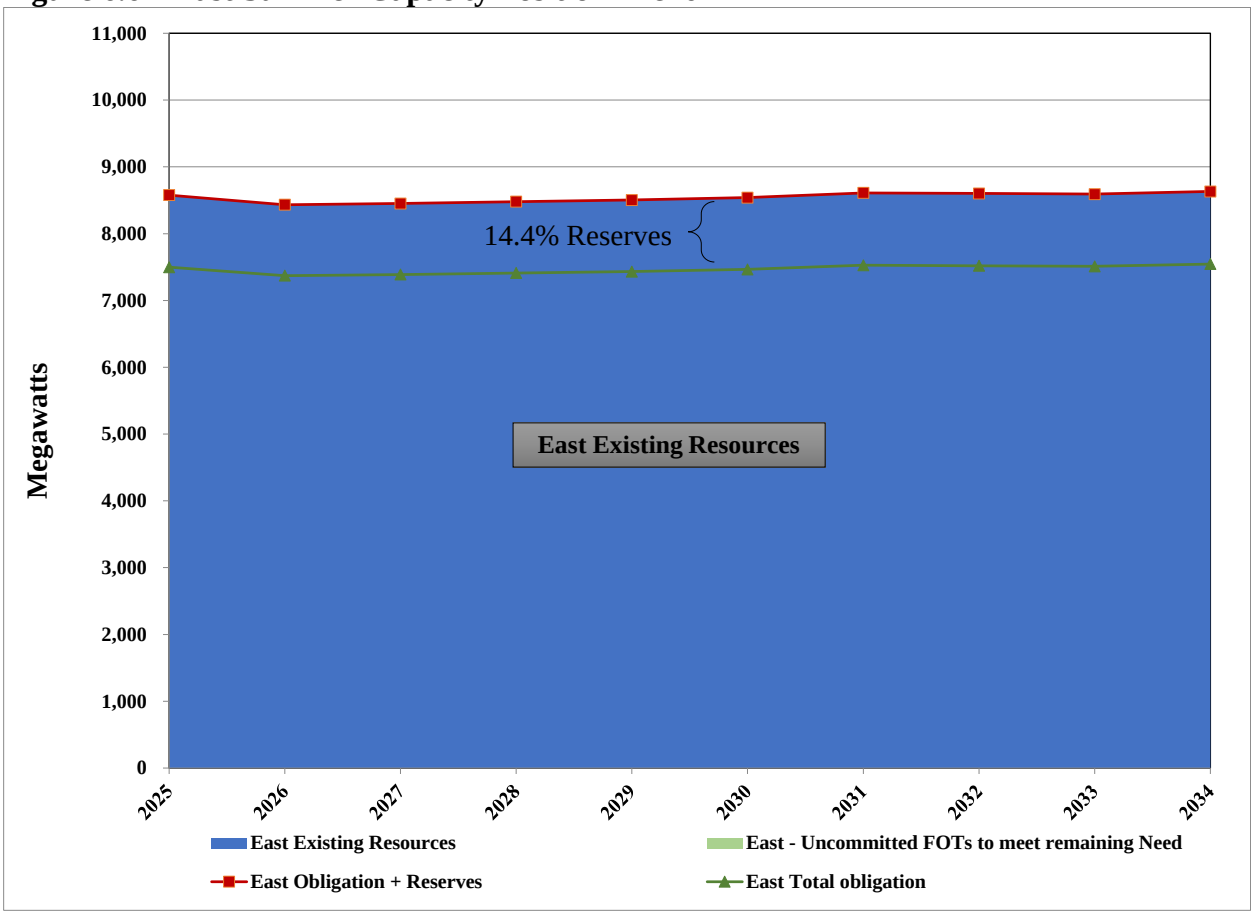
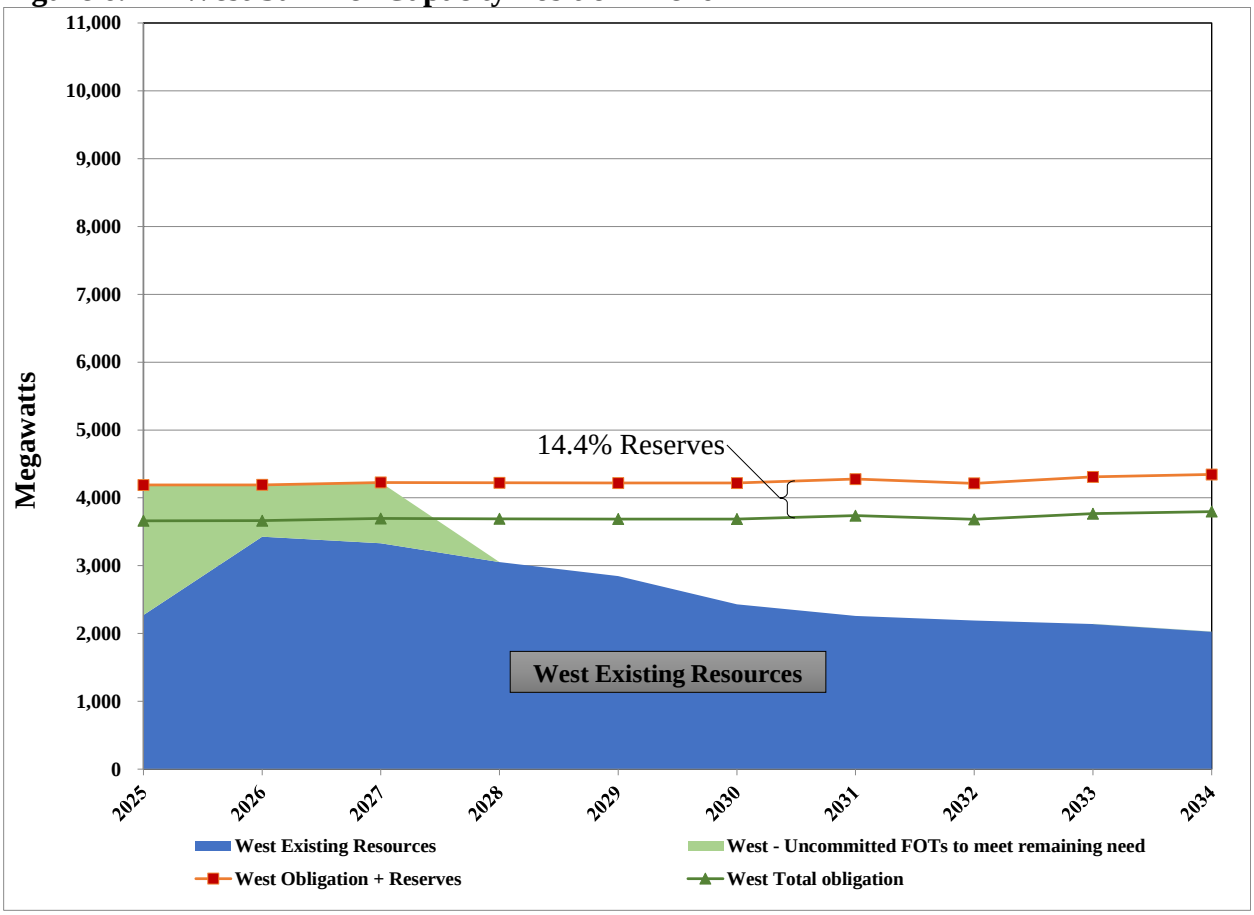


Figure 6.7 – West Summer Capacity Position Trend



CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp's resource attributes and costs for future generation resource options reflect updated information, based on assumptions from the National Renewable Energy Laboratory's 2024 Annual Technology Baseline to the extent data was available.[1]
- In addition to utility-scale resources (generally 200 megawatts (MW) or more), the 2025 IRP includes small-scale (20 MW) wind, solar, and biodiesel peaking options. These small-scale resource options are assumed to be sited in relative proximity to load, such that they do not require significant transmission system upgrades.
- Renewable resource generation profiles have been updated and expanded to include more proxy resource locations as well as distinct profiles for utility-scale and small-scale wind resources, rather than one generation profile per state as in the 2023 IRP. This update extends to online and contracted resources, as well as proxy resource options, and includes expanded historical data for use with stochastic analysis.
- Options for utility-scale lithium-ion batteries (20 MW and 200 MW options), gravity energy storage systems, pumped hydro energy storage (PHES), thermal energy storage, one-hundred-hour iron-air storage, and adiabatic compressed air energy storage are included in this IRP. In a change from prior IRPs, hydrogen peaking resources are also treated as storage resources (rather than using pipelines and a market price for hydrogen). Hydrogen is electrolyzed using excess generation output and stored in either high-pressure tanks or underground caverns.
- PLEXOS endogenously models transmission upgrades, allowing for increases to transfer limits and resource interconnection. Where applicable, upgrades are restricted until all pre-requisites are in place.
- PacifiCorp continues to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

[1] https://atb.nrel.gov/electricity/2024/index

Supply-Side Resources

The list of supply-side resource options reflects the expected realities evidenced through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input. The process began with the list of major generating resources from the 2023 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[2] was used as much as possible to maintain consistency. Some of the terminology used in this chapter is from the ATB. A glossary of some of the terminology is provided below in Table 7.12 and a list of acronyms is provided in Table 7.13.

The supply-side resource options include the following technologies grouped by energy source. More information about each technology is provided in the "Resource Option Descriptions" section of this chapter. The terminology here matches that used in the supply-side resource table, although some may have been shortened per the acronym list in Table 7.13.

- Natural Gas
  - Internal Combustion Engines.
  - SCCT, Aero, & F-Frame.
  - CCCT, 1x1, & 2x1.
    - Adjustments for 95% Carbon Capture.
    - Adjustments for Brownfield Construction.
    - Adjustments for advanced technology innovation scenario ("Innovations far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases. For biopower technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages."[3])
- Hydrogen
  - Adjustments for 100% Hydrogen burning capability.
  - Adjustments for Hydrogen Storage.
  - Electrolyzer.
- Coal, Carbon Capture Retrofits at existing plants
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW all with 4-hour duration):
    - Adjustments for double duration (i.e., 8-hour duration).
    - Adjustments for co-location with other generating resources.
    - Adjustments for advanced technology innovation scenario.
  - Gravity Batteries.
  - Adiabatic Compressed Air Energy Storage (ACAES).
  - 100-Hour Iron Air Batteries.
  - PHES (single and double reservoirs).
  - Pumped Thermal.
- Solar

[2] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[3] https://atb.nrel.gov/electricity/2024/definitions#scenarios

    - Adjustments for advanced technology innovation scenario.
- Wind (various on-shore wind classes and off-shore class 12, as appropriate for PacifiCorp's service area)
    - Adjustments for advanced technology innovation scenario.
- Nuclear[4]
    - Small Modular Reactor.
        - Adjustments for adding thermal energy storage.
    - Large Light Water Reactor.
        - Adjustments for advanced technology innovation scenario (in addition to the earlier definition: "for nuclear technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.")
- Geothermal (near field enhanced geothermal system, binary)
    - Adjustments for advanced technology innovation scenario.

Derivation of Resource Attributes

Once a basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table, which is used to develop inputs for IRP modeling:

- Annual Technology Baseline (ATB) prepared by the National Renewable Energy Laboratory (NREL).[5]
- U.S. Energy Information Administration (EIA) "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" ("EIA Report," both the 2024[6] and 2020[7] editions) prepared by Sargent and Lundy.
- Original equipment manufacturers capital and operation and maintenance estimates.
- Developer cost and performance estimates.
- Publicly available cost and performance estimates.
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes.
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.
- Additional references are provided in the Resource Option Descriptions section of this chapter.

[4] Nuclear technology is intentionally limited to years outside the 2-4 year action plan window. Nuclear resource assumptions were discussed in the 2025 IRP public input meeting series and stakeholder feedback,
See Appendix M, stakeholder feedback form #1 (Peter Gross).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

[5] https://atb.nrel.gov/electricty/2024/index.

[6] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the supply-side resource table are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers, and original equipment manufacturers (OEM's). The 2024 ATB with its numerous references and the 2024 EIA Report was used for:

- Natural Gas
  - SCCT (Aero).
  - CCCT (1x1 & 2x1).
    - Adjustments for 95% Carbon Capture.
    - Adjustments for advanced technology innovation scenario.
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW, 4-hour duration).
    - Adjustments for double duration.
    - Adjustments for co-location.
    - Adjustments for advanced technology innovation scenario.
  - PHES (single and double reservoirs).
- Solar
  - Adjustments for advanced technology innovation scenario.
- Wind
  - Adjustments for advanced technology innovation scenario.
- Nuclear
  - Small Modular Reactor.
  - Large Light Water Reactor.
  - Adjustments for advanced technology innovation scenario.
- Geothermal (near field enhanced geothermal system, binary)
  - Adjustments for advanced technology innovation scenario.

The 2020 EIA Report provided the Internal Combustion Engines (ICE) data because no ICE option was included in the 2024 EIA report. The ICE option was included to address Oregon requirements for small-scale resources under 20 MW. Although the ICE option consists of 4 x 5.6 MW engines at ISO conditions, it is assumed that the engines, if not derated due to altitude or other factors, can be curtailed to meet the 20 MW threshold.

The brownfield cost adjustment was developed based on prior IRP estimates.

Hydrogen capable resource data is based on the following:[8]

- Adjustments for 100% hydrogen burning capability are based on conversations with OEMs and industry experts and the report "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems."[9] A 15% cost adder for new gas turbines indicated by Table 3 in the report was corroborated by OEMs and other industry experts.

[8] The option of hydrogen as an alternative fuel, including electrolyzer cost and performance, was discussed in the course of the 2025 IRP public input meeting series. For specific recommendations and PacifiCorp's response, see Appendix M, stakeholder feedback form #23 (NP Energy, LLC)

[9] Simon Oberg, Mikael Odenberger, Filip Johnsson "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems," Division of Energy Technology, Chalmers University of Technology, 412 96, Gothenburg, Sweden, https://www.sciencedirect.com/science/article/pii/S0360319921039768

- Adjustments for hydrogen storage are based on information in the U.S. Department of Energy (DOE) reports: "Pathways to Commercial Liftoff: Clean Hydrogen"[10] (Clean Hydrogen Liftoff report), "2022 Grid Energy Storage Technology Cost and Performance Assessment,"[11] and the Hydrogen and Fuel Cell Technologies Office's "Multi-Year Program Plan."[12]
- Electrolyzer costs are based on the DOE report "Hydrogen Production Cost from PEM Electrolysis – 2019,"[13] and the NREL report "Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers."

Data for "Carbon Capture Retrofits at existing coal plants" is based on adjustments made to incorporate capital and operational costs of emission control technologies (SCR and FGD) needed to scrub flue gas prior to the carbon capture technology, and adjustments made to account for economies of scale.

Gravity Batteries costs were escalated from the 2023 IRP.

Adiabatic Compressed Air Energy Storage (ACAES) were originally escalated from the 2023 IRP which used data provided by Renewable Energy Storage Company (RESC) but later updated based on input from Hydrostor.

100-Hour Iron Air Battery data is based on information provided by Form Energy.[14]

Pumped Thermal energy storage is based on integrated thermal storage for nuclear, but with a resistive heater for energy storage.

Data for "Adjustments for adding thermal energy storage to nuclear plants" represents thermal energy storage and only stores energy from the heat of the reactor, not from a resistive heater.
The following costs were excluded from the cost estimates provided by the referenced sources, but were added by the Company as appropriate, using confidential data specific to the Company's business practices:[15]

- Allowance for Funds Used During Construction (AFUDC).
- Capital Surcharge.
- Escalation.
- Property taxes.

Interconnection costs and sales tax are included in the PLEXOS modeling depending on the locational node in which each technology is being considered.

[10] https://liftoff.energy.gov/
[11] https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf
[12] https://www.energy.gov/sites/default/files/2024-05/hfto-mypp-2024.pdf
[13] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master
[14] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[15] Additional cost considerations were the subject of discussion and feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #24 (NP Energy, LLC).

Wind and Solar Generation Profiles

For the 2025 IRP, PacifiCorp has updated the wind and solar generation profiles for both existing resources and proxy resource options. PacifiCorp provided the location and expected generation levels for existing and contracted resources to a consultant, Hendrickson Renewables, and received back an hourly generation profile for 2006-2023 that reflects expected performance under historical weather conditions.

For existing resources, results were tuned to recent historical actual generation levels, while resources that are not yet operating were tuned to forecasted output. For wind, hourly generation is based on hourly wind speeds and air density from the ERA5 reanalysis dataset, with scaling and adjustments to represent project-specific power curves and expected output.[16] For solar, hourly solar irradiance and weather data was extracted from a Vaisala satellite irradiance dataset[17] and configured in a PV_{syst} model[18] that was tuned to correspond to actual or forecasted output.

For proxy resources, PacifiCorp identified locations across its system, and Hendrickson Renewables determined the expected output of the equipment represented in NREL's ATB, which was used to develop cost inputs. In the 2023 IRP, PacifiCorp used one wind and solar profile for each of its five largest state jurisdictions (excluding California). For the 2025 IRP, wind and solar profiles have been developed which to correspond to thirteen different transmission areas spread across PacifiCorp's system. To account for technological differences that impact generation output, generation profiles were also developed for five small-scale wind profiles for the west side of the system, along with an off-shore wind profile for the potential lease area near Brookings.[19]

For many years, PacifiCorp has used a chaotic normal load forecast to account for the range of load conditions experienced. For each month of the year, the chaotic normal load forecast is derived from the most representative historical month from recent history (currently 2013-2022). The pattern of load in each of the selected months from history is reflected in every year of the forecast, with adjustments to account for the rotation of calendar days and weekdays from year to year, as well as for forecasted changes in load over time. As a result, every day of PacifiCorp's load forecast is tied to a specific day in history. For the 2025 IRP, the normalized wind and solar output modeled in PLEXOS is drawn from the same historical day as the load forecast. The result is a generation profile specific to each of the years of the IRP forecast (2025-2045) that inherently represents the correlation between renewable generation and load. The expanded historical generation data set developed for the 2025 IRP also enables stochastic analysis that captures the relationship between renewable generation and load in each of the historical years (2006-2023).

Natrium Demonstration Project

PacifiCorp's 2025 IRP includes the Natrium® advanced nuclear demonstration project: an 840 megawatt thermal pool-type sodium fast reactor that contains a compact and simple safety envelope and a molten salt energy storage system which enables the plant to vary its supply of energy to the grid, up to 500 megawatts electric net, providing both firm and flexible emissions-free energy. The reactor operates near atmospheric pressure, circulating sodium through its core

[16] European Centre for Medium-Range Weather Forecasts.https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5
[17] Vaisala. https://www.vaisala.com/
[18] PV_{syst}. https://www.pvsyst.com/
[19] Bureau of Ocean Energy Management. https://www.boem.gov/renewable-energy/state-activities/Oregon

with pumps. The design includes reliable inherent and passive safety features including near atmospheric operating pressures, always-on passive air cooling and inherent reactivity feedback.

At this time, the specific cost and performance assumptions for the Natrium® advanced nuclear demonstration project are confidential and are not summarized in the supply-side resource table. TerraPower and PacifiCorp remain committed to bringing the Natrium technology to market to enhance the company's ability to serve its customers, meet growing demand and ensure a reliable and resilient energy future. PacifiCorp is also committed to protecting customers from first-of-a-kind (FOAK) technology risk and FOAK program and construction costs. The Company is implementing an innovative commercial energy acquisition structure that allows Natrium benefits to flow to customers while ensuring those customers are not burdened with FOAK technology cost and risk. This commercial structure is in the final stages of development and the details are confidential at this time.

The Natrium advanced nuclear demonstration project has been named Kemmerer Power Station Unit 1 (KU1) which is planned to be built near the Naughton Power Plant. KU1 is currently in the design and licensing phase. TerraPower submitted the Construction Permit Application to the US Nuclear Regulatory Commission (US NRC) in March 2024. The US NRC has published their review schedule and anticipates the Preliminary Safety Analysis Report and Environmental Report to be approved by August 2026, and the Construction Permit Application to be approved by December 2026. This approval will allow the beginning of construction of the Nuclear Island. An Operating License is also required. TerraPower anticipates the Operating License Application to be submitted in September 2027 and achieving commercial operations the fall of 2031.

On June 10, 2024, TerraPower broke ground for the Natrium reactor demonstration project with construction of the sodium test and fill facility commencing first. On January 14, 2025, the State of Wyoming Industrial Siting Council (ISC) approved TerraPower's permit for construction and operational activities on the Natrium plant that are not under jurisdiction of the US NRC. This approval allows for the construction of non-nuclear facilities, including the energy island portion of the Natrium plant that houses the molten salt energy storage tanks and turbines.

Resource Options and Attributes

Table 7.2 through Table 7.11 report characteristics, attributes and costs for resource options considered in the 2025 IRP. Unlike previous IRP's the supply-side resource table does not list multiple versions of the same technology for various altitudes. Instead, the location adjustments from Appendix A and B of the 2024 EIA[20] report are applied in PLEXOS. Total resource cost attributes for supply-side resource options are based on estimates of the first-year, real-levelized

[20] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

costs for resources, stated in June 2024 dollars.[21,22] Table 7.1 provides a listing of these ten tables for convenience.

Table 7.1 – Supply-Side Resource Option Tables

	Characteristics and Costs	**Operating Characteristics and Environmental Data**
Thermal	Table 7.2	Table 7.4
Non-Thermal and Storage	Table 7.3	Table 7.5
	Additional Attributes and Fixed O&M	**Variable O&M, Total Cost and Credits**
Thermal	Table 7.6	Table 7.9
Non-Thermal	Table 7.7	Table 7.10
Storage	Table 7.8	Table 7.11

A Glossary of Terms and a Glossary of Acronyms from the supply-side resource table is summarized in Table 7.12 and Table 7.13.

[21] Supply-side resource attributes were discussed throughout the 2025 public input meeting series and generated stakeholder feedback forms inquiries. 2028 was determined to be the appropriate earliest commercial online year for most proxy resource options. However, PacifiCorp does not preclude the possibility of achieving specific (non-proxy) projects on an earlier timeline outside of the IRP.
See Appendix M, stakeholder feedback form #7 (Renewable Northwest).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
[22] The supply-side resource table was made publicly available during the 2025 IRP public input meeting series and discussed extensively as it developed. https://www.pacificorp.com/energy/integrated-resource-plan/support.html

Table 7.2 – 2025 Thermal Supply-Side Resources, Characteristics and Costs (2024$)

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	0	20	2025	2.5	2027	30	$2,131	$6.93	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR	0	50	2025	3.5	2028	40	$2,613	$7.40	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR	0	211	2025	3.5	2028	40	$1,789	$5.92	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR	0	233	2025	5.0	2030	40	$1,387	$7.75	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	0	649	2025	5.0	2030	40	$1,839	$2.70	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	0	1,227	2025	5.0	2030	40	$1,553	$2.28	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	0	565	2025	5.0	2030	+40	$3,429	$5.32	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	0	1085	2025	5.0	2030	+40	$2,846	$4.83	0%	100%	$62.99	0%	$65.08
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	0	20	2025	2.5	2027	30	$1,918	$6.24	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	0	50	2025	3.5	2028	40	$2,352	$6.66	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	0	211	2025	3.5	2028	40	$1,610	$5.33	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	0	233	2025	5.0	2030	40	$1,248	$6.98	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	0	649	2025	5.0	2030	40	$1,655	$2.43	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	0	1,227	2025	5.0	2030	40	$1,398	$2.05	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	0	565	2025	5.0	2030	40	$3,086	$4.78	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	0	1,085	2025	5.0	2030	40	$2,561	$4.34	0%	100%	$62.99	0%	$65.08
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	0	233	2025	5.0	2030	40	$1,595	$8.91	100%	99%	$27.92	3%	$13.95
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	649	2025	5.0	2030	40	$2,115	$3.11	0%	100%	$42.44	0%	$13.89
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	1,227	2025	5.0	2030	40	$1,786	$2.62	0%	100%	$35.18	0%	$13.67
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	233	2025	5.0	2030	40	$2,586	$8.18	100%	99%	$35.12	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	649	2025	5.0	2030	40	$3,038	$3.13	0%	100%	$49.64	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,752	$2.70	0%	100%	$42.38	0%	$26.89
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	233	2025	5.0	2030	40	$2,098	$8.32	100%	99%	$40.78	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	649	2025	5.0	2030	40	$2,550	$3.27	0%	100%	$55.30	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,264	$2.85	0%	100%	$48.04	0%	$26.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	0	649	2025	5.0	2030	+40	$1,832	$2.68	0%	100%	$41.33	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	0	1227	2025	5.0	2030	+40	$1,518	$2.23	0%	100%	$34.07	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	0	565	2025	5.0	2030	+40	$3,261	$5.03	0%	100%	$72.60	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	0	1085	2025	5.0	2030	+40	$2,637	$4.49	0%	100%	$57.74	0%	$65.08
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	0	-119	2025	5.0	2030	40	$561	$23.91	+0%	0.00	$10.28	100%	$32.46
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	5,541	-85	2027	5.0	2032	30	$3,501	$11.40	0%	0%	$277.68	0%	$53.20
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	6,429	-297	2027	5.0	2032	30	$2,951	$9.73	0%	0%	$235.36	0%	$53.20
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	6,933	-233	2027	5.0	2032	30	$2,951	$9.63	0%	0%	$242.12	0%	$53.20
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	7,513	-174	2025	5.0	2030	30	$2,598	$10.57	0%	0%	$254.91	0%	$53.20
Coal	CCS Wyodak (costs on post retrofit basis)	4,448	-69	2027	5.0	2032	30	$3,504	$11.69	0%	0%	$309.51	0%	$53.20
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	N/A	600	2030	5.0	2035	60	$9,662	$9.74	0%	0%	$97.42	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	N/A	600	2030	4.0	2034	60	$6,368	$8.74	0%	0%	$84.53	0%	$12.00
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	5.0	2035	60	$10,628	$10.72	0%	0%	$107.16	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	4.0	2034	60	$7,005	$9.61	0%	0%	$92.98	0%	$12.00
Nuclear	Large Light Water Reactor, Moderate Technology Case	N/A	2,000	2030	7.0	2037	60	$7,563	$9.38	0%	0%	$125.36	0%	$10.00
Nuclear	Large Light Water Reactor, Advanced Technology Case	N/A	2,000	2030	5.0	2035	60	$6,265	$7.88	0%	0%	$90.26	0%	$9.00
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	707	2025	3.0	2028	30	$7,593	included in FOM	0%	0%	$194.00	6%	$125.09
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	707	2025	3.0	2028	30	$5,949	included in FOM	0%	0%	$173.90	6%	$125.09

Table 7.3 – 2025 Non-Thermal Supply-Side Resources, Characteristics and Costs (2024$)[23]

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Storage[1]	Li-Ion, 4-hour, 20 MW	N/A	20	2025	1.0	2026	20	$1,748	Included in FOM	0%	0%	$45.05	0%	$29.94
Storage[1]	Li-Ion, 4-hour, 200 MW	N/A	200	2025	2.0	2027	20	$1,498	Included in FOM	0%	0%	$38.77	0%	$25.66
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	N/A	200	2025	2.0	2027	20	$2,557	Included in FOM	0%	0%	$69.78	0%	$46.19
Storage[1]	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	20	$1,459	Included in FOM	0%	0%	$36.92	0%	$25.66
Storage	Gravity Battery, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	50	$2,021	Included in FOM	0%	0%	$50.51	0%	$0.19
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	N/A	1,000	2025	3.0	2028	50	$3,006	Included in FOM	0%	0%	$90.92	0%	$0.35
Storage	Adiabatic CAES, 500 MW, 4000 MWh	N/A	500	2025	3.0	2028	50	$3,754	$2.60	50%	0%	$19.20	42%	$49.31
Storage	100-hour Iron Air	N/A	200	2028	2.0	2030	20	$2,730	Included in FOM	0%	0%	$21.04	19%	$171.06
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	N/A	400	2025	5.0	2030	100	$2,984	$0.58	0%	0%	$20.20	45%	$149.21
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	N/A	400	2025	5.0	2030	100	$4,159	$0.58	0%	0%	$20.20	45%	$207.95
Storage	Pumped Hydro, One New Reservoir, 4-hour	N/A	400	2025	5.0	2030	100	$2,883	$0.58	0%	0%	$20.20	45%	$144.16
Storage	Pumped Hydro, One New Reservoir, 10-hour	N/A	400	2025	5.0	2030	100	$3,537	$0.58	0%	0%	$20.20	45%	$176.87
Storage	Pumped Thermal Energy Storage, 10-hour	N/A	100	2026	5.0	2031	60	$6,174	$0.70	0%	0%	$2.00	0%	$60.00
Storage	Pumped Thermal Energy Storage, 24-hour	N/A	50	2026	5.0	2031	60	$11,525	$0.70	0%	0%	$1.00	0%	$60.00
Solar	PV, 20 MW, Class 1-10	by location	20	2025	3.0	2028	25	$1,965	included in FOM	0%	0%	$18.16	12%	$39.29
Solar	PV, 200 MW, Class 1-10	by location	200	2025	3.0	2028	25	$1,217	included in FOM	0%	0%	$20.52	12%	$24.33
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	20	2025	3.0	2028	25	$1,832	included in FOM	0%	0%	$17.24	12%	$37.33
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	200	2025	3.0	2028	25	$1,135	included in FOM	0%	0%	$19.47	12%	$23.11
Wind	Wind Class 1-10, 20 MW	by location	20	2025	3.0	2028	30	$2,555	included in FOM	0%	0%	$38.79	35%	$63.57
Wind	Wind Class 1-6, 200 MW	by location	200	2025	5.0	2030	30	$1,421	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Wind Class 7, 200 MW	by location	200	2025	5.0	2030	30	$1,492	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Offshore, Wind Class 12	0	200	2027	5.0	2032	30	$8,341	included in FOM	0%	0%	$69.26	35%	$169.16
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	by location	20	2025	3	2028	30	$2,434	included in FOM	0%	0%	$34.87	35%	$60.58
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,354	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,422	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	0	200	2027	5	2032	30	$6,011	included in FOM	0%	0%	$63.21	35%	$121.92

[1] Assumed co-located

[23] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users)

Table 7.4 – 2025 Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02000	0.000	117
Natural Gas	SCCT Aero, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Aero x4, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02131	0.000	117
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	9,717	35.12%	2.70%	3.90%	28.4	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,040	56.49%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,122	55.74%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	N/A	79.13%	1.50%	1.5%	45.7	0.00000	0.00000	0.000	0
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	14,795	23.06%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	14,011	24.35%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	13,662	24.98%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	14,483	23.56%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Wyodak (costs on post retrofit basis)	16,653	20.49%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Moderate Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Advanced Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	N/A	10%	10%	510.0	n/a	n/a	n/a	n/a
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	N/A	10.00%	10.00%	510.0	n/a	n/a	n/a	n/a

Table 7.5 – 2025 Non-Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage[1]	Li-Ion, 4-hour, 20 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW	n/a	85%	1%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	n/a	85.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 1000 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW	n/a	83%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	n/a	83.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Adiabatic CAES, 500 MW, 4000 MWh	n/a	63%	1.1%	1.1%	n/a	0.00000	0.00000	0.000	0
Storage	100-hour Iron Air	n/a	43%	1.0%	included in CF	0.0	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 10-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 24-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Solar	PV, 20 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a

[1] Assumed co-located

Table 7.6 – 2025 IRP Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes							Fixed O&M						
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Gas Transport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	Yes	0	$ 2,130.94	$ 14.59	6.890%	$147.83	92.50%	$42.82	2.62%	$1.12	$0.00	$43.94	$191.77	$23.67
SCCT Aero, with SCR	No	0	$ 2,612.80	$ 32.46	6.101%	$161.39	33.00%	$12.42	2.62%	$0.32	$0.00	$12.74	$174.13	$60.24
SCCT Aero x4, with SCR	No	0	$ 1,789.35	$ 32.46	6.104%	$111.20	33.00%	$9.93	2.62%	$0.26	$0.00	$10.19	$121.40	$41.99
SCCT Frame "F" x1, with SCR	Yes	0	$ 1,386.92	$ 12.13	6.100%	$85.34	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$114.00	$39.43
Goshen	Yes	2,814	$ 1,400.79	$ 12.13	6.100%	$86.19	33.00%	$27.92	2.62%	$0.73	$96.20	$124.85	$211.04	$73.00
Wasatch Front	Yes	4,225	$ 1,373.05	$ 12.13	6.100%	$84.50	33.00%	$27.92	2.62%	$0.73	$14.72	$43.38	$127.87	$44.23
Wyoming East	Yes	6,130	$ 1,373.05	$ 12.13	6.100%	$84.50	33.00%	$27.92	2.62%	$0.73	$25.80	$54.45	$138.95	$48.07
CCCT Dry "H", 1X1, DF, with SCR	Yes	0	$ 1,839.00	$ 12.08	6.233%	$115.38	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$158.93	$23.26
Goshen	Yes	2,814	$ 1,857.39	$ 12.08	6.233%	$116.52	78.00%	$42.44	2.62%	$1.11	$60.34	$103.89	$220.41	$32.26
Wasatch Front	Yes	4,225	$ 1,820.61	$ 12.08	6.233%	$114.23	78.00%	$42.44	2.62%	$1.11	$9.25	$52.81	$167.04	$24.45
Wyoming East	Yes	6,130	$ 1,820.61	$ 12.08	6.233%	$114.23	78.00%	$42.44	2.62%	$1.11	$16.33	$59.88	$174.11	$25.48
CCCT Dry "H", 2X1, DF, with SCR	Yes	0	$ 1,553.26	$ 11.89	6.234%	$97.57	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$133.67	$19.56
Goshen	Yes	2,814	$ 1,568.79	$ 11.89	6.234%	$98.54	78.00%	$35.18	2.62%	$0.92	$61.16	$97.26	$195.80	$28.66
Wasatch Front	Yes	4,225	$ 1,537.73	$ 11.89	6.234%	$96.60	78.00%	$35.18	2.62%	$0.92	$9.38	$45.48	$142.08	$20.79
Wyoming East	Yes	6,130	$ 1,537.73	$ 11.89	6.234%	$96.60	78.00%	$35.18	2.62%	$0.92	$16.55	$52.65	$149.26	$21.84
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	0	$ 3,429.38	$ 65.28	6.239%	$218.03	78.00%	$77.07	5.54%	$4.27	$0.00	$81.34	$299.37	$43.81
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	0	$ 2,846.02	$ 65.08	6.241%	$181.68	78.00%	$62.99	5.54%	$3.49	$0.00	$66.48	$248.16	$36.32
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	0	$ 1,917.85	$ 14.59	6.891%	$133.16	33.00%	$42.82	2.62%	$1.12	$0.00	$43.94	$177.10	$61.26
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	0	$ 2,351.52	$ 32.46	6.102%	$145.47	33.00%	$12.42	2.62%	$0.32	$0.00	$12.74	$158.21	$54.73
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	0	$ 1,610.42	$ 32.46	6.105%	$100.30	33.00%	$9.93	2.62%	$0.26	$0.00	$10.19	$110.49	$38.22
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,248.23	$ 12.13	6.100%	$76.88	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$105.53	$36.51
Goshen-Brownfield	No	2,814	$ 1,260.71	$ 12.13	6.100%	$77.64	33.00%	$27.92	2.62%	$0.73	$96.20	$124.85	$202.50	$70.05
Wasatch Front-Brownfield	Yes	4,225	$ 1,235.75	$ 12.13	6.100%	$76.12	33.00%	$27.92	2.62%	$0.73	$14.72	$43.38	$119.50	$41.34
Wyoming East-Brownfield	Yes	6,130	$ 1,235.75	$ 12.13	6.100%	$76.12	33.00%	$27.92	2.62%	$0.73	$25.80	$54.45	$130.57	$45.17
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,655.10	$ 12.08	6.234%	$103.93	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$147.48	$21.58
Goshen-Brownfield	No	2,814	$ 1,671.65	$ 12.08	6.234%	$104.96	78.00%	$42.44	2.62%	$1.11	$60.34	$103.89	$208.85	$30.57
Wasatch Front-Brownfield	Yes	4,225	$ 1,638.55	$ 12.08	6.234%	$102.90	78.00%	$42.44	2.62%	$1.11	$9.25	$52.81	$155.71	$22.79
Wyoming East-Brownfield	Yes	6,130	$ 1,638.55	$ 12.08	6.234%	$102.90	78.00%	$42.44	2.62%	$1.11	$16.33	$59.88	$162.78	$23.82
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,397.93	$ 11.89	6.234%	$87.89	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$123.99	$18.15
Goshen-Brownfield	No	2,814	$ 1,411.91	$ 11.89	6.234%	$88.76	78.00%	$35.18	2.62%	$0.92	$61.16	$97.26	$186.02	$27.22
Wasatch Front-Brownfield	Yes	4,225	$ 1,383.95	$ 11.89	6.234%	$87.02	78.00%	$35.18	2.62%	$0.92	$9.38	$45.48	$132.50	$19.39
Wyoming East-Brownfield	Yes	6,130	$ 1,383.95	$ 11.89	6.234%	$87.02	78.00%	$35.18	2.62%	$0.92	$16.55	$52.65	$139.67	$20.44
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	0	$ 3,086.44	$ 65.28	6.240%	$196.67	78.00%	$77.07	5.54%	$4.27	$0.00	$81.34	$278.00	$40.69
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	0	$ 2,561.42	$ 65.08	6.242%	$163.95	78.00%	$62.99	5.54%	$3.49	$0.00	$66.48	$230.43	$33.72
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,594.96	$ 13.95	5.605%	$90.18	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$118.83	$41.11
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 2,114.85	$ 13.89	5.604%	$119.29	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$162.85	$23.83
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,786.25	$ 13.67	5.604%	$100.87	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$136.97	$20.05
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,585.93	$ 27.13	9.271%	$242.26	33.00%	$35.12	2.62%	$0.92	$0.00	$36.04	$278.30	$96.27
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 3,038.01	$ 27.08	9.254%	$283.64	78.00%	$49.64	2.62%	$1.30	$0.00	$50.94	$334.59	$48.97
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,752.27	$ 26.89	9.263%	$257.43	78.00%	$42.38	2.62%	$1.11	$0.00	$43.49	$300.93	$44.04
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,097.84	$ 27.13	9.255%	$196.67	33.00%	$40.78	2.62%	$1.07	$0.00	$41.85	$238.51	$82.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,549.91	$ 27.08	9.245%	$238.24	78.00%	$55.30	2.62%	$1.45	$0.00	$56.75	$294.99	$43.17
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,264.18	$ 26.89	9.250%	$211.92	78.00%	$48.04	2.62%	$1.26	$0.00	$49.30	$261.22	$38.23
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	0	$ 1,831.63	$ 12.08	6.233%	$114.92	78.00%	$41.33	2.62%	$1.08	$0.00	$42.41	$157.33	$23.02
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	0	$ 1,517.84	$ 11.89	6.234%	$95.36	78.00%	$34.07	2.62%	$0.89	$0.00	$34.96	$130.32	$19.07
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	No	0	$ 3,260.88	$ 65.28	6.233%	$207.32	78.00%	$72.60	5.54%	$4.02	$0.00	$76.62	$283.94	$41.56
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	No	0	$ 2,637.12	$ 65.08	6.234%	$168.46	78.00%	$57.74	5.54%	$3.20	$0.00	$60.94	$229.40	$33.57
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	Yes	0	$ 2,858.50	$ 44.94	4.170%	$121.07	98.00%	$60.95	0.00%	$0.00	$0.00	$60.95	$182.03	$21.20
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	No	0	$ 560.99	$ 32.46	4.170%	$24.75	97.00%	$10.28	0.00%	$0.00	$0.00	$10.28	$35.03	$4.12
Δ CCS Dave Johnston 4 (costs on post retrofit basis)	No	5,541	$ 3,500.78	$ 53.20	6.447%	$229.12	85.00%	$277.68	5.54%	$15.38	$0.00	$293.06	$522.19	$70.13
Δ CCS Hunter 1-3 (costs on post retrofit basis)	No	6,429	$ 2,951.20	$ 53.20	6.451%	$193.81	85.00%	$235.36	5.54%	$13.04	$0.00	$248.39	$442.21	$59.39
Δ CCS Huntington 1&2 (costs on post retrofit basis)	No	6,933	$ 2,951.40	$ 53.20	6.451%	$193.83	85.00%	$242.12	5.54%	$13.41	$0.00	$255.53	$449.36	$60.35
Δ CCS Jim Bridger 3&4 (costs on post retrofit basis)	Yes	7,513	$ 2,598.38	$ 53.20	6.454%	$171.13	85.00%	$254.91	5.54%	$14.12	$0.00	$269.03	$440.16	$59.11
Δ CCS Wyodak (costs on post retrofit basis)	No	4,448	$ 3,504.25	$ 53.20	6.447%	$229.35	85.00%	$309.51	5.54%	$17.15	$0.00	$326.65	$556.00	$74.67
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	N/A	$ 9,662.09	$ 17.00	5.042%	$488.02	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$594.62	$72.99
Goshen	Yes	2,814	$ 9,855.33	$ 17.00	5.042%	$497.76	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$604.36	$74.18
Wasatch Front	Yes	4,225	$ 9,855.33	$ 17.00	5.042%	$497.76	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$604.36	$74.18
Wyoming East	Yes	6,130	$ 9,565.47	$ 17.00	5.042%	$483.15	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$589.75	$72.39
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	N/A	$ 6,368.23	$ 12.00	5.042%	$321.69	93.00%	$84.53	9.42%	$7.97	$0.00	$92.49	$414.18	$50.84
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 10,628.30	$ 17.00	5.042%	$536.74	93.00%	$107.16	9.42%	$10.10	$0.00	$117.26	$654.00	$80.28
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 7,005.05	$ 12.00	5.042%	$353.80	93.00%	$92.98	9.42%	$8.76	$0.00	$101.74	$455.54	$55.92
Large Light Water Reactor, Moderate Technology Case	No	N/A	$ 7,562.87	$ 10.00	5.042%	$381.82	93.00%	$125.36	9.42%	$11.81	$0.00	$137.17	$518.99	$63.71
Large Light Water Reactor, Advanced Technology Case	No	N/A	$ 6,265.25	$ 9.00	5.042%	$316.35	93.00%	$90.26	9.42%	$8.51	$0.00	$98.76	$415.11	$50.95
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	Yes	N/A	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89
Southern OR	Yes	497	$ 8,883.88	$ 125.09	6.262%	$564.14	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$759.83	$108.42
Wasatch Front	Yes	4,225	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table 7.7 – 2025 IRP Non-Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes							Fixed O&M					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
PV, 20 MW, Class 1-10	Yes	by location	$ 1,964.64	$ 39.29	6.861%	$137.49	27.33%	$18.16	1.37%	$0.25	$18.41	$155.90	$65.11
Portland North Coast	Yes	19	$ 2,082.51	$ 39.29	6.861%	$145.58	24.49%	$18.16	1.37%	$0.25	$18.41	$163.99	$76.45
Southern OR	Yes	497	$ 2,180.75	$ 39.29	6.861%	$152.32	29.29%	$18.16	1.37%	$0.25	$18.41	$170.73	$66.54
Walla Walla	Yes	2,353	$ 2,003.93	$ 39.29	6.861%	$140.19	25.96%	$18.16	1.37%	$0.25	$18.41	$158.60	$69.74
Goshen	Yes	2,814	$ 1,984.28	$ 39.29	6.861%	$138.84	27.79%	$18.16	1.37%	$0.25	$18.41	$157.25	$64.59
Wasatch Front	Yes	4,225	$ 1,964.64	$ 39.29	6.861%	$137.49	29.00%	$18.16	1.37%	$0.25	$18.41	$155.90	$61.38
Wyoming East	Yes	6,130	$ 1,964.64	$ 39.29	6.861%	$137.49	27.47%	$18.16	1.37%	$0.25	$18.41	$155.90	$64.79
PV, 200 MW, Class 1-10	Yes	by location	$ 1,216.55	$ 24.33	6.861%	$85.14	27.33%	$20.52	1.37%	$0.28	$20.80	$105.93	$44.24
Portland North Coast	Yes	19	$ 1,289.55	$ 24.33	6.861%	$90.15	24.49%	$20.52	1.37%	$0.28	$20.80	$110.94	$51.72
Southern OR	Yes	497	$ 1,350.37	$ 24.33	6.861%	$94.32	29.29%	$20.52	1.37%	$0.28	$20.80	$115.12	$44.87
Walla Walla	Yes	2,353	$ 1,240.88	$ 24.33	6.861%	$86.81	25.96%	$20.52	1.37%	$0.28	$20.80	$107.60	$47.32
Goshen	Yes	2,814	$ 1,228.72	$ 24.33	6.861%	$85.97	27.79%	$20.52	1.37%	$0.28	$20.80	$106.77	$43.86
Wasatch Front	Yes	4,225	$ 1,216.55	$ 24.33	6.861%	$85.14	29.00%	$20.52	1.37%	$0.28	$20.80	$105.93	$41.71
Wyoming East	Yes	6,130	$ 1,216.55	$ 24.33	6.861%	$85.14	27.47%	$20.52	1.37%	$0.28	$20.80	$105.93	$44.02
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,832.22	$ 37.33	6.862%	$128.29	27.33%	$17.24	1.37%	$0.24	$17.48	$145.76	$60.88
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,134.56	$ 23.11	6.862%	$79.44	27.33%	$19.47	1.37%	$0.27	$19.74	$99.18	$41.42
Wind Class 1-10, 20 MW	Yes	by location	$ 2,554.58	$ 63.57	6.292%	$164.73	29.07%	$38.79	4.39%	$1.70	$40.49	$205.22	$80.60
Portland North Coast	Yes	19	$ 2,835.59	$ 63.57	6.292%	$182.42	24.91%	$38.79	4.39%	$1.70	$40.49	$222.90	$102.14
Southern OR	Yes	497	$ 3,014.41	$ 63.57	6.292%	$193.67	25.18%	$38.79	4.39%	$1.70	$40.49	$234.15	$106.14
Walla Walla	Yes	2,353	$ 2,656.77	$ 63.57	6.292%	$171.16	23.13%	$38.79	4.39%	$1.70	$40.49	$211.65	$104.46
Goshen	Yes	2,814	$ 2,605.68	$ 63.57	6.292%	$167.95	34.26%	$38.79	4.39%	$1.70	$40.49	$208.44	$69.45
Wasatch Front	Yes	4,225	$ 2,580.13	$ 63.57	6.292%	$166.34	33.69%	$38.79	4.39%	$1.70	$40.49	$206.83	$70.08
Wyoming East	Yes	6,130	$ 2,503.49	$ 63.57	6.292%	$161.52	33.22%	$38.79	4.39%	$1.70	$40.49	$202.01	$69.41
Wind Class 1-6, 200 MW	Yes	by location	$ 1,421.10	$ 63.57	6.316%	$93.77	34.37%	$31.65	4.39%	$1.39	$33.04	$126.81	$42.12
Portland North Coast	Yes	19	$ 1,577.43	$ 63.57	6.316%	$103.65	37.62%	$31.65	4.39%	$1.39	$33.04	$136.68	$41.47
Southern OR	Yes	497	$ 1,676.90	$ 63.57	6.316%	$109.93	34.06%	$31.65	4.39%	$1.39	$33.04	$142.97	$47.92
Walla Walla	Yes	2,353	$ 1,477.95	$ 63.57	6.316%	$97.36	32.59%	$31.65	4.39%	$1.39	$33.04	$130.40	$45.68
Goshen	Yes	2,814	$ 1,449.53	$ 63.57	6.316%	$95.57	30.28%	$31.65	4.39%	$1.39	$33.04	$128.61	$48.49
Wasatch Front	Yes	4,225	$ 1,435.32	$ 63.57	6.316%	$94.67	30.42%	$31.65	4.39%	$1.39	$33.04	$127.71	$47.93
Wyoming East	Yes	6,130	$ 1,392.68	$ 63.57	6.316%	$91.98	41.25%	$31.65	4.39%	$1.39	$33.04	$125.02	$34.60
Wind Class 7, 200 MW	No	by location	$ 1,491.78	$ 63.57	6.313%	$98.19	34.37%	$31.65	4.39%	$1.39	$33.04	$131.23	$43.59
Offshore, Wind Class 12	Yes	0	$ 8,340.57	$ 169.16	5.202%	$442.68	31.54%	$69.26	4.39%	$3.04	$72.30	$514.98	$186.38
Southern OR	Yes	497	$ 9,841.87	$ 169.16	5.202%	$520.77	48.94%	$69.26	4.39%	$3.04	$72.30	$593.07	$138.33
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 2,434.26	$ 60.58	6.292%	$156.98	29.07%	$34.87	4.39%	$1.53	$36.40	$193.37	$75.95
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,354.17	$ 60.58	6.316%	$89.36	34.37%	$28.45	4.39%	$1.25	$29.70	$119.06	$39.54
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,421.51	$ 60.58	6.313%	$93.56	34.37%	$28.45	4.39%	$1.25	$29.70	$123.27	$40.94
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	0	$ 6,011.05	$ 121.92	4.841%	$296.90	84.43%	$63.21	4.39%	$2.78	$65.99	$362.89	$49.06

Table 7.8 – 2025 IRP Storage Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes								Fixed O&M					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Li-Ion, 4-hour, 20 MW[1]	No	N/A	$ 1,747.61	$ 29.94	5.354%	$95.17	16.67%	85%	$45.05	0.00%	$ -	$45.05	$140.22	$96.04
Li-Ion, 4-hour, 200 MW[1]	Yes	N/A	$ 1,497.89	$ 25.66	5.354%	$81.57	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$120.34	$82.42
Portland North Coast	Yes	19	$ 1,587.77	$ 25.66	5.354%	$86.38	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$125.15	$85.72
Southern OR	Yes	497	$ 1,617.73	$ 25.66	5.354%	$87.99	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$126.75	$86.82
Walla Walla	Yes	2,353	$ 1,542.83	$ 25.66	5.354%	$83.98	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$122.74	$84.07
Goshen	Yes	2,814	$ 1,527.85	$ 25.66	5.354%	$83.18	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$121.94	$83.52
Wasatch Front	Yes	4,225	$ 1,542.83	$ 25.66	4.452%	$69.83	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$108.60	$74.38
Wyoming East	Yes	6,130	$ 1,482.92	$ 25.66	4.452%	$67.16	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$105.93	$72.55
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	Yes	N/A	$ 2,556.57	$ 46.19	5.355%	$139.38	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$209.16	$71.63
Portland North Coast	Yes	19	$ 2,709.97	$ 46.19	5.355%	$147.59	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$217.37	$74.44
Southern OR	Yes	497	$ 2,761.10	$ 46.19	5.355%	$150.33	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$220.11	$75.38
Walla Walla	Yes	2,353	$ 2,633.27	$ 46.19	5.355%	$143.48	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$213.27	$73.04
Goshen	Yes	2,814	$ 2,607.71	$ 46.19	5.355%	$142.12	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$211.90	$72.57
Wasatch Front	Yes	4,225	$ 2,633.27	$ 46.19	4.453%	$119.32	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$189.10	$64.76
Wyoming East	Yes	6,130	$ 2,531.01	$ 46.19	4.453%	$114.76	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$184.54	$63.20
Li-Ion, 4-hour, 1000 MW[1]	No	N/A	$ 1,459.50	$ 25.66	5.356%	$79.55	16.67%	85%	$36.92	0.00%	$0.00	$36.92	$116.47	$79.77
Gravity Battery, 4-hour, 1000 MW	Yes	N/A	$ 2,020.99	$ 0.19	2.916%	$58.94	16.67%	83%	$50.51	0.00%	$0.00	$50.51	$109.45	$74.97
Wasatch Front	Yes	4,225	$ 2,081.62	$ 0.19	2.916%	$60.71	16.67%	83%	$50.51	0.00%	$0.00	$50.51	$111.22	$76.18
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	No	N/A	$ 3,006.34	$ 0.35	2.916%	$87.68	33.33%	83%	$90.92	5.48%	$4.98	$95.90	$183.58	$62.87
Adiabatic CAES, 500 MW, 4000 MWh	No	N/A	$ 3,754.00	$ 49.31	4.288%	$163.09	33.33%	63%	$19.20	0.00%	$0.00	$19.20	$182.29	$62.43
100-hour Iron Air	Yes	N/A	$ 2,729.67	$ 171.06	4.581%	$132.88	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$154.47	$58.64
Portland North Coast	Yes	19	$ 2,893.45	$ 171.06	5.484%	$168.06	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$189.65	$72.00
Wasatch Front	Yes	4,225	$ 2,811.56	$ 171.06	4.581%	$136.63	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$158.22	$60.07
Pumped Hydro, Two New Reservoirs, 4-hour	No	N/A	$ 2,984.23	$ 149.21	3.121%	$97.79	16.67%	80%	$20.20	2.62%	$0.53	$20.73	$118.52	$81.18
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	N/A	$ 4,158.90	$ 207.95	3.121%	$136.29	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$157.02	$43.02
Portland North Coast	Yes	19	$ 4,408.44	$ 207.95	3.121%	$144.08	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$164.81	$45.15
Southern OR	Yes	497	$ 4,491.61	$ 207.95	3.121%	$146.67	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$167.40	$45.86
Goshen	Yes	2,814	$ 4,242.08	$ 207.95	3.121%	$138.89	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$159.61	$43.73
Wasatch Front	Yes	4,225	$ 4,283.67	$ 207.95	2.582%	$115.97	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$136.70	$37.45
Wyoming East	Yes	6,130	$ 4,117.31	$ 207.95	2.582%	$111.68	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$132.41	$36.28
Pumped Hydro, One New Reservoir, 4-hour	No	N/A	$ 2,883.24	$ 144.16	3.121%	$94.49	16.67%	80%	$20.20	2.62%	$0.53	$20.73	$115.21	$78.91
Pumped Hydro, One New Reservoir, 10-hour	No	N/A	$ 3,537.41	$ 176.87	3.121%	$115.92	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$136.65	$37.44
Pumped Thermal Energy Storage, 10-hour	No	N/A	$ 6,173.76	$ 60.00	3.361%	$209.52	35.48%	55%	$2.00	2.62%	$0.05	$2.05	$211.57	$68.06
Pumped Thermal Energy Storage, 24-hour	No	N/A	$ 11,525.17	$ 60.00	3.362%	$389.49	35.48%	55%	$1.00	1.37%	$0.01	$1.01	$390.51	$125.63

[1]Assumed co-located

Table 7.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

	Variable O&M					Credits		
Resource Description	Levelized Fuel ($/MWh)	O&M ($/MWh)	Capitalized Premium	O&M Capitalized ($/MWh)	Total Resource Cost ($/MWh)	Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	$ 357.85	$6.93	14.39%	$1.00	$389.44	-	$389.44	$191.77
SCCT Aero, with SCR	$ 53.04	$7.40	14.39%	$1.07	$121.75	-	$121.75	$174.13
SCCT Aero x4, with SCR	$ 53.04	$5.92	14.39%	$0.85	$101.81	-	$101.81	$121.40
SCCT Frame "F" x1, with SCR	$ 54.56	$7.75	14.39%	$1.12	$102.86	-	$102.86	$114.00
Goshen	$ 55.25	$7.75	14.39%	$1.12	$137.12	-	$137.12	$211.04
Wasatch Front	$ 55.27	$7.75	14.39%	$1.12	$108.37	-	$108.37	$127.87
Wyoming East	$ 47.47	$7.75	14.39%	$1.12	$104.40	-	$104.40	$138.95
CCCT Dry "H", 1X1, DF, with SCR	$ 33.91	$2.70	14.39%	$0.39	$60.26	-	$60.26	$158.93
Goshen	$ 34.65	$2.70	14.39%	$0.39	$70.00	-	$70.00	$220.41
Wasatch Front	$ 34.74	$2.70	14.39%	$0.39	$62.27	-	$62.27	$167.04
Wyoming East	$ 30.05	$2.70	14.39%	$0.39	$58.62	-	$58.62	$174.11
CCCT Dry "H", 2X1, DF, with SCR	$ 34.37	$2.28	14.39%	$0.33	$56.54	-	$56.54	$133.67
Goshen	$ 35.12	$2.28	14.39%	$0.33	$66.39	-	$66.39	$195.80
Wasatch Front	$ 35.21	$2.28	14.39%	$0.33	$58.61	-	$58.61	$142.08
Wyoming East	$ 30.45	$2.28	14.39%	$0.33	$54.90	-	$54.90	$149.26
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	$ 37.86	$5.32	11.52%	$0.61	$87.60	-	$87.60	$299.37
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	$ 38.42	$4.83	11.52%	$0.56	$80.12	-	$80.12	$248.16
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	$ 46.57	$6.24	14.39%	$0.90	$114.97	-	$114.97	$177.10
SCCT Aero, with SCR + Δ for CT Brownfield construction	$ 53.04	$6.66	14.39%	$0.96	$115.39	-	$115.39	$158.21
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	$ 53.04	$5.33	14.39%	$0.77	$97.36	-	$97.36	$110.49
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	$ 54.56	$6.98	14.39%	$1.00	$99.05	-	$99.05	$105.53
Goshen-Brownfield	$ 54.23	$6.98	14.39%	$1.00	$132.26	-	$132.26	$202.50
Wasatch Front-Brownfield	$ 54.29	$6.98	14.39%	$1.00	$103.60	-	$103.60	$119.50
Wyoming East-Brownfield	$ 53.90	$6.98	14.39%	$1.00	$107.05	-	$107.05	$130.57
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	$ 33.91	$2.43	14.39%	$0.35	$58.28	-	$58.28	$147.48
Goshen-Brownfield	$ 34.01	$2.43	14.39%	$0.35	$67.36	-	$67.36	$208.85
Wasatch Front-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$59.69	-	$59.69	$155.71
Wyoming East-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$60.72	-	$60.72	$162.78
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	$ 34.37	$2.05	14.39%	$0.30	$54.87	-	$54.87	$123.99
Goshen-Brownfield	$ 34.48	$2.05	14.39%	$0.30	$64.05	-	$64.05	$186.02
Wasatch Front-Brownfield	$ 34.58	$2.05	14.39%	$0.30	$56.32	-	$56.32	$132.50
Wyoming East-Brownfield	$ 34.58	$2.05	14.39%	$0.30	$57.37	-	$57.37	$139.67
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	$ 37.86	$4.78	11.52%	$0.55	$83.88	-	$83.88	$278.00
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	$ 38.42	$4.34	11.52%	$0.50	$76.99	-	$76.99	$230.43
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	$ 54.56	$8.91	14.39%	$1.28	$105.86	-	$105.86	$118.83
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 33.91	$3.11	14.39%	$0.45	$61.30	-	$61.30	$162.85
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 34.37	$2.62	14.39%	$0.38	$57.42	-	$57.42	$136.97
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 54.56	$8.18	14.39%	$1.18	$160.18	-	$160.18	$278.30
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 33.91	$3.13	14.39%	$0.45	$86.46	-	$86.46	$334.59
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 34.37	$2.70	14.39%	$0.39	$81.51	-	$81.51	$300.93
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 54.56	$8.32	14.39%	$1.20	$146.59	-	$146.59	$238.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 33.91	$3.27	14.39%	$0.47	$80.83	-	$80.83	$294.99
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 34.37	$2.85	14.39%	$0.41	$75.86	-	$75.86	$261.22
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	$ 33.91	$2.68	14.39%	$0.39	$60.00	-	$60.00	$157.33
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	$ 34.37	$2.23	14.39%	$0.32	$56.00	-	$56.00	$130.32
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	$ 37.86	$5.03	11.52%	$0.58	$85.02	-	$85.02	$283.94
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	$ 38.42	$4.49	11.52%	$0.52	$77.00	-	$77.00	$229.40
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	$ -	$0.00	0.00%	$0.00	$21.20	$ (4.85)	$21.20	$182.03
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	$ -	$23.91	0.00%	$0.00	$28.03	$ (0.96)	$28.03	$35.03
CCS Dave Johnston 4 (costs on post retrofit basis)	$ -	$11.40	11.52%	$1.31	$82.84	$ (160.13)	$ (77.29)	$ (487.20)
CCS Hunter 1-3 (costs on post retrofit basis)	$ -	$9.73	11.52%	$1.12	$70.24	$ (160.13)	$ (89.89)	$ (565.96)
CCS Huntington 1&2 (costs on post retrofit basis)	$ -	$9.63	11.52%	$1.11	$71.09	$ (160.13)	$ (89.04)	$ (562.82)
CCS Jim Bridger 3&4 (costs on post retrofit basis)	$ -	$10.57	11.52%	$1.22	$70.90	$ (160.13)	$ (89.23)	$ (554.00)
CCS Wyodak (costs on post retrofit basis)	$ -	$11.69	11.52%	$1.35	$87.70	$ (160.13)	$ (72.43)	$ (459.16)
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	$ -	$9.74	0.00%	$0.00	$82.73	$ (20.29)	$62.44	$448.80
Goshen	$ -	$9.74	0.00%	$0.00	$83.93	$ (20.29)	$63.64	$458.27
Wasatch Front	$ -	$9.74	0.00%	$0.00	$83.93	$ (22.29)	$61.64	$443.88
Wyoming East	$ -	$9.74	0.00%	$0.00	$82.13	$ (22.29)	$59.85	$429.73
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	$ -	$8.74	0.00%	$0.00	$59.58	$ (22.29)	$37.29	$259.26
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	$ -	$10.72	0.00%	$0.00	$90.99	$ (20.29)	$70.71	$508.18
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	$ -	$9.61	0.00%	$0.00	$65.53	$ (22.29)	$43.24	$300.62
Large Light Water Reactor, Moderate Technology Case	$ -	$9.38	0.00%	$0.00	$73.09	$ (20.29)	$52.80	$374.94
Large Light Water Reactor, Advanced Technology Case	$ -	$7.88	0.00%	$0.00	$58.83	$ (22.29)	$36.55	$257.87
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	$ -	$0.00	0.00%	$0.00	$96.89	$ (23.46)	$73.43	$514.59
Southern OR	$ -	$0.00	0.00%	$0.00	$108.42	$ (23.46)	$84.96	$595.43
Wasatch Front	$ -	$0.00	0.00%	$0.00	$96.89	$ (25.77)	$71.12	$498.40

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table 7.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

Resource Description	Total Resource Cost ($/MWh)	Credits		
		Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
PV, 20 MW, Class 1-10	$65.11	$ (25.15)	$39.96	$95.69
Portland North Coast	$76.45	$ (25.15)	$51.30	$110.04
Southern OR	$66.54	$ (25.15)	$41.39	$106.20
Walla Walla	$69.74	$ (25.15)	$44.59	$101.40
Goshen	$64.59	$ (25.15)	$39.44	$96.03
Wasatch Front	$61.38	$ (27.63)	$33.75	$85.73
Wyoming East	$64.79	$ (27.63)	$37.16	$89.42
PV, 200 MW, Class 1-10	$44.24	$ (25.15)	$19.09	$45.72
Portland North Coast	$51.72	$ (25.15)	$26.57	$56.99
Southern OR	$44.87	$ (25.15)	$19.72	$50.59
Walla Walla	$47.32	$ (25.15)	$22.17	$50.41
Goshen	$43.86	$ (25.15)	$18.71	$45.54
Wasatch Front	$41.71	$ (27.63)	$14.08	$35.76
Wyoming East	$44.02	$ (27.63)	$16.40	$39.46
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	$60.88	$ (27.63)	$33.25	$79.62
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	$41.42	$ (27.63)	$13.80	$33.03
Wind Class 1-10, 20 MW	$80.60	$ (23.46)	$57.14	$145.49
Portland North Coast	$102.14	$ (23.46)	$78.68	$171.70
Southern OR	$106.14	$ (23.46)	$82.68	$182.40
Walla Walla	$104.46	$ (23.46)	$81.00	$164.12
Goshen	$69.45	$ (23.46)	$45.99	$138.03
Wasatch Front	$70.08	$ (25.77)	$44.31	$130.77
Wyoming East	$69.41	$ (25.77)	$43.64	$127.01
Wind Class 1-6, 200 MW	$42.12	$ (23.46)	$18.66	$56.18
Portland North Coast	$41.47	$ (23.46)	$18.01	$59.36
Southern OR	$47.92	$ (23.46)	$24.46	$72.97
Walla Walla	$45.68	$ (23.46)	$22.22	$63.43
Goshen	$48.49	$ (23.46)	$25.03	$66.38
Wasatch Front	$47.93	$ (25.77)	$22.16	$59.04
Wyoming East	$34.60	$ (25.77)	$8.83	$31.90
Wind Class 7, 200 MW	$43.59	$ (23.46)	$20.13	$60.59
Offshore, Wind Class 12	$186.38	$ (32.72)	$186.38	$514.98
Southern OR	$138.33	$ (24.88)	$138.33	$593.07
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	$75.95	$ (25.77)	$50.18	$127.76
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	$39.54	$ (25.77)	$13.77	$41.47
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	$40.94	$ (25.77)	$15.17	$45.68
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	$49.06	$ (11.74)	$49.06	$362.89

Table 7.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

Resource Description	Variable O&M	Credits	
	O&M ($/MWh)	Tax Credits ($/MWh) (ITC already applied)	Total Fixed Cost with Tax Credit ($/kW-yr)
Ion, 4-hour, 20 MW[1]	$0.00	$ (32.40)	$140.22
Ion, 4-hour, 200 MW[1]	$0.00	$ (27.77)	$120.34
Portland North Coast	$0.00	$ (29.44)	$125.15
Southern OR	$0.00	$ (29.99)	$126.75
Walla Walla	$0.00	$ (28.61)	$122.74
Goshen	$0.00	$ (28.33)	$121.94
Wasatch Front	$0.00	$ (38.14)	$108.60
Wyoming East	$0.00	$ (36.66)	$105.93
Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	$0.00	$ (23.69)	$209.16
Portland North Coast	$0.00	$ (25.11)	$217.37
Southern OR	$0.00	$ (25.59)	$220.11
Walla Walla	$0.00	$ (24.40)	$213.27
Goshen	$0.00	$ (24.17)	$211.90
Wasatch Front	$0.00	$ (32.54)	$189.10
Wyoming East	$0.00	$ (31.27)	$184.54
Ion, 4-hour, 1000 MW[1]	$0.00	$ (27.05)	$116.47
Gravity Battery, 4-hour, 1000 MW	$0.00	$ (33.10)	$109.45
Wasatch Front	$0.00	$ (34.09)	$111.22
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	$0.00	$ (24.62)	$183.58
Adiabatic CAES, 500 MW, 4000 MWh	$2.60	$ (27.92)	$182.29
100-hour Iron Air	$0.00	$ (37.40)	$154.47
Portland North Coast	$0.00	$ (29.72)	$189.65
Wasatch Front	$0.00	$ (38.52)	$158.22
Pumped Hydro, Two New Reservoirs, 4-hour	$0.58	$ (33.01)	$118.52
Pumped Hydro, Two New Reservoirs, 10-hour	$0.58	$ (18.40)	$157.02
Portland North Coast	$0.58	$ (19.51)	$164.81
Southern OR	$0.58	$ (19.87)	$167.40
Goshen	$0.58	$ (18.77)	$159.61
Wasatch Front	$0.58	$ (25.28)	$136.70
Wyoming East	$0.58	$ (24.30)	$132.41
Pumped Hydro, One New Reservoir, 4-hour	$0.58	$ (31.89)	$115.21
Pumped Hydro, One New Reservoir, 10-hour	$0.58	$ (15.65)	$136.65
Pumped Thermal Energy Storage, 10-hour	$0.70	$ (34.12)	$211.57
Pumped Thermal Energy Storage, 24-hour	$0.70	$ (63.70)	$390.51

1Assumed co-located

Table 7.12 - Glossary of Terms Used in the Supply-Side Resource Tables

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Resource Availability Year	The earliest year the Company would sign a contract for a Resource being studied in this IRP. If available prior to the development of this database, this defaults to IRP year.
Total Implementation Time	Number of years necessary to implement all phases of resource development and construction after signing a contract to build the Resource: permitting (e.g., air, land, water, and wildlife), maintenance contracts, owner's engineering, construction, testing, and grid interconnection.
Commercial Operation Year	Year when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time.
Design Life (years)	Average number of years the resource is expected to be "used and useful."
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt ($/kW) for the development and construction of a Resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit, and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, and owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes, and escalation during construction, if applicable).
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance, and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
Efficiency	Typical operational round-trip efficiency of energy storage of alternating current (AC) energy delivered to the grid divided by AC energy stored from the grid.

Term	Description
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given Resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given Resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a Resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NOx) (expressed as NO2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO2 (lbs/MMBtu)	Pounds of carbon dioxide (CO2) emitted per million Btu of heat input.

Table 7.13 - Glossary of Acronyms Used in Chapter 7

Acronyms	Description
ACAES	Adiabatic Compressed Air Energy storage
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
CT	Combustion Turbine
DF	Duct Firing
DOE	United States Department of Energy
EIA	Energy Information Agency
FGD	Flue Gas Desulfurization
GAIN	Gateway for Accelerated Innovation in Nuclear
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine (reciprocating engine)
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organization (Temperature = 59 degrees Fahrenheit (°F) / 15 degrees Celsius (°C), Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)
MW	Megawatt
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OSTI	Office of Scientific and Technical Information

OSW	Offshore Wind
PCCC	Post Combustion CO2 Capture
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
RTE	Round Trip Efficiency (typical operational AC to AC energy storage efficiency)
SCCT	Simple Cycle Combustion Turbine
SCR	Selective catalytic reduction
STG	Steam turbine generator

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.2 through Table 7.11. For all technology that is included in the 2024 NREL ATB, the ATB costs were used. For incremental items, a percentage difference between the technology with and without the incremental resource was used. Where data is available for an advanced technology innovation scenario[24], there is a resource row for that scenario.

Internal Combustion Engine x4, renewable biofuel, with SCR & fuel tank – This is a reciprocating internal combustion engine (RICE) power plant based on four large-scale engines, that are assumed to burn a liquid renewable biofuel like biodiesel or renewable diesel. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW."[25] It is presented in the IRP as a 20 MW resource to meet Oregon's regulatory requirements for distributed generation resources, under the assumption that it could be derated to meet the requirements. The 24-hour fuel tank was added to the 2020 EIA Report's resource based on available market information on in-ground fuel tanks.[26]

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – This is "four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also

[24] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[25] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[26] See Appendix M, stakeholder feedback form #59 (Renewable Northwest).

equipped with burners designed to reduce the CT's emission of NO_X. Included are SCR units for further reduction of NO_X emissions and CO catalysts for further reduction of CO emissions."[27]

Natural Gas, SCCT Frame "F" x 1, with SCR – This is "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X."[28] Although the 2020 EIA Report does not include an SCR for this resource, to be on par with the other IRP resources, the approximate cost of an SCR was added based on the cost difference on a percentage basis from previous IRP's.

Natural Gas, CCCT "H", 1x1, DF, with SCR – This is "one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross, and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW."[29]

Natural Gas, CCCT "H", 2x1, DF, with SCR – This is "a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW."[30]

Natural Gas, Δ for adding 95% CCS – This option reflects incremental changes for a greenfield "power plant w/ commercially available solvent-based post combustion CO_2 capture (PCCC) designed for 95% capture."[31] The 95% option was chosen because that is the most economic option available in the NREL ATB that meets the EPA 111 regulations.

Natural Gas, Δ for CT Brownfield construction – This option reflects incremental changes for construction of a resource at an existing powerplant site with the same technology.

Hydrogen, Δ for 100% Hydrogen burning capability – This option reflects incremental changes for a CT to burn a mixture of fuel up to 100% hydrogen.

Hydrogen, Δ for Hydrogen storage, cavern, 80 bar, 1 week – This option reflects incremental changes for storing hydrogen underground in a solution-mined geologic salt dome. Hydrogen gas

[27] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[28] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[29] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[30] Ibid 17
[31] 2024 ATB Excel Workbook, available at https://atb.nrel.gov/electricity/2024/data.

is compressed and stored at ambient temperature in at elevated pressure (70-190 bar). Salt domes only exist in a limited number of locations (~2000 salt caverns in North America with an average capacity of 10^5-10^6 m^3). There are at least two salt domes under development within PacifiCorp's area of operation. This assumes a "600 tons per day (TPD) pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume."[32] In addition to the Pathways to Commercial Liftoff: Clean Hydrogen (Clean Hydrogen Liftoff Report), the Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan[33] was used for cost and technical data.

Hydrogen, Δ for Hydrogen storage, tanks, 500 bar, 24-hour – This option reflects incremental changes for storing hydrogen in tanks constructed above ground. "H_2 gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of H_2 at room temperature. Assumes 950 kg stored at 500 bar with 1 cycle per week."[34]

Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day – Also known as polymer electrolyte membrane, including balance of plant (BOP) costs, the "electrolyzer design is intended to represent the current state-of-the-art (2022) stacks with respect to catalyst loadings (3 milligrams per square centimeter [mg/cm2] total platinum group metal [PGM] loading) and material specifications."[35] Data from the DOE Hydrogen and Fuel Cells Program Record[36] was also used in the development of this resource.

Coal, CCS– These are retrofits of an existing conventional coal-fired boiler and steam-turbine generator resources with amine based post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCS would remove 95 percent of the carbon dioxide and would provide reductions in other emissions.[37]

Storage, Lithium Ion Battery – This is lithium-ion batteries rated at 20 and 200 MW capacities with 4-hour duration. The 20 MW option uses the ATB's "Commercial Battery" data, while the 200 MW option uses the ATB's "Utility-Scale" data.

[32] Pathways to Commercial Liftoff: Clean Hydrogen, U.S. Department of Energy, Office of Technology Transitions: Hannah Murdoch; Office of Clean Energy Demonstrations: Jason Munster; Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi; Argonne National Laboratory: Amgad Elgowainy; National Renewable Energy Laboratory: Michael Penev, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf

[33] Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan, Dr. Sunita Satyapal, U.S. Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-multi-year-program-plan

[34] ibid 20

[35] Badgett, Alex, Joe Brauch, Amogh Thatte, Rachel Rubin, Christopher Skangos, Xiaohua Wang, Rajesh Ahluwalia, Bryan Pivovar, and Mark Ruth. 2024. *Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87625. https://www.nrel.gov/docs/fy24osti/87625.pdf.

[36] David Peterson, James Vickers, Dan DeSantis, *Hydrogen Production Cost From PEM Electrolysis – 2019*, February 3, 2020, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

[37] Carbon capture costs and parameters were the subject of discussion and feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #25 (NP Energy, LLC).
See Appendix M, stakeholder feedback form #44 (Sierra Club).

Storage, Δ double duration – This option reflects incremental changes for doubling the duration of a battery energy storage resource, modifiers on this row must be applied to the data in the appropriate resource row. Appropriate resources are limited to those utilizing lithium-ion energy storage, including lithium-ion energy storage collocated with other resources.

Storage, Δ for Co-Located Energy Storage – This option reflects incremental changes for lithium-ion energy storage collocated with another resource, modifiers on this row must be applied to the appropriate energy storage data.

Storage, Gravity Battery, 4-hour, 1000 MW – This is an estimate for any technology that uses the potential energy differential of a large mass but excludes pumped hydro. Pumped hydro is a well-established technology and because of this there is more accurate data available for pumped hydro. Examples include dense weights lifted vertically, heavy rail cars moved up and down a steep track, or a piston displacing a fluid vertically. Costs were escalated from the 2023 IRP.

Storage, Adiabatic CAES – Compressed air energy storage (CAES) system consists of an air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. Only the system sizes of 500 MW are included because that size was the lowest cost per kWh in the 2023 IRP. The air storage reservoir is an engineered tank. "Adiabatic" conserves heat during storage and discharge and means the system does not burn natural gas to generate power.

Storage, Pumped Hydro, Two New Reservoirs – Also known as closed-loop pumped hydro, this technology pumps and releases water between a higher and a lower reservoir. It is modeled as a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 1 data.

Storage, Pumped Hydro, One New Reservoirs – Also known as an open-loop system, this technology pumps and releases water between a higher reservoir and a lower natural water body, usually a river. It is modeled as a nominal 400 MW PHES system using both natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 5 data.

Storage, 100-hour Iron Air – This is a low capital cost battery option with the trade off a low round trip efficiency. "While discharging, the battery breathes in oxygen from the air and converts iron metal to rust. While charging, the application of an electrical current converts the rust back to iron and the battery breathes out oxygen."[38]

Storage, Pumped Thermal Energy Storage – This is a system using a storage tank of high temperature fluid to store energy. A resistive heater converts electric energy to heat energy in the

[38] https://formenergy.com/technology/battery-technology/

fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator.

Solar, PV, Class 1 - 10 – This is ATB PV Class 1 through 10 (20 MW or 200 MW) solar photovoltaic resources using crystalline silica solar panels in a single axis tracking system. The 20 MW option uses the ATB's "Commercial" data, while the 200 MW option uses the ATB's "Utility-Scale" data. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-10, 20 MW – This is ATB "Distributed Wind, Large Turbine Technology Class." It is a wind resource of 1,500 kW turbines with 107-meter rotor diameter and 80-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-6, and 7200 MW – This is ATB Land-Based Wind technology configuration T1. It is a wind resource of 34 x 6 MW turbines with 170-meter rotor diameter and 115-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 7, 200 MW – This is the same as wind classes 1- 6, but different wind conditions and cost data.

Wind, Offshore, Wind Class 12 – This is ATB "Floating Offshore Wind." It is a wind resource of 12 MW turbines with 216-meter rotor diameter and 137-meter hub height. Wind Class 12 represents the wind conditions off the coast of northern California and southern Oregon. The ATB lists a net capacity factor of 47% for Offshore Wind Class 12.

Nuclear, Small Modular Reactor or Advanced Reactor – This is a conceptual technology that could be a small modular reactor or small advanced reactor. "Modular" refers to a reactor that can be built off site and easily transported to the installation location, however scale of economy requires multiple modular reactors to share support facilities at a single powerplant site. Data is from the ATB and relies heavily on a DOE Office of Scientific and Technical Information, Gateway for Accelerated Innovation in Nuclear report[39] ("OSTI GAIN Report").

Nuclear, Δ for nuclear integrated thermal storage, 5 hours - This option reflects incremental changes for a system using a storage tank of high temperature fluid. To store energy, heat from a nuclear reactor is transferred in a heat exchanger to the storage fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator. This method eliminates the resistive heater losses in the stand-alone thermal storage, and therefore has a much higher RTE.

Nuclear, Large Light Water Reactor – This is a modern dual unit reactor similar to most of the existing utility reactors in the United States. Data is from the ATB and relies heavily on the OSTI GAIN Report.

[39] Abdalla Abou-Jaoude, Levi M Larsen, Nahuel Guaita, Ishita Trivedi, Frederick Joseck, and Christopher Lohse, Idaho National Laboratory; Edward Hoffman and Nicolas Stauff. Argonne National Laboratory; Koroush Shirvan, Massachusetts Institute of Technology; Adam Stein, Breakthrough Institute; Gateway for Accelerated Innovation in Nuclear (GAIN); *Meta-Analysis of Advanced Nuclear Reactor Cost Estimations*, July 2024, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

Geothermal, Near Field Enhanced Geothermal System (NF-EGS) Binary – This is the ATB geothermal plant utilizing a 175°C thermal resource with 1.5 km wells and production well flow rates of 60 kg/s.[40]

Locational Modifiers and Selected Cost Forecasts

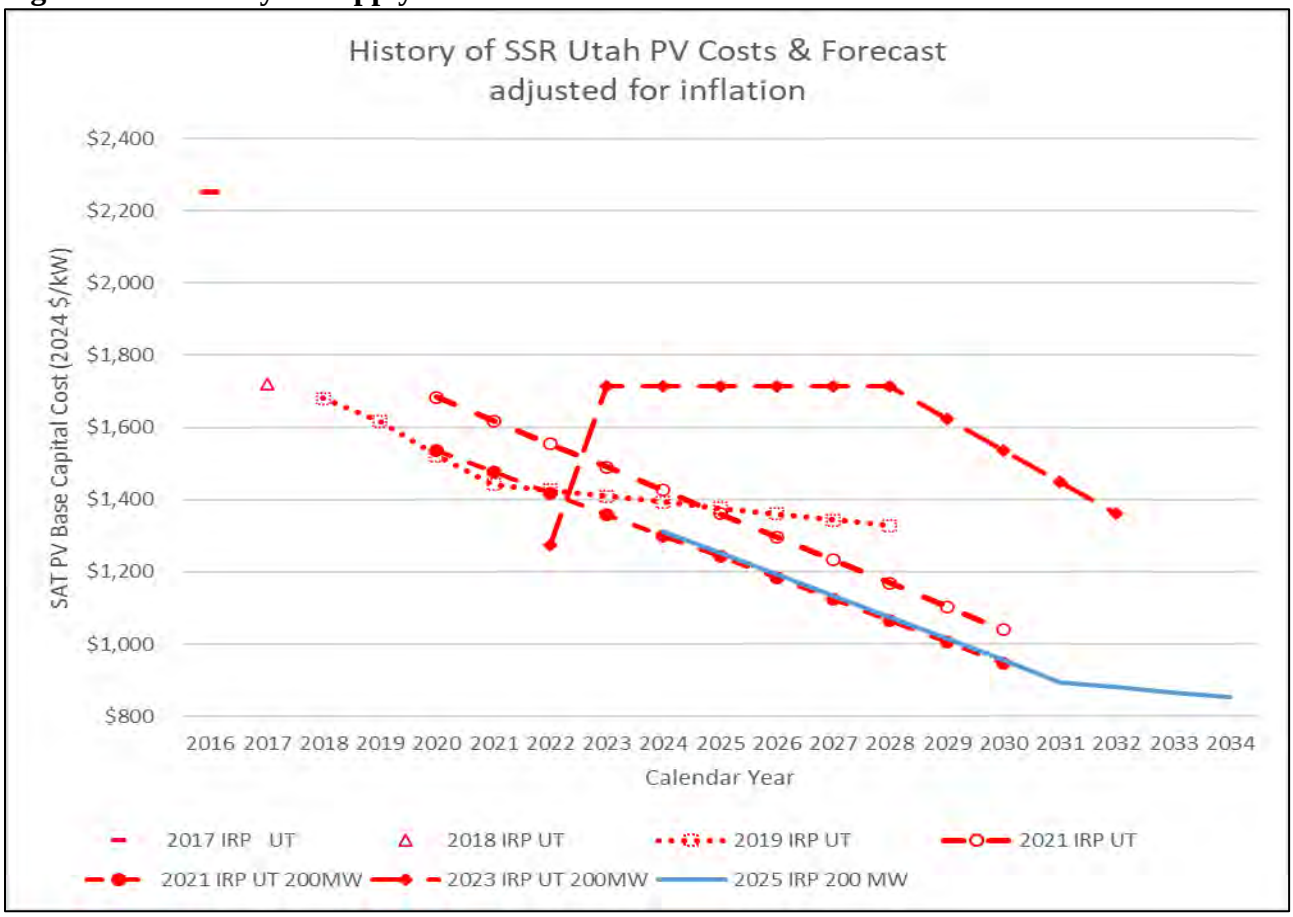
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options in the supply-side resource table. For any resource option without a technology specific cost forecast, escalation is assumed to be level. These locational modifiers and cost forecasts are applied in PLEXOS. Cost forecast histories for selected resource types are shown in the following sections.

PV Cost Forecast History

Figure 7.1 shows a history of capital cost forecasts used in the supply-side resource table for PV resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost estimates for solar resources are based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is essentially the same as the trend line of the 2021 IRP.

[40] Geothermal modeling was the subject of stakeholder feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

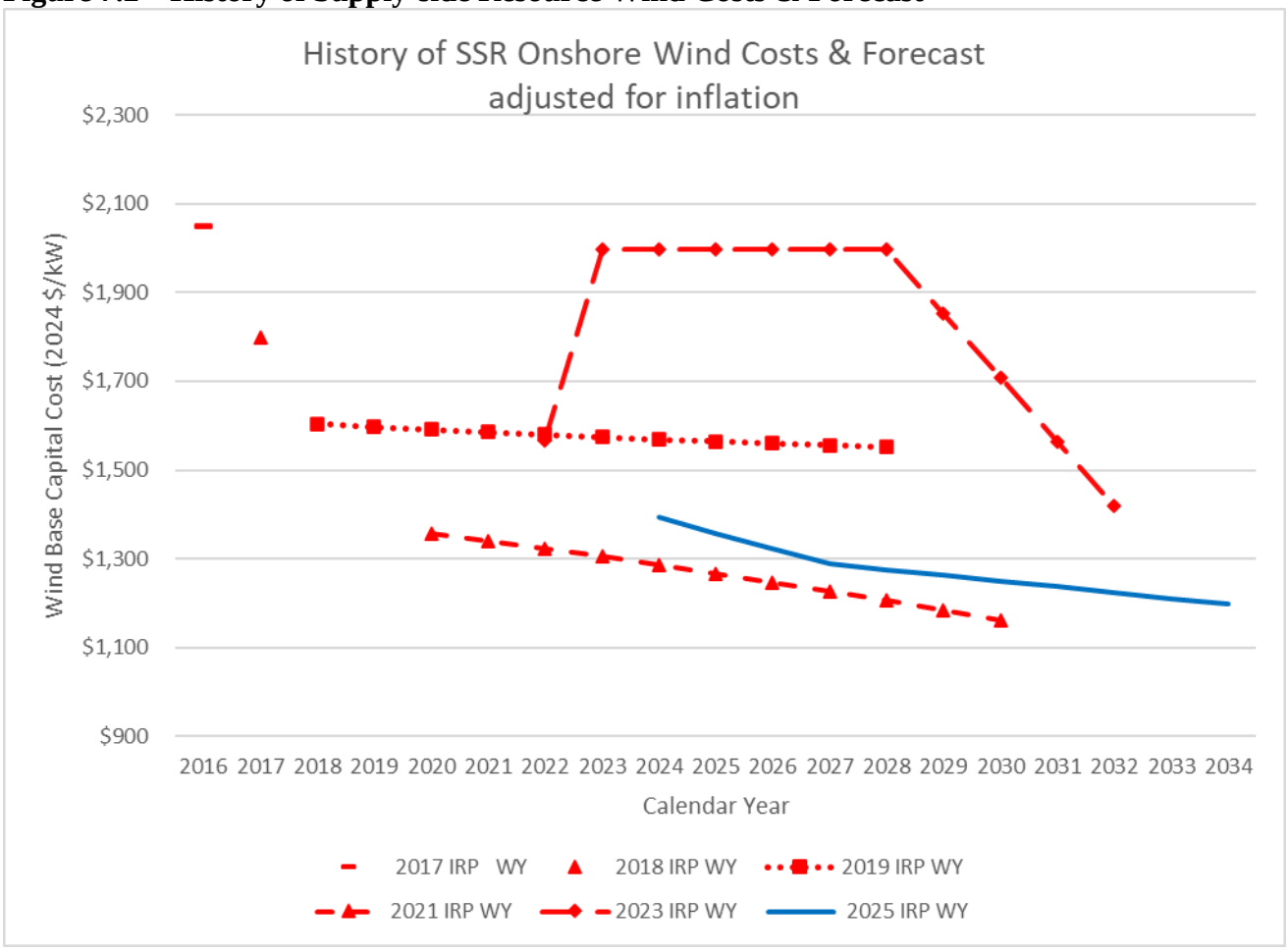
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast



Wind Cost Forecast History

Figure 7.2 shows a history of capital cost forecasts used in the supply-side resource table for resources in Wyoming from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for wind resources is based on the ATB forecast. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is close to the trend line of the 2021 IRP.

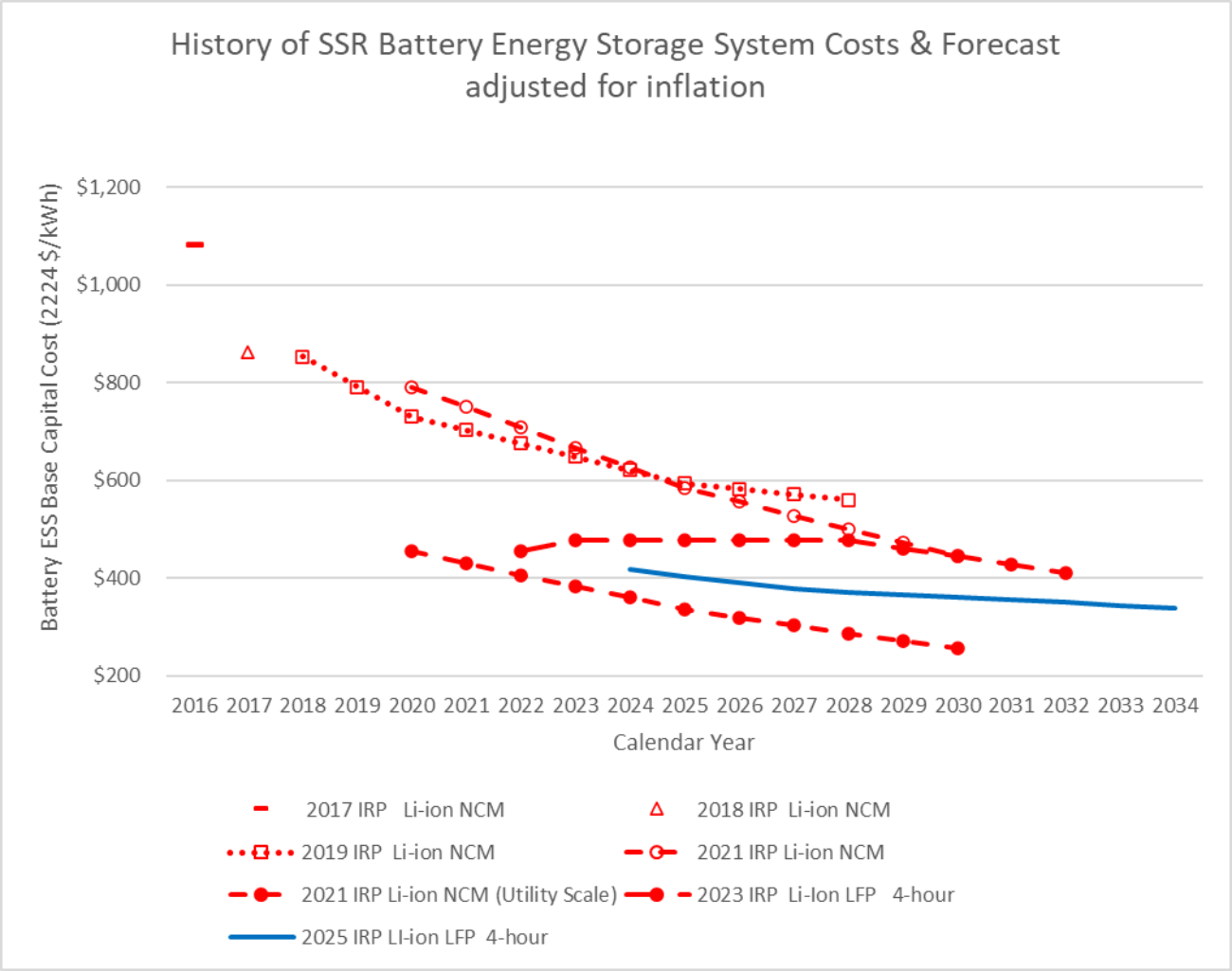
Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



Energy Storage

Figure 7.3 shows a history of capital cost forecasts used in the supply-side resource table for BESS resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for BESS resources is based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been partially mitigated by federal policy changes and the forecast costs are about midway between the less expensive 2021 IRP and the more expensive 2023 IRP.

Figure 7.3 – History of Battery Energy Storage System Costs & Forecast



Utility-scale Energy Storage Resources

PacifiCorp has contracted for the following utility-scale energy storage resources:

- Faraday solar and storage (525 MW solar, 150 MW battery storage with 4-hour duration) is a project supporting customer clean energy goals under Utah Schedule 34.
- Green River solar and storage (400 MW solar, 400 MW battery storage with 4-hour duration) is a project that was originally part of the final shortlist in the 2020 All-Source Request for Proposals. An amendment to the contract expanded the battery from 200 MW with two-hour duration to 400 MW with four-hour duration.
- Dominguez Grid (200 MW battery storage with four-hour duration) is a stand-alone energy storage resource.
- Enterprise/Escalante/Granite Mountain East/Iron Springs storage: each of these contracts is an 80 MW battery storage resource with four-hour duration. Battery storage is being added at existing solar resources and will use surplus interconnection. A surplus interconnection allows for resources to be added at any existing interconnection location so long as the total output to the grid is kept within the existing interconnection capacity.

As a result of the contracts described above, PacifiCorp expects to bring more than one gigawatt of energy storage resources online by the summer of 2026.

Comparison of Lazard's Levelized Cost of Energy Analysis-Version 17 (LCOE+ 17)[41] and NREL's 2024 ATB[42]

Lazard's LCOE+ 17 and the NREL ATB both inform stakeholders about the economic viability of different energy sources, but they differ in scope, methodology, and the specifics of their cost assumptions. Each report is assumed to use a consistent but distinct methodology across all technologies, with technology specific nuances treated fairly. Table 7.14 provides a side-by-side comparison of pertinent information in the two reports.

Lazard's LCOE+ 17 cost assumptions are based on a standardized financial model with fixed debt and equity costs. The analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost, resulting in an after-tax weighted average cost of capital (WACC) of 7.7%.

NREL's ATB offers a range of financial assumption options to reflect different market conditions and provide a more comprehensive view of potential costs.

Table 7.14 – Comparison of Lazard LCOE+ and NREL ATB

	Lazard LCOE+ 17	NREL ATB
Levelized Cost of Energy (LCOE)	Historic Ranges & Averages	Historic and future "Technology Advancement Scenarios" options
Levelized Cost of Storage (LCOS)	Yes	No
Levelized Cost of Hydrogen (LCOH)	Yes	No
Finance Assumptions	No	Yes
Tax Credits	Yes	Optional
Capital Cost	Yes, but not clearly defined	"Capital Expenditure" (CAPEX)
Construction Cost	Assumed to be included	Yes
Overnight Capital Cost	No	Yes
Grid Connection Cost	Not clear	Yes
Construction Finance Factor	No	Yes
Construction Cashflow Curve	No	No
Weighted Average Cost of Capital	Yes	Yes
Fixed O&M (FOM)	Yes	Yes
Variable O&M (VOM)	Yes	Yes
Capacity Factor (CF)	Yes	Yes
Facility Net Power Capacity	Yes	Yes
Heat Rate	Yes	Yes

[41] Lazard Levelized Cost of Energy +, June 2024, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf
[42] https://atb.nrel.gov/electricity/2024/index

Construction Time	Yes	Yes
Design Life	Yes	Yes
Energy Storage Duration	Yes	Yes
Energy Storage Round Trip Efficiency (RTE)	Yes	Yes
Energy Storage Degradation	Yes	Included in FOM
Regional Resolution Level	Regional markets, including CAISO but not WECC	Select cites in each state, per referenced reports
Regional Adjustment Factors	No	Included in referenced reports
Effective Load Carrying Capability (ELCC) Analysis	Yes	No
Demolition Costs	No	No
Outage Rates, Forced and Planned	Assumed to be included in CF	Assumed to be included in CF
References or Bibliography	No	Yes

The costs reported by Lazard and NREL can differ due to variations in their methodologies and assumptions. Lazard's LCOE+ 17 tends to provide a more standardized comparison across technologies, which can be useful for high-level decision-making. In contrast, NREL's ATB offers a more detailed and nuanced view, considering different scenarios and market conditions.
Reasons for Cost Differences:

- Methodological Differences: Lazard uses a fixed financial model, while NREL incorporates a range of scenarios and assumptions, leading to different cost estimates.
- Scope of Analysis: Lazard focuses on a high-level comparison of technologies, whereas NREL provides detailed data for specific scenarios and market conditions.
- Financial Assumptions: Differences in debt and equity costs, as well as WACC, can lead to variations in the reported costs.
- Technology Assumptions: NREL's ATB includes projections for future technology advancements, which can result in lower cost estimates compared to Lazard's more conservative approach.

In summary, while both Lazard's LCOE+ 17 and NREL's ATB provide valuable insights into the costs of energy technologies, their differences in scope, methodology, and assumptions can lead to varying cost estimates. Understanding these differences is crucial for stakeholders to make informed decisions about energy investments.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data
PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2025-2044, which provided DSM resource opportunity estimates for the 2025 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of

the size, type, location and cost of demand-side resources.[43] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g., products and quantities) based on each resource's competitiveness against alternative resource options.[44] Due to the timing of the 2025 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2025 DSM program acquisition targets. To ensure that the 2025 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2025. In 2026, energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period.
- Persistence of resource savings (e.g., energy efficiency equipment measure lives).
- Seasonal availability and hours available (e.g., irrigation load control programs).
- The hourly shape of the resource (e.g., load shape of the resource).
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

<u>Demand Response: DSM Capacity Supply Curves</u>

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2025, PacifiCorp has launched and expanded several demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2025.

[43] The 2025 Conservation Potential Study is available on PacifiCorp's IRP Support & Studies web page: www.pacificorp.com/energy/integrated-resource-plan/support.html.

[44] Demand-side management modeling and methodology was a frequent topic of discussion in the 2025 IRP public input meeting series and in stakeholder feedback forms.
See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
See Appendix M, stakeholder feedback form #45 (Utah Clean Energy).

Table 7.15 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – HVAC DLC	OR, WA	Planned
Res – EV Load Control	OR, WA, UT	Planned
Res – Battery DLC	OR, WA	Planned
Res – Battery DLC	ID, UT	Existing
C&I – Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.16 and Table 7.16 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2025 CPA.[45] Potential shown is incremental to the existing DSM resources identified in Table 7.17. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2025. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2026. New program offerings are assumed to be available in 2026 accounting for the time required for program design, regulatory approval, vendor selection, procurement, and implementation.

Table 7.16 – Demand Response Program Attributes West Control Area,[46]*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res – EV DLC	15.1	$412	15.1	$412
Res – DLC of Smart Home	0.1	$1,306	0.1	$686
Res – HVAC DLC	17.4	$175	81.7	$73
Res – Pool Pump DLC	0.2	$742	0.1	$1,956
Res – Water Heater DLC	2.7	$134	4.0	$90
Res – Smart Thermostat	40.2	$37	28.9	$29
Res – Grid Interactive Water Heaters	14.6	$97	24.5	$66
Battery DLC	6.1	$31	4.9	$30
C&I – Third Party	8.5	$46	12.4	$54
Ag – Irrigation DLC	1.8	$24	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

[45] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
[46] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Table 7.17 – Demand Response Program Attributes East Control Area,[47]*

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res – EV DLC	24.8	$416	24.8	$416
Res – DLC of Smart Home	0.1	$1,601	0.3	$772
Res – HVAC DLC	234.2	$158	141.3	$272
Res – Pool Pump DLC	0.2	$834	0.1	$2,199
Res – Water Heater DLC	12.8	$175	17.5	$117
Res – Smart Thermostat	90.4	$38	50.2	$94
Res – Grid Interactive Water Heaters	1.1	$209	2.0	$139
Battery DLC	65.3	$36	65.2	$41
C&I – Third Party	66.6	$52	72.7	$50
Ag – Irrigation DLC	19.1	$29	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2025 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[48]
- **Measure:**
  - 120 residential measures
  - 146 commercial measures
  - 105 industrial measures
  - 19 irrigation measures

- **Facility type:**[49]
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types

[47] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

[48] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

[49] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in Volume 1 of the 2025 CPA.

- Two irrigation facility type

The 2025 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e., incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the 20-year CPA planning horizon totaled approximately 15.1 million MWh.[50] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 12.8 million MWh for all five states. The technical achievable potential for all six states, i.e., including Oregon, for modeling consideration is 17.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated just over 50,500 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 21-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[51]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2025 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency

[50] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

[51] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

resource supply curves. Table 7.18 shows the 21-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure's temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity ($/kW-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are "free." These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

Table 7.18 – 2045 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	34,469	42,040	609,077	1,282,306	102,772	108,946
Heating Measures	28,535	75,471	870,110	751,888	197,253	122,268
Summer Measures	68,513	119,447	1,292,227	1,244,883	366,577	221,926
Winter Measures	221	14,417	103,548	221,229	3,524	347,464
Zero Cost Temperature Dependent Measures	18,360	84,725	295,605	1,550,447	127,775	84,371
Zero Cost Non-Temperature Dependent Measures	33,056	260,493	1,224,970	3,470,030	376,187	626,797

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.19)
- Stochastic risk reduction credit.[52]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only).[53]

[52] PacifiCorp develops this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

[53] The formula for calculating the $/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Table 7.19 – State-specific Transmission and Distribution Credits (2024$)

State	Transmission Deferral Value ($/kW-year)	Distribution Deferral Value ($/kW-year)	Total
California	$5.83	$11.23	$17.06
Oregon	$5.83	$15.65	$21.49
Washington	$5.83	$18.93	$24.76
Idaho	$5.83	$23.11	$28.94
Utah	$5.83	$18.62	$24.46
Wyoming	$5.83	$9.61	$15.44

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. As in the 2023 IRP, PacifiCorp has reshaped daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For temperature dependent measures, the simulated savings are proportionate with the temperature-sensitive load across in each month, so that the highest savings occur on the highest load days in the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape. These shapes reflect measure-level annual energy savings, differentiated by state, sector, market segment, and end use. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 275 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME across the Pacific Power and Rocky Mountain Power service areas. This resulted in more than 34 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation).

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations.

Market transactions can encompass a wide variety of product types that can be classified as either forward (entered well in advance of delivery) or spot (entered no more than a day or two before delivery). Currently, the most commonly traded forward products are for heavy load hours (HLH) and/or light load hours (LLH) and are typically for calendar quarters (e.g. "Q3" spanning July, August, and September) or individual months. Other timeframes are less common but could include super-peak products (noon to 8:00 p.m.). All the common forward market products represent undifferentiated system power supplied at a point, but forward transactions can also be based on the costs, availability, options, and/or restrictions of specific physical resources. Some examples include slices of hydropower resources, or a tolling agreement for a natural gas-fired resource.

Examples of spot market transactions include day-ahead HLH and LLH products, day-ahead hourly transactions in the CAISO market, hour-ahead products, and intra-hour products facilitated by the Western Energy Imbalance Market (EIM).

In the next few years, two changes are coming that will change the landscape of markets in both forward and spot timeframes. First, the Western Resource Adequacy Program (WRAP) requires a showing of capacity resources several months in advance of the summer and winter seasons. Current HLH and LLH market products will not count as capacity for WRAP unless the two counterparties agree to a capacity transfer, which may incur a higher cost or reduce a counterparty's willingness to sell. While contracts for physical resources would count as capacity for WRAP if the seller attests the capacity is surplus to its needs and the resource is registered in the program, it is unclear how much capacity of that sort is likely to be available, particularly as many WRAP participants all seek to become compliant. Second, CAISO's Enhanced Day-Ahead Market (EDAM) will expand day-ahead resource optimization beyond the current CAISO footprint and will impact spot market participation. While EDAM takes over much of the optimization function in the day-ahead timeframe, to prevent leaning participants will be required to pass balancing tests to ensure they bring sufficient resources to meet their load, and this may necessitate transactions ahead of the EDAM.

In past IRPs, PacifiCorp included front office transactions (FOT) as proxy resource options, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Consistent with the current WRAP rules for unspecified-source purchases, FOTs are not included in the calculation of WRAP compliance in the 2025 IRP, so forward market purchases will not count as capacity. While the 2025 IRP does not allow FOTs to meet WRAP compliance requirements, PacifiCorp expects to continue pursuing economic short-term and intermediate term market opportunities that assist with WRAP compliance and/or balancing.

Spot market purchases and sales also provide opportunities to economically balance loads and resources. The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model's hourly balancing optimization of market purchase and sales volumes against static hourly market prices.

In the EDAM and EIM, market prices are based on marginal supply and demand, so significant increases in supply are likely to reduce prices while increases in demand are likely to increase prices. When demand is high and begins to approach the limits of available supply, economic opportunities will diminish, and adequate capacity will still be needed to participate. The 2025 IRP has incorporated historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand; however, it still relies upon a static forecast of prices that do not account for portfolio selections through time. With these various factors in mind, hourly market purchase volumes have been restricted during key hours on the top five load days within each month. These restrictions apply from 4:00 p.m. to 12:00 a.m. throughout the year, and in the winter an additional restriction applies in the morning, from 4:00 a.m. to 8:00 a.m. Outside of these hours (and all day on lower load days), market purchases are allowed up to modeled transmission limits. Similarly, hourly market sales volumes have been restricted to historical levels, to avoid increasing reliance on wholesale sales at favorable prices that may not persist in an organized market.

Chapter 5 describes the relationship of front office transactions (FOTs) to reliability and WRAP compliance, and FOTs are also considered a resource. Front office transactions can be made years, quarters, or months in advance of use; however, they are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point.

Additional discussion of how FOTs are considered in the 2025 IRP, refer to Chapter 5 and Chapter 8.

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used PLEXOS software to produce unique resource portfolios across a range of different planning cases. Informed by the public input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 21 years.[1]
- The PLEXOS long-term (LT) model was used to generate initial portfolios and identify the resulting fixed costs. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three federal carbon dioxide (CO_2) policy scenarios (zero compliance requirements, a high price on CO_2 emissions, and compliance with current Environmental Protection Agency (EPA) CO_2 regulations). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/current EPA regulations, medium gas/zero CO_2, high gas and coal/high CO_2, low gas/zero CO_2, and medium gas/social cost of greenhouse gases).
- Each initial portfolio was also evaluated in the short-term (ST) model to establish system costs over the entire 21-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- A selection of competitive "variant" portfolios was analyzed using the other four price-policy scenarios in PLEXOS modeling to evaluate how each portfolio performs under differing future market and policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from ST reporting and stochastic modeling, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

[1] PacifiCorp's IRP is typically modeled with a 20-year planning horizon, expanded in the 2025 IRP to 21 years to accommodate a specific Washington State requirement extending through 2045. Some discussions and data graphs in the 2025 IRP will refer to the standard 20-year horizon.

Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

As addressed in public input meetings and stakeholder feedback forms, the subject of modeling for portfolio evaluation is highly technical. PacifiCorp consults regularly with the provider of the PLEXOS optimization modeling software as these methods are developed. Interested parties are encouraged to review publicly available materials (including recordings) from the 2025 IRP public input meeting series for additional context and information.[2]

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 9 (Modeling and Portfolio Selection Results).

Key Changes Since the 2023 IRP

The 2025 IRP public meeting inputs series encompassed many key advancements in modeling and evaluation strategy, many driven by stakeholder input. These changes are described in detail later in this chapter. These enhancements are in addition to standard updates applicable to core data such as load and price forecasting. Each change has been incorporated into the company's engagement strategy via public input meetings and stakeholder feedback.[3]

In the 2025 IRP:

- Portfolios must achieve regional and system WRAP compliance.
- Existing thermal units can operate indefinitely with ongoing maintenance.
- IRA Tax Credits are extended through the model horizon (21 years).[4]
- Jurisdictional portfolios are used to integrate final portfolios.
    - States are only able to impact the disposition of resources in which they have an active share.
    - Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction.
- Improved granularity and reliability evaluation.
- No federal CO_2 policy adder is assumed in the expected case.
- Transmission representation now includes a distinct bubble for the Wasatch Front.

[2] For discussion of public materials and feedback, see also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[3] See also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[4] The value of production tax credits (PTCs) is reduced in the last five years of the study horizon, to better represent the value of resource additions in the latter half of the horizon. See Appendix M, stakeholder feedback form #63 (Utah Clean Energy) for additional discussion.

- A new price-policy variation ("MR", medium gas price with at-risk federal regulation) has been added to account for changing expectations for future federal policy.
- No market purchases are allowed in peak hours on the five days with the highest peak load in each month, market purchases are allowed up to transmission limits in all other hours.
- The stochastic analysis incorporates wide-ranging historical volatility in renewable shapes, thermal outages, load, market prices, and hydro availability.

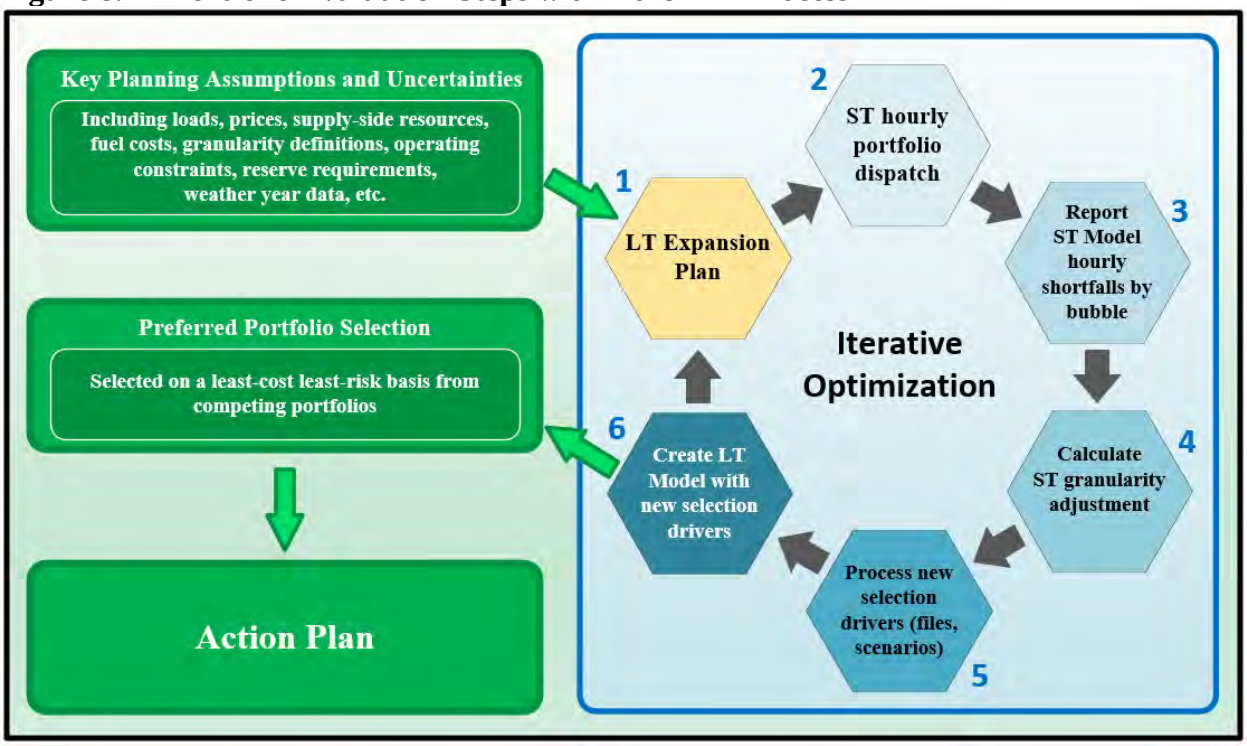
Modeling and Evaluation Steps

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure 8.1 summarizes the modeling and evaluation steps for the 2025 IRP. The process flow begins at left with the development of key inputs and assumptions. Next, studies are mathematically optimized using PLEXOS software tools[5], as illustrated in the six steps at right ("Iterative Optimization", highlighted in blue). Results are evaluated to determine the least-cost least-risk preferred portfolio from among all eligible portfolios. Finally, the preferred portfolio is used to develop the action plan.[6]

[5] PLEXOS technical modeling assumptions and parameters were discussed in the 2025 IRP public input meeting series and in stakeholder feedback.
See Appendix M, stakeholder feedback form #21 (Renewable Northwest).
See Appendix M, stakeholder feedback form #42 (First Principals Advisory).

[6] The topic of portfolio change was discussed extensively in the 2025 IRP public input meeting series. The modeling and evaluation steps explain how updated inputs are processed – such as updated resource costs as presented in Chapter 7 – resulting in new portfolio outcomes.
See Appendix M, stakeholder feedback form #13 (Joan Entwistle).
See Appendix M, stakeholder feedback form #15 (Sierra Club).
See Appendix M, stakeholder feedback form #27 (Vote Solar).

Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



The portfolio development process in the 2025 IRP is an iterative process, whereby PacifiCorp completes initial LT capacity expansion modeling runs for each portfolio. Portfolios are evaluated for cost, reliability and compliance using the ST model, dispatch focused, modeling results. Data regarding resource value and unserved energy quantities from the ST model is fed back into PLEXOS, and the next phase of iterative portfolio optimization is launched. Each cycle through the six steps is one modeling "phase." Iterations continue until the LT capacity expansion model has produced a portfolio that demonstrates no unserved energy in the ST dispatch model run, and then for several phases thereafter, to identify a range of potentially economic candidate portfolios. Each price-policy scenario and each candidate variant study follows this iterative optimization process. Once a completed portfolio phase achieves reliability, as measured using ST model results, evaluation is completed, and results can be compared to other portfolios.

Overview of Steps in an Iterative Phase

Step 1

For each case, the LT capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a "portfolio."

Step 2

The LT model expansion plan is fed into the ST model. The ST model performs an hourly dispatch of the portfolio.

Step 3

The ST model reports shortfalls as megawatts of unserved energy. These megawatts must be covered for each location (or "bubble") in the IRP transmission topology. Greater detail regarding use of these reported shortfalls to create the reliability adjustment is below.

Step 4

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity. Greater detail regarding the calculations which comprise the granularity adjustment is below.

Step 5

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

Step 6

The next phase LT model is built in PLEXOS, if necessary, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adjustment (either an increase or decrease in costs) to every resource option.

Granularity Adjustment Detail

The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 4 blocks of hours per month over the 21-year horizon. This means the LT model groups similar hours into a block, calculates the average load and resource parameters specific to each block, and then concurrently solves the entire 21-year horizon. In contrast, the ST model concurrently solves (or dispatches) of a given week, or roughly 52 steps per year of 168 hours each, for a specified portfolio of resources as selected in the LT model. When PLEXOS optimizes the system in the 4-block LT view, it calculates a locational marginal price (LMP) specific to each block of hours. The value of a resource in the LT is equal to its generation in each block, multiplied by the LMP during that block specific to its location, and this value is part of the reported results based on the 48 blocks the LT evaluates during each year (4 blocks per month times 12 months). When the ST model dispatches the same resources at an hourly granularity, it calculates the LMP based on hourly conditions, multiplies by a resource's hourly generation, and reports the resulting value for each resource on an annual basis. The ST model also assigns specific resources to hold operating reserves necessary to meet reliability requirements, calculates the marginal price of reserves, and includes this as part of the reported resource value. The mathematical difference between the ST value and the LT value is the granularity adjustment.

The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between key resource types, they can't capture the full range of hourly conditions.

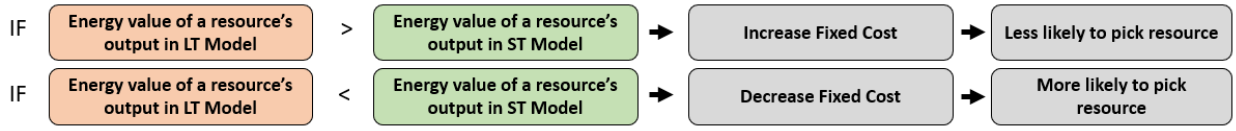
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy

scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 8.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 8.2 – Granularity Adjustment Determination



This iterative process was conducted for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2025 IRP, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with hourly granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments, these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

In order to avoid diluting singular hourly shortfalls across the entirety of a block, the highest monthly shortfall figure is taken, divided by 4 and applied to each hour in the top ten percent of highest net load hour blocks. The highest shortfall in a month is divided by 4 to avoid overshooting the total amount of resources needed. As an example, suppose the phase zero portfolio (the very first iteration of the six steps for a particular study) reports a maximum shortfall of 400 megawatts in Wasatch Front on June 8, 2032, at 8 PM. The 400-megawatt shortfall is divided by 4 to create a 100-megawatt adder to Wasatch Front load. This 100-megawatt adder is added to the base load file for all of the top ten percent net load hours in Wasatch Front in June of 2032, and phase 1 is run with the adjusted load file. If the portfolio selected in phase 1 reports a maximum shortfall of 100 megawatts in Wasatch Front in 2032, the same process is undertaken and 25 megawatts is added to all ten percent top net load hours, such that the load for that block is now 125 megawatts higher than the original phase zero load forecast. Once no shortfalls are reported by the ST model

(a deterministic run using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These reliability and granularity adjustments result in an iterative loop from the LT model to the ST model and back to the LT model, with results that evolve over multiple phases. This process leads to a portfolio that is reliable on a deterministic hourly basis. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios no longer results in additional cost reductions.

Cost and Risk Analysis

Sufficiently reliable resource portfolios developed by the LT model are simulated through stochastics to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. New to the 2025 IRP, stochastic risk modeling of resource portfolios is performed using actual historical conditions as a guide to volatility and stochastic relationships. These conditions, including weather patterns, thermal outages, fuel and market prices, hydro generation, and wind and solar generation profiles, are mapped to historical dates underlying PacifiCorp's chaotic normal load forecast. PacifiCorp has 18 distinct years of historical data and ran each portfolio using each specific historical year for all years of the 21-year horizon.

The reported stochastic results are based on fifty randomized combinations of the forecasted results based on each historical year. In each of the fifty draws, one historical data year is drawn for each of the years of the IRP study horizon (2025-2045). For example, one draw could include 2025 results based on 2006 weather conditions, 2026 results based on 2015 weather conditions, and 2027 results based on 2020 weather conditions. The same randomized historical year draws are used for all portfolios so that all portfolios can be examined on a comparable stochastic basis. Probabilistic analysis therefore depends upon draws from actual historical variance, which is both more volatile and realistic than prior parameterized variance, improving the verisimilitude of outcomes. The results from these runs are used to calculate a risk adjustment which is combined with ST model system costs to achieve a risk-adjusted PVRR to guide portfolio selection.

Responsive to stakeholder feedback, and like consideration made in past IRPs, cases eligible to become the preferred portfolio which report the possibility of significant end-effects are further evaluated to determine if a portfolio represents significant long-term costs or risks compared to other eligible portfolios.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability, resource adequacy, and CO_2 emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment step as described above. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

Long-Term (LT) Capacity Expansion Model

In the 2025 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, zero CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[7] for each load area represented in the model.

The resource portfolios developed using the iterative approach outlined at the beginning of this chapter are appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2025 IRP is based on compliance with the Western Resource Adequacy Program (WRAP) at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2025 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both before and after existing generation resources retire, as well as the years in which to retire existing resources.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025

[7] The PLEXOS model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

IRP, each month was split into four blocks of hours based on load, wind, and solar, based on wind and solar generation profiles based on weather conditions during the specific days used to develop PacifiCorp's chaotic normal load forecast:

1. The top ten percent highest net load hours. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

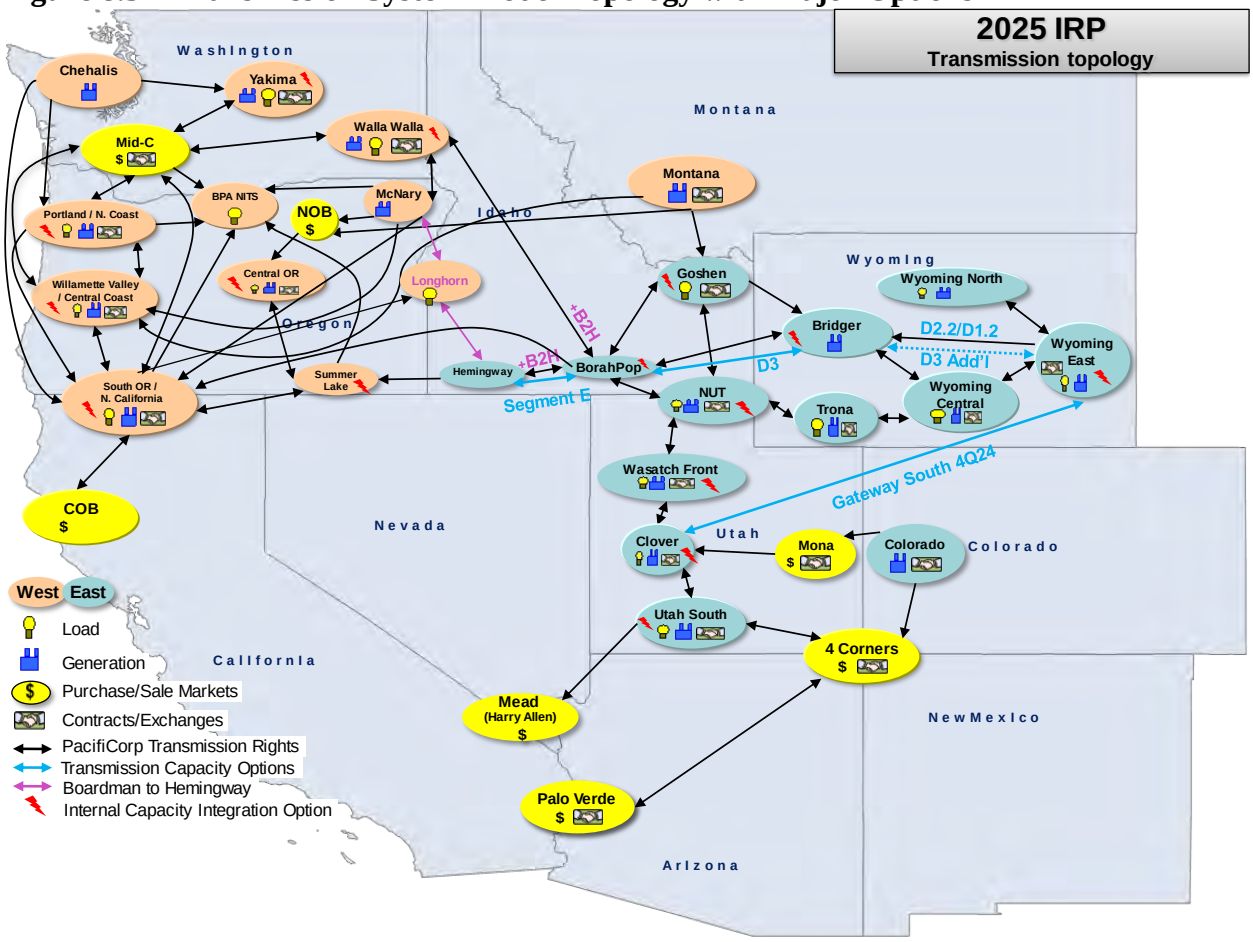
Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths.[8] Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

[8] Continued interest was expressed on stakeholder feedback regarding the assumption of a Wyoming market hub to represent the opportunity afforded by certain transmission constraints. In light of the restrictions on the types of market products that can count toward WRAP capacity requirements, PacifiCorp's modeling does not count any short-term market products toward WRAP compliance and has limited market purchases at all points during the highest load conditions in each month, to represent potential market liquidity limits. See Appendix M, stakeholder feedback form #39 (Western Resource Advocates).

Figure 8.3 – Transmission System Model Topology with Major Options



This map is for general reference only regarding IRP topology.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Figure 8.3 illustrates the 2025 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meetings, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.[9,10]

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be

[9] Wildfire mitigation in the context of transmission was discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).
[10] Transmission modeling, cluster studies and details of resource-to-transmission relationships were discussed extensively during the 2025 IRP public input meeting series and in stakeholder feedback. See Appendix M, stakeholder feedback form #40 (Renewable Northwest).

impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.
- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Cluster Study 3:** Spring 2023 requests
- **Colstrip:** Interconnection to jointly owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. For the 2025 IRP, PacifiCorp has transitioned to using cluster studies to indicate the earliest year a resource type is eligible for selection in any given location (as well as using recent cluster study data as compiled by PacifiCorp Transmission to indicate potential transmission upgrades and costs). Cluster studies are described further in Chapter 4.

Surplus Interconnections

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time at that location cannot exceed the original interconnection capacity.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2025 IRP, PacifiCorp included the monthly planning reserve margin requirements from the Western Resource Adequacy Program (WRAP) in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. While WRAP is expected to enhance reliability, the monthly capacity contribution values assigned to each resource may not be sufficient to meet hourly requirements in every location, so it does not eliminate the need for reliability assessment. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2025 IRP public-input process, the granularity adjustment reflects the difference in economic value in resource options and transmission between an hourly 8760 cost calculation in ST modeling, and the monthly blocking representation used in the LT model.[11]

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, in a single pass, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger

[11] See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon) for responses to questions regarding modeling transmission and granularity adjustments. The method for evaluating granularity value for transmission is the same as for supply-side resources, in that the model reports values used for the granularity adjustments based on the resource's contribution to reducing cost and risk.
See also Appendix M, stakeholder feedback form #36 (Sierra Club).

share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Continuing best practice from the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection in the 2025 IRP. Other renewable technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when, or whether, they should retire.

Table 8.1 and Table 8.2 report the coal unit options modeled in the 2025 IRP, whereas Table 8.3 summarizes the options available for natural gas-fired units.

Table 8.1 – Majority-Owned Coal Generator Resource Options[12,13]

Jim Bridger Units 3 and 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal-CCS 2030						CCS+45Q												CCS	-	-	-
Dave Johnston 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028-2029/Gas Conv. 2029				-	Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028				Retired																	
Dave Johnston 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Wyodak	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Hunter 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Huntington 1-2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-

Key

	Default/current operation	45Q	CCS
	Retirement Option		Alternative Fuel
	Gas conversion option		Assumed retired

[12] While 111(d) compliance can be met with dual fuel operations in 2030-2038, due to engineering uncertainty and modeling complexity, starting in 2030 100% of the fuel input for these options comes from natural gas or alternative fuel. For Hunter and Huntington, which are not located in proximity to natural gas pipeline transport, the alternative fuel modeled in the 2025 IRP is based on the cost of biodiesel, which results in a dispatch price of over $400/MWh (2024$).

[13] After the filing of the 2023 IRP Update on March 31, 2024, a change occurred in the timing of implementation of carbon capture on Jim Bridger Units 3 and 4. CCS assumption for these units is updated for the 2025 IRP. See Appendix M, stakeholder feedback form #5 (Powder River Basin).

Table 8.2 - Minority-Owned Coal Generator Resource Options

Minority-Owned Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Colstrip 3		PAC share moves to Unit 4																			
Colstrip 4	*Includes Unit 3 share*																				
Craig 1																					
Craig 2																					
Hayden 1																					
Hayden 2																					

Key: Default/current operation; Assumed retired

Table 8.3 - Natural Gas Generator Resource Options[14]

Chehalis	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire/non-emitting 2030																					
Currant Creek	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston 1/2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2039/Alt. Fuel				-	-	-	-	-	-	-	-	-	-	-	-						
Jim Bridger Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 1	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2026 thru 2045		Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Unit 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby Steam 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby CTs 4-6	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Key: Default/current operation; Retirement option; Assumed retired; Alternative Fuel; Current (Coal)

New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

[14] PacifiCorp has insufficient detail at this time to evaluate alternative fueling options at its Chehalis and Hermiston natural gas-fired facilities, particularly in light of possible impacts on cost-allocation and market participation and has adopted Action Plan item 1h to advance options for potential implementation by 2030.

Wind and Solar Resources

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources are based on the weather conditions from the same historical days used to develop the load forecast.

The ability for wind and solar resources to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio.

Non-Emitting Resources

Four non-CO_2-emitting thermal resources are considered: nuclear projects, small renewable fuel peaking resources, geothermal resources, and non-emitting hydrogen peaking units leveraging on-site electrolysis with 24 hours of tank storage. Nuclear resources and geothermal are characterized by continuous operation, with the Natrium project combining this operation with storage in the form of heat stored as molten salt. In contrast, peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The small renewable peaking resource for the 2025 IRP is assumed to use biodiesel or renewable diesel, both of which are commercially available. While combustion of these fuels releases CO_2 it is not derived from fossil sources and is eligible to meet compliance requirements in both Oregon and Washington.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period.
- Energy return – energy used to fill (or charge) a storage reservoir.
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or

the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes, income taxes, and demolition costs over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2025 IRP models for a 21-year period beginning January 1, 2025, and ending December 31, 2045. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

Inflation Rates

The 2025 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.18 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2025 through 2045, using PacifiCorp's September 2024 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2025 IRP is 6.38 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[15] PVRR figures reported in the 2025 IRP are reported in 2024 dollars.

[15] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

CO_2 Price Scenarios

PacifiCorp used three different CO_2 price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse gas scenario is derived from forecasts of greenhouse gas costs in Washington and California but is applied like a federal obligation throughout the system starting in 2030. Impacts in the scenario which includes current federal regulations also become relevant in 2030, as coal-fired resources must select between retirement, carbon capture, or co-firing by this time.

The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.[16] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

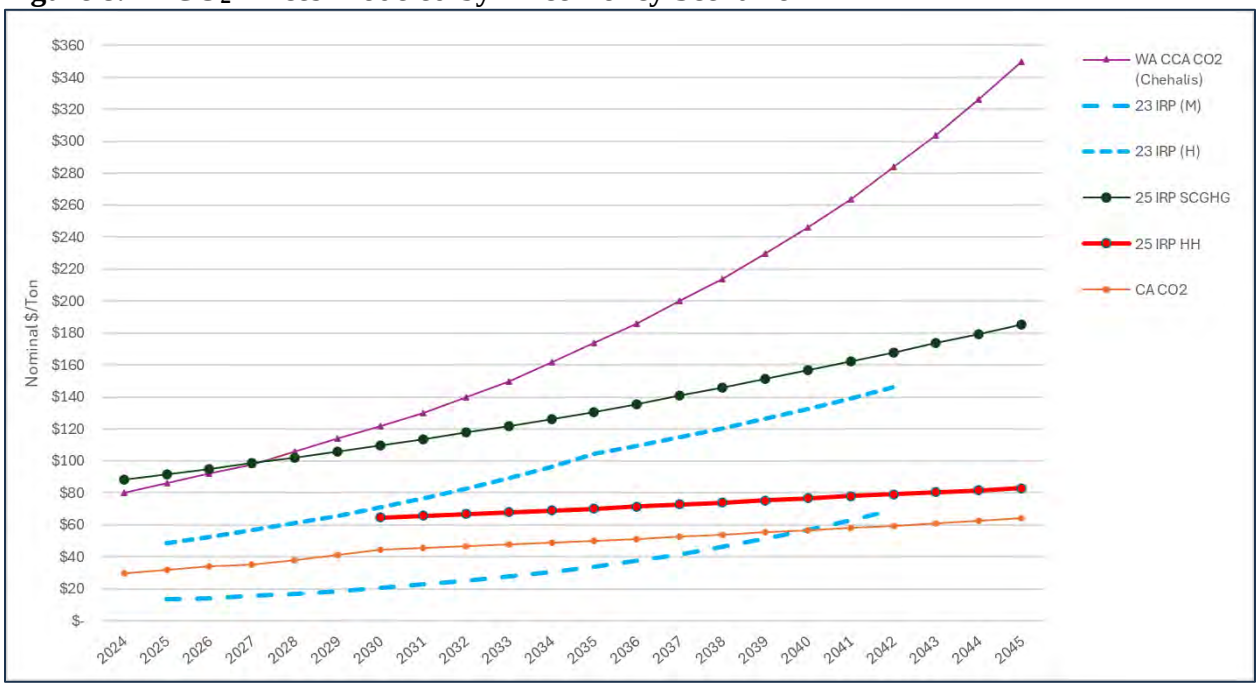
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[17] This is in addition to the assumed federal CO_2 policy represented in the zero, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost is based on the allowance cost cap identified by the Washington Department of Ecology and starts at $88 metric ton in 2024.[18]

[16] Washington Utilities and Transportation Commission, Order 05, Docket No. U-190730, July 25, 2024. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=27&year=2019&docketNumber=190730 (Accessed 11/8/2024).

[17] Stakeholder feedback requested modeling Chehalis without consideration of Washington's Climate Commitment Act. Notwithstanding that certain commissions have declined to allow the company to recover these costs, the company continues to incur these costs, which are therefore modeled. See Appendix M, stakeholder feedback form #19 (Wyoming Office of Consumer Advocate).

[18] Washington Cap-and-Invest Program 2024 Annual Allowance Price Containment Reserve Tier Price and Price Ceiling Unit Price Notice. December 2023. Available online at: https://apps.ecology.wa.gov/publications/documents/2302066.pdf (Accessed 11/8/2024).

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenario



Wholesale Electricity and Natural Gas Forward Prices

For 2025 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2025 IRP modeling inputs were prepared, the September 2024 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[19] As such, these 36 months are market forwards as of September 2024. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[20] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios using high or low gas prices do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also

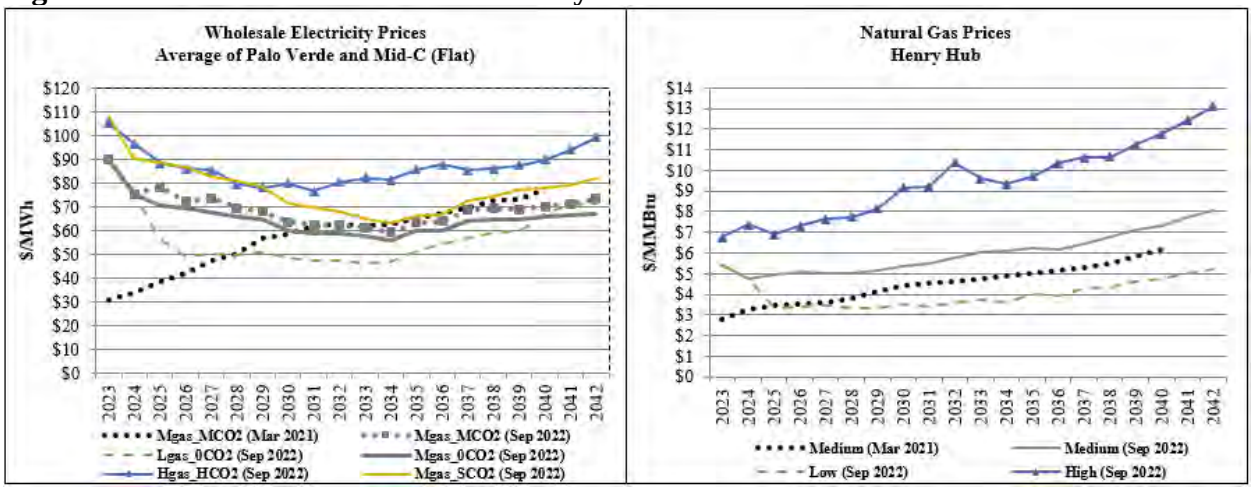
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

derived from an expert third-party forecast. Similarly, the SCGHG scenario does not incorporate any market forwards since that greenhouse gas policy represents an alternative view that applies throughout the study period.

New to the 2025 IRP, in response to stakeholder feedback and requests related to volatility in coal pricing, the high gas and market price-policy scenario also includes an elevated coal fuel supply cost. This represents risks such as supply-chain issues as well as the potential for increased transportation costs or other increased variable coal costs which are not present in the base forecast for coal pricing.[21] The increased cost calculated for coal pricing was developed by evaluating the percentage difference in the average annual gas prices at Henry Hub between the medium and high cases. Annual percentage differences were then applied to each coal plant's coal supply price over the 21-year horizon.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model coupled with the portfolio selected by the LT model. LT results provide the initial capacity expansion plan for the ST model to dispatch.

[21] Coal supply, costs and risks were discussed in the 2025 IRP public input meeting series and stakeholder feedback. In the 2025 IRP, PacifiCorp considers base coal cost assumptions, the Jim Bridger Long-term Fuel Plan sensitivity, and coal-related variant studies. For stakeholder feedback and responses:
See Appendix M, stakeholder feedback form #28 (Utah Citizens Advocating Renewable Energy).
See Appendix M, stakeholder feedback form #29 (Utah Clean Energy).
See Appendix M, stakeholder feedback form #30 (Katie Pappas).
See Appendix M, stakeholder feedback form #31 (Jane Myers).
See Appendix M, stakeholder feedback form #32 (Sara Kenney).

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario.

As discussed at the start of the chapter, these data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

Resource Value

PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. PLEXOS also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, utility scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. New for the 2025 IRP, small resources (those with a capacity of fewer than 20 megawatts) are eligible to be sited within any of the load regions and unconstrained by new transmission requirements, as PacifiCorp's studies have shown resources that are sufficiently small and sized consistent with the local grid can be feasible without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply-side resource table). In initial jurisdictional runs, small generator and local battery resources are limited based on the load in each transmission bubble, due to the assumption these are sized to serve local load so as not to require transmission investment.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. Within a transmission constraint, batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

Each run of the ST model produces an optimized dispatch of a portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT model. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual energy not served (ENS)
- Annual CO_2 emissions.

Stochastic Modeling

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. For the 2025 IRP, stochastic risk modeling of resource portfolio alternatives is performed with the ST model.

The standard ST model inputs reflect a normalized view of future conditions and the typical range of outcomes across each month. For stochastic modeling in the 2025 IRP, alternative inputs are used that reflect conditions analogous to actual results in a specific historical year. Stochastic

inputs for the 2025 IRP have been expanded and now include wind and solar generation profiles, along with the energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

Stochastic Conditions

For the 2025 IRP, PacifiCorp has data reflecting eighteen discrete annual conditions, specifically the historical data and variances from 2006-2023 for each of the stochastic inputs. By running eighteen ST model scenarios covering each of these conditions, results can encompass the full range of conditions. However, each of these ST model scenarios represents conditions from a single year repeating in every year of the study horizon, with slight differences from year to year to account for days of the week, plus load growth, climate change impacts on load and hydro, and changes in the resource portfolio. For instance, using historical data based on 2015, every year from 2025-2045 would be a dry hydro year (below average). There are benefits to compiling the results in this way, as it will be easier to identify specific historical weather conditions that are leading to high costs and ENS. But to produce portfolio performance measures, random sampling of the annual results may be appropriate, particularly for assessment of multi-year compliance requirements such as renewable portfolio standards (RPS) and Washington's Clean Energy Transformation Act (CETA).

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the Monte Carlo annual draws include:

- Stochastic mean PVRR
- 5^{th}, 90^{th} and 95^{th} percentile PVRR
- Standard deviation
- Risk-adjustment
- Energy Not Served (ENS)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long-term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.
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5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 18 results drawn from the ST runs under 18 distinct stochastic conditions. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 random draws of the 18 runs under stochastic conditions. The production cost is expressed as a net present value of annual costs over the IRP horizon. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The model outcomes of the 50 random draws are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 random draws for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Energy Not Served (ENS)

In past IRPs, the use of the reduced granularity in the PLEXOS MT model limited the relevance of the reported ENS. In the 2025 IRP, the ST model's full 8760 granularity is being reflected in stochastic analysis, so reported ENS is representative of a portfolio's performance in the real-world historical conditions that underlie the stochastic inputs.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed under up to five price-policy scenarios.

Other PLEXOS Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the PLEXOS models. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in normalized and stochastic ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. For the 2025 IRP, PRM and resource contributions based on WRAP are used as part of portfolio selection, but this is not part of resource dispatch. In addition to WRAP compliance, ST reliability modifications to the portfolio evaluate hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level.

Energy Storage Resources

Storage resources have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each PLEXOS model dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance
To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 (Modeling and Portfolio Selection Results). Starting in the

2021 IRP, market purchases were restricted compared to past IRPs, as described in Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS, CO_2 emissions, and compliance with state and federal policies. The risk-adjusted PVRR accounts for relative risk of volatility among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include stochastic PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the PLEXOS models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2025 IRP, organized here into major development categories:

- Initial Portfolios, including all variants
    - Initial portfolios and variants are evaluated under three distinct sets of jurisdictional requirements:
        - Utah/Idaho/Wyoming/California.
        - Oregon.
        - Washington.

    - Integrated Portfolios incorporate selections from the top performing initial portfolios under each set of jurisdictional requirements.
    - The preferred portfolio is selected based on the integrated portfolio results.
- Jurisdictional Analysis
- Sensitivity Cases

Additional portfolio detail can be found in Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the initial cases explore significant interactions among retirement options including the potential to convert coal units to natural gas or biodiesel operations, install carbon-capture equipment on coal-fired facilities, and retire units during the study horizon. The modeling continues to include a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and zero CO_2 price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of the optimization models within PLEXOS.

Jurisdictional Definitions and Modeling

As discussed above, distinct requirements exist for various jurisdictions, and some of these requires conflict. As a result, initial portfolio modeling is used to separate the requirements as described below, allowing for the development of optimal portfolios of resources to meet jurisdictional needs.

Compared to Oregon and Washington, modeling for Utah/Idaho/Wyoming/California (UIWC) is more focused on least-cost resource selection regardless of fuel type. UIWC resources must meet the Western Resource Adequacy Program (WRAP) requirements for this jurisdiction. As a result, the only modeling constraint for this jurisdiction is one which combines load and requires the model to select enough total resources (including existing resources under current allocation protocols) to meet WRAP planning requirements. All resources are eligible for inclusion in these states and this requirement.

All Washington resource selections are analyzed and optimized assuming the SCGHG price-policy scenario, as required under RCW 19.280.030 for clean energy planning.

Oregon initial portfolios model compliance with House Bill 2021. Oregon participates in existing coal-fired resources through 2029 and existing gas-fired resources (including the gas conversions of Naughton 1 and 2 in 2026 and the endogenously selected conversion of Dave Johnston Units 3 and 4 in 2029) through 2039. Emissions allocated to Oregon from existing resources are calculated based on Oregon's current share of the resources and the appropriate Oregon DEQ emissions factors. Like other jurisdictions, Oregon must be WRAP compliant. PLEXOS models face challenges meeting annual emissions constraints due to the need to model slices of time in each different model (as described earlier in this chapter). This has been addressed by assessing a

shadow price on Oregon allocated emissions as a model driver to ensure HB 2021 compliance is achieved. The shadow price is not reported from the model as a cost to customers, but is instead used to impose a penalty on the model if Oregon allocated resources emit CO_2-E. This price drives the model to reduce emissions (and generation) and select additional resources to meet Oregon load. Compliance for Oregon is measured by determining whether there is enough Oregon-allocated generation to meet Oregon load on an annual basis while also having emissions below the Oregon required thresholds.

Five price-policy scenarios were evaluated in this IRP:

- MN: Medium natural gas/No federal CO_2regulations
- MR: Medium natural gas/current federal CO_2 regulations under Section 111 of the Clean Air Act.
- LN: Low natural gas/No federal CO_2 regulations.
- HH: High natural gas/High CO_2 cost applied to all generators (updated CO_2 forecast, starting 2030) with no other federal CO_2 regulations.
- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal CO_2 regulations.

Table 8.4 provides the price-policy case definitions for the 2025 IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Appendix I (Capacity Expansion Results).

Table 8.4 – Price-Policy Case Definitions

Price-Policy	Existing Coal[(b)]	Existing Gas[(b)]	Other Existing Resources	Proxy Resources[(c)]
MN	Optimized	Optimized	End of Life	All allowed
MR	Optimized	Optimized	End of Life	All allowed
LN	Optimized	Optimized	End of Life	All allowed
HH	Optimized	Optimized	End of Life	All allowed
SC	Optimized	Optimized	End of Life	All allowed

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(b) Optimized proxy portfolio selections include renewables, offshore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

In all five price-policy scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This cost is incremental to the CO_2 cost included in each price-policy scenario. Where applicable, the price-policy scenarios above represent CO_2 as a cost applicable to all emitting resources, based on the direct emissions associated with the fuel consumed by each generator.

The 2023 IRP included a medium natural gas/medium CO_2 (MM) price-policy scenario. The MM price-policy scenario, which was the price-policy included in the 2023 IRP preferred portfolio, was excluded from the 2025 IRP. In the 2023 IRP, the MM price-policy was included as a proxy to represent potential future federal CO_2 regulations. For the 2025 IRP the MR price-policy scenario, which was not included in the 2023 IRP, encompasses federal CO_2 regulations. This

price-policy scenario was added in response to the final CO_2 regulations issued by EPA on April 25, 2024, which apply to new natural gas-fired combustion turbines and existing coal, oil, and gas-fired steam turbines.

All portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

Certain additional cases were developed based on stakeholder feedback and state requirements to evaluate the impacts of specific future scenarios. These cases are all eligible to be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2025 IRP, there are the following variant portfolio selection cases as shown in Table 8.5.

Table 8.5 – Portfolio Variants

Variant	Description	Refer to Case
No CCS	No coal units are able to select CCS technology	-
No Nuclear	No nuclear resources are eligible for selection	-
No Coal 2032	All coal must retire or convert to gas by January 1, 2032	-
Offshore Wind	Counterfactual to the Preferred Portfolio selection: Offshore wind must be selected	-
No Forward Technology	No nuclear, hydrogen storage, 100-hour storage or biodiesel peaking	-
Geothermal	Counterfactual to the Preferred Portfolio selection: Geothermal must be selected	-
Hunter Retire	Require all Hunter units to retire no later than 1/1/2030	-
All Coal End of Life	Continue 2025 coal technology	See the No CCS variant
No New Gas	No new gas resources allowed	See the Preferred Portfolio
Force All Gas Conversions	Force all coal-to-gas options	See the No Coal 2032 variant

Each variant case begins with the same PLEXOS dataset inputs and assumptions, and adds the constraints to either force a selection, disallow a specific resource or resource type, delay a project or force retirements as outlined below.

No CCS

This variant removes the CCS option at Jim Bridger 3 and 4. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were not a commercially viable

option. This variant was analyzed twice, once using the MN price-policy scenario and once using the MR price-policy scenario.

No Nuclear

This variant removes the Natrium™ demonstration project in 2030 and all other nuclear resources from available resource options. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of the variant is to evaluate resource alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk if nuclear resources are unable to achieve online and operating status for any reason.

No Coal 2032

In this variant all coal plants are assumed to retire no later than 2032. Coal plants are eligible to run past 2032 if gas conversion is selected at that plant. No CCS options are available in this variant. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if external factors required coal plants to cease coal-fired operations by 2032.

Offshore Wind

Offshore wind was available for selection in all portfolios beginning in 2033, based on the timing of necessary transmission upgrades. As offshore wind has not been endogenously selected in the preferred portfolio, a minimum of 1000 MW was required to be selected in this variant. Additionally, the necessary onshore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. This counterfactual is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

No Forward Technology

In this variant all nuclear, hydrogen storage, 100-hour battery, and biodiesel peaking resources are removed from the preferred portfolio and the portfolio is re-optimized without these resource options. The removal of 100-hour battery as an option in this variant is in response to stakeholder request.[22] The purpose of this variant is to evaluate the cost and risk impacts of limited new resource types becoming available in the future.

Geothermal Counterfactual

Like the offshore wind case, advanced geothermal units are available for selection in all portfolios in Central Oregon and Southern Utah starting in 2027. These resources require transmission upgrades to be enabled. Pursuant to stakeholder interest[23], as geothermal is not selected for the Preferred Portfolio, a minimum of 707 MW of geothermal resource must be built

[22] See Appendix M, stakeholder feedback form #55 (Utah Division of Public Utilities).
[23] See Appendix M, stakeholder feedback form #56 (Utah Clean Energy).

in Central Oregon or Southern Utah. This counterfactual is used to assess system impacts and the magnitude of costs associated with geothermal and its associated transmission requirements.

Hunter Retire

Responsive to stakeholder interest, a variant is considered that forces all three Hunter coal units to cease all operations by 2030.[24] This variant forces the retirement of the Hunter Plant in any year from 2028 to 2030. The purpose of this variant is to assess the impact on cost and emissions when Hunter is precluded from continued operation.

All Coal End of Life

> *The No CCS run selects coal at all current coal sites and does not choose to retire any eligible units. Please refer to the No CCS variant for results.*

In this variant all coal plants are assumed to run as coal-fired units using the technology present on the plant as of January 1, 2025, and are not eligible to retire during the study horizon unless otherwise required to do so. Dave Johnston units 1-3 along with Naughton units 1 and 2 still retire or cease coal-fired operation as necessary. Minority owned coal plants are also assumed to retire as necessary for environmental compliance. The purpose of this variant is to evaluate how the preferred portfolio would change if majority-owned coal resources were allowed to run as coal-fired to end-of-life.

No New Gas

> *The unconstrained integrated MN case does not select new natural gas resources. Please refer to the Preferred Portfolio for results.*

This variant assumes no new gas resources are allowed to be selected. This does not include the conversion of coal plants from coal-fired to gas-fired. The purpose of this variant is to evaluate the cost and risk impacts of replacing new gas resources selected in the preferred portfolio with other energy resources.

Force All Gas Conversions

> *The No Coal 2032 selected all plants eligible for gas conversion. Please refer to the No Coal 2032 variant for results.*

In this variant all coal plants eligible for gas conversion are forced to do so. The gas converted coal plants are allowed to retire endogenously, and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts associated with gas conversion becoming the only future option for all coal-fired plants. Hunter and Huntington, which are not eligible for gas conversion, were eligible for alternative fuel conversion but were not forced to convert.

Integrated Portfolios

Portfolio integration involves combining resource selections from each of the initial jurisdictional portfolio results under a given price-policy scenario or variant. Every initial jurisdictional portfolio

[24] See Appendix M, stakeholder feedback form #53 (Sierra Club).

evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies, identified as 1) "UIWC" for Utah, Idaho, Wyoming and California, 2) "OR" for Oregon and 3) "WA" for Washington. Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction's initial portfolio result. Given concerns related to the availability of transmission on an hourly basis between the West and East sides of PacifiCorp's system, the selection of proxy resources on the West is determined jointly by the Oregon and Washington initial jurisdictional portfolios, and the selection of proxy resources on the East is determined by the initial jurisdictional UIWC portfolio. Accordingly, only the jurisdictional portfolios that determine the selection of a given resource are eligible to participate in that resource.

Table 8.6 – Portfolio Integration Resource Example

Jurisidiction	Fixed Share	Initial Portfolio Selection (MW)	Total Allocation (MW)
Oregon	75%	150	112.5
Washington	25%	60	37.5
Total	100%		150

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year. This integration process is applied to every initial portfolio.

The initial integration step has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may be shared with other jurisdictions. Thus, the final step of the integration process is to identify and remedy any such shortfalls in energy and capacity compliance.

Washington Portfolios

The integrated preferred portfolio reflects Washington customer energy and capacity needs and the CETA clean energy standards from 2030 onwards. The final integrated portfolio presents a CETA-compliant path towards the production of a quantity of clean megawatt hours that meets Washington's retail sales on an annual basis, as described in further detail in Appendix O (Washington's Clean Energy Action Plan). This CETA-compliant portfolio is a starting point for the analysis that will be provided in the forthcoming 2025 Clean Energy Implementation Plan (CEIP), expected to be filed with the Washington Utilities and Transportation Commission in October 2025.

The focus of this IRP filing is to present an integrated preferred portfolio that meets all state-specific requirements. As described in this chapter and further in Appendix Othe IRP preferred portfolio presents a strategy to get to a portfolio that is optimized to meet Washington CETA clean energy standards over the next twenty years. The following scenarios and sensitivities required by Washington rule are also included.

Per WAC 480-100-620(10): the IRP must also include a range of possible future scenarios and input sensitivities. These include:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is comparable to the initial SCGHG price-policy scenario study but includes Washington-specific capacity requirements based on WRAP. This sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding how climate change is incorporated into the base load forecast. Climate change impacts are also incorporated in the base hydro forecast. Because the base forecast includes climate change, all the IRP analysis reflects impacts related to climate change and a separate sensitivity to include these impacts is not necessary.

- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission options and relies on increased small-scale renewables. Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

PacifiCorp identified a variety of sensitivities outlined in Table 8.7 and discussed further in Chapter 9.

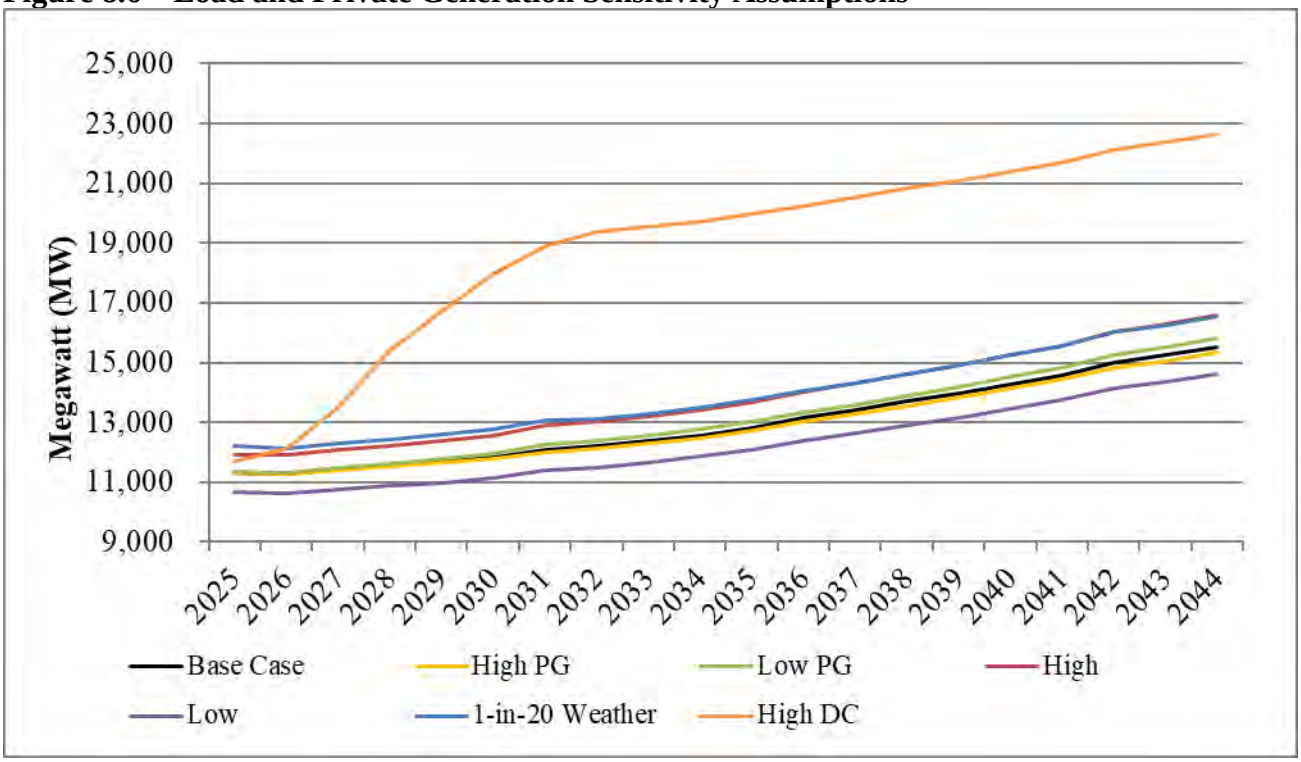
Table 8.7 – Sensitivity Case Definitions

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Private Generation	Assumes lower load due to high private generation adoption
Low Private Generation	Assumes higher load due to low private generation adoption
Large Metered Load Growth	Assumes significant large-metered customer load growth
Low-Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan	First 3 years are aligned with the current business plan

Load Sensitivities

The 2025 IRP includes several sensitivities related to load forecast assumptions. Figure 8.6 provides a comparison of load by year for each case, including the base assumption for comparison. Definitions for all sensitivities are then discussed individually, below.

Figure 8.6 – Load and Private Generation Sensitivity Assumptions



High Load Growth

In this sensitivity the base load forecast is replaced with a high load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher loads.

Low Load Growth
In this sensitivity the base load forecast is replaced with a low load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of lower loads.

1 in 20 Peak Load
In this sensitivity the base load forecast based on median load conditions (exceedance in 10 of 20 years) is replaced with a higher load forecast based on peaks that reflect an expected 1 in 20 year exceedance level. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher peak loads.

High Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high private generation adoption which reduces load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with high private generation adoption.

Low Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating low private generation adoption which increases load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with low private generation adoption.

Large-Metered Load Growth
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high large-metered load growth. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of this future. A variety of transmission upgrades are necessary to meet the significant load increases contemplated in this sensitivity, including B2H. This portfolio uses the same integration process as the preferred portfolio to address any state compliance shortfalls.

Low-Cost Renewables

This sensitivity assumes high IRA/IIJA adoption results in significant cost reductions for PTC/ITC eligible resources, making them more likely to displace non-PTC/ITC eligible resources. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how the availability of lower cost renewables might impact cost and risk.

Low PTC and ITC Eligibility

This sensitivity assumes IRA/IIJA changes result in PTC and ITC eligibility ending in 2030. Resources coming online after 2030 do not have the cost reductions associated with PTC and ITC. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how lower than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

All CCS

This sensitivity allows CCS to be selected at Wyodak, Hunter Units 1-3, Huntington Units 1 and 2, and Dave Johnston Unit 4, in addition to the option of CCS at Jim Bridger Units 3 and 4. , This sensitivity relies on the assumption that it is feasible to complete installations at all of these units prior to 2032. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were a commercially viable option at more than one coal site before 2032.

Business As Usual[25] (No Pending Legislation or State Requirements; Locked Coal Assumptions)

In this sensitivity, all pending legislation and state requirements are removed so that the only obligations to be met are load and federal policy obligations. Coal outcomes are also set so that coal plants retire no earlier than assumed in the 2017 IRP Update except to the extent that updated commitments or requirements supersede the older assumptions. The portfolio is otherwise fully endogenous. The purpose of this variant is to evaluate how the preferred portfolio would change if no potential state requirements or early economic retirements were considered.

Business Plan Sensitivity

The unconstrained integrated MN case does not select new resources in the first three years, please refer to the Preferred Portfolio for results.

In the 2025 IRP, this case has the same assumptions as the integrated preferred portfolio. For this reason, no additional sensitivity is needed. The case complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the PLEXOS models.

[25] Per the Wyoming Public Service Commission's (WPSC) 2019 Investigation Order (DOCKET NO. 90000-144-XI-19, and DOCKET NO. 90000-147-XI-19), "reference case" is the formal terminology for the business-as-usual study. Regarding this study, the WPSC mandates the following:

> "In the anticipated 2021 IRP, and in IRPs and updates thereto filed by the Company thereafter, Rocky Mountain Power shall:
>
> a) Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and only incorporate environmental investments or costs required by current law"

This case was the subject of stakeholder feedback and discussion in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #35 (Wyoming Energy Authority).

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

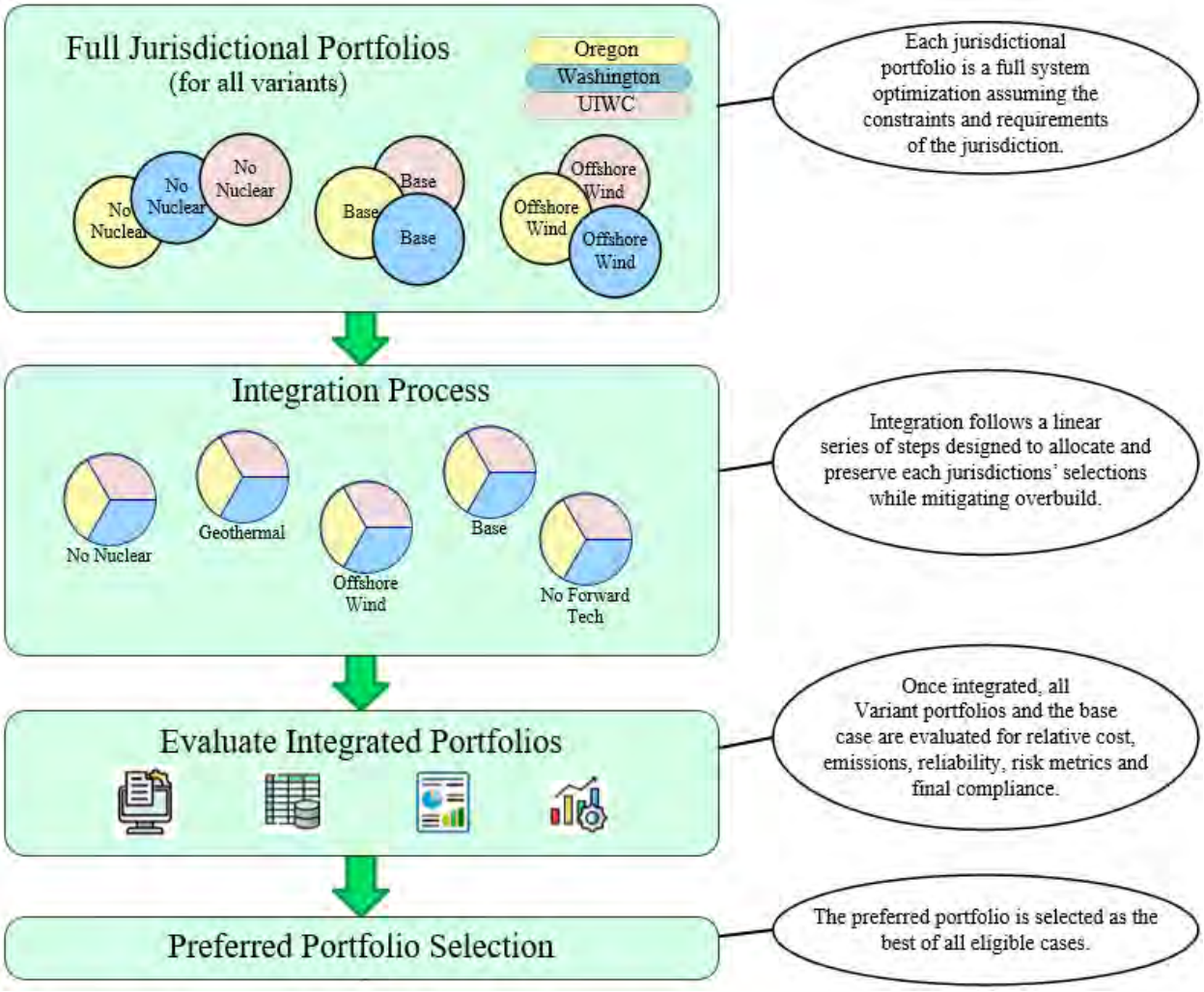
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio includes continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The 2025 IRP preferred portfolio builds upon resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that forthcoming RFPs as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium^{TM} demonstration project, anticipated to achieve online status by the end of 2031. Over the planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind, and 5,912 MW of new solar, of which 1,147 MW is small-scale.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, and additional upgrades that increase transfer and interconnection capability on the west side of PacifiCorp's system.
- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation were converted to natural gas where the option was available.
- In the 2025 IRP, four factors related to emitting resources drive a reduction in CO_2 emissions after 2025. These factors are retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities (influenced by additions of renewable resources and energy storage), and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially because of renewable resource additions but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. As illustrated in Figure 9.1, the final preferred portfolio selection is informed by all relevant modeling results.

Figure 9.1 – Portfolio Integration and Selection Workflow



This chapter also presents discussion of Oregon's compliance position in the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic analysis is also discussed in Volume II, Appendix H (Stochastics).

Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 9.1 below shows the various phases of the Oregon MN initial jurisdictional run to show how iterative jurisdictional portfolios were evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase was selected for integration. In Table 9.1, phase 17 was selected as the Oregon initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $26,298 million, and the stream of unserved energy costs that led to a total cost of $0 and had no unserved energy after 2027. Other phases which were considered were phase 11, phase 15, and phase 5, however the higher PVRR of phases 15 and 5, and the fact that phase 17 was more WRAP compliant than phase 11 led to phase 17 being selected.

Table 9.1 – Iterative phases of Oregon MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	OR	Medium Gas, No CO2	26,108	1
1	OR	Medium Gas, No CO2	26,809	0
2	OR	Medium Gas, No CO2	26,314	0
3	OR	Medium Gas, No CO2	26,353	1
4	OR	Medium Gas, No CO2	26,405	0
5	OR	Medium Gas, No CO2	26,372	0
6	OR	Medium Gas, No CO2	26,370	1
7	OR	Medium Gas, No CO2	26,343	0
8	OR	Medium Gas, No CO2	26,442	1
9	OR	Medium Gas, No CO2	26,365	0
10	OR	Medium Gas, No CO2	26,498	2
11	OR	Medium Gas, No CO2	26,298	0
12	OR	Medium Gas, No CO2	26,461	1
13	OR	Medium Gas, No CO2	26,366	0
14	OR	Medium Gas, No CO2	26,447	1
15	OR	Medium Gas, No CO2	26,361	0
16	OR	Medium Gas, No CO2	26,388	2
17	OR	Medium Gas, No CO2	26,298	0
18	OR	Medium Gas, No CO2	26,463	1
19	OR	Medium Gas, No CO2	27,058	0

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal CO_2 policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimized combinations of resources, transmission, and thermal retirement options.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

Jurisdictional Shares of the Preferred Portfolio

Table 9.2 through Table 9.4 present each jurisdiction's assumed *share* of total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

Table 9.2 – Oregon Share[1, 2, 3]

OR Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
DSM - Energy Efficiency	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
DSM - Demand Response	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
Renewable - Wind	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
Renewable - Utility Solar	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
Renewable - Battery, < 8 hour	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
Renewable - Battery, 24+ hour	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
Potential Solar Acceleration[2]				***794***		***(794)***																

Table 9.3 – Washington Share[4]

WA Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
DSM - Demand Response	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
Renewable - Wind	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
Renewable - Utility Solar	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
Renewable - Battery, < 8 hour	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
Renewable - Battery, 24+ hour	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
Potential Solar Acceleration[4]				***212***		***(212)***																

[1] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[2] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving compliance with Oregon's clean energy compliance requirements, PacifiCorp's 2025 CEP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.2. For more details, please refer to Appendix P (Oregon Clean Energy Update)
[3] Planned Energy efficiency and demand response selections in 2025 and 2026 are not presented in Tables 9.2 through 9.4.

Table 9.4 – Utah, Idaho, Wyoming, and California Share

UIWC Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931
DSM - Demand Response	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566
Renewable - Wind	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744
Renewable - Utility Solar	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	-	713	-	459	733	1,933
Renewable - Battery, 24+ hour	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	105

Full Jurisdictional Portfolios

Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration.

The following portfolios shown in Table 9.5 through Table 9.7 report the entirety of each jurisdictional portfolio's selections when planning for the entire system, which were then integrated into the preferred portfolio. This same integration process is used to develop integrated portfolios specific to each variant and price-policy scenario, and the preferred portfolio is selected based on the results for the integrated portfolios.

[4] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving CETA compliance, PacifiCorp's 2025 CEIP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.3.For more details, please refer to Appendix O (Washington Clean Energy Action Plan)

Table 9.5 – Oregon Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency	92	89	201	209	220	237	306	280	283	280	300	309	333	303	283	291	266	286	252	230	189	5,239
DSM - Demand Response	18	2	-	53	17	9	53	5	1	3	3	11	259	15	50	23	4	100	9	50	25	710
Renewable - Wind	-	-	-	21	260	1,066	100	51	-	29	347	40	175	37	-	376	50	-	20	-	96	2,668
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	122	99	1,871	19	220	315	225	13	-	-	-	554	104	12	-	-	197	75	3,826
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	876	255	228	31	119	39	210	20	83	-	104	100	314	58	-	2	-	-	2,439
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	224	-	-	-	-	-	241
Renewable - Battery, 24+ hour	-	-	-	-	-	134	-	-	-	-	-	-	-	59	4	752	128	-	341	-	59	1,477
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,949)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
Coal - Gas Conversions	-	46	-	-	-	687	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	315
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(79)
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**153**	**201**	**1,026**	**523**	**3,444**	**302**	**1,193**	**664**	**765**	**713**	**575**	**667**	**795**	**1,008**	**2,084**	**249**	**(140)**	**581**	**387**	**(18)**	

Table 9.6 – Washington Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	224	235	215	234	289	287	291	290	316	323	356	324	304	293	278	302	268	234	186	5,430
DSM - Demand Response	18	2	2	197	5	17	-	-	-	-	-	43	-	17	24	8	5	331	31	27	107	834
Renewable - Wind	-	-	-	-	1,607	-	260	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1,868
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	201	138	463	1,437	770	527	418	772	249	100	1	-	-	-	-	-	-	-	5,076
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	38	856	232	1,376	-	-	-	-	-	-	-	129	67	66	129	149	646	170	1,357	5,215
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(906)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(2,679)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,241)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(526)	0
Coal - Gas Conversions	-	311	-	-	205	1,979	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	(448)	1,717
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**418**	**264**	**548**	**2,074**	**1,669**	**1,447**	**1,558**	**818**	**705**	**1,088**	**615**	**356**	**439**	**395**	**367**	**14**	**782**	**898**	**198**	**656**	

Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

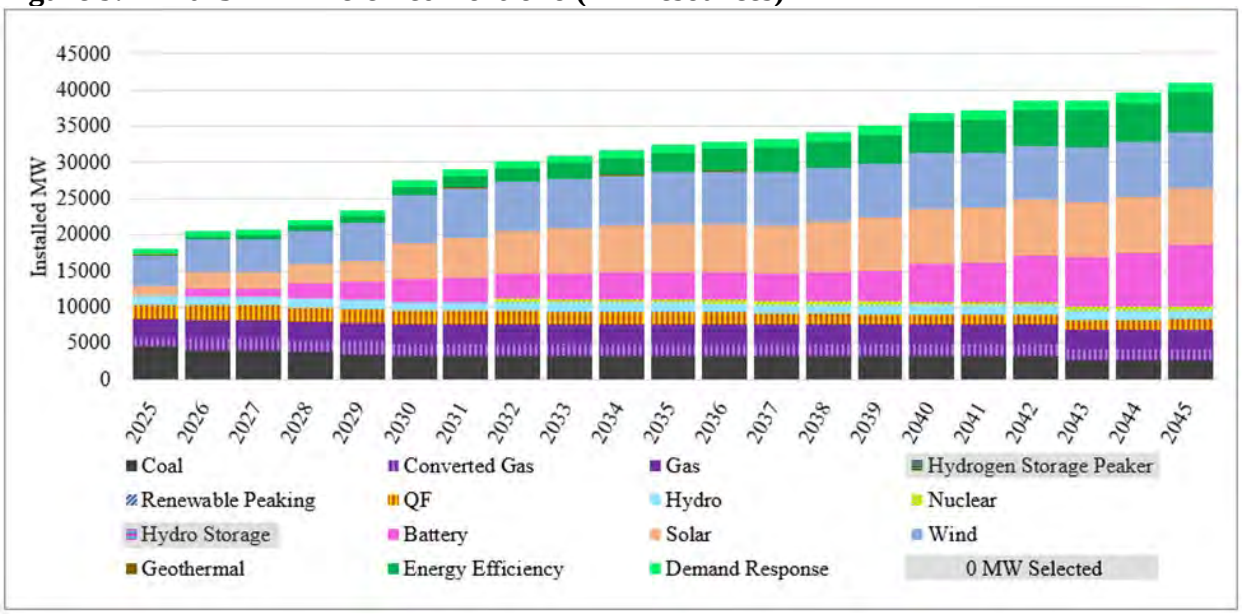
Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	164	170	182	196	270	236	247	251	261	286	312	284	278	257	252	283	216	200	165	4,691
DSM - Demand Response	18	2	-	2	7	112	99	-	-	-	5	39	115	3	-	4	70	106	43	30	32	687
Renewable - Wind	-	-	-	-	306	684	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,334
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	153	12	79	668	-	31	123	133	3	-	-	-	2	-	-	-	65	-	1,269
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	193	71	224	-	-	-	-	85	171	4	474	249	140	469	713	896	1,097	733	5,519
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	104
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
Coal - Gas Conversions	-	251	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	239
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(5)	-	(52)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**358**	**164**	**263**	**394**	**874**	**1,172**	**736**	**278**	**371**	**484**	**499**	**331**	**729**	**527**	**403**	**393**	**1,206**	**426**	**1,157**	**910**	

The 2025 IRP Preferred Portfolio

The preferred portfolio is selected from among all of the variant and price-policy portfolios after integration. PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear. The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources are scheduled to come online in the 2024 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by fall 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912 MW of new solar.

Figure 9.2 – 2025 IRP Preferred Portfolio (All Resources)



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

New since the 2023 IRP, the 2025 IRP preferred portfolio includes a number of smaller incremental upgrades to enhance transfer capability, including lines between southern Utah and the Wasatch Front in Utah, Walla Walla and Yakima in Washington, Walla Walla and Deschutes County in Oregon, and Summer Lake and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Eight out of the fourteen transmission selections are expected to increase interconnection capability only, while the other six transmission selections provide both interconnection capability and increased transfer capability among the transmission areas modeled in the IRP. Table 9.8 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio.

Table 9.8 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
	Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
	Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032	Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total		**4,250**	**4,250**	**5,404**	**4,169**			

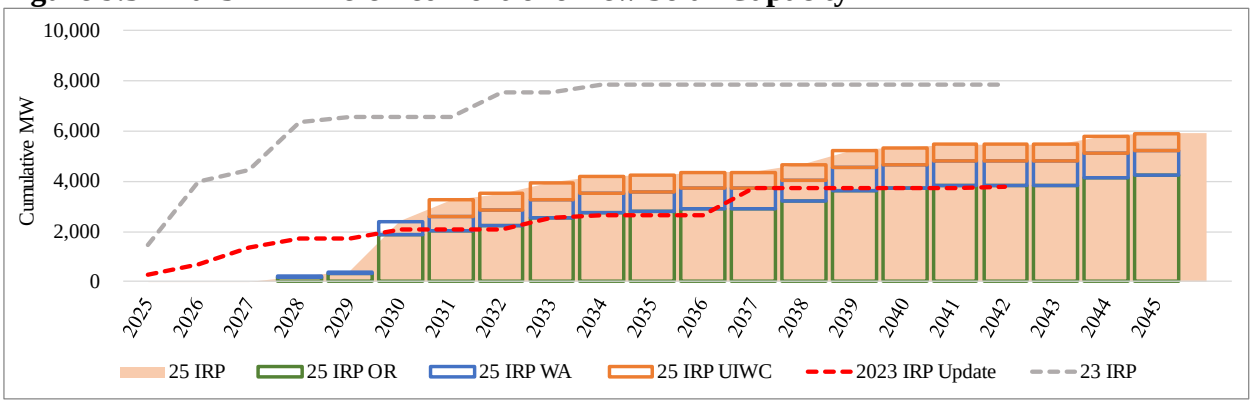
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 9.3.

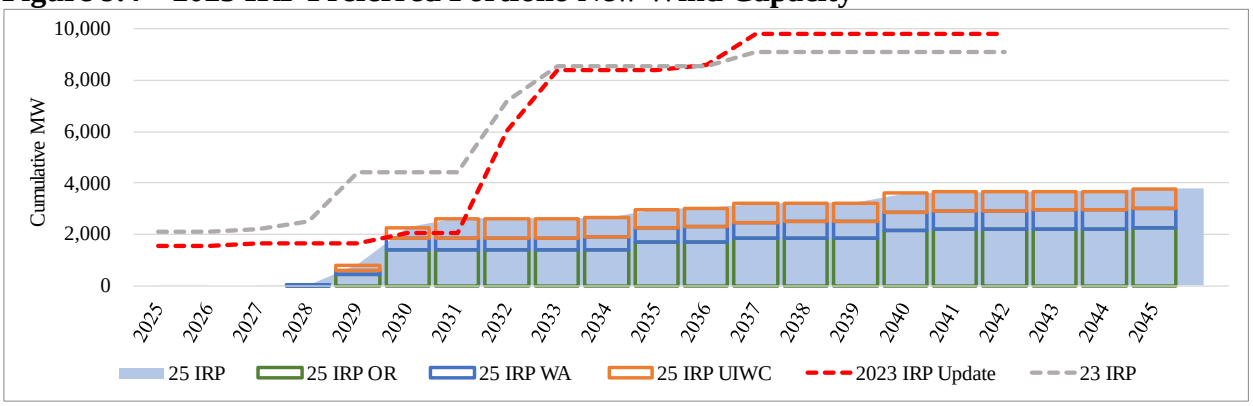
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 9.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

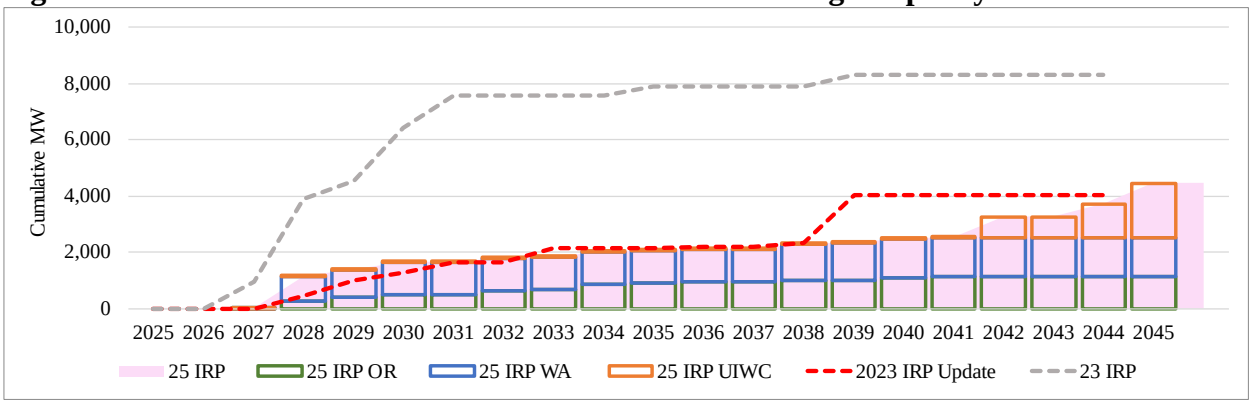
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

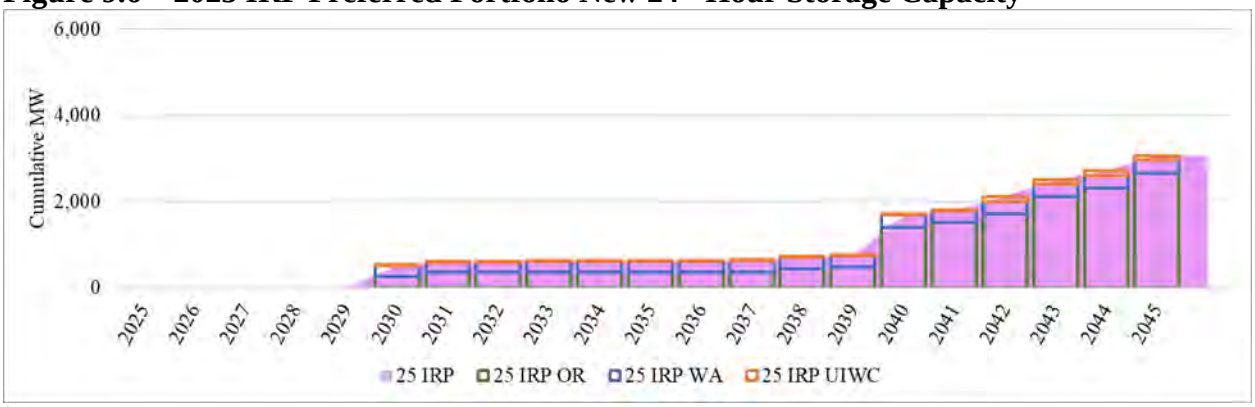
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of storage with at least 24 hours duration by the end of 2030 and growing to 616 MW by 2035 and 3,073 MW by 2045. Cumulative storage selections, inclusive of both short and long duration resources, total 7,524 MW by 2045.

Figure 9.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not categorized as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 9.5 include a minimal amount of intermediate duration storage.

Figure 9.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]

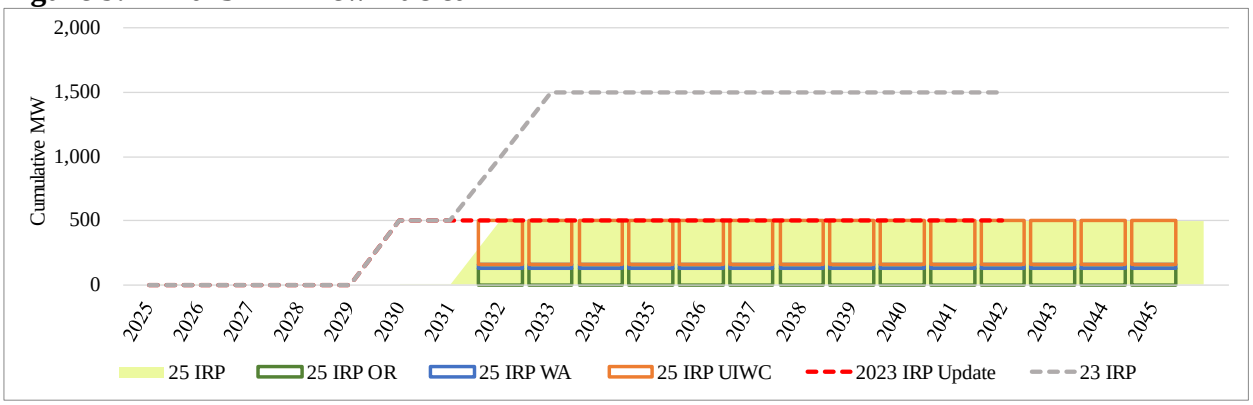


[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.7, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by fall 2031.

Figure 9.7 – 2025 IRP New Nuclear[1]



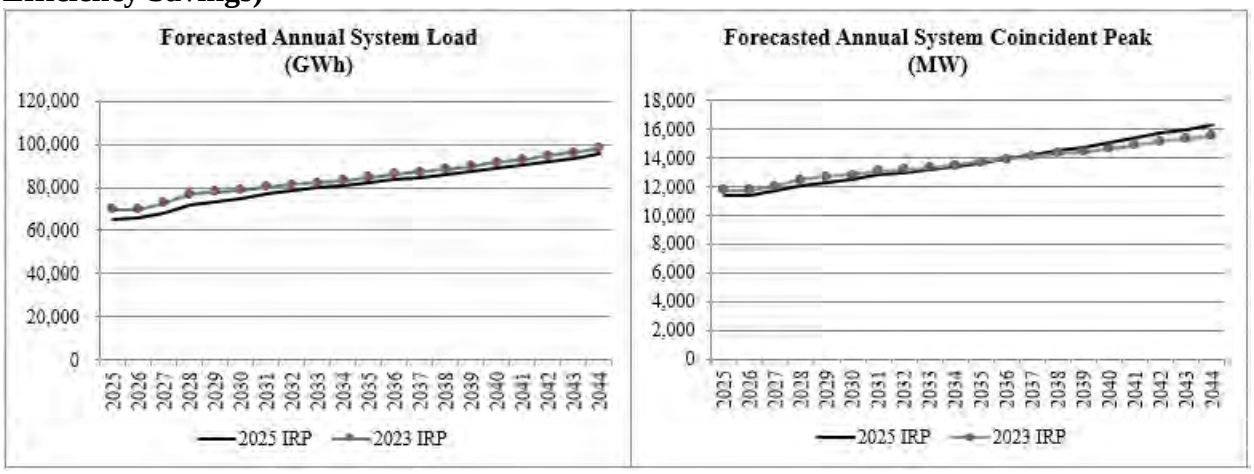
[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over

the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, thus lowering the commercial forecast.[5]

Figure 9.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

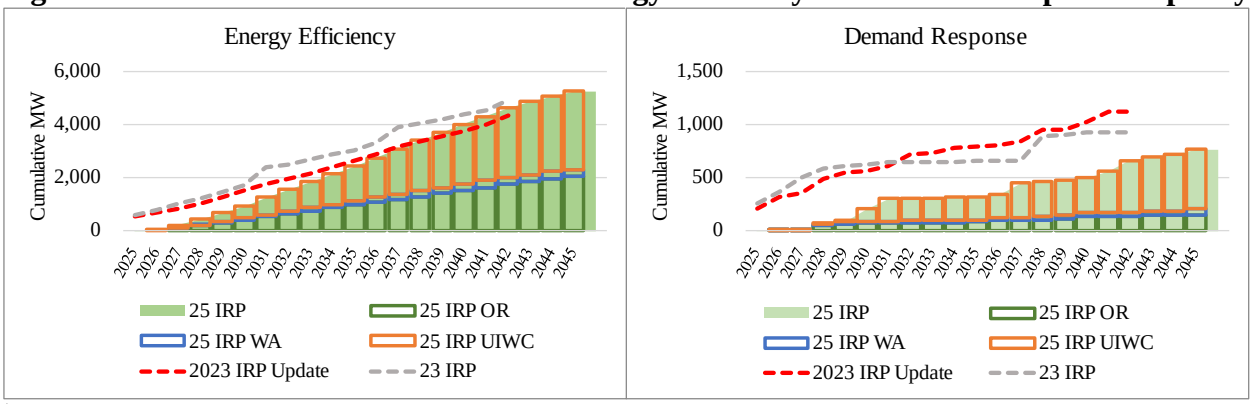


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 IRP preferred portfolio totals 5,436 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.9 compares cumulative demand response program capacity in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2025 IRP has a cumulative capacity of demand response programs totaling 515 MW by 2040. By year-end 2045, the 2025 IRP preferred portfolio has a cumulative capacity of demand response programs totaling 789 MW.

[5] A different approach is needed to protect existing customers from sizeable resource and transmission infrastructure investment costs associated with certain new large loads. Consequently, these loads fall outside of the traditional planning process. Should those loads materialize, we are working with certain large customers to ensure they can bring sufficient resources and are prepared to pay for the incremental transmission upgrades required to serve them.

Figure 9.9 – 2025 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity



[1] Energy efficiency and demand response in the 2023 IRP began escalating two years prior to when escalation begins in the 2025 IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 9.11 illustrates that the 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 9.11 reports that the 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Market transactions in the 2025 IRP are purely economic as market purchases do not contribute to capacity like they did in the 2023 IRP and 2023 IRP Update. In the 2023 IRP and 2023 IRP Update, market purchases were limited to 1,000 MW in the winter and 500 MW in the summer. For the 2025 IRP, economic market purchases for energy could be made up to transmission limits, but market purchases were not allowed on the top five load days during peak hours in peak seasons and could never be used for capacity. Refer to Chapter 5: Reliability and Resiliency for additional details.

Figure 9.10 – 2025 IRP Preferred Portfolio Market Purchases

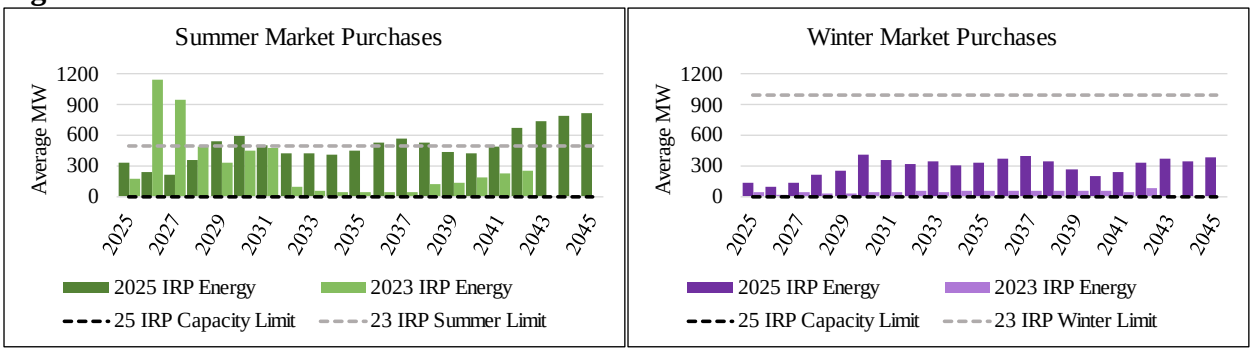
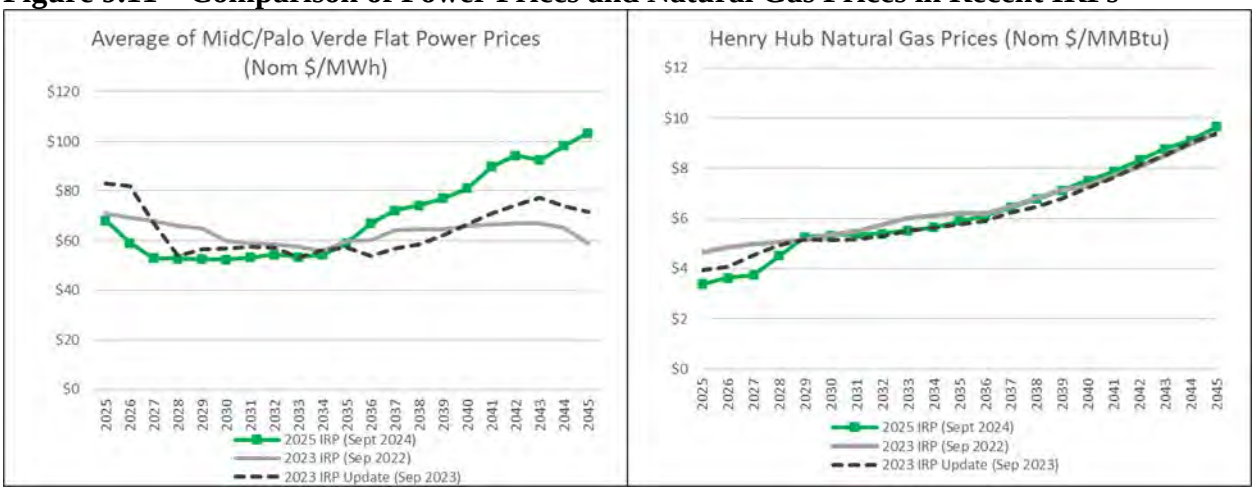


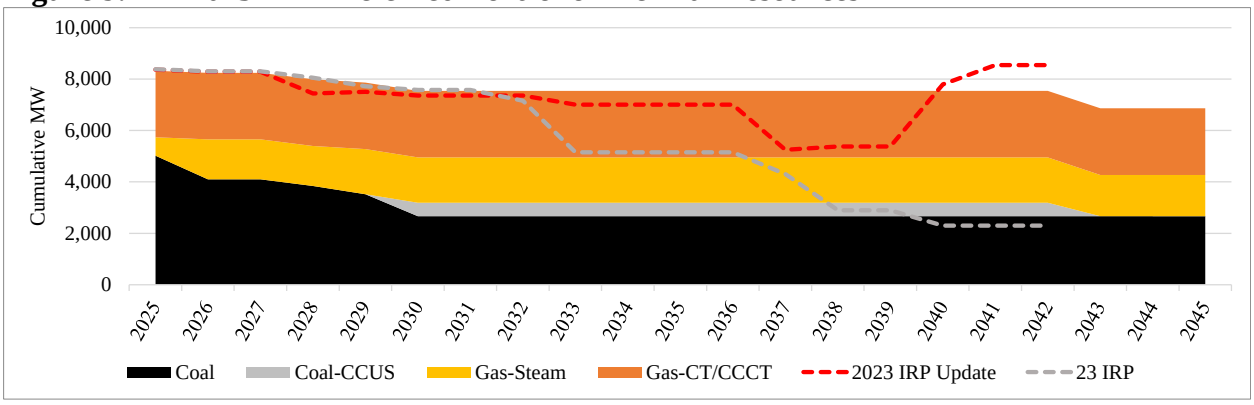
Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



Coal and Gas Retirements/Gas Conversions

Coal-fuel plants have been an important contributor to PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that have enabled the company to reduce fuel consumption, associated costs and emissions, and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 9.12, the 2025 IRP converts 562 MW of coal-fueled generation to natural gas fueled, exits PacifiCorp's share in 386 MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 9.12 – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 9.9. Also shown in Table 9.9 are

the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[6]

Table 9.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Carbon Dioxide Equivalent Emissions

The 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new battery storage resources, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the top in Figure 9.13 compares projected annual CO_2e emissions across the 2025 IRP and the 2023 IRP preferred portfolios and is inclusive of emissions attributed to market purchases. In the current 2025 IRP preferred portfolio, emissions are generally higher than projected in the 2023 IRP. This relative increase is primarily the result of two differences in modeling assumptions. In the 2023 IRP, a medium CO2 price was included in the expected price-

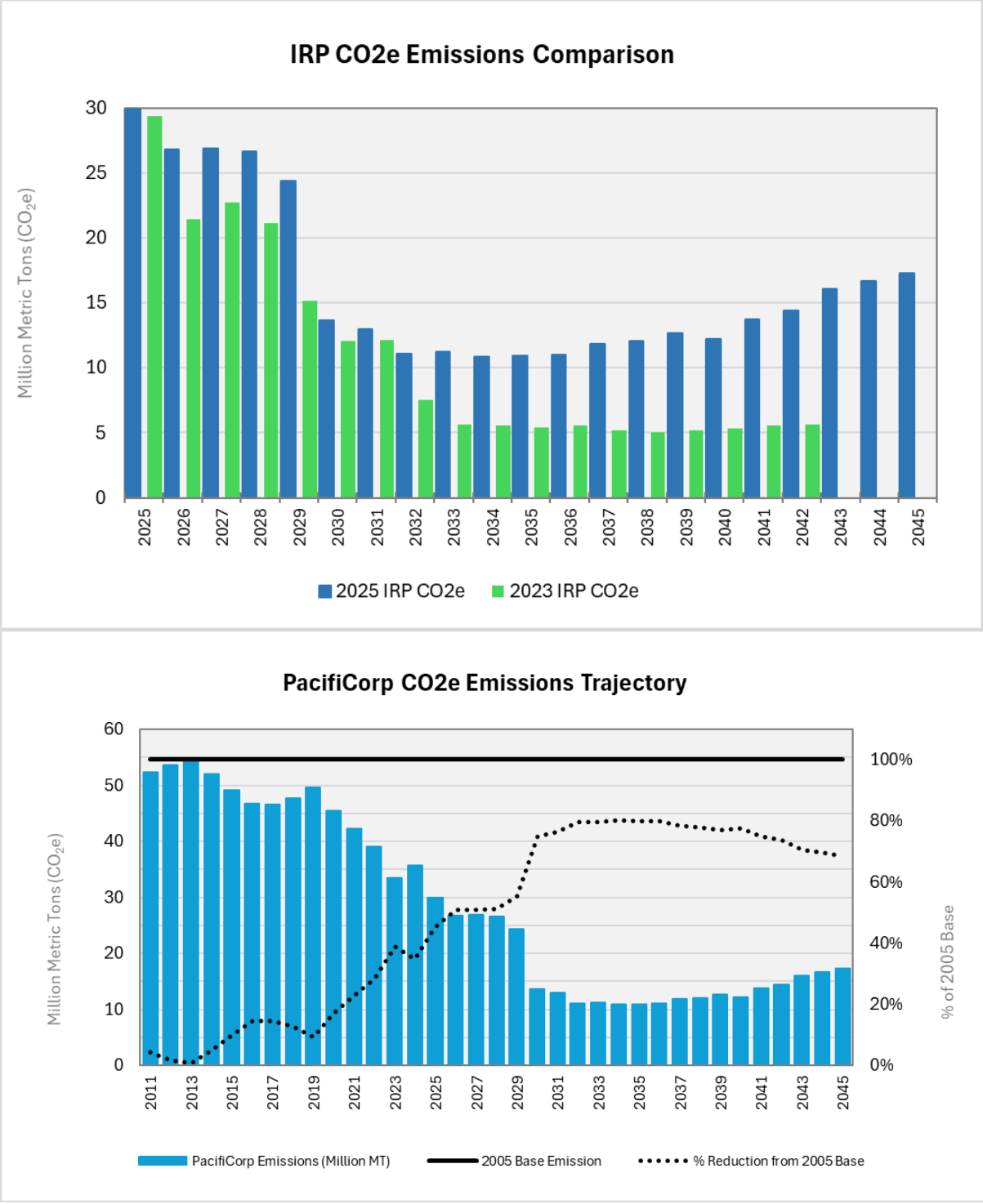
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

policy scenario used to forecast emissions. No CO2 price was included in the dispatch of the 2025 IRP preferred portfolio used to forecast emissions. The 2023 IRP also modeled the EPA's proposed implementation of the Ozone Transport Rule as a significant dispatch target on emissions. No dispatch target was included in the expected price-policy scenario used to forecast emissions in the 2025 IRP. The MR (medium gas price with at-risk federal regulation) price-policy scenario accounts for the effects of possible federal policy, and the portfolio optimized and dispatched under the MR price-policy scenario is a better comparison to the 2023 IRP preferred portfolio.

The difference in emissions between the 2023 IRP and the 2025 IRP is also partly due to an increase in unspecified market purchases, which are assigned a default emission factor of 0.428 MT CO2e/MWh. This default factor, often established by state regulations and widely used in GHG compliance reporting across multiple states, remains constant throughout the planning period. However, energy industry experts believe the market is trending toward lower emissions as renewable energy and storage capacity expand. As more renewables enter the market, overall emissions are expected to decline, translating to a lower emission factor. PacifiCorp is actively engaging with states to discuss updating this default emission factor to better reflect the market's transition to cleaner energy. Finally, the difference in emissions from the 2023 IRP reflects the 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing existing coal plants to operate through the planning period at a reduced capacity factor. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals.

The bottom chart in Figure 9.13 presents historical data and assigns emissions to unspecified market purchases at a rate of 0.428 metric tons CO_2 equivalent per MWh – with no credit to market sales. It also accounts for emissions from specified purchases. The graph shows that system CO2e emissions have declined by approximately 45% in 2025, 75% in 2030, and 77% in 2040, compared to a 2005 baseline of 54.6 million metric tons. In the final five years of the planning horizon, emissions increase moderately due to the factors outlined above.

Figure 9.13 – 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed.

Renewable Portfolio Standards

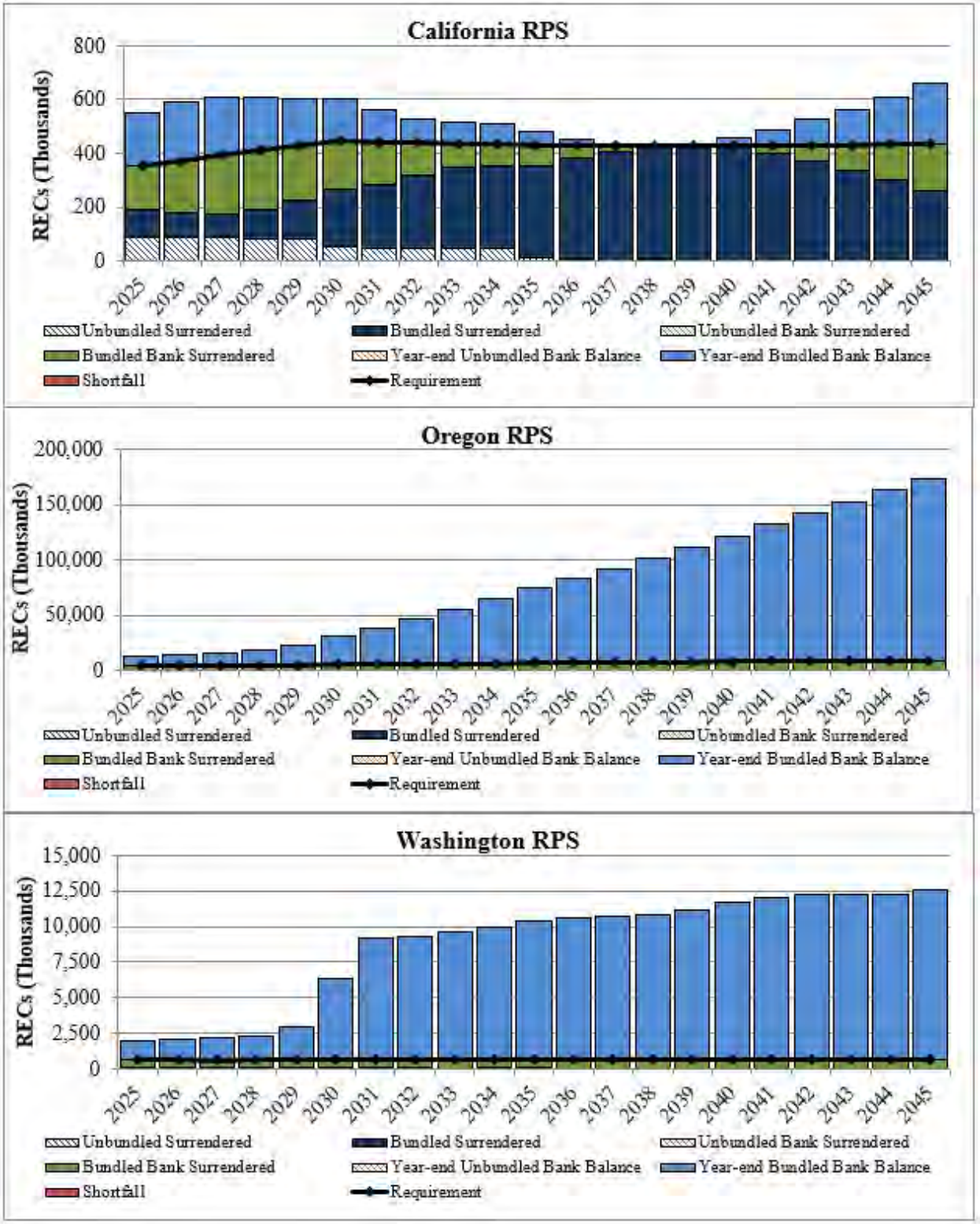
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2045 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a share of renewable resources across PacifiCorp's system; however, Washington may also benefit from the situs allocation of new renewable resources as necessary for compliance.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as unbundled REC purchases at various points throughout the 2025 IRP study period. The increasing RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the long term. The company will rely on a combination of new renewable resources from the preferred portfolio and unbundled RECs to meet future shortfalls.

Although not depicted in Figure 9.14, PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the 2025 IRP preferred portfolio.

Figure 9.14 – Annual State RPS Compliance Forecast



Oregon HB 2021 Compliance

In 2021, Oregon adopted House Bill 2021, an energy policy seeking to reduce emissions from electric generation facilities used to serve customers in the state. HB 2021 sets targets to reduce emissions associated with Oregon retail sales from a baseline, calculated as the average emissions reported from years 2010 through 2012, by 80 percent in 2030, 90 percent by 2035 and 100 percent by 2040. For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalents (CO_2e) to 1.79 MMT CO_2e by 2030, 0.89 MMT CO_2e by 2035, and zero by 2040. The law also increased Oregon's small-scale renewable energy project purchase requirement from 8 to 10 percent by 2030.

The 2025 IRP preferred portfolio was developed to incorporate resources specifically selected to meet all state-specific requirements, including Oregon's greenhouse gas emission reduction targets defined by HB 2021. PacifiCorp also modeled the small-scale renewable portfolio requirement to ensure that at least 10 percent of Oregon-allocated capacity will be small-scale (20 MW or less), in each year from 2030 onwards. For more information on Oregon's planning requirements and the compliance position of the preferred portfolio, refer to Volume II, Appendix P (Oregon Clean Energy Update).

Capacity and Energy

Figure 9.15 and Figure 9.16 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon dispatch under base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[7] On an energy basis, coal generation drops below 20 percent in 2030 and remains below 15 percent through the end of the planning period. On a capacity basis, coal resources drop below 10 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, and DSM resources.

[7]The projected PacifiCorpIRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp'sIRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.15 – Projected Energy Mix with Preferred Portfolio Resources

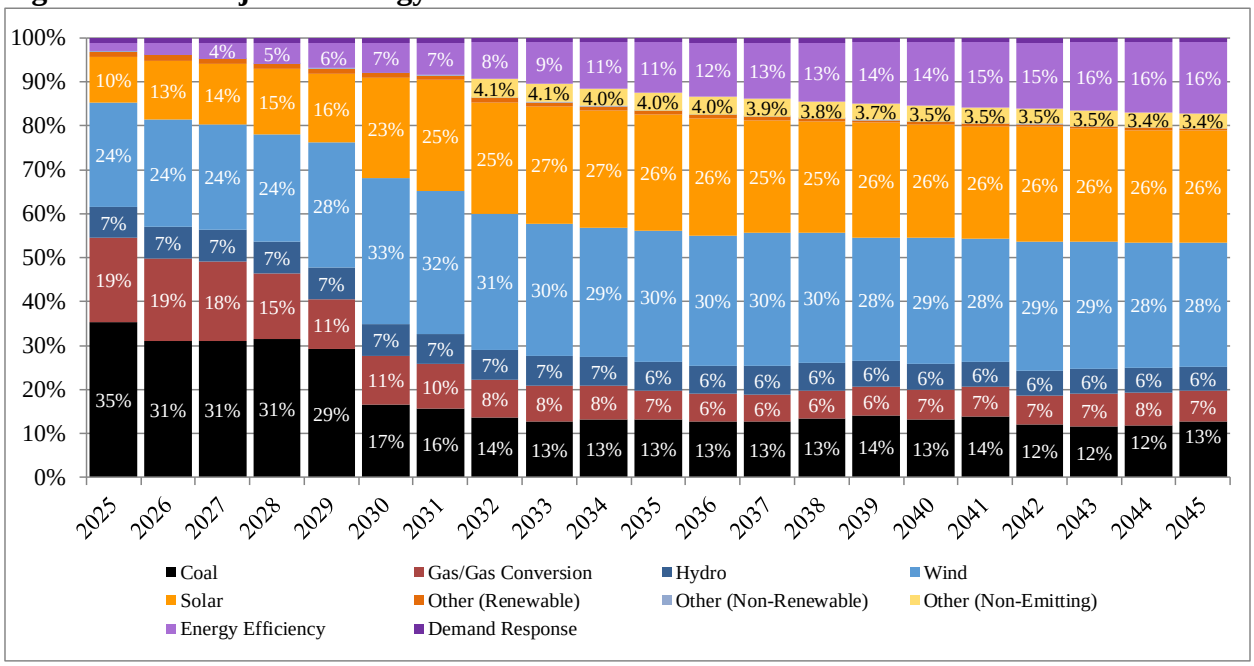
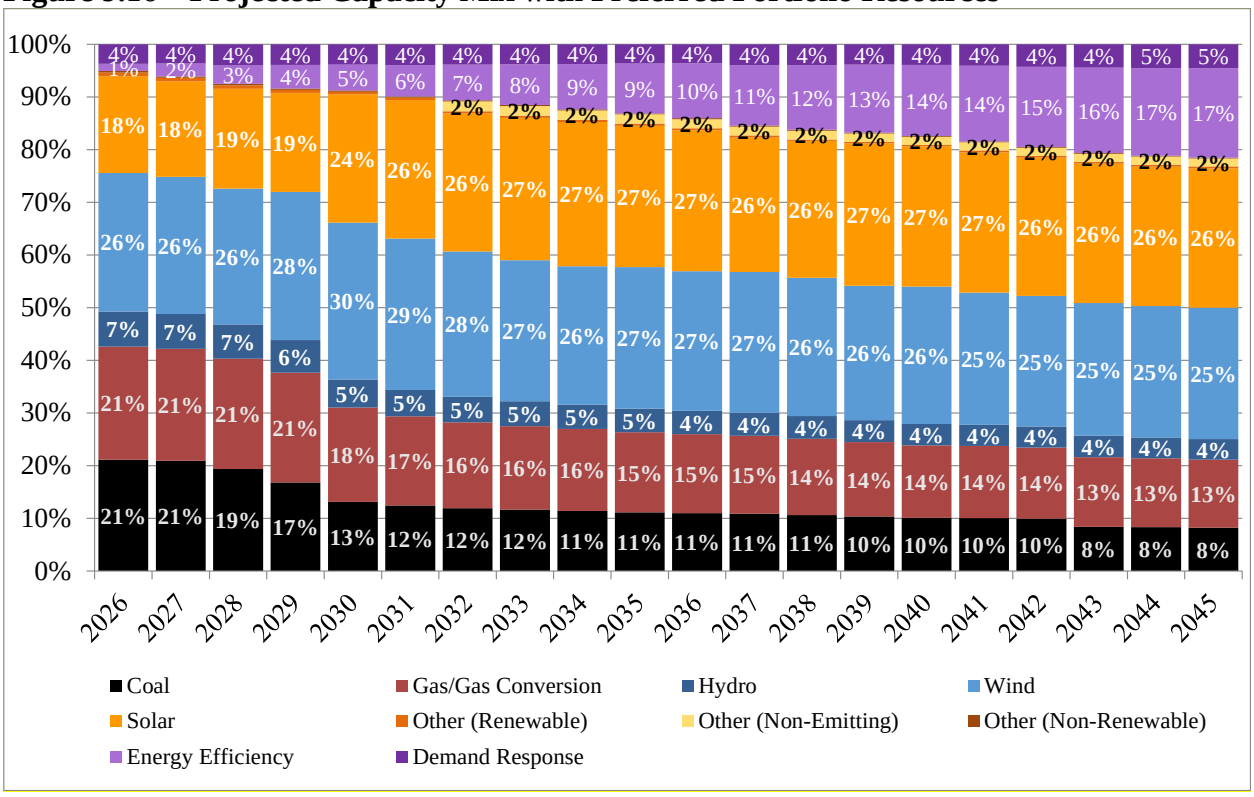


Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 9.10 provides line-item detail of PacifiCorp's 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon. Table 9.11 shows jurisdictional resource selections of PacifiCorp's 2025 IRP preferred portfolio. Table 9.12 and Table 9.13 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon. Table 9.14 and Table 9.15 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

Table 9.10 – PacifiCorp's 2025 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
DSM - Demand Response	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
Renewable - Wind	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**464**	**209**	**1,417**	**1,353**	**4,229**	**1,505**	**1,177**	**772**	**783**	**716**	**559**	**546**	**904**	**956**	**1,857**	**331**	**1,453**	**(31)**	**994**	**1,530**	

Table 9.11 – Preferred Portfolio with Jurisdictional Resource Selections

	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	**500**	-	-	-	-	-	-	-	-	-	-	-	-	-	**500**
OR	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
WA	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
UIWC	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**19**	-	**4**	-	**18**	**41**
OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	**92**	**89**	**209**	**220**	**239**	**261**	**329**	**291**	**299**	**295**	**299**	**315**	**347**	**314**	**293**	**301**	**303**	**315**	**238**	**205**	**182**	**5,255**
OR	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
WA	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
UIWC	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931
DSM - Demand Response	**18**	**2**	-	**63**	**21**	**120**	**99**	**5**	**1**	**3**	**3**	**21**	**112**	**18**	**5**	**24**	**61**	**106**	**29**	**26**	**52**	**769**
OR	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
WA	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
UIWC	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566
Renewable - Wind	-	-	-	**21**	**794**	**1,452**	**344**	**1**	-	**29**	**347**	**40**	**175**	**37**	-	**376**	**50**	-	**20**	-	**96**	**3,782**
OR	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
WA	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
UIWC	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	**222**	**180**	**1,690**	**849**	**240**	**403**	**225**	**13**	-	**1**	-	**554**	**104**	**12**	-	-	**197**	**75**	**4,765**
OR	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
WA	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
UIWC	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668
Renewable - Small Scale Solar	-	-	-	-	-	**320**	**2**	**18**	**26**	**21**	**30**	**132**	-	**309**	-	-	**110**	-	-	**143**	**36**	**1,147**
OR	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
WA	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	**1,146**	**242**	**296**	-	**119**	**39**	**210**	**20**	**47**	-	**175**	**67**	**113**	**67**	**713**	**5**	**459**	**733**	**4,451**
OR	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
WA	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
UIWC	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	-	713	-	459	733	1,933
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	**511**	**91**	**3**	**4**	**3**	**4**	**4**	**11**	**83**	**37**	**939**	**107**	**319**	**402**	**197**	**358**	**3,073**
OR	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
WA	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
UIWC	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	105
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 9.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(281)	(1,447)	(1,369)	(1,105)	(973)	0	0	0	0	0
East Existing Resources	**8,571**	**8,426**	**8,443**	**8,470**	**8,433**	**9,171**	**9,087**	**9,024**	**8,973**	**8,909**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	35	68	124	121	119	117
Solar	0	0	0	0	0	0	151	147	143	139
Storage	0	0	2	2	25	27	27	27	26	26
Nuclear	0	0	0	0	0	0	0	457	454	452
Demand Response	7	7	7	7	8	80	151	149	146	143
East Planned Resources	**7**	**7**	**9**	**9**	**70**	**177**	**455**	**903**	**891**	**879**
East Total Resources	**8,578**	**8,433**	**8,452**	**8,479**	**8,504**	**9,348**	**9,542**	**9,927**	**9,863**	**9,788**
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	**7,498**	**7,372**	**7,388**	**7,412**	**7,433**	**7,465**	**7,527**	**7,520**	**7,511**	**7,545**
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	25.2%	26.8%	32.0%	31.3%	29.7%
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	281	1,447	1,369	1,105	973	0	0	0	0	0
West Existing Resources	**2,277**	**3,433**	**3,339**	**3,063**	**2,916**	**1,800**	**1,784**	**1,771**	**1,761**	**1,751**
Additional Proxy/Short-Term Purchases	1,910	757	885	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	202	201	201	200	202
Solar	0	0	0	117	205	1,185	1,231	1,306	1,446	1,496
Storage	0	0	1	839	982	1,684	1,759	1,828	1,841	1,969
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	2	2	2	2	2	2	2	2	2	2
West Planned Resources	**1,911**	**759**	**889**	**960**	**1,255**	**3,072**	**3,193**	**3,336**	**3,488**	**3,668**
West Total Resources	**4,189**	**4,192**	**4,227**	**4,022**	**4,171**	**4,872**	**4,977**	**5,107**	**5,249**	**5,419**
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	**3,662**	**3,664**	**3,695**	**3,690**	**3,688**	**3,688**	**3,738**	**3,684**	**3,767**	**3,798**
West Reserve Margin	14.4%	14.4%	14.4%	9.0%	13.1%	32.1%	33.1%	38.6%	39.4%	42.7%
System										
Total Resources	12,767	12,625	12,680	12,501	12,675	14,220	14,518	15,034	15,113	15,207
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	0	0	0	(199)	(48)	1,461	1,631	2,217	2,211	2,231
Reserve Margin	**14.4%**	**14.4%**	**14.4%**	**12.6%**	**14.0%**	**27.5%**	**28.9%**	**34.2%**	**34.0%**	**34.1%**

Table 9.13 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,851**	**8,763**	**8,643**	**8,569**	**8,519**	**8,472**	**8,383**	**8,310**	**7,622**	**7,564**	**7,472**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	64	0	672	628	475
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	115	112	110	108	106	104	101	99	97	95	92
Solar	135	131	127	123	120	116	111	107	104	100	96
Storage	26	25	25	25	24	24	23	592	581	858	1,289
Nuclear	450	447	445	442	440	437	435	432	430	427	426
Demand Response	141	138	197	193	189	186	209	253	257	264	270
East Planned Resources	**868**	**856**	**907**	**895**	**882**	**869**	**947**	**1,487**	**2,144**	**2,373**	**2,650**
East Total Resources	**9,719**	**9,620**	**9,550**	**9,464**	**9,401**	**9,340**	**9,330**	**9,797**	**9,766**	**9,937**	**10,123**
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	**7,596**	**7,752**	**7,792**	**7,865**	**7,946**	**8,057**	**8,156**	**8,413**	**8,536**	**8,686**	**8,848**
East Reserve Margin	27.9%	24.1%	22.6%	20.3%	18.3%	15.9%	14.4%	16.5%	14.4%	14.4%	14.4%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,741**	**1,731**	**1,708**	**1,700**	**1,689**	**1,681**	**1,651**	**1,644**	**1,621**	**1,613**	**1,608**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	238	241	259	262	261	299	303	302	303	302	310
Solar	1,455	1,446	1,383	1,431	1,553	1,510	1,470	1,387	1,307	1,314	1,255
Storage	1,966	1,980	1,971	2,144	2,200	3,176	3,299	3,487	3,863	4,035	4,365
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	2	3	3	3	3	3	3	3	3	3	8
West Planned Resources	**3,660**	**3,670**	**3,616**	**3,840**	**4,016**	**4,988**	**5,075**	**5,179**	**5,476**	**5,654**	**5,938**
West Total Resources	**5,401**	**5,401**	**5,325**	**5,540**	**5,705**	**6,668**	**6,727**	**6,823**	**7,097**	**7,267**	**7,545**
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	**3,841**	**3,885**	**3,929**	**3,998**	**4,073**	**4,154**	**4,233**	**4,340**	**4,562**	**4,663**	**4,764**
West Reserve Margin	40.6%	39.0%	35.5%	38.6%	40.1%	60.5%	58.9%	57.2%	55.6%	55.9%	58.4%
System											
Total Resources	15,120	15,021	14,875	15,003	15,106	16,009	16,057	16,620	16,863	17,205	17,668
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	2,036	1,709	1,465	1,432	1,357	2,040	1,885	2,031	1,878	1,933	2,095
Reserve Margin	**32.2%**	**29.1%**	**26.9%**	**26.5%**	**25.7%**	**31.1%**	**29.6%**	**30.3%**	**28.7%**	**28.9%**	**29.8%**

Table 9.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,226)	(930)	0	0	0	0	0
East Existing Resources	**7,804**	**8,523**	**8,433**	**8,495**	**8,581**	**9,208**	**9,042**	**8,954**	**8,875**	**8,780**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	90	175	316	306	297	287
Solar	0	0	0	0	0	0	39	37	36	35
Storage	0	0	1	1	17	18	18	18	18	17
Nuclear	0	0	0	0	0	0	0	403	401	398
Demand Response	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**2**	**2**	**109**	**196**	**374**	**767**	**754**	**740**
East Total Resources	**7,804**	**8,523**	**8,435**	**8,496**	**8,689**	**9,404**	**9,417**	**9,722**	**9,629**	**9,520**
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	**5,821**	**5,790**	**5,876**	**5,963**	**6,033**	**6,119**	**6,231**	**6,309**	**6,440**	**6,560**
East Reserve Margin	34.1%	47.2%	43.5%	42.5%	44.0%	53.7%	51.1%	54.1%	49.5%	45.1%
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,226	930	0	0	0	0	0
West Existing Resources	**3,345**	**3,342**	**3,333**	**2,956**	**2,655**	**1,574**	**1,571**	**1,568**	**1,566**	**1,561**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	201	201	200	199	202
Solar	0	0	0	30	52	299	309	326	359	368
Storage	0	0	1	1,091	1,276	2,037	2,104	2,193	2,206	2,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	41	51	56	55	58	58	59
West Planned Resources	**0**	**0**	**2**	**1,164**	**1,446**	**2,594**	**2,669**	**2,776**	**2,821**	**2,997**
West Total Resources	**3,345**	**3,342**	**3,335**	**4,120**	**4,101**	**4,168**	**4,240**	**4,344**	**4,387**	**4,559**
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	**3,459**	**3,506**	**3,521**	**3,527**	**3,511**	**3,517**	**3,558**	**3,578**	**3,609**	**3,647**
West Reserve Margin	-3.3%	-4.7%	-5.3%	16.8%	16.8%	18.5%	19.2%	21.4%	21.5%	25.0%
System										
Total Resources	11,149	11,865	11,769	12,616	12,790	13,572	13,657	14,066	14,016	14,079
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,559	1,562	1,579	1,594	1,603	1,619	1,645	1,661	1,688	1,715
Obligation + Reserves	10,840	10,858	10,975	11,084	11,147	11,255	11,434	11,549	11,738	11,922
System Position	309	1,008	794	1,532	1,643	2,317	2,223	2,517	2,278	2,157
Reserve Margin	**20.1%**	**27.6%**	**25.2%**	**32.9%**	**34.0%**	**40.8%**	**39.5%**	**42.3%**	**39.5%**	**37.9%**

Table 9.15 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,697**	**8,600**	**8,511**	**8,412**	**8,336**	**8,262**	**8,096**	**8,008**	**7,276**	**7,204**	**7,101**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	278	268	259	250	240	231	221	212	202	193	183
Solar	33	32	31	30	28	27	26	25	23	22	21
Storage	17	16	16	16	15	15	14	370	360	499	711
Nuclear	396	394	392	389	387	384	381	379	377	374	372
Demand Response	0	0	0	0	0	0	0	0	0	0	1
East Planned Resources	**727**	**713**	**700**	**687**	**673**	**660**	**645**	**988**	**965**	**1,091**	**1,291**
East Total Resources	**9,423**	**9,313**	**9,212**	**9,099**	**9,009**	**8,921**	**8,742**	**8,996**	**8,241**	**8,294**	**8,392**
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	**6,659**	**6,786**	**6,932**	**7,084**	**7,248**	**7,387**	**7,498**	**7,717**	**7,872**	**8,070**	**8,131**
East Reserve Margin	41.5%	37.2%	32.9%	28.4%	24.3%	20.8%	16.6%	16.6%	4.7%	2.8%	3.2%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,559**	**1,555**	**1,552**	**1,550**	**1,546**	**1,544**	**1,541**	**1,539**	**1,536**	**1,534**	**1,531**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	237	241	258	261	260	298	301	300	301	300	308
Solar	355	349	331	339	363	348	333	309	286	280	260
Storage	2,362	2,379	2,362	2,558	2,619	3,606	3,732	3,910	4,279	4,439	4,761
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	60	67	66	73	75	82	83	82	85	84	87
West Planned Resources	**3,013**	**3,036**	**3,018**	**3,231**	**3,317**	**4,334**	**4,450**	**4,601**	**4,951**	**5,103**	**5,417**
West Total Resources	**4,572**	**4,591**	**4,570**	**4,781**	**4,863**	**5,878**	**5,991**	**6,140**	**6,488**	**6,636**	**6,948**
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	**3,662**	**3,707**	**3,800**	**3,888**	**3,957**	**4,010**	**4,097**	**4,239**	**4,463**	**4,567**	**4,535**
West Reserve Margin	24.9%	23.9%	20.3%	23.0%	22.9%	46.6%	46.2%	44.8%	45.4%	45.3%	53.2%
System											
Total Resources	13,995	13,904	13,782	13,880	13,872	14,799	14,732	15,136	14,729	14,930	15,340
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	2,188	1,901	1,505	1,327	1,053	1,760	1,467	1,458	618	474	850
Reserve Margin	**35.6%**	**32.5%**	**28.4%**	**26.5%**	**23.8%**	**29.8%**	**27.1%**	**26.6%**	**19.4%**	**18.1%**	**21.1%**

Integrated Portfolio Resource Comparisons by Technology and Year

Table 9.16 through Table 9.28 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 9.29 through Table 9.32 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology. Table 9.33 summarizes how full jurisdictional studies were identified for each variant and price-policy scenario. Full jurisdictional studies are only modified and endogenously developed to the extent the variant relates to resources that can be selected for that jurisdiction. As a result, the Oregon and Washington full jurisdictional portfolios are not modified in the variants that examine coal resource alternatives. Similarly, Washington requires planning under the social cost of greenhouse gases, so its full jurisdictional portfolio is not modified under other price-policy scenarios. Those variants related to clean resources in which all jurisdictions can participate have full jurisdictional portfolios for each jurisdiction.

Table 9.16 – New Gas[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	-	-	99
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	496	496
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.17 - Nuclear[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MR Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No CCS	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Offshore Wind	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Hunter Retire	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
LN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
HH Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
SC Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.18 – Renewable Peaking[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.19 – DSM – Energy Efficiency

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
MR Base	92	89	209	221	231	256	329	313	326	315	318	326	369	335	313	308	304	315	254	224	209	5,656
MN - No CCS	92	89	207	218	229	253	326	287	284	282	294	300	333	312	292	289	304	315	260	232	219	5,417
MN - No Nuclear	92	89	210	220	237	256	331	314	310	299	299	314	324	267	283	251	286	299	282	261	220	5,444
MN - No Coal 2032	92	89	210	221	231	251	319	304	308	298	309	325	347	314	293	299	304	315	270	246	220	5,565
MN - Offshore Wind	92	89	209	219	240	260	331	292	306	294	299	322	345	314	310	301	303	314	222	218	182	5,462
MN - No Forward Technology	92	89	210	220	237	256	331	315	310	301	301	315	324	267	283	251	286	299	282	247	219	5,435
MN - Geothermal	92	89	207	217	227	245	306	298	303	293	313	320	354	335	313	308	305	314	270	259	218	5,586
MN - Hunter Retire	92	89	219	232	243	265	332	306	310	307	312	328	358	326	306	301	304	315	258	224	209	5,636
LN Base	92	89	207	223	236	257	325	288	300	289	311	318	343	309	322	305	302	291	272	244	217	5,540
HH Base	92	89	211	223	237	257	309	295	300	289	309	315	347	326	305	302	305	316	259	252	230	5,568
SC Base	92	89	211	226	241	263	329	293	314	305	318	325	357	325	320	308	305	315	270	260	219	5,685

Table 9.20 – DSM – Demand Response

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
MR Base	18	2	-	63	19	16	3	5	1	5	3	19	323	18	5	24	114	34	34	25	205	936
MN - No CCS	18	2	-	63	19	34	187	5	1	3	3	21	93	18	5	25	6	176	30	26	50	785
MN - No Nuclear	18	2	-	63	20	136	13	8	26	79	32	4	70	14	151	24	46	31	12	102	48	899
MN - No Coal 2032	18	2	-	63	19	16	-	5	1	3	3	19	328	18	5	25	5	146	33	27	51	787
MN - Offshore Wind	18	2	-	63	20	206	21	8	-	10	4	4	110	29	5	11	8	166	30	31	50	796
MN - No Forward Technology	18	2	-	63	21	131	13	10	26	77	35	6	70	13	151	24	45	31	12	102	57	907
MN - Geothermal	18	2	-	60	20	16	-	8	-	7	5	7	-	13	10	26	450	29	8	7	103	789
MN - Hunter Retire	18	2	-	63	19	211	14	5	1	3	3	23	113	18	129	25	7	147	29	30	87	947
LN Base	18	2	-	63	19	75	149	7	2	4	4	14	110	14	5	24	124	-	8	80	51	773
HH Base	18	2	-	63	22	13	-	5	1	3	3	19	-	18	8	24	5	463	15	157	30	869
SC Base	18	2	2	64	28	191	14	5	1	1	18	11	108	18	10	24	6	150	12	50	46	779

Table 9.21 – Utility Scale Wind[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
MR Base	-	-	-	21	694	1,931	200	382	100	129	447	40	175	37	-	376	50	-	20	-	96	4,698
MN - No CCS	-	-	-	21	594	1,252	276	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,314
MN - No Nuclear	-	-	-	-	500	1,728	300	301	302	322	380	292	2	-	-	-	-	-	-	-	-	4,127
MN - No Coal 2032	-	-	-	21	594	2,914	-	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,700
MN - Offshore Wind	-	-	100	100	762	630	400	1	1,000	98	100	100	-	-	-	353	95	-	-	-	162	3,901
MN - No Forward Technology	-	-	-	-	694	1,482	302	301	-	22	294	53	176	38	-	367	91	-	1	-	147	3,968
MN - Geothermal	-	-	-	-	594	402	200	1	2	-	169	204	185	89	-	360	62	-	38	-	19	2,325
MN - Hunter Retire	-	-	-	21	894	1,842	340	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,268
LN Base	-	-	-	-	594	1,265	594	2	-	24	369	1	176	38	-	365	90	-	3	-	150	3,671
HH Base	-	-	-	21	1,214	2,677	-	2	-	29	349	40	175	37	-	376	50	-	20	-	96	5,086
SC Base	-	-	-	20	1,614	1,353	352	1	-	65	293	237	114	26	29	423	47	-	-	11	196	4,781

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.22 – Small Scale Wind[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.23 – Utility Solar[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
MR Base	-	-	-	222	180	1,690	863	934	420	467	213	133	1	-	554	104	12	-	-	197	75	6,065
MN - No CCS	-	-	-	222	180	1,690	614	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,530
MN - No Nuclear	-	-	-	656	-	1,444	962	299	326	395	456	391	1	-	-	-	-	-	-	22	108	5,060
MN - No Coal 2032	-	-	-	222	180	1,690	494	635	545	792	114	100	1	-	554	104	12	-	-	197	75	5,715
MN - Offshore Wind	-	-	103	237	205	1,382	885	249	104	100	100	100	103	392	444	100	-	-	-	116	26	4,646
MN - No Forward Technology	-	-	119	13	-	1,968	962	220	327	316	49	-	1	-	577	85	34	-	-	239	111	5,021
MN - Geothermal	-	-	29	505	1	1,168	200	163	349	199	103	-	2	27	82	229	211	-	-	333	104	3,705
MN - Hunter Retire	-	-	-	222	180	2,352	1,173	240	403	225	13	-	1	-	554	104	12	-	-	197	75	5,751
LN Base	-	-	-	200	138	1,761	517	239	398	230	7	-	1	-	570	93	61	-	-	44	110	4,369
HH Base	-	-	-	222	181	1,813	1,904	734	603	360	196	-	1	-	554	104	12	-	-	197	75	6,956
SC Base	-	-	22	381	144	2,005	1,259	335	400	206	225	90	1	-	471	115	-	-	-	288	92	6,034

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.24 – Small Scale Solar[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MR Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No CCS	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No Nuclear	-	-	-	-	-	320	2	18	26	21	26	53	-	307	-	49	153	-	10	126	36	1,147
MN - No Coal 2032	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - Offshore Wind	-	-	-	-	-	416	-	-	-	-	-	-	-	24	29	114	142	-	36	250	26	1,037
MN - No Forward Technology	-	-	-	-	-	320	2	18	26	21	30	127	-	307	-	-	117	-	35	108	36	1,147
MN - Geothermal	-	-	-	-	-	304	-	11	29	17	23	17	15	201	331	13	21	-	35	18	26	1,061
MN - Hunter Retire	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
LN Base	-	-	-	-	-	320	2	18	26	21	31	153	-	306	-	-	97	-	35	101	36	1,146
HH Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
SC Base	-	-	-	-	-	320	2	19	26	23	24	20	9	312	-	42	170	-	-	56	26	1,049

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.25 – Geothermal

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	403	304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	707
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.26 – Battery, < 8 hour [1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
MR Base	-	-	-	1,156	215	438	-	119	39	210	20	47	27	175	67	113	582	33	5	305	324	3,875
MN - No CCS	-	-	2	1,146	215	299	-	119	39	210	20	47	-	175	188	113	67	115	5	758	-	3,518
MN - No Nuclear	-	-	16	1,399	109	462	-	274	39	209	34	72	313	130	6	937	159	-	605	10	602	5,376
MN - No Coal 2032	-	-	-	1,145	215	565	-	119	39	210	20	47	-	175	67	113	67	152	5	416	18	3,373
MN - Offshore Wind	-	-	7	2,291	527	528	-	149	-	131	46	54	2	251	113	1,454	211	675	768	82	834	8,123
MN - No Forward Technology	-	-	-	1,349	179	316	6	182	41	279	30	83	333	186	112	1,322	272	287	444	251	605	6,277
MN - Geothermal	-	-	-	1,048	184	650	-	241	4	203	37	70	-	179	37	1,437	473	-	104	53	449	5,169
MN - Hunter Retire	-	-	4	1,145	215	836	-	119	39	210	20	47	41	175	67	113	67	129	5	109	185	3,526
LN Base	-	-	-	1,252	220	609	-	99	39	209	23	82	-	239	67	1,126	1,060	-	272	12	1,437	6,746
HH Base	-	-	2	1,146	302	1,383	-	119	39	210	20	47	-	175	67	113	67	-	5	-	-	3,695
SC Base	-	-	-	2,147	329	484	-	175	7	194	2	23	-	286	121	1,095	138	245	192	237	531	6,206

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.27 – Battery, 8-23 hour[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.28 – Battery, 24+ hour [1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
MR Base	-	-	-	-	-	510	91	3	4	3	4	4	175	83	37	939	107	510	401	197	455	3,523
MN - No CCS	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	261	402	197	358	3,015
MN - No Nuclear	-	-	-	-	-	191	2	3	3	3	3	3	114	3	3	186	78	233	168	118	4	1,115
MN - No Coal 2032	-	-	-	-	-	510	91	3	4	3	4	4	33	83	37	939	107	390	401	197	358	3,164
MN - Offshore Wind	-	-	-	-	-	1,577	20	23	23	22	25	26	24	27	28	127	34	142	96	30	34	2,258
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	85	1	1	1	1	1	1	1	1	2	13	84	85	316	174	88	855
MN - Hunter Retire	-	-	-	-	-	837	91	3	4	3	4	4	123	83	146	939	107	455	401	197	537	3,934
LN Base	-	-	-	-	-	271	95	4	4	3	4	4	17	38	40	132	26	215	137	159	16	1,165
HH Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	641	402	197	598	3,635
SC Base	-	-	-	-	-	1,410	107	19	19	18	20	21	69	22	34	141	141	442	219	169	94	2,945

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.29 – Majority Owned Coal Retirements[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MR Base	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Coal 2032	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Forward Technology	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Geothermal	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Hunter Retire	-	-	-	(220)	-	(1,158)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,378)
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
HH Base	-	-	-	(220)	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(488)
SC Base	-	-	-	(488)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(757)

[1] Negative values indicate retirement of coal capacity.

Table 9.30 – Carbon Capture and Sequestration Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No Forward Technology	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - Geothermal	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
MN - Hunter Retire	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526

Table 9.31 – Coal to Gas Conversion Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MR Base	-	357	-	-	205	1,979	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	2,385
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(403)	-	-	159
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - No Coal 2032	-	357	-	-	205	2,679	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	3,085
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MN - No Forward Technology	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Geothermal	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Hunter Retire	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
LN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
HH Base	-	357	-	-	205	599	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	892
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	(99)	-	-	793

Table 9.32 – Gas Retirements[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(167)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(167)

[1]Only reports retirements of existing gas plants.

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 7 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. Consequently, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS. As discussed in Chapter 8, some of the studies below were able to fulfill the requirements of another study and are noted as such. Table 9.33 summarizes the jurisdictional studies which were integrated for each of the variants and price-policy scenarios. Variants evaluating technology that is available in all jurisdictions have jurisdictional portfolios developed for each jurisdiction. Where a jurisdiction does not use the applicable technology or assumptions under consideration in the variant, selections for that jurisdiction are held constant at their base scenario. For example, neither Oregon nor Washington participates in coal-fired resources over the long term, so studies that evaluate alternative decisions for coal-fired resources hold Oregon and Washington jurisdictional results constant. Similarly, Washington requires that the SCGHG price-policy scenario be used for planning, so Washington selections under SCGHG are integrated regardless of the price-policy scenario under consideration.

Table 9.33 – Jurisdictional Studies for Variants and Price-Policy Scenarios

Price-policy / Variant	UIWC	OR	WA	Description
MN - Base	Base	Base		MN price-policy scenario
MR - Base	✓			MR price-policy scenario
LN - Base	✓	✓		LN price-policy scenario
HH - Base	✓	✓		HH price-policy scenario
SC - Base	✓	✓	Base	SCGHG price-policy scenario
MN - No CCS	✓			No coal units are able to select CCS technology
MN - No Coal 2032	✓			All coal must retire or convert by January 1, 2032
MN - Hunter Retire	✓			Require all Hunter units to retire no later than 1/1/2030
MN - No Nuclear	✓	✓	✓ (SC)	No nuclear resources are eligible for selection
MN - Offshore Wind	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - No Forward Technology	✓	✓	✓ (SC)	No nuclear, hydrogen or 100-hour storage, or biodiesel peaking
MN - Geothermal	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - All Coal End of Life	Same as No CCS			Continue 2025 coal technology
MN - No New Gas	Same as Preferred Portfolio			No new gas resources allowed
MN - Force All Gas Conversions	Same as No Coal 2032			All coal must be converted to natural gas where available

Table 9.34 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no CO_2) price-policy scenario. As in previous IRPs, model results can indicate the need to examine costs and risks beyond the model horizon. End effects were applied to all portfolios run under the MN price-policy for a 5-year period after the study horizon, results of which can be seen in this table. The specific trends that led to this examination can be found in the discussion of individual cases below.

Table 9.34 – Integrated Portfolios Under Medium Gas/ Zero CO_2

	ST Value			Risk Adjusted			With End Effects			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Stochastic PVRR	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Portfolio	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	27,233	$171	4	27,618	$106	2	34,663	$0	1	317,054	109,082	9
Integrated No CCS MN	28,345	$1,283	6	28,886	$1,374	6	35,768	$1,105	6	386,023	178,051	13
Integrated No Nuclear MN	28,878	$1,816	9	29,301	$1,789	8	36,457	$1,794	7	320,486	112,515	10
Integrated No Coal Post 2032 MN	28,438	$1,376	7	29,235	$1,723	7	36,751	$2,088	8	215,237	7,265	3
Integrated Offshore Wind MN	34,645	$7,583	13	35,127	$7,615	13	42,917	$8,255	13	310,014	102,043	7
Integrated No Future Tech MN	29,110	$2,048	10	29,534	$2,022	10	36,946	$2,284	10	330,034	122,063	11
Integrated Geothermal MN	29,208	$2,146	11	29,946	$2,434	11	37,188	$2,525	11	310,138	102,167	8
Integrated Hunter Retire MN	27,062	$0	1	27,765	$253	3	34,960	$297	3	269,208	61,237	6
Integrated Base MR	27,176	$114	3	27,913	$401	4	35,385	$723	5	207,971	0	1
Integrated No CCS MR	28,581	$1,519	8	29,374	$1,862	9	36,896	$2,233	9	213,302	5,331	2
Integrated Base LN	27,785	$723	5	27,970	$458	5	35,167	$504	4	340,068	132,096	12
Integrated Base HH	27,119	$57	2	27,512	$0	1	34,714	$51	2	238,450	30,479	4
Integrated Base SC	29,787	$2,725	12	30,088	$2,575	12	37,904	$3,242	12	257,126	49,155	5

Table 9.35, below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero CO_2) price-policy scenario.

Table 9.35 –Integrated Portfolios Under Low Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - LN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN	25,113	$498	4	315,803	54,380	10
Integrated Base MN	25,226	$611	5	334,470	73,047	12
Integrated No CCS MN	25,847	$1,232	8	361,938	100,514	13
Integrated No Nuclear MN	28,638	$4,023	12	315,004	53,580	9
Integrated No Coal Post 2032 MN	25,428	$814	6	261,423	0	4
Integrated Offshore Wind MN	37,505	$12,890	13	299,472	38,049	7
Integrated No Future Tech MN	26,507	$1,892	9	326,791	65,368	11
Integrated Geothermal MN	26,936	$2,322	10	300,704	39,281	8
Integrated Hunter Retire MN	24,959	$344	2	273,675	12,251	6
Integrated Base MR	24,615	$0	1	254,697	(6,726)	2
Integrated No CCS MR	25,580	$965	7	261,242	(181)	3
Integrated Base HH	24,990	$375	3	248,840	(12,584)	1
Integrated Base SC	27,805	$3,190	11	270,860	9,437	5

Table 9.36 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high CO_2) price-policy scenario.

Table 9.36 – Integrated Portfolios Under High Gas and Coal/ High CO_2

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	31,498	$0	1	174,521	444	2
Integrated Base MN	34,498	$3,000	8	232,976	58,900	13
Integrated No CCS MN	35,762	$4,264	11	219,378	45,302	12
Integrated No Nuclear MN	35,275	$3,777	10	202,255	28,178	10
Integrated No Coal Post 2032 MN	33,052	$1,553	4	179,879	5,803	4
Integrated Offshore Wind MN	45,727	$14,228	13	194,780	20,703	8
Integrated No Future Tech MN	35,902	$4,404	12	207,187	33,110	11
Integrated Geothermal MN	35,247	$3,749	9	189,861	15,785	7
Integrated Hunter Retire MN	31,973	$475	3	179,948	5,871	5
Integrated Base MR	31,796	$297	2	180,431	6,355	6
Integrated No CCS MR	33,110	$1,612	5	178,538	4,461	3
Integrated Base LN	33,995	$2,496	6	201,609	27,532	9
Integrated Base SC	34,207	$2,709	7	174,077	0	1

Table 9.37 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario.

Table 9.37 – Integrated Portfolios Under Medium Gas/ Social Cost of CO_2

	ST Value			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	40,268	$2,628	7	103,326	3,072	3
Integrated Base MN	40,882	$3,242	8	117,244	16,990	9
Integrated No CCS MN	41,851	$4,210	11	120,282	20,028	12
Integrated No Nuclear MN	38,899	$1,258	4	115,060	14,806	8
Integrated No Coal Post 2032 MN	39,186	$1,545	5	105,996	5,742	5
Integrated Offshore Wind MN	51,719	$14,079	13	110,124	9,870	7
Integrated No Future Tech MN	41,797	$4,157	10	117,608	17,354	10
Integrated Geothermal MN	40,942	$3,302	9	106,062	5,808	6
Integrated Hunter Retire MN	38,034	$394	2	101,094	840	2
Integrated Base MR	38,708	$1,067	3	117,634	17,380	11
Integrated No CCS MR	39,227	$1,586	6	104,731	4,477	4
Integrated Base LN	42,873	$5,232	12	157,891	57,637	13
Integrated Base HH	37,640	$0	1	100,254	0	1

Integrated Portfolios Under Medium Gas/ Federal Regulation (MR)

Three variant cases examined compliance under the current language in EPA 111(d): the base MR case, the MR No CCS case, and the No Coal Post-2032 case. Details for each MR case is included with the discussions of the integrated portfolio results below.

Variant Study Analysis

No CCS Variant

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were found not to be commercially viable at this location. As Jim Bridger 3 and 4 run as coal in this case, the No CCS variant serves as the "All Coal End of Life" variant as well.

Figure 9.17 shows the cumulative (at left) and incremental (at right) portfolio changes when CCS at Jim Bridger 3 and 4 is not allowed on the system starting in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Over the course of the horizon, fewer proxy resources are built. There is reduction of 469 MW of wind, 236 MW of solar and 989 MW of battery, with battery reductions occurring in 2042 and 2045.

Figure 9.17 - Increase/(Decrease) in Proxy Resources with No CCS

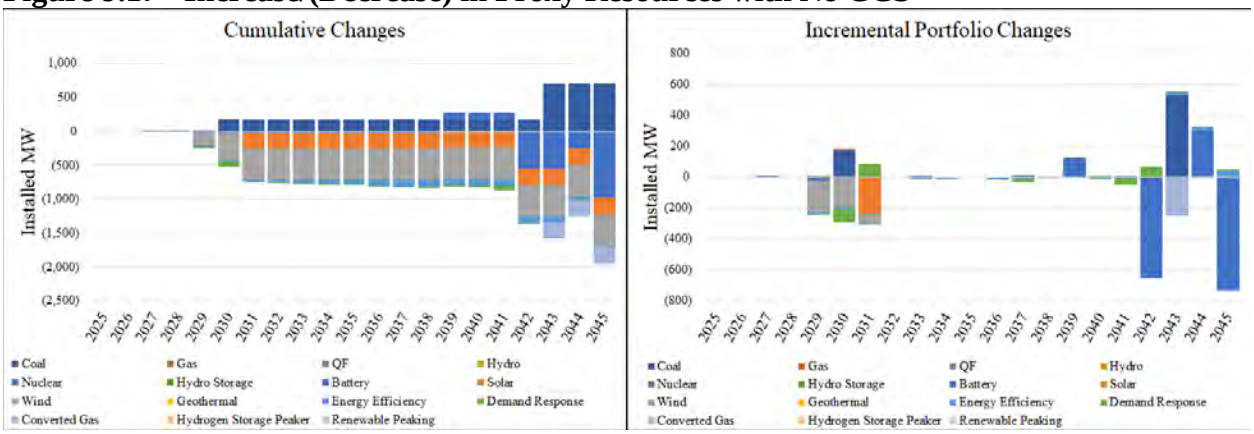
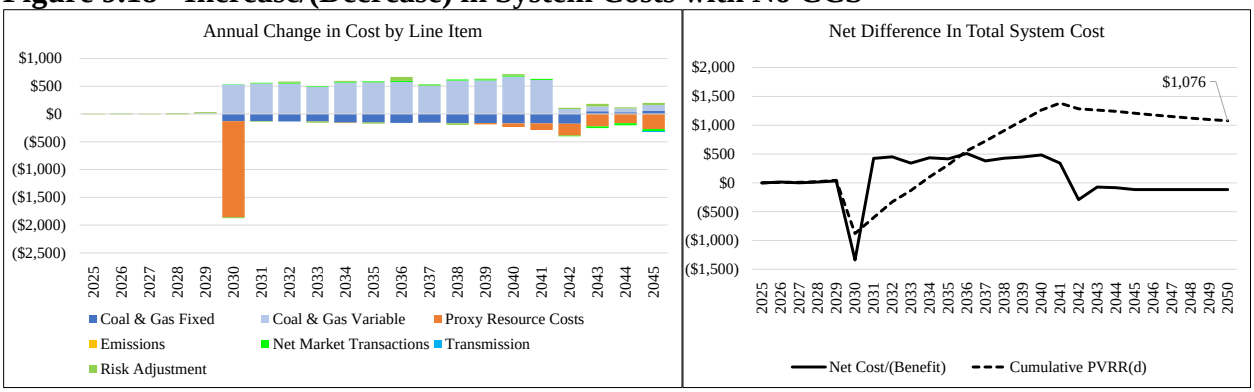


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.076 billion increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.18 - Increase/(Decrease) in System Costs with No CCS



No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2032. Additionally, this variant does not allow any proxy nuclear to be selected as a potential replacement for the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the nuclear projects prove unviable.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case does not select small renewable peaking resources and reduces 100-hour battery selection by 1,955 MW. The No Nuclear portfolio does add an additional 923 MW of 4-hour storage, 347 MW

of wind, 296 MW of solar, and 120 MW of DSM. This study also keeps the CCS at Jim Bridger and Naughton 1 gas conversion through the end of the study horizon.

Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Nuclear

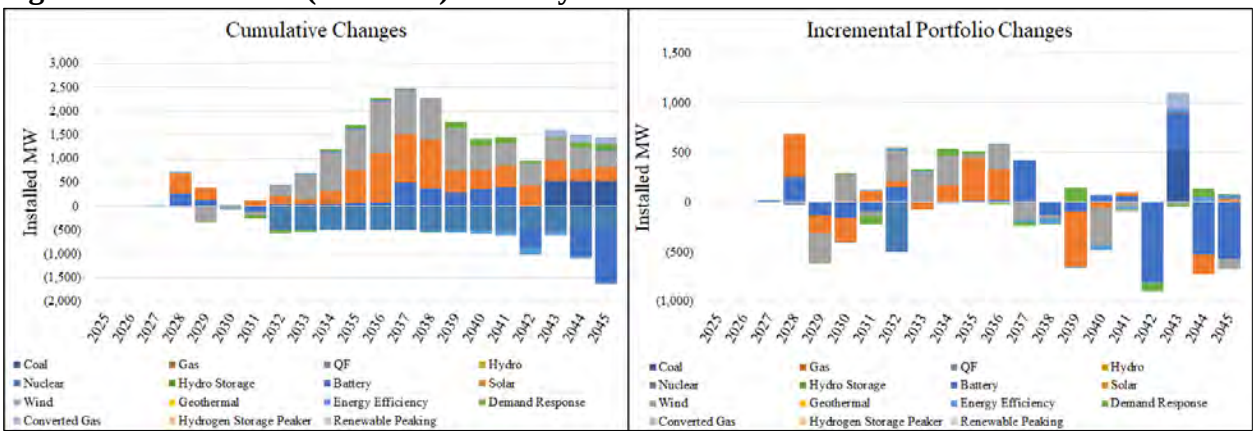
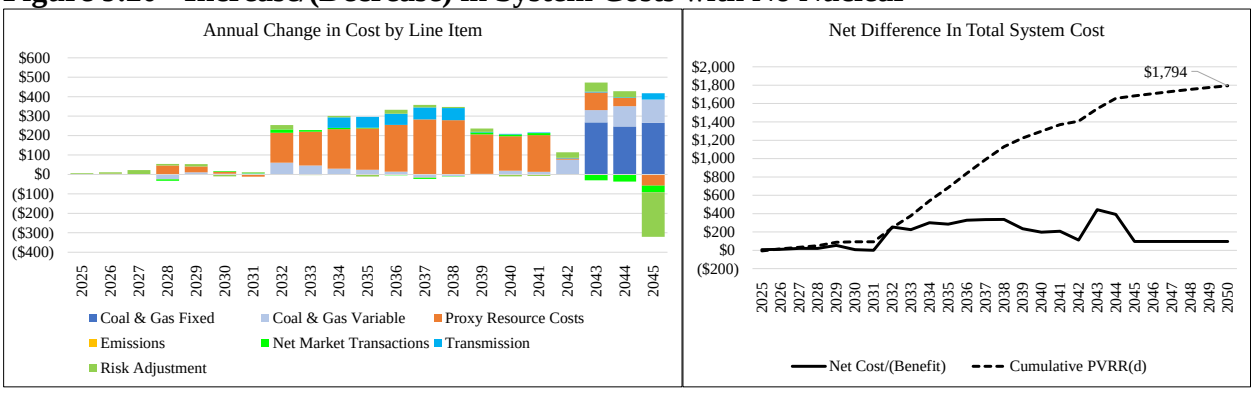


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.794 billion increase in costs compared to the preferred portfolio. Given that no costs associated with the Natrium™ demonstration project are included in modeling, the increase in costs reflects the loss of all energy and PTC benefits associated with the project.

As seen in Figure 9.20 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.20 - Increase/(Decrease) in System Costs with No Nuclear



No Coal Post-2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS. Because all units eligible for gas conversion either convert to gas or retire early, this study also serves as the "Force Gas Conversion" variant.

Figure 9.21 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects additional energy efficiency and demand response, over 2,200 MW of additional wind and solar, and a shift in storage from 4-hour to long duration.

Figure 9.21 - Increase/(Decrease) in Proxy Resources with No Coal Post-2032

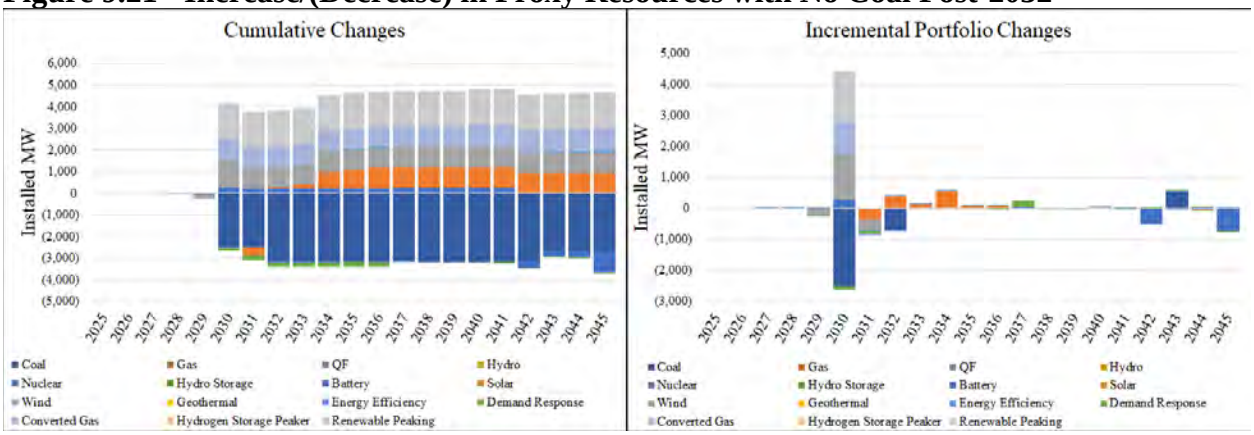
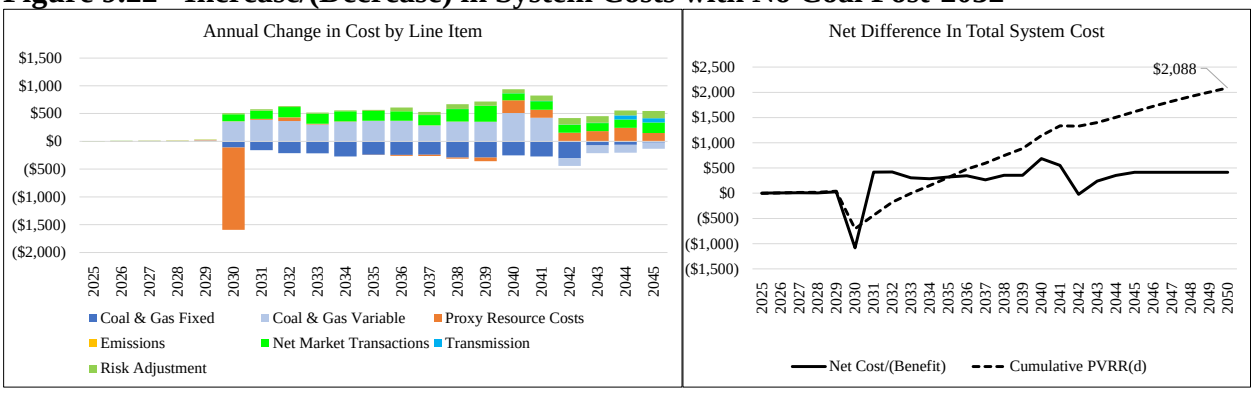


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or converted to gas by 2032, the resulting portfolio has a $2.088 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.22 below, the system cost increase exceeds the impact of 45Q tax credits and CCS capital cost. Additionally, this case has higher levels of market purchases and has higher proxy resource costs in nearly all years of the study horizon.

Figure 9.22 - Increase/(Decrease) in System Costs with No Coal Post-2032



Force Offshore Wind

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 9.23 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2033. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The portfolio selects and additional 120 total MW of wind, 3,760 MW of 4-hour storage and 35 MW of additional DSM. These increased selections are partially offset by a reduction of 132 MW of solar and 812 MW of 100-hour storage. Retirements are the same between the studies.

Figure 9.23 - Increase/(Decrease) in Proxy Resources with Offshore Wind

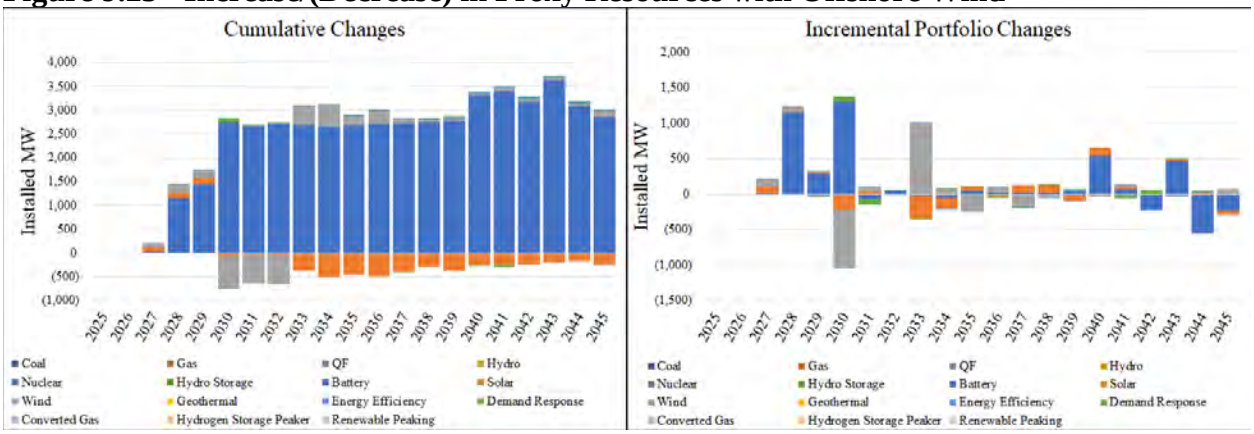
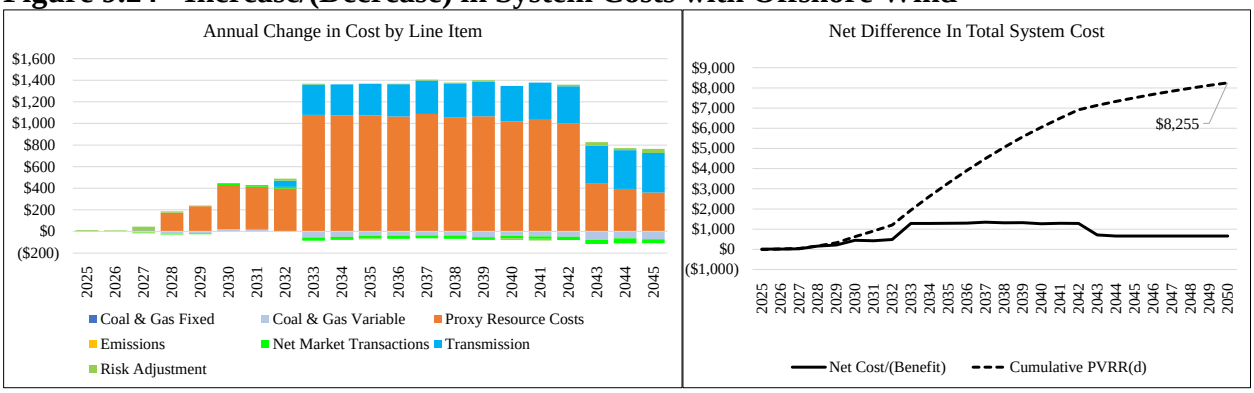


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $8.255 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.24 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

Figure 9.24 - Increase/(Decrease) in System Costs with Offshore Wind



No Forward Technology

This variant does not allow the Natrium™ demonstration nuclear project, hydrogen storage, 100-hour battery or small biodiesel peaking units to be selected as resource options. The analysis explores the potential costs and benefits of replacement resource options should these technologies not become commercially viable during the assumed time frame as modeled.

Figure 9.25 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case selects 120 MW of additional DSM, 187 MW of additional wind and 254 additional MW of solar. The model replaces the 3,073 MW of 100-hour storage with 1,826 MW of 4-hour storage and also does not retire CCS at Jim Bridger or the Naughton 1 gas conversion.

Figure 9.25 - Increase/(Decrease) in Proxy Resources with No Forward Technology

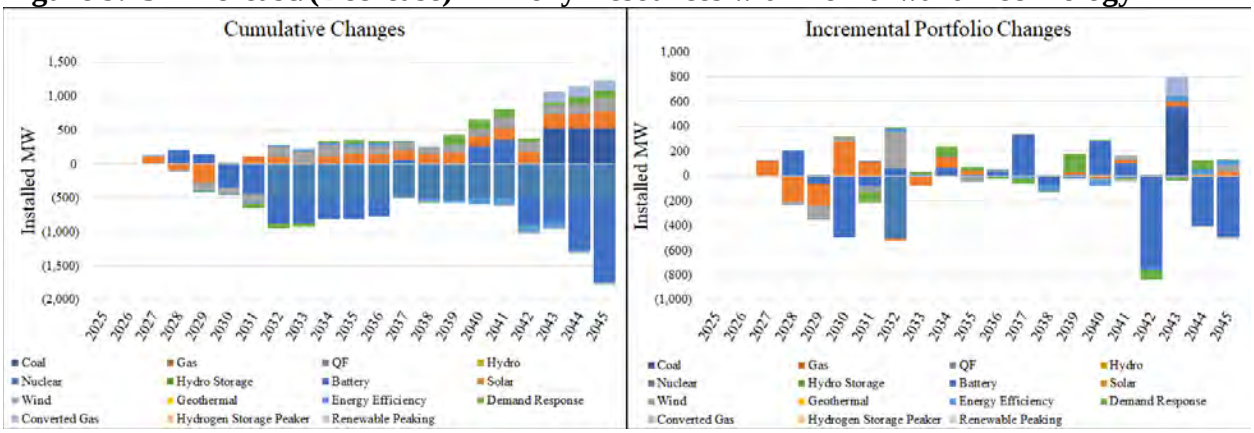
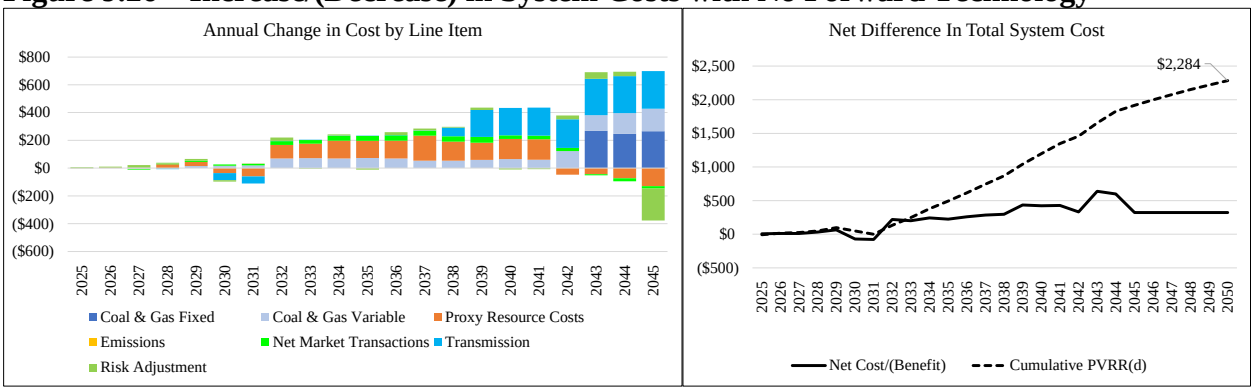


Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all forward technology is removed from the portfolio, the resulting portfolio has a $2.284 billion increase in costs compared to the preferred portfolio, somewhat higher than the impact of removing Natrium™ alone as shown in Figure 9.20.

As seen in Figure 9.26 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease

in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.26 – Increase/(Decrease) in System Costs with No Forward Technology



Force Geothermal

Since geothermal was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor geothermal resource.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when geothermal is forced into the portfolio by 2028. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The geothermal study does not retire the Naughton 1 gas conversion. Additionally, the firm capacity more than 700 MW of geothermal reduces the need for other renewable resources. Over 2,500 MW of wind and solar are removed, as well as over 2,200 MW of long duration storage. 719 MW of 4-hour storage is selected in the geothermal study.

Figure 9.27 - Increase/(Decrease) in Proxy Resources with Geothermal

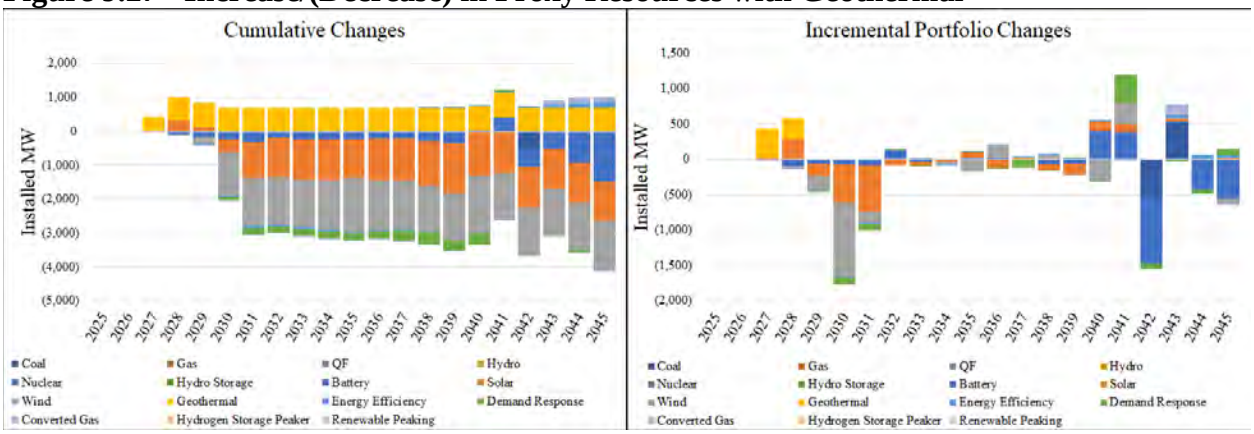
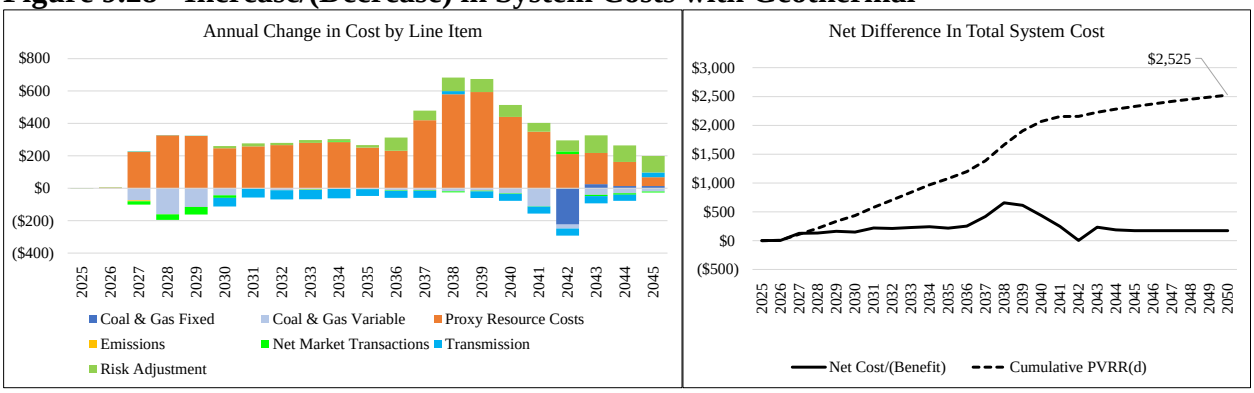


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the geothermal is forced into the portfolio, the resulting portfolio has a $2.525 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.28 below, these increases come primarily from increased costs of the geothermal compared to the lower costs of the renewable resources that were replaced by the geothermal.

Figure 9.28 - Increase/(Decrease) in System Costs with Geothermal



Force Hunter Retirement

Responsive to stakeholder request, PacifiCorp performed a variant analysis exploring what the impact of an early retirement of the Hunter plant would be on the portfolio. In this variant, all units at Hunter were required to retire by 2030. The analysis explores the potential costs and benefits of replacing the Hunter plant with resources selected in the UIWC jurisdictional portfolio when Hunter is not available. Additional consideration of Utah regulations would be necessary before the company would be able to move forward with implementing this variant.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when Hunter is forced to retire in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The Hunter study does not retire the Naughton 1 gas conversion. The loss of 1,100 MW of firm capacity in 2030 leads to the selection of over 1,100 MW of wind and solar, coupled with 866 MW of additional storage in 2030. By the end of the study horizon, the model selects 99 MW of new gas, an additional 355 MW of energy efficiency and demand response, and over 1,400 MW of new renewables. Total battery selection over the horizon stays the same but has a shift from 4-hour to 100-hour storage.

Figure 9.29 - Increase/(Decrease) in Proxy Resources with Hunter Retirement

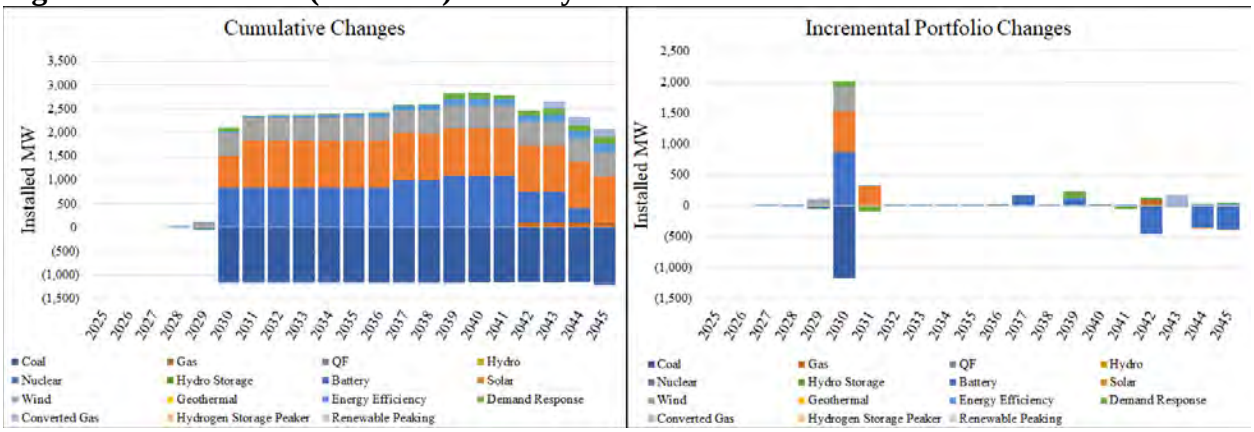
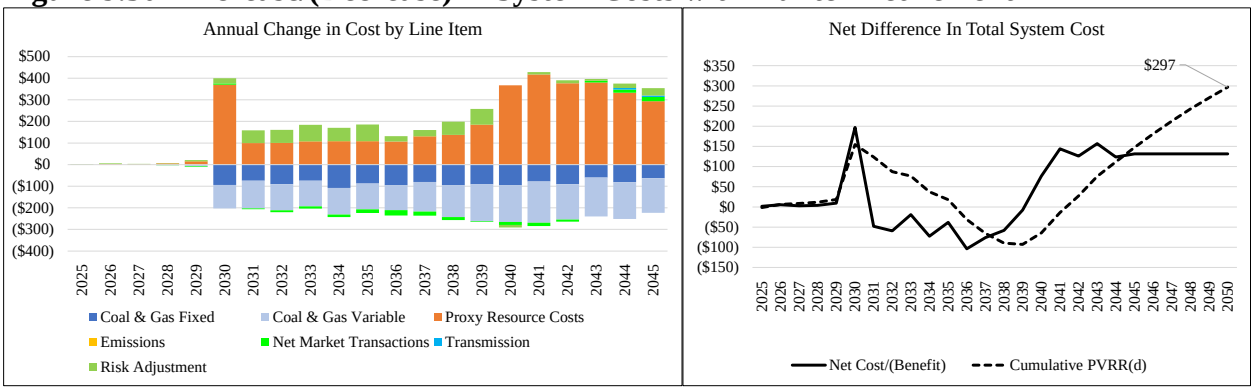


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Hunter is forced to retire in 2030, the resulting portfolio has a $297 million increase in costs compared to the preferred portfolio.

As seen in Figure 9.30 below, these increases come primarily from the additional proxy resource costs associated with replacing the Hunter plant in 2030.

Figure 9.30 - Increase/(Decrease) in System Costs with Hunter Retirement



MR Portfolio

The MR portfolio evaluates resource selections assuming EPA 111(d) rules remain in effect through the study horizon. This portfolio limits new gas capacity factors and requires either installation of CCS, gas conversion, or retirement of existing coal units by 2032. The purpose of this study is to evaluate a path PacifiCorp would pursue for long-term compliance with this rule.

Figure 9.31 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In an MR future, all plants that are eligible to convert from using coal to using a different fuel type do. Wyodak and Hunter 1 both retire in 2032. This reduction in coal capacity and the significantly lower capacity factor of converted units leads to an additional 1,299 MW of solar, 916 MW of wind and 369 MW of DSM. The portfolio also selects 451 MW of additional 100-hour battery, while removing 575 MW of 4-hour storage.

Figure 9.31 - Increase/(Decrease) in Proxy Resources with MR

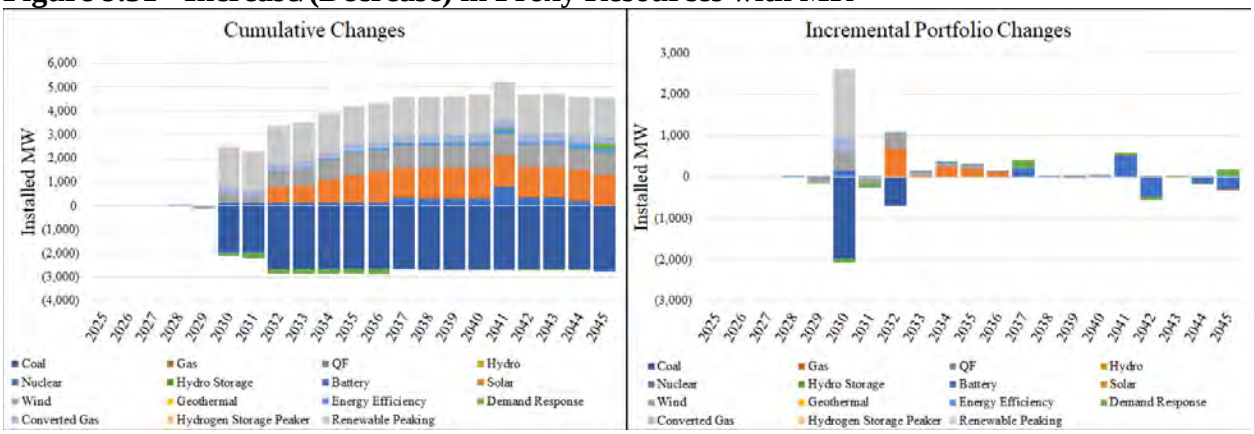
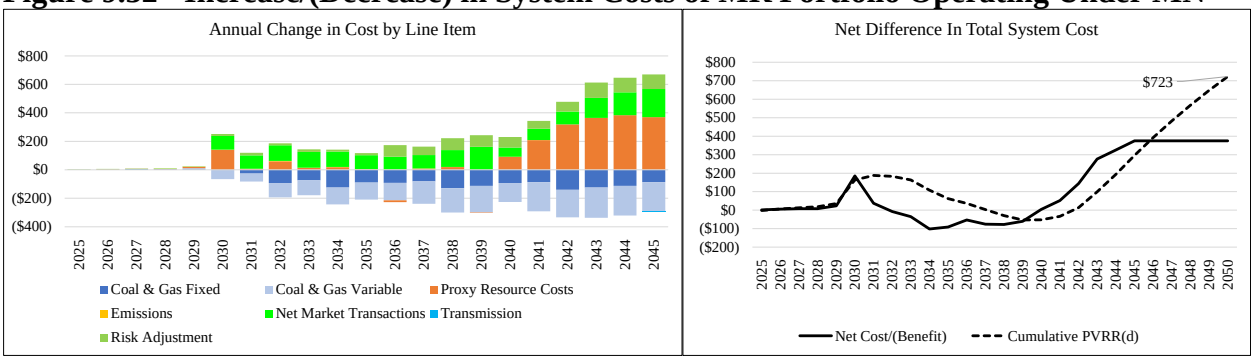


Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the MR portfolio is operating under the MN price policy, the resulting portfolio has a $723 million increase in costs compared to the preferred portfolio.

Figure 9.32 - Increase/(Decrease) in System Costs of MR Portfolio Operating Under MN



MR No CCS

The MR No CCS portfolio evaluates what changes would occur to the MR portfolio if CCS at Jim Bridger were to prove to not be a viable option for EPA 111(d) compliance. This portfolio limits new gas capacity factors and requires either gas conversion, or retirement of existing coal units by 2032, precluding CCS selections. The purpose of this study is to evaluate the path PacifiCorp would take to be compliant with this rule in the absence of CCS at Bridger.

Figure 9.33 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Jim Bridger 3 and 4 gas convert in lieu of installing CCS and does not retire Naughton 1 gas conversion. Hunter 1 retires in 2031 instead of 2032. Keeping the Jim Bridger and Naughton units leads to lower proxy resource selections across all generating types. The portfolio reduces wind by 55 MW, DSM by 378 MW and solar by 561 MW. Battery selections remain cumulatively the same with a shift from 24-hour battery to 4-hour battery.

Figure 9.33 - Increase/(Decrease) in Proxy Resources with MR No CCS vs. MR

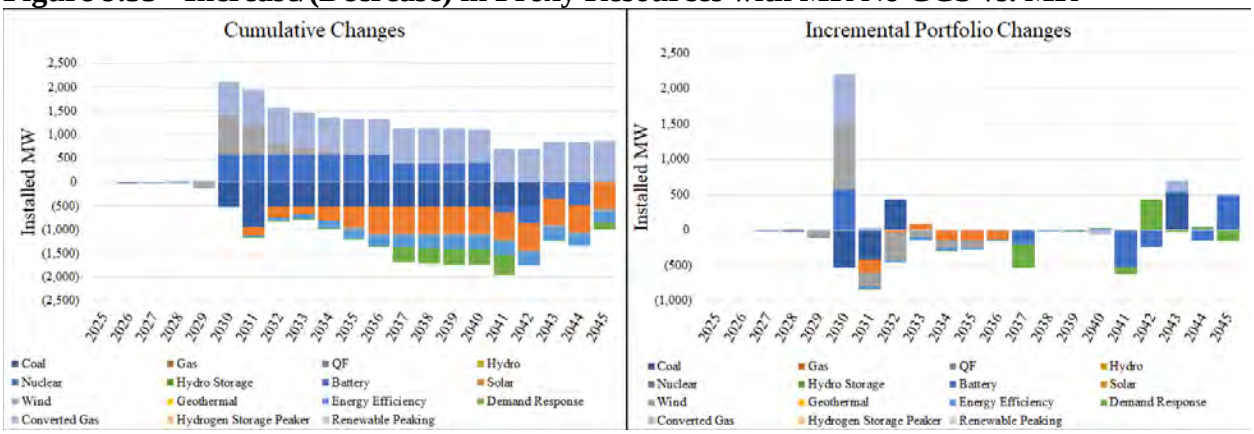
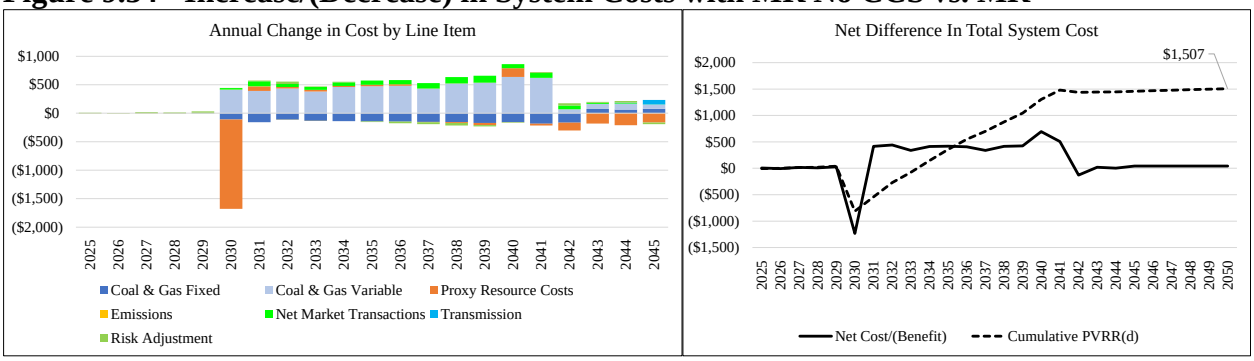


Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.507 billion increase in costs compared to the MR portfolio with CCS.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.34 - Increase/(Decrease) in System Costs with MR No CCS vs. MR



HH Portfolio

The HH portfolio evaluates what selections would be made under high future costs, including gas, market, and coal. This portfolio integrated Oregon selections under HH, UIWC selections under HH and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a high-cost future was most likely.

Figure 9.35 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a high price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The HH Portfolio selects Dave Johnston 4 and Hunter 2 to convert from coal to a different fuel in 2030. The HH also retires Hunter 2 in 2033. The model increases brownfield renewable selections by 2007 MW and selects 562 additional MW of 100-hour storage. There is a reduction in 4-hour

storage of 757 MW, however all selections of additional 4-hour storage occur in 2030 in the HH run. An additional 208 MW of DSM is also selected.

Figure 9.35 - Increase/(Decrease) in Proxy Resources with HH

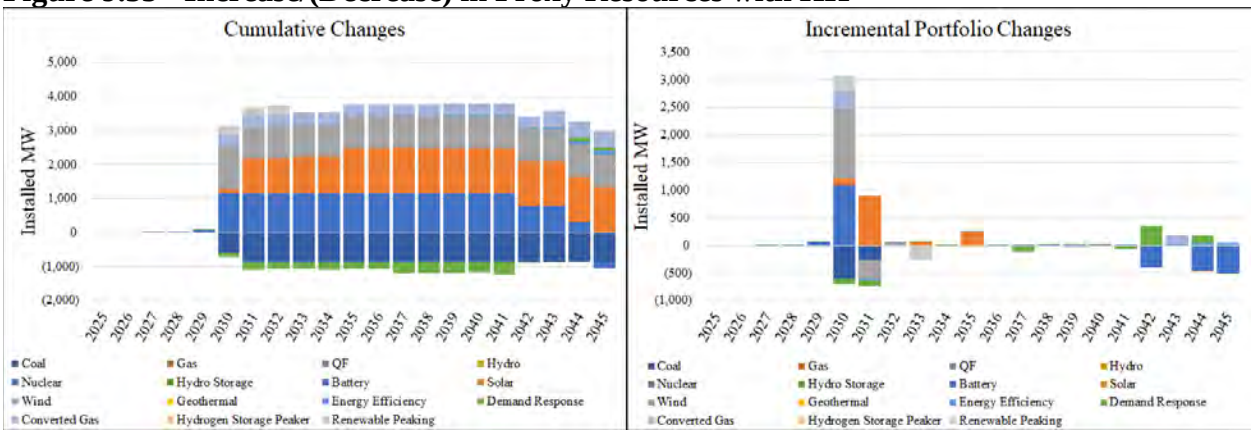
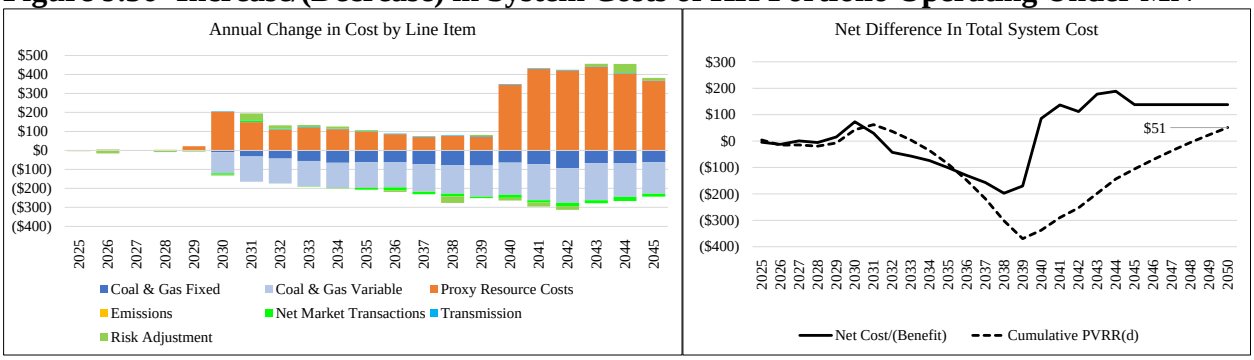


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the HH portfolio is operating under the MN price policy, the resulting portfolio has a $51 million increase in costs compared to the preferred portfolio.

Figure 9.36- Increase/(Decrease) in System Costs of HH Portfolio Operating Under MN



LN Portfolio

The LN portfolio evaluates what selections would be made under low future costs, including gas and market with no CO_2 tax adder. This portfolio integrated Oregon selections under LN, UIWC selections under LN and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a low-cost future was most likely.

Figure 9.37 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a low-price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The LN portfolio delays the retirement of the Jim Bridger CCS conversions one year and does not retire Naughton 1. The LN does select 496 MW of new gas peaking units in 2045 in place of the 41 MW of renewable peaking in the preferred portfolio. There is an increase of 91 MW of DSM, and a reduction of 508 MW of new renewable generation. The model selects and additional 389 MW of storage, swapping 100-hour for 4-hour battery.

Figure 9.37 - Increase/(Decrease) in Proxy Resources with LN

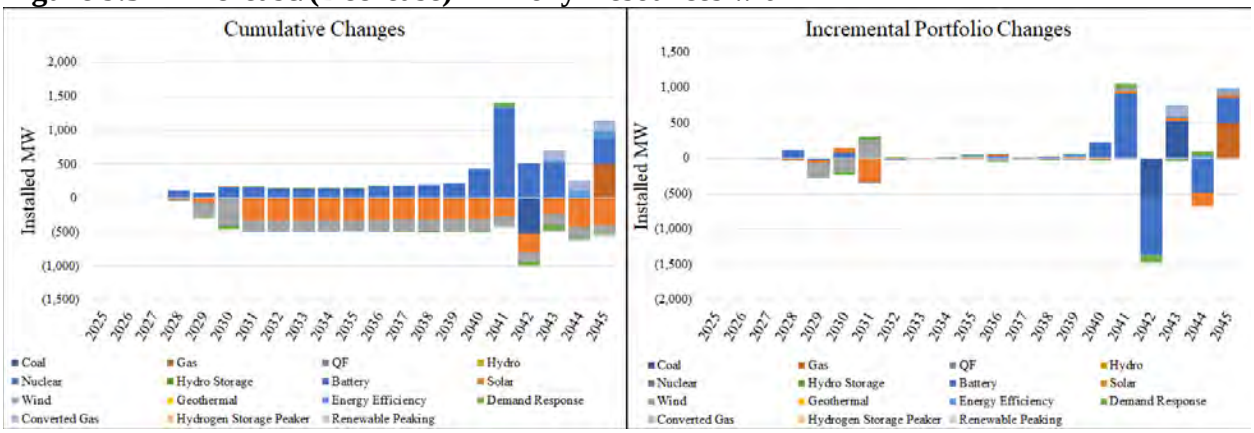
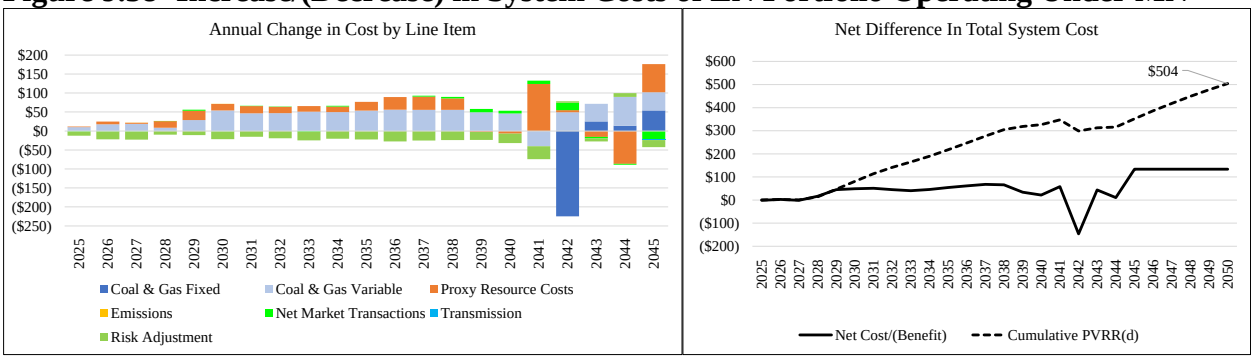


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the LN portfolio is operating under the MN price policy, the resulting portfolio has a $504 million increase in costs compared to the preferred portfolio.

Figure 9.38- Increase/(Decrease) in System Costs of LN Portfolio Operating Under MN



SCGHG Portfolio

The SCGHG portfolio evaluates what selections would be made under a Social Cost of Greenhouse Gas future. This portfolio integrated all jurisdiction's selections under SCGHG. The purpose of this study is to evaluate the selections PacifiCorp would make if an SCGHG future was most likely.

Figure 9.39 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and an SCGHG future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The SCGHG portfolio does not retire the Jim Bridger CCS conversions or Naughton 1 but does retire Wyodak in 2028 and the Dave Johnston 1 gas conversion in 2043. Additionally, the SCGHG case chooses gas conversion at Dave Johnston 4 and allows it to continue through the 21-year horizon and does not retire Naughton 1. The SCGHG case selects an additional 999 MW of utility scale wind, 1,269 MW of utility scale solar, 1,756 MW of 4-hour battery and 240 MW of DSM. The portfolio reduces small scale solar selections by 101 MW and 100-hour storage by 126 MW.

Figure 9.39 - Increase/(Decrease) in Proxy Resources with SCGHG

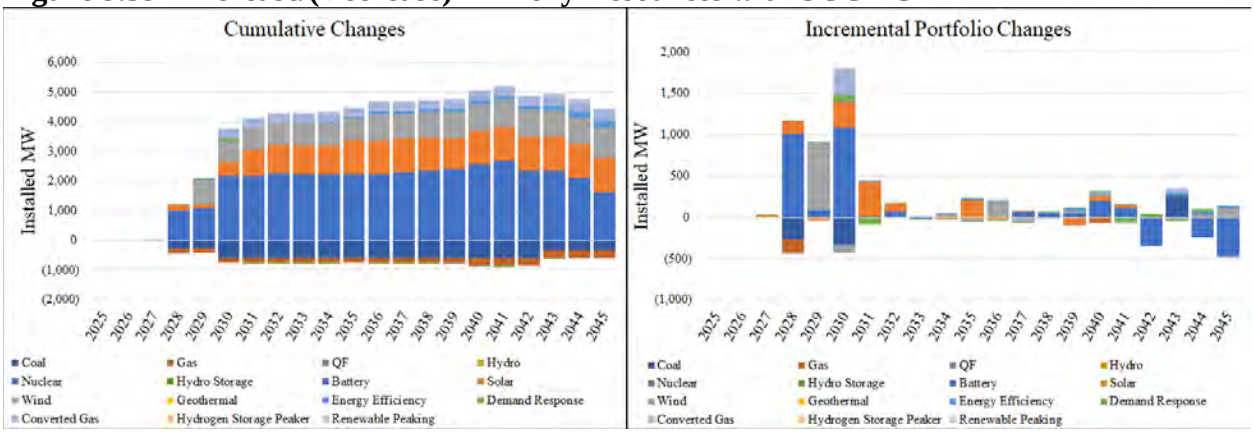
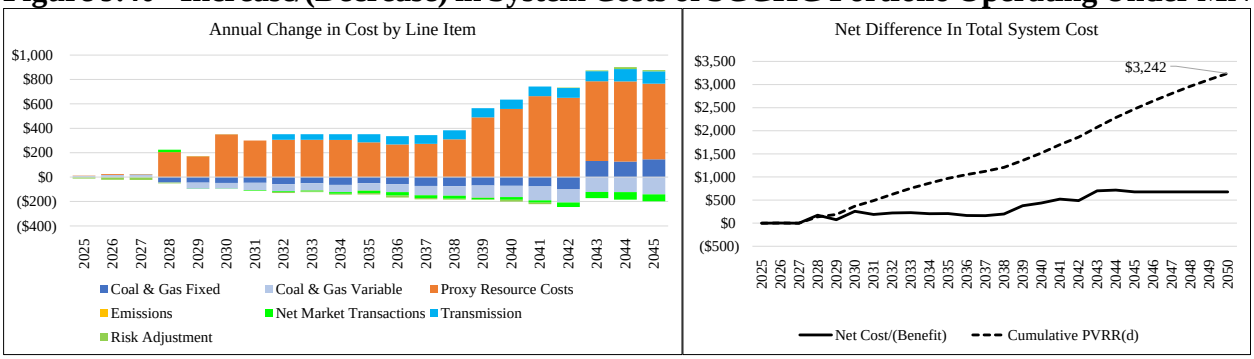


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the SCGHG portfolio is operating under the MN price policy, the resulting portfolio has a $3.242 billion increase in costs compared to the preferred portfolio.

Figure 9.40 - Increase/(Decrease) in System Costs of SCGHG Portfolio Operating Under MN



Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases were developed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. It is assumed that state level compliance would still be required to be met in these sensitivities; Oregon would still need to reduce emissions, and Washington would need to meet CETA targets. These sensitivity cases are also useful as "bookend" analysis to aid in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risks.

Table S.1 lists additional sensitivity studies to be performed for the 2025 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are evaluated in comparison to the preferred portfolio.

Table S.1– Summary of Additional Sensitivity Cases

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Distributed Generation	Assumes lower load due to high Distributed Generation adoption
Low Distributed Generation	Assumes higher load due to low Distributed Generation adoption
Large-metered Load Growth	Assumes significant large-metered customer load growth
Low Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan[8]	First 3 years are aligned with the current business plan

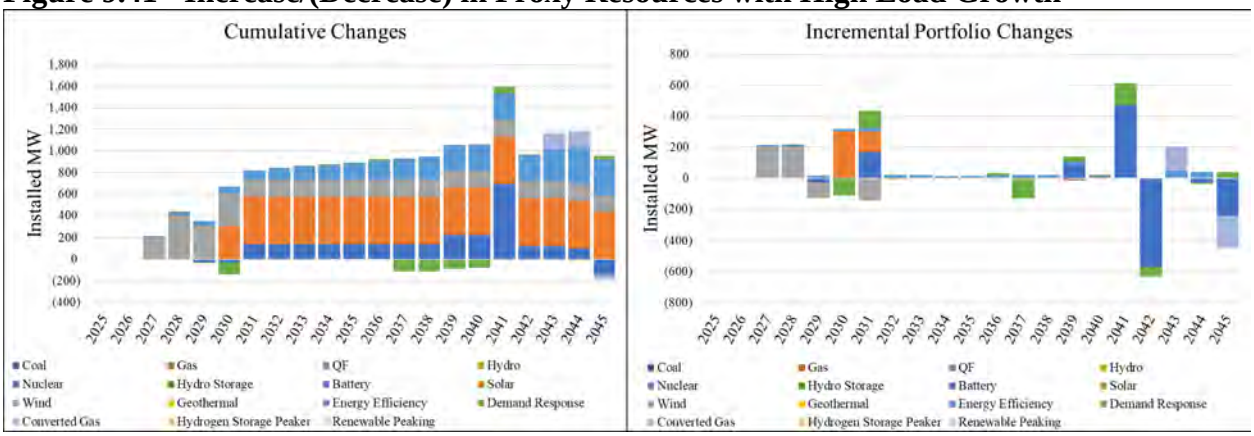
High Load Growth

The High Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if load grows faster than anticipated.

Figure 9.41 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high load growth portfolio does not retire Naughton 1 but does retire Naughton 2 in 2045. The higher load growth leads to an additional 319 MW of DSM, 160 MW of wind, and 435 MW of solar. There is a total reduction of 137 MW of storage, with 329 fewer MW of 4-hour storage offset by 100 MW of 8-hour and 92 MW of 100-hour storage.

[8] In the 2025 IRP, the business plan sensitivity is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed.

Figure 9.41 - Increase/(Decrease) in Proxy Resources with High Load Growth

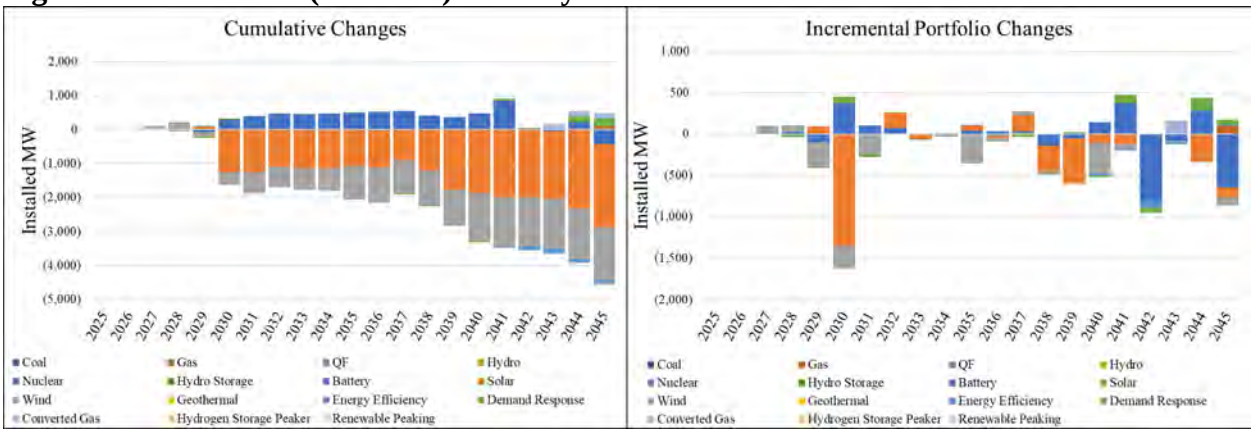


Low Load Growth

The Low Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify which resources might be economic if load grows more slowly than anticipated.

Figure 9.42 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low load growth portfolio does not retire Naughton 1. Due to the lower need, the portfolio selects 1,566 MW less wind, 2,440 MW less solar and 425 MW less storage, with a reduction in 100-hour storage offset by additional 4-hour storage. The portfolio does select an additional 125 MW of DSM.

Figure 9.42 - Increase/(Decrease) in Proxy Resources with Low Load Growth



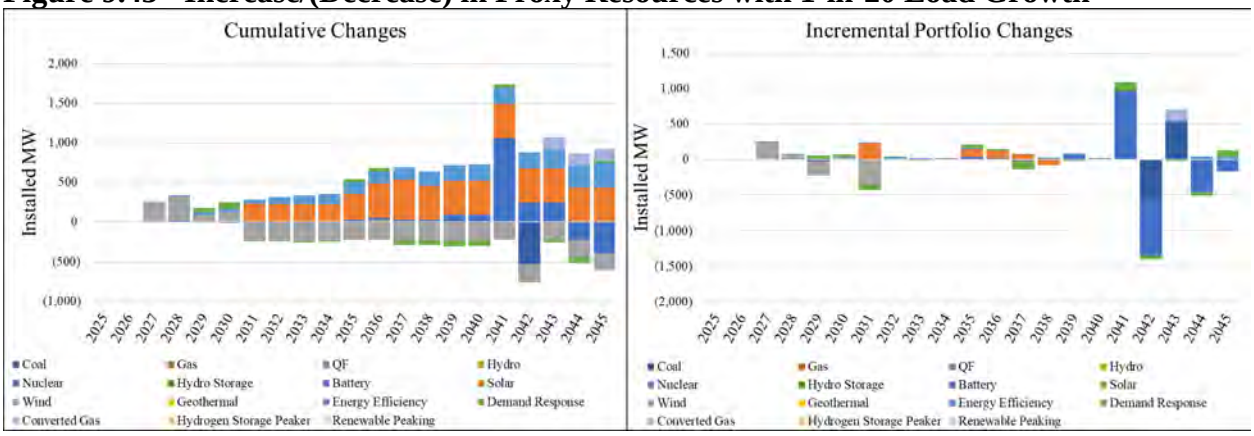
1-in-20 Peak Load Growth

The 1-in-20 Peak Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if peak load is higher than anticipated.

Figure 9.43 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and higher 1-20 peak loads. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The 1-20 peak

load portfolio retires the Jim Bridger CCS conversions 1 year later and does not retire Naughton 1. The higher peak loads lead to an additional 317 MW of DSM and 431 MW of additional solar. There is a reduction of 222 MW of wind and 385 MW of storage.

Figure 9.43 - Increase/(Decrease) in Proxy Resources with 1-in-20 Load Growth

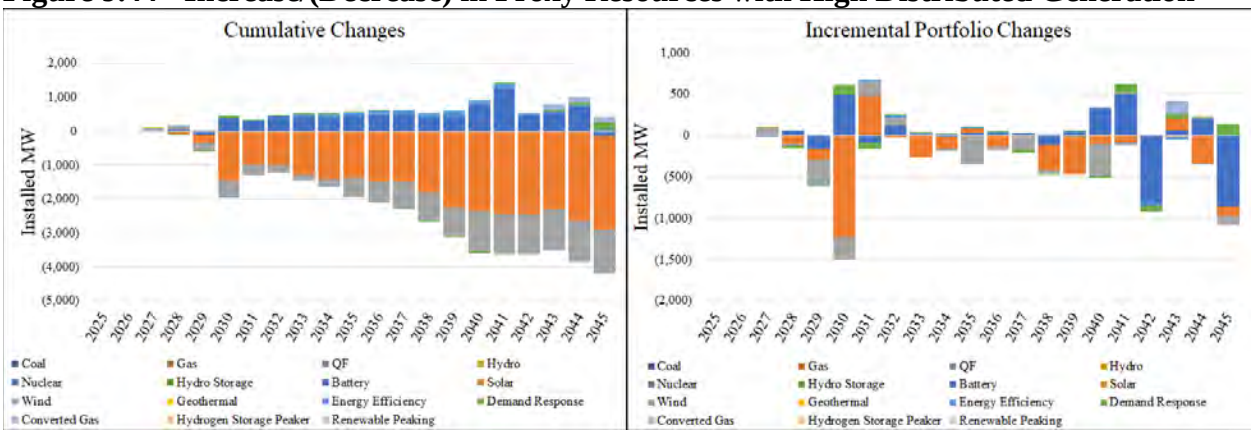


High Distributed Generation Growth

The High Distributed Generation Growth sensitivity evaluates what selections would be made if distributed generation growth were higher than projected (and load was lower as a result). The purpose of this study is to identify which resources would be economic if load is lower than anticipated.

Figure 9.44 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high distributed generation growth portfolio selects an additional 269 MW of DSM. The portfolio reduces renewable resources by 4,078 MW and storage resources by 135 MW over the course of the 21-year horizon.

Figure 9.44 - Increase/(Decrease) in Proxy Resources with High Distributed Generation

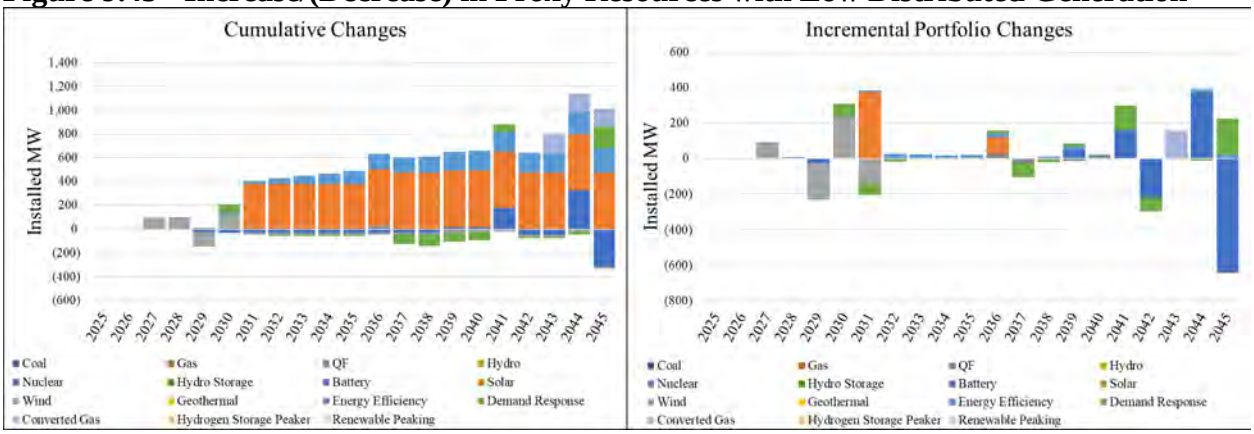


Low Distributed Generation Growth

The low distributed generation growth sensitivity evaluates what selections would be made if distributed generation growth were lower than projected. The purpose of this study is to identify potential additional resource needs if distributed generation growth is lower than anticipated.

Figure 9.45 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low distributed generation portfolio does not retire Naughton 1. The higher load need leads to 349 additional MW of DSM and 471 MW of solar. There is a reduction of 15 MW of wind and 351 MW of 4-hour storage partially offset by an additional 40 MW of 100-hour storage.

Figure 9.45 - Increase/(Decrease) in Proxy Resources with Low Distributed Generation



Large-Metered Load Growth

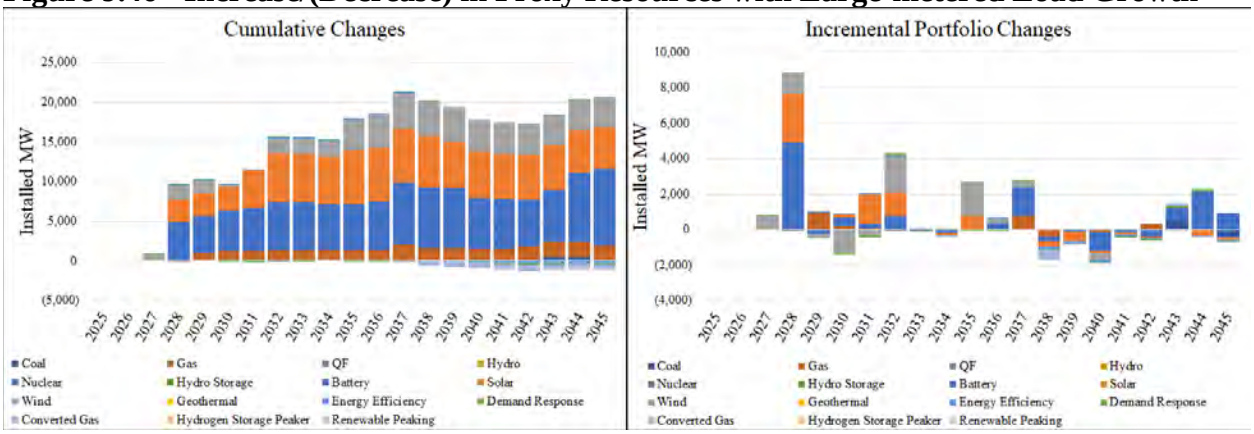
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the system had to serve all of these large-metered loads.

Figure 9.46 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This sensitivity selects 2,354 MW of gas peaking units, an additional 3,872 MW of utility scale wind, an additional 5,993 MW of utility scale solar and 9,650 MW of additional storage. In 2038, the large-metered load growth portfolio retires 804 MW of existing thermal units that were not retired in the preferred portfolio. In addition to significant resource additions, serving large-metered load requires significant transmission investments. Table 9.38 shows the transmission required in the large-metered load growth study.

Table 9.38 – Large-metered Load Transmission Selections

Line	Year Selected
INC B2H2 Hemingway>Longhorn - 2033	2033
INC BorahPop > Hemingway 2037 Segment E	2037
INC BorahPop > Wasatch Front 2035 D3.2	2044
INC BorahPop > Wasatch Front 2035 D3.3	2035
INC Bridger > BorahPop 2032	2032
INC Bridger > BorahPop 2035 D3.2	2044
INC Bridger > Wyoming East 2032 D2.2	2032
INC Goshen > NUT 2035 1b	2035
INC NUT > Goshen 2029	2029
INC NUT > Wasatch Front 2029	2029
INC NUT > Wasatch Front 2030 2C7 3C6	2030
INC Portland North Coast > Willamette Valley 2037	2037
INC Portland North Coast > Yakima 2029	2029
INC Utah South > Wasatch Front 2028B	2028
INC Utah South > Wasatch Front 2029	2029
INC Utah South > Wasatch Front 2035	2035
INC Willamette Valley > Central OR 2032	2032
INC Willamette Valley > Southern OR 2036	2036
INC Wyoming East > BorahPop 2035 D3.3	2035
INC Wyoming East > Bridger 2032	2032
INC Wyoming East > Clover 2035 GWS2	2044

Figure 9.46 - Increase/(Decrease) in Proxy Resources with Large-metered Load Growth



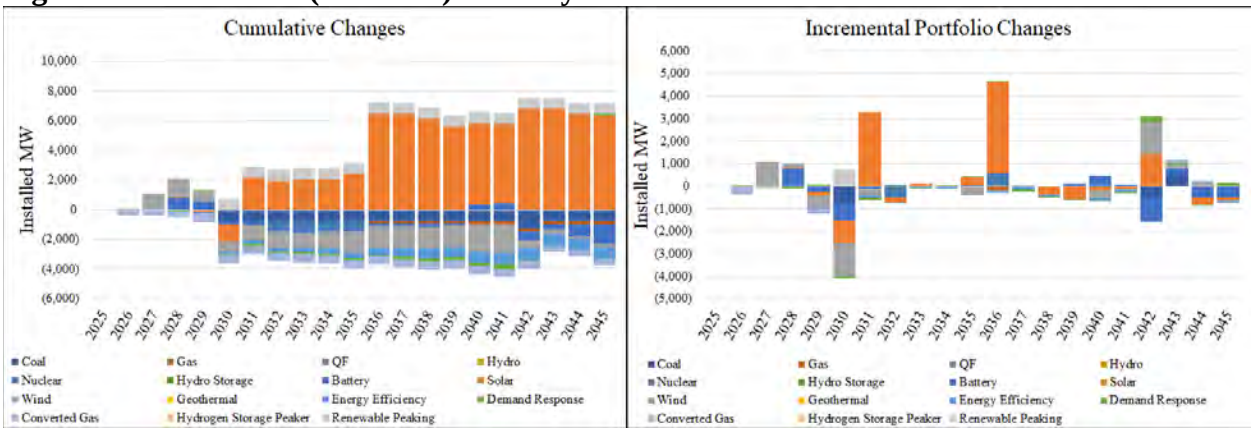
Low-Cost Renewables

The low-cost renewables sensitivity evaluates what selections would be made if renewable resources were lower cost than the current modeling expectations. The purpose of this study is to identify potential additional resources if the company were able to take advantage of all tax credits and assumes advantageous financing to complete projects.

Figure 9.47 shows the cumulative (at left) and incremental (at right) portfolio changes between the preferred portfolio and a portfolio acquiring resources on the advantageous basis described above. A positive value indicates an increase in resources and a negative value indicates a decrease when

a resource is reduced or eliminated. The low-cost renewables portfolio selects 199 MW less wind, but 7,187 MW of additional utility scale solar. The model also selects 950 more MW of short and medium duration storage, but 2,549 MW less 100-hour battery. Of note, coal plants which are able to endogenously retire throughout the horizon convert to alternate fuels but do not retire under this sensitivity.

Figure 9.47 - Increase/(Decrease) in Proxy Resources with Low-Cost Renewables

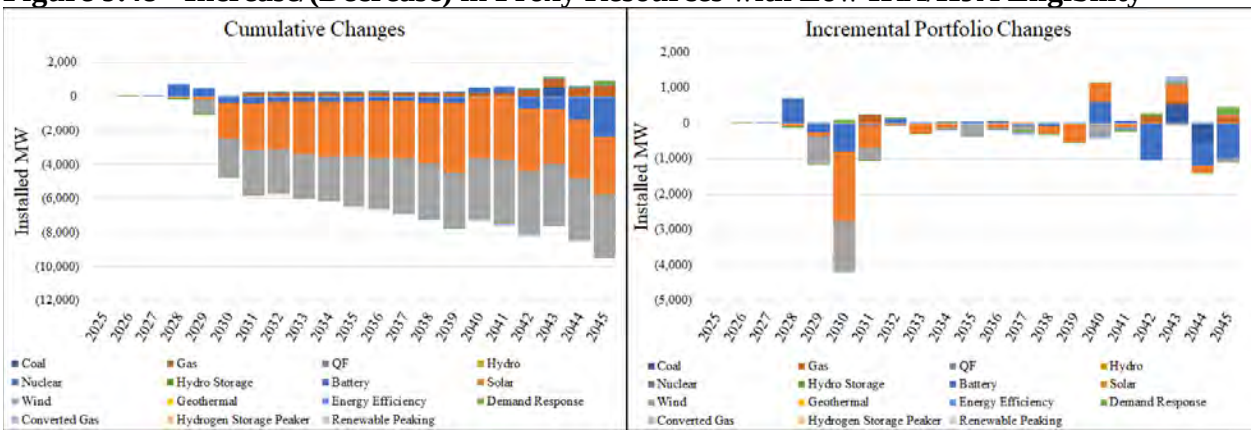


Low IRA/IIJA Eligibility

The low IRA/IIJA sensitivity evaluates what selections would be made if no resources were ever eligible for IRA or IIJA credits. The purpose of this study is to identify the impact if tax credits were not available to any new resources.

Figure 9.48 shows the cumulative (at left) and incremental (at right) portfolio changes between the low IRA/IIJA portfolio and the preferred portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low IRA/IIJA portfolio includes an additional 627 MW of gas peaking units, and 311 more MW of DSM. The low IRA/IIJA portfolio also includes a reduction of 3,782 MW of wind and 3,366 MW of solar, as well as 2,382 MW of storage. This sensitivity delays the Bridger CCS retirement by one year.

Figure 9.48 - Increase/(Decrease) in Proxy Resources with Low IRA/IIJA Eligibility

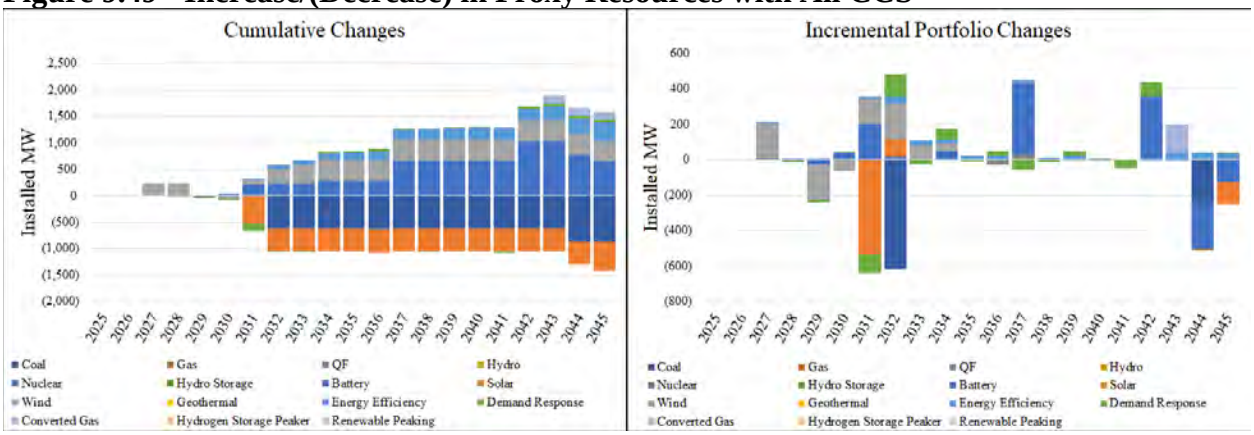


All CCS

The All CCS sensitivity evaluates what selections would change if it were feasible to convert all units to CCS that would be eligible for conversion. The purpose of this study is to identify the impact of installing up to 8 CCS units.

Figure 9.49 shows the cumulative (at left) and incremental (at right) portfolio changes between the base assumption and allowing all CCS. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In this sensitivity, all eligible units except Wyodak convert to CCS. The lower maximum output means that the sensitivity selects additional resources, including 391 MW of DSM, 397 MW of additional wind and 637 more MW of storage. The only significant reduction is 431 MW of solar.

Figure 9.49 - Increase/(Decrease) in Proxy Resources with All CCS

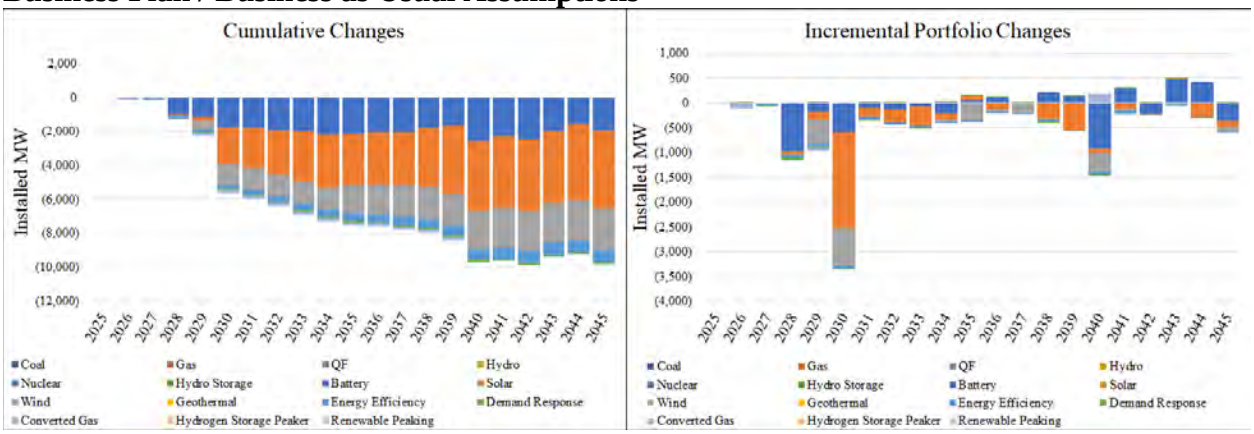


Business as Usual/Business Plan

The business as usual and business plan sensitivities were able to be covered by the same study. The business-as-usual study requires that coal retires no earlier than in the 2017 IRP unless otherwise mandated to do so by law. The business plan study requires that the first three years of the horizon align with the business plan, and then the model is able to endogenously choose any outcomes. These studies explicitly require operation and resource selection in the absence of any state or federal requirements, and the portfolio must be selected only on the basis of economics.

Figure 9.50 shows the cumulative (at left) and incremental (at right) portfolio changes between be preferred portfolio and a business-as-usual case. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This view selects significantly fewer resources. In total, there are 9,879 fewer MW chosen, and coal continues to remain on the system as in the preferred portfolio. This portfolio selects 2,488 MW less wind, 3,496 MW less utility scale solar, 1,147 MW less small scale solar and a total of 1,903 MW less storage (replacing 100-hour battery with 4-hour battery).

Figure 9.50 - Increase/(Decrease) in Proxy Resources with Business Plan / Business as Usual Assumptions



Washington Scenarios

As described in Chapter 8, in addition to the information provided throughout the 2025 IRP, Washington's CETA legislation mandates three key studies for analysis, in addition to the least-cost, least-risk portfolio developed to meet CETA clean energy standards:

- Alternative Lowest Reasonable Cost
- Maximum Customer Benefit
- Climate Change[9]

This analysis plus additional detail related to Washington requirements is found in Appendix O (Washington Clean Energy Action Plan)

[9] Note: The Washington requirement for a climate change sensitivity, which includes climate change impacts, is met by the incorporation of climate change considerations into all 2025 IRP studies.

CHAPTER 10 –ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2025 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio. The action plan has been shaped by changes in the planning environment, ongoing review and validation, and stakeholder feedback.
- PacifiCorp's 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[1]
- The 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

[1] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2025 IRP Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public input process. Table 10.1 details specific 2025 IRP action items by resource category.

Table 10.1 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. The Company is pursuing a front-end engineering design study as part of compliance with Wyoming's low carbon portfolio standard requirements as a site-specific analysis is needed to better understand the feasibility of the project.[2]
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

[2] See Appendix M, stakeholder feedback form #59 (Renewables Northwest).

1f	**Natrium™ Demonstration Project:** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	**Ozone Transport Rule Compliance:** • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** • The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** • EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** • PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process. • Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	**<u>Local Reinforcement Projects</u>** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**<u>Gateway West Support</u>** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

- PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources.

<table>
<tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2025</td><td>595</td><td>92</td></tr>
<tr><td>2026</td><td>573</td><td>89</td></tr>
<tr><td>2027</td><td>597</td><td>209</td></tr>
<tr><td>2028</td><td>648</td><td>220</td></tr>
</table>

- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2025</td><td>18</td></tr>
<tr><td>2026</td><td>2</td></tr>
<tr><td>2027</td><td>0</td></tr>
<tr><td>2028</td><td>63</td></tr>
</table>

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

Action Item	5. Market Purchases
5a	**Market Purchases:** • PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

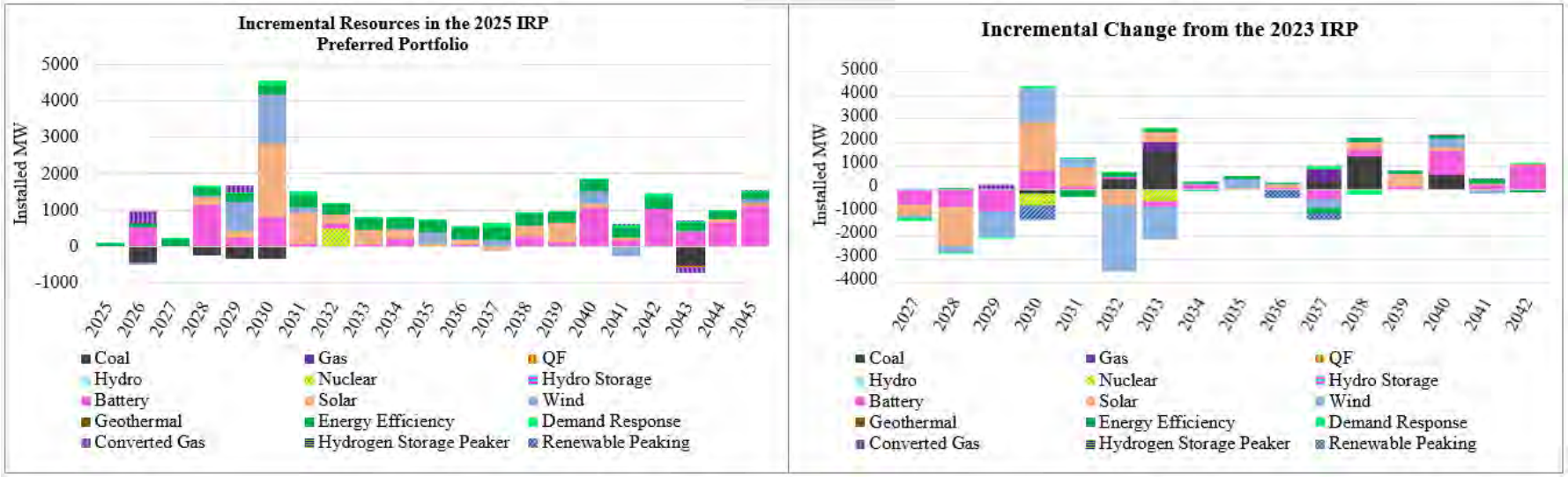
Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the 2025 IRP action plan. The status for all action items from the 2025 IRP is summarized in Table 10.2.

Figure 10.1 below presents two views of incremental resource changes in the 2025 IRP preferred portfolio. The figure at left reports the incremental resource additions from the 2025 IRP preferred portfolio, whereas the figure at right illustrates how these selections differ from the incremental changes in the 2023 IRP preferred portfolio.[6, 7]

Figure 10.1 – Incremental Resources in the 2025 IRP Preferred Portfolio



[6] The timeframe presented in these charts shows only years where expansion resources were selected.

[7] These figures support Wyoming Public Service Commission Guideline E, "Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP". A load comparison is provided in Appendix A (Load Forecast), Figure A.1.

Table 10.2 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	**Naughton Units 1 and 2 Gas Conversion:** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.	• PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. • Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.
1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• PacifiCorp received an approval order on December 7, 2023, from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. • PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023. • Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024.

1e	**<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>** • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>**	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the

	• PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	Natrium™ project and expects to finalize these arrangements by the end of 2025.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

Action Item	2. New Resource Actions	Status
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2030. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation	The 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities. • EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource

	certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.	procurement needs coming out of the 2022 All-Source Request for Proposals. • PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals.
Action Item	3. **Transmission Action Items**	**Status**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	The Energy Gateway South transmission project is in-service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service in Q4 2024 •	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date.

	• Continue negotiations for plan of service post B2H for parties to the permitting agreement.	
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. **Demand-Side Management (DSM) Actions**	**Status**
4a	**<u>Energy Efficiency Targets:</u>** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	For energy efficiency, PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and achieved 96.2% of the 2024 target, excluding HERs. Since the 2023 IRP, PacifiCorp launched demand response programs and expanded offerings within its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023-24 incremental capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs.

Year	1st year Energy Efficiency (GWh)	Annual Capacity (MW)
2023	543	123
2024	559	220
2025	568	259
2026	628	197

<table>
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- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2023 IRP.

Year	Annual Incremental Capacity (MW)
2023	72
2024	39
2025	152
2026	109

</td><td></td></tr>
<tr><th>Action Item</th><th>5. Market Purchases</th><th>Status</th></tr>
<tr><td>5a</td><td>

<u>Market Purchases:</u>

- Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
- Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
- Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

</td><td>

Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.

</td></tr>
</table>

Action Item	6. **Renewable Energy Credit (REC) Actions**	Status

6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, state and federal environmental policy also influences resource selections in the 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event in Table 10.3, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[8] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[8] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Load Growth"	• A new load forecast incorporating higher than anticipated load growth increases load relative to the base forecast. • Through 2030, resource additions would be similar to the preferred portfolio with a small amount of additional wind and solar added to the portfolio to meet higher than anticipated loads. • From 2031 through 2034, small amounts of solar, 4-hour battery and DSM resources are added to meet higher than anticipated loads.	• In the long-term acquisition window, slightly fewer incremental resources are required due to additional incremental resources shifting into the near-term window to meet higher than anticipated loads compared to the preferred portfolio.
Lower sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Load Growth".	• A new load forecast incorporating lower than anticipated load growth decreases load relative to the base forecast. • In the near-term acquisition window, far fewer incremental resources are required to meet load compared to the preferred portfolio. • Through 2034, significant amounts of wind and solar along with moderate amounts of small-scale solar and 100-hour battery fall out of the portfolio while additional 4-hour battery is added compared to the preferred portfolio. • Fewer incremental transmission options are required to meet fewer incremental resources while the timing of some incremental transmission options is shifted outward compared to the preferred portfolio.	• In the long-term acquisition window, even fewer incremental resources are required due to lower loads compared to the preferred portfolio. • From 2035-2045, significant amounts of wind, solar, small-scale solar and 100-hour battery fall out of the portfolio compared to the preferred portfolio and would not need to be procured.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Private Generation"	• A new load forecast incorporating higher than anticipated private generation adoption decreases load relative to the base forecast. • In response to high private generation adoption, far fewer incremental resource selections are required in the action plan window compared to the preferred portfolio. • Through 2030, significant amounts of wind, solar, small-scale solar and moderate amounts of 100-hour battery fall out of the preferred portfolio while a significant amount of 4-hour battery is selected. • Through the remainder of the near-term acquisition window, resource additions are similar to the preferred portfolio. • Transmission selections are similar to the preferred portfolio with the location and timing of incremental transmission changing depending on incremental resource selections.	• From 2035-2045, higher private generation results in 2,696 MW of resource additions falling out of the portfolio compared to the preferred portfolio. • On average, far less wind, solar and 100-hour air battery are selected while additional 4-hour battery is selected in similar amounts compared to the preferred portfolio.
Lower sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Private Generation"	• A new load forecast incorporating lower than anticipated private generation adoption increases load relative to the base forecast. • To counteract low private generation adoption, minimal additional resources are required relative to the preferred portfolio through 2029. • From 2030 through 2034, moderate amounts of wind and solar are added to what is selected in the preferred portfolio.	• In the long-term resource acquisition window, resource selections are similar to the preferred portfolio as lower private generation levels cause incremental resource builds in the near-term acquisition window. • 156 MW of Naughton gas conversion would remain online compared to retiring in 2043 in the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher than expected large-metered load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Large Metered Load Growth"	• A new load forecast incorporating higher than anticipated large-metered load growth beginning in 2027 increases load relative to the base forecast. • High large-metered load growth results in significant resource additions compared to the preferred portfolio, including significant resource additions in the near-term acquisition window. • By 2028, nearly 10,000 MW of additional resources are selected compared to the preferred portfolio including significant amounts of wind, solar, small-scale solar, 4-hour battery and a moderate amount of 8-hour battery. • By the end of 2034, a significant amount of new gas is added to the portfolio, along with nearly 4,500 MW of additional incremental renewable resources. • Significant transmission investment would be required to serve new resource additions.	• From 2035-2045, significant additional resources are required compared to the preferred portfolio including more than 1,000 MW of new gas and 5,000 MW of new renewables.
Changes to IRA/IIJA result in lower-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low-Cost Renewables"	• High adoption of the IRA/IIJA resulting in lower-than-expected new renewable resource costs would result in significantly more incremental renewable resource additions than selected in the preferred portfolio. • Significant incremental wind, solar and 4-hour battery additions would result in lower thermal output and less 100-hour battery storage additions. • Significant transmission investment would be required to serve new resource additions.	• From 2035-20445, significant additional incremental renewable resources would be built along with more incremental transmission. • Thermal resources would run at lower capacity factors with some thermal capacity retiring in the long-term acquisition window.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Changes to IRA/IIJA result in higher-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low PTC/ITC eligibility"	• In the absence of tax credits from the IRA/IIJA resulting in higher-than-expected renewable resource costs, significant amounts of incremental renewable resource additions would fall out of the portfolio compared to the preferred portfolio. • By 2030, significant wind, solar, small-scale solar and 100-hour iron battery would fall out from the portfolio. • By the end of 2034, significant additional incremental renewable capacity falls out of the portfolio while some new gas is selected. • If renewable resources become more expensive in the absence of IRA/IIJA benefits, very little capacity would be needed to replace renewable capacity as thermal resources would run at higher capacity factors to meet load obligations.	• In the long-term acquisition window, additional new gas is built along with a small amount of gas peaking to replace lost renewables from the preferred portfolio. • Existing thermal resources would remain online past retirement dates selected in the preferred portfolio to continue providing energy and capacity.
No legislation under consideration is adopted and state environmental requirements impacting thermal plants are unwound	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Business as Usual" (also called the Wyoming Reference Case).	• With only load requirements to meet (no other federal or state requirements), far fewer resources are selected compared to the preferred portfolio as existing thermal resources are able to run at higher capacity factors and less capacity and energy is needed on the system. • In the near-term acquisition window, significantly fewer MW are selected compared to the preferred portfolio, including less wind, solar, small-scale solar, 4-hour battery and 100-hour battery. • With far fewer new resources compared to the preferred portfolio, "business as usual" would require significantly fewer incremental transmission interconnect MW in the near-term acquisition window.	• From 2035-2045, significantly fewer MW are selected compared to the preferred portfolio including less wind, solar, small-scale solar and 100-hour battery. • Additional 4-hour battery is added from 2035 through 2045 compared to the preferred portfolio, revealing that in a "business as usual" scenario, 4-hour batteries remain valuable new resource options in the absence of other new renewables.
Legislation forces all coal to retire or gas convert by 2032	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Coal 2032"	• With all coal units forced to retire or gas convert by 1/1/2032, 2,679 MW of nameplate capacity would convert to natural gas in 2030. Jim Bridger units 3 and 4 were assumed to not be allowed to install CCS, and in this case, units 3 and 4 would convert to natural gas in 2030 instead of retiring. • By 1/1/2032, 686 MW of coal retires. • Significant additional incremental renewable resources and are added to the portfolio including wind, solar, 4-hour battery and 100-hour battery within the near-term acquisition window.	• In the long-term acquisition window resource additions are similar to the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
No Natrium™ Advanced Nuclear Demonstration Project in 2032, and no other nuclear projects	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Nuclear"	• Without the 500 MW Natrium™ demonstration project in 2032, moderate amounts of renewable resources are added to the portfolio by 2032. • In 2033 and 2034, additional incremental renewable resources are added to the portfolio.	• While the type, timing and location of resources change, the amount of incremental resource additions in the long-term acquisition window without Natrium™ is similar to the preferred portfolio. • Batteries and other renewables would fall out of the portfolio in 2041 through 2045 as incremental amounts of these resources are built earlier to replace Natrium™. • 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.
Technologies such as nuclear, hydrogen storage, 100-hour battery storage and biodiesel peaking do not become commercially viable	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Forward Technology"	• Without nuclear, hydrogen storage, 100-hour battery or biodiesel peaking, nuclear and 100-hour battery selected in the preferred portfolio are replaced by a significant amount of 4-hour battery and moderate amounts of wind and solar. • In the near-term acquisition window, the capacity of future technology that falls out of the portfolio is greater than the capacity of incremental resources needed to replace the lost capacity.	• While the type, timing and location of resources change as is required by the absence of nuclear and 100-hour battery, the amount of incremental resource additions in the long-term acquisition window is similar to the preferred portfolio. • 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Legislation requires the Hunter plant to retire no later than 1/1/2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "Hunter Retire"	• By 1/1/2030, 1,158 MW of nameplate coal capacity retires at Hunter. • To replace the lost Hunter capacity, by 2030, moderate amounts of wind and solar would be added to the portfolio, including solar at Hunter. Additionally, a significant amount of 4-hour battery and moderate amount of 100-hour battery would be added to the portfolio.	• From 2035-2045, moderate amounts of incremental resource additions would be added to the portfolio, including new gas. • In 2043, 156 MW of nameplate capacity at Naughton 1 running as gas remains online through the end of the planning horizon instead of retiring as it does in the preferred portfolio.
No CCS available at Jim Bridger in 2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No CCS"	• Incremental resource selections with Jim Bridger CCS unavailable are similar to the preferred portfolio with slight changes in the location and timing of incremental resources. • By 1/1/2030, 174 MW of nameplate capacity remains available at Jim Bridger without the installation of CCS. • Moderate amounts of wind and solar, some of which is sited at Jim Bridger, falls out of the portfolio, along with some 4-hour battery.	• From 2039-2045 fewer 4-hour battery resources are selected. • In 2043, 247 MW of Naughton gas conversion retires without CCS in the portfolio.

Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable resilient grid operations and statutory compliance. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, there may be insufficient potential resource development deliverable to the jurisdiction with resource need, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

As the range of events is unknowable, these potential impacts are represented by broad sensitivity studies such as those which raise or lower resource availability (such as natrium, carbon capture, coal, offshore wind) and competition for resources (load, distributed generation, IRA adoption, DSM). In addition, IRP resource potential availability is informed by an assessment of publicly available data derived from the cluster study process.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.

- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Consequently, please refer to the 2025 IRP preferred portfolio as described in Chapter 9.

Resource Procurement Strategy

To acquire resources outlined in the 2025 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates if jurisdictional need is warranted. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs to include but not limited to load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2025 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[9]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings and has continued Wattsmart outreach and communications. Educating customers regarding

[9] Class 1 DSM is most commonly referred to as “demand response” in the 2023 IRP; Class 2 DSM is most commonly referred to as “energy efficiency”. Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in June 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by December 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is discussed in Appendix P (Oregon Clean Energy Update) and will be further addressed in PacifiCorp's 2025 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. The level of debt imputation associated with long-term contracts will have an impact on PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes

recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not fully reflected in rates and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission

infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

CHAPTER 11 –UTAH EXECUTIVE SUMMARY

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to these three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

Maintaining customer focus

The Utah Integrated Resource Plan (IRP) is a roadmap for continual progress to safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.
- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in the fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

- The following resources are added in the Utah 2025 IRP:
  - 6,379 megawatts of new wind resources
  - 7,668 megawatts of storage resources, including four-hour, eight-hour, and 100-hour durations
  - 5,492 megawatts of new solar resources
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,149 megawatts of capacity saved through energy efficiency programs
- 1,052 megawatts of capacity saved through direct load control programs

Transmission

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington
- 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon
- New transmission, including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon
- A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2)
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

Changes to our Portfolio

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Continue to evaluate coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are allocated to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[2] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements are represented:

- Utah, Idaho, Wyoming, and California (UIWC)[3]
  - Cost-effective resources
  - Includes WRAP compliance constraints for UIWC load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Includes WRAP compliance constraints for Oregon load
  - Includes small-scale renewable capacity requirement
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and only allocated to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a

[2] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[3] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of the draft necessitated coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off, PacifiCorp hosted stakeholders in seven online public input meetings. An additional two meetings were held with stakeholders after the distribution of the draft. Analysis conducted aligned to those meetings, after the Draft 2025 IRP filing, informs Chapters 1 through 10 and Appendices A through Z, which comprise the majority of this document.

Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 11.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action

plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

Figure 11.1 – Key Elements of PacifiCorp's 2025 IRP Approach

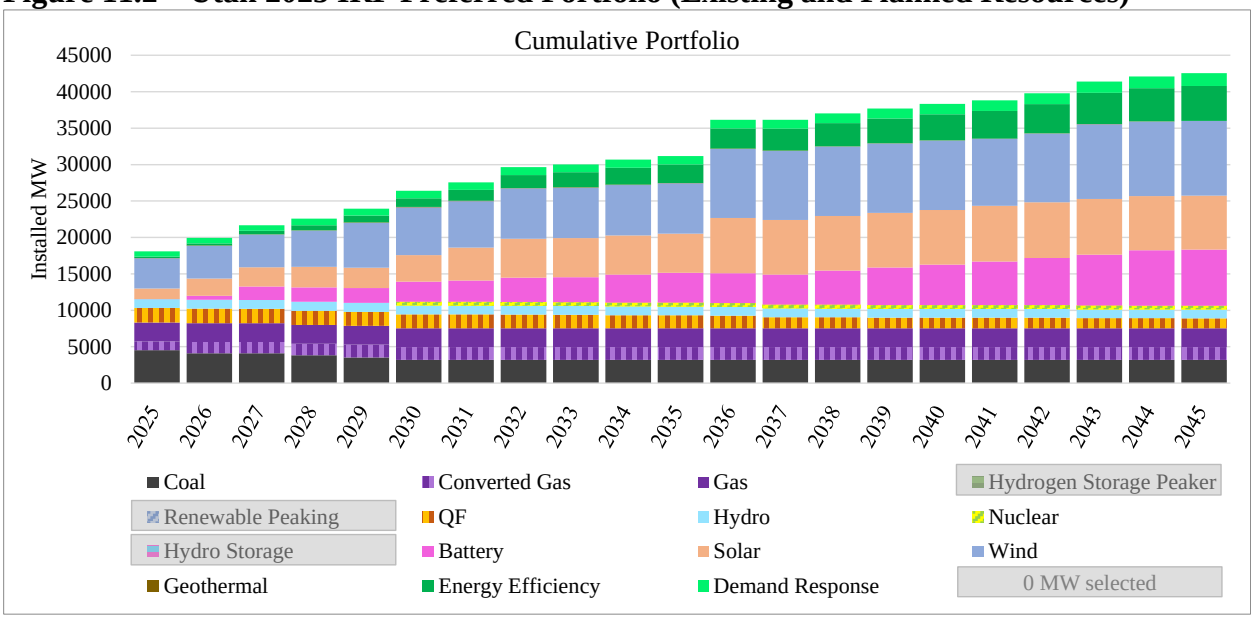
Preferred Portfolio Highlights

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in Chapters 2 through 8, and the Appendices that follow. Figure 11.2 shows that PacifiCorp's Utah 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and non-emitting peaking resources facilitated by incremental transmission investments.

The Utah 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium^{TM} demonstration project, anticipated to achieve online status by the end of 2030. By the end of 2032, the preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 20-year planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 11.2 – Utah 2025 IRP Preferred Portfolio (Existing and Planned Resources)*



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah, known as Energy Gateway South 2, planned to come online in 2036. Smaller upgrades increase transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 11.1 summarizes the incremental transmission projects in the Utah 2025 IRP preferred portfolio. Note, at this time, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 11.1 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

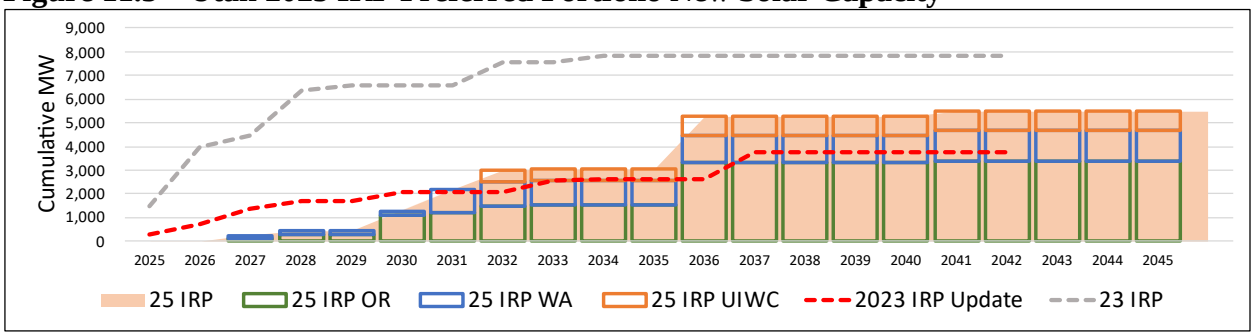
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

In Chapter 12 – Utah Model Results, a sensitivity analysis evaluates the impacts of significant new loads coming online in the 2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

The Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and 5,492 MW by the end of 2045, as shown in Figure 11.3.

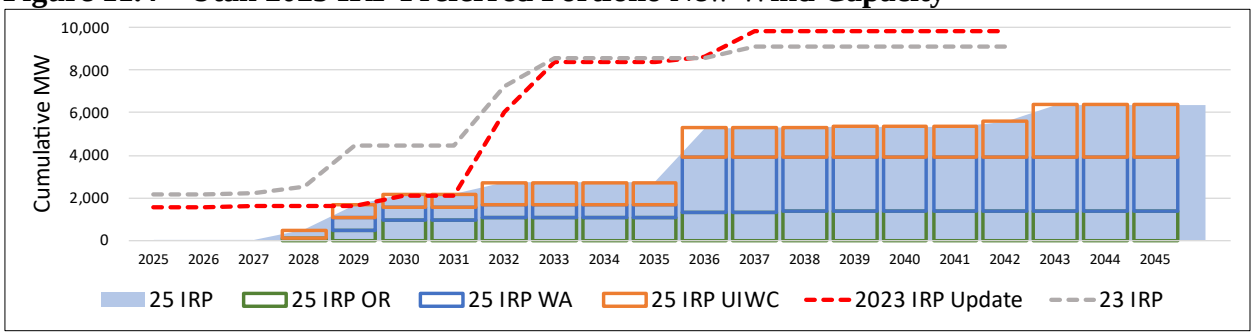
Figure 11.3 – Utah 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 11.4, PacifiCorp's 2025 IRP Utah preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379MW of cumulative new wind by the end of 2045.

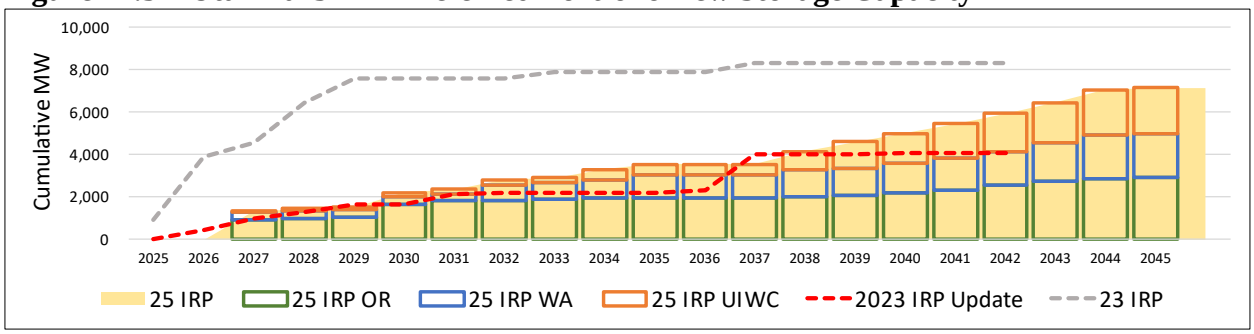
Figure 11.4 – Utah 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 11.5. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4-hour and 8-hour lithium-ion storage. By year-end 2030, the Utah 2025 IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

Figure 11.5 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1,2]

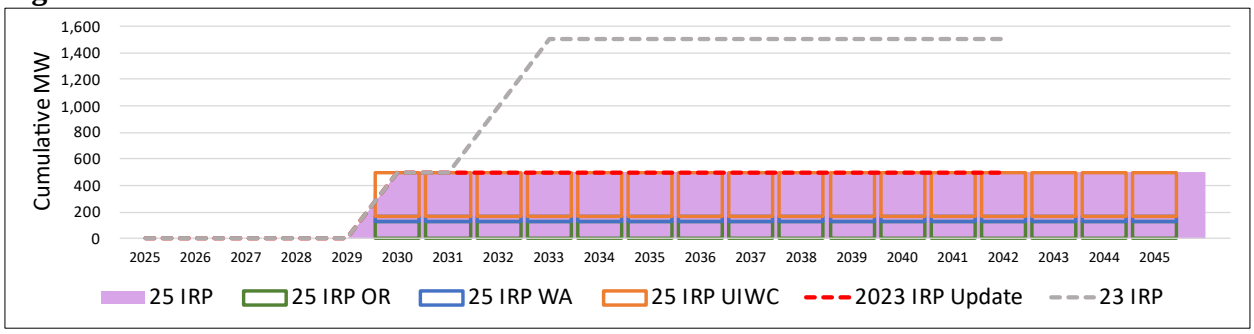


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The Utah 2025 IRP preferred portfolio includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 11.6, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the end of 2030.

Figure 11.6 – Utah 2025 IRP Preferred Portfolio New Nuclear



Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers, who are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits.

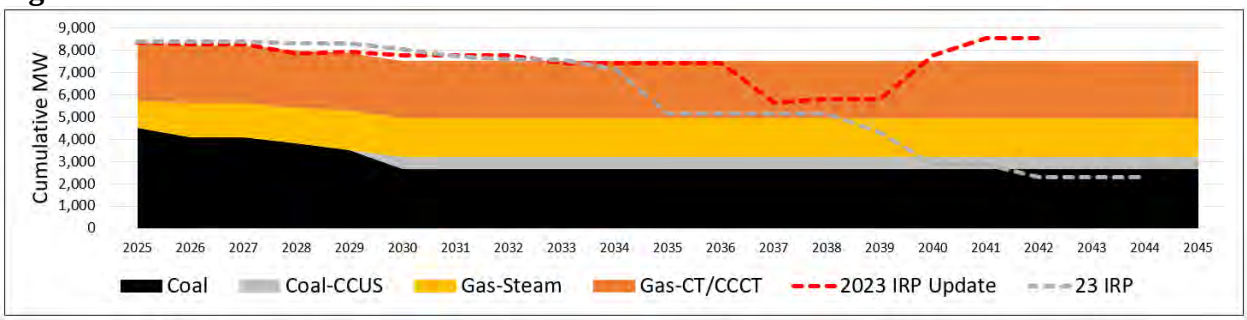
- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
    - 678 megawatts of energy efficiency between 2025 and 2028
    - 213 megawatts of demand response between 2025 and 2028

Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled

the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 11.7, the Utah 2025 IRP preferred portfolio converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386 MW of minority-owned coal, and also retires 220 MW of majority-owned coal at Dave Johnston by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 11.7 – Utah 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 11.2. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

Table 11.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal			
Unit	Utah 2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	Not retired (Alt. fuel conv. 2030)	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	7 (Gas conversion 2024)
Jim Bridger 3 & 4	Not retired (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 11.3 details specific 2025 IRP action items by resource category.

Table 11.3 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the Utah 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

Action Item	1. Existing Actions (continued)
1f	**Natrium™ Demonstration Project:** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	**Ozone Transport Rule Compliance:** • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** • The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** • EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** • PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer needs. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[4] • In light of the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate local reinforcement projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

[4] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

Action Item	4. Demand-Side Management (DSM) Actions
4a	**Energy Efficiency Targets:** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP. • PacifiCorp will pursue cost-effective energy efficiency resources. • PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.
Action Item	**5. Market Purchases**
5a	**Market Purchases:** • PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 12 – UTAH MODEL RESULTS

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The Utah 2025 IRP preferred portfolio includes resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The Utah 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that a forthcoming RFP as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The Utah 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind, 2,308 MW of which is small-scale, and 5,492 MW of new solar.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, a new 230 kV line from the Willamette Valley to Central Oregon, and Gateway

[1] https://pscdocs.utah.gov/electric/23docs/2303510/335635230351009-24-2024.pdf

South 2, a new 500 kV line from the Aeolus substation in Wyoming to the Clover substation in Utah.

- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation are converted to natural gas where the option is available.

- In the 2025 IRP, four factors drive a reduction in CO_2 emissions after 2025. These factors are: retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities, and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially as a result of renewable resource additions, but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the Utah 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios supporting Washington's Clean Energy Transformation Act (CETA)[2] and discussion of Oregon's compliance position in the Utah preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 12.1 below shows the various phases of the Utah, Idaho, Wyoming and California (UIWC) MN fully initial jurisdictional run to demonstrate a snapshot of how iterative jurisdictional portfolios were

[2] Volume II, Appendix O provides additional detail relevant to Washington requirements.

evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase is selected for integration. In Table 12.1, phase 5 was selected as the UIWC initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $21,842 million, and the stream of unserved energy costs that led to a total cost of $1 million which had no unserved energy after 2027. No other phase had both a lower PVRR and a lower unserved energy cost. Other phases which were considered were phase 1, phase 3 and phase 9, however the higher PVRR of phases 3 and 9, and the fact that phase 1 had small amounts of unserved energy through the 21-year study horizon led to phase 5 being selected.

Table 12.1 – Iterative phases of Utah, Idaho, Wyoming and California MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	UIWC	Medium Gas, No CO2	20,628	14
1	UIWC	Medium Gas, No CO2	21,587	1
2	UIWC	Medium Gas, No CO2	21,212	10
3	UIWC	Medium Gas, No CO2	21,848	1
4	UIWC	Medium Gas, No CO2	22,036	22
5	UIWC	Medium Gas, No CO2	21,842	1
6	UIWC	Medium Gas, No CO2	20,942	29
7	UIWC	Medium Gas, No CO2	21,999	1
8	UIWC	Medium Gas, No CO2	21,128	30
9	UIWC	Medium Gas, No CO2	21,932	1
10	UIWC	Medium Gas, No CO2	21,145	25
11	UIWC	Medium Gas, No CO2	22,143	1
12	UIWC	Medium Gas, No CO2	21,157	19
13	UIWC	Medium Gas, No CO2	22,216	1
14	UIWC	Medium Gas, No CO2	20,526	18
15	UIWC	Medium Gas, No CO2	22,503	3

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal CO_2 policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimized combinations of resources, transmission and thermal retirement options.

As discussed in Chapter 8 (Modeling and Portfolio Evaluation), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and Utah preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

Jurisdictional Shares of the Preferred Portfolio

Table 12.2 through Table 12.4 present each jurisdiction's assumed *share* of the total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

Table 12.2 – Oregon Share

OR Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
DSM - Energy Efficiency	-	55	79	81	84	87	93	94	94	93	93	83	89	89	87	90	91	101	169	160	151	1,966
DSM - Demand Response	-	24	7	38	6	60	7	4	2	3	1	-	53	51	3	21	30	3	3	37	7	361
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable - Utility Wind	-	-	-	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	0	-	-	246	4	37	5	-	-	-	-	-	-	1,267
Renewable - Utility Solar	-	-	109	165	-	848	102	579	45	4	-	1,888	1	-	-	-	-	-	-	-	-	3,741
Renewable - Battery	-	132	940	7	-	10	-	2	3	1	1	-	-	2	2	3	7	234	1	1	1	1,346
Renewable - Battery (Long Duration)	-	-	1	26	62	590	166	11	93	44	17	-	-	35	53	100	140	-	198	139	44	1,720

Table 12.3 – Washington Share

WA Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
DSM - Energy Efficiency	-	14	13	14	15	15	16	16	16	15	15	13	12	10	9	8	7	7	7	6	4	233
DSM - Demand Response	-	15	4	8	1	-	6	1	-	1	0	-	0	11	1	12	1	1	1	3	1	67
Nuclear	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable - Utility Wind	-	-	-	-	594	-	-	0	-	-	3	1,988	-	-	-	-	-	-	-	-	-	2,585
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	5
Renewable - Utility Solar	-	-	136	17	-	-	794	0	4	0	-	-	-	-	-	-	237	-	-	-	-	1,189
Renewable - Battery	-	37	354	6	-	-	-	400	-	93	173	-	-	247	4	78	95	58	192	274	9	2,020
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	11	-	-	4	-	-	7	8	12	5	-	31	6	-	83

Table 12.4 – Utah, Idaho, Wyoming and California Share

UIWC Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
DSM - Energy Efficiency	50	57	145	167	172	182	233	219	197	174	157	159	149	134	123	109	102	123	107	103	84	2,947
DSM - Demand Response	14	1	1	98	26	21	-	31	-	42	23	12	13	13	38	18	16	30	68	22	135	622
Nuclear	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable - Utility Wind	-	-	-	403	211	-	-	451	-	-	-	338	-	-	-	-	-	-	-	-	-	1,403
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	802	-	-	1,039
Renewable - Utility Solar	-	-	-	-	-	-	-	226	-	0	-	333	3	-	-	-	-	-	-	-	-	563
Renewable - Battery	-	352	2	103	-	30	-	14	-	224	2	-	11	4	4	-	4	197	63	4	4	1,018
Renewable - Battery (Long Duration)	-	-	-	-	-	65	-	-	-	44	46	-	-	285	405	200	180	-	35	187	35	1,481

Full Jurisdictional Portfolios

Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration.

The following portfolios shown in Table 12.5 through Table 12.7 report the entirety of portfolio selections made when planning for the entire system, not just the jurisdictional share, according to each jurisdiction's constraints.

Table 12.5 – Oregon Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	233	253	261	275	325	322	302	277	260	248	250	233	219	208	201	232	283	269	235	5,064
DSM - Demand Response	18	25	7	38	86	60	7	4	2	3	1	-	255	85	47	46	46	27	79	61	43	940
Renewable - Wind	-	-	222	166	-	594	-	-	-	-	3	-	31	256	-	-	-	-	-	-	-	1,272
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	-	-	1,270
Renewable - Utility Solar	-	-	109	165	-	848	102	807	45	4	2	2,221	4	-	-	-	-	-	-	-	-	4,307
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,091	10	-	19	5	3	25	3	4	-	-	146	6	7	16	504	67	6	6	2,438
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**487**	**1,663**	**403**	**666**	**3,035**	**400**	**1,243**	**467**	**372**	**337**	**2,715**	**444**	**855**	**455**	**895**	**246**	**860**	**659**	**435**	**344**	

Table 12.6 – Washington Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	179	-	-	-	-	400
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	214	236	243	252	326	322	300	283	265	258	260	243	229	217	210	230	285	271	236	5,058
DSM - Demand Response	18	17	4	8	37	-	185	35	-	54	57	-	26	44	42	52	24	45	30	78	40	796
Renewable - Wind	-	-	1,008	-	594	-	-	17	-	-	3	1,990	130	-	-	-	-	-	-	-	-	3,742
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	157	-	-	-	194	660	1,132
Renewable - Utility Solar	-	-	136	17	-	-	794	630	4	1	-	-	-	406	-	-	237	-	-	-	-	2,225
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	490	6	-	-	5	747	-	296	196	-	-	269	28	471	177	152	347	285	15	4,004
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	25	-	-	132	-	-	121	139	224	92	395	107	108	-	1,343
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	892
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total	**107**	**479**	**1,852**	**12**	**972**	**331**	**1,101**	**1,776**	**304**	**631**	**653**	**2,248**	**316**	**1,051**	**559**	**1,121**	**521**	**822**	**722**	**703**	**931**	

Table 12.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	203	247	256	271	331	319	298	273	255	259	250	233	220	208	207	232	283	271	239	5,033
DSM - Demand Response	18	1	-	157	40	33	-	46	-	86	29	27	17	17	47	47	46	33	74	61	144	923
Renewable - Wind	-	-	-	486	211	-	-	1,045	-	-	-	340	-	-	-	-	-	-	-	-	-	2,082
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143	390	802	-	-	1,335
Renewable - Utility Solar	-	-	-	-	-	-	-	1,675	-	4	-	670	4	-	-	-	-	-	-	-	-	2,353
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	4	444	355	134	-	389	-	232	4	-	11	6	6	-	14	462	65	6	6	2,658
Renewable - Battery (Long Duration)	-	-	-	-	-	130	-	-	-	100	78	368	383	359	466	312	325	-	51	332	70	2,974
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**463**	**207**	**1,079**	**739**	**647**	**122**	**3,474**	**298**	**692**	**366**	**1,664**	**565**	**583**	**739**	**567**	**337**	**1,117**	**1,228**	**437**	**439**	

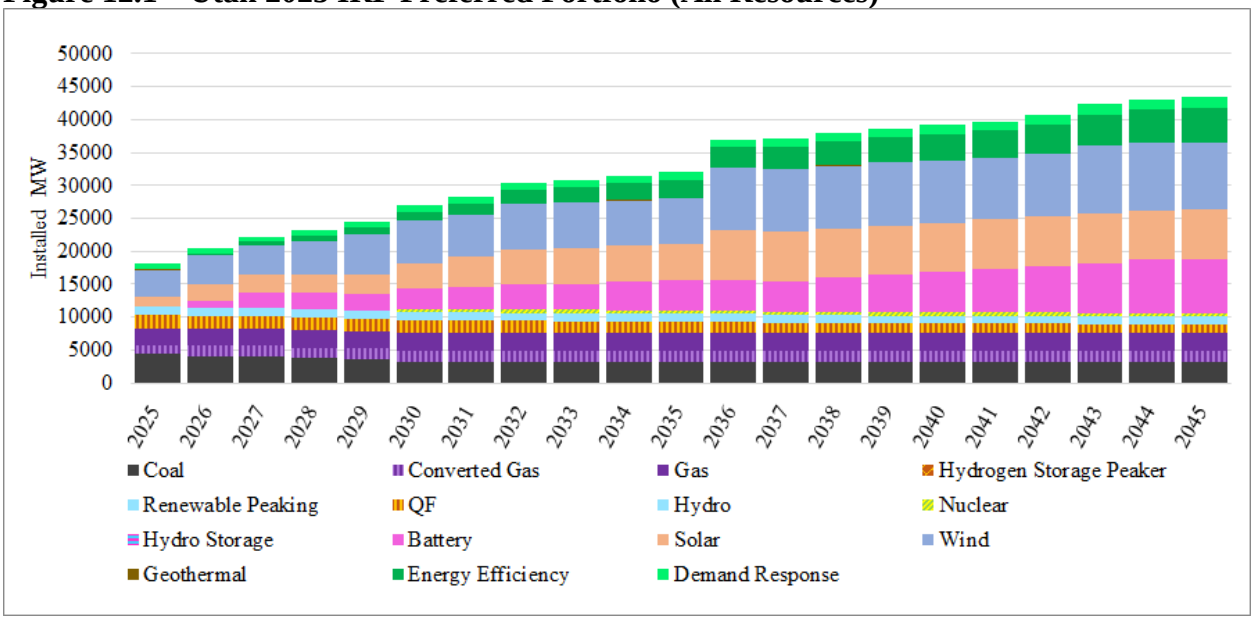
The Utah 2025 IRP Preferred Portfolio

PacifiCorp's selection of the Utah 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 12.1 shows that PacifiCorp's Utah preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear.

The Utah 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2024 to 2026 timeframe.

The Utah 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the Utah preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the Utah 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 12.1 – Utah 2025 IRP Preferred Portfolio (All Resources)



New since the 2023 IRP, the Utah 2025 IRP preferred portfolio includes a second 416-mile transmission line, known as Energy Gateway South 2, running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This line is scheduled to be operational by 2036. Additionally, smaller upgrades will enhance transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 12.8 summarizes the incremental transmission projects in the Utah 2025 IRP Preferred Portfolio.

Table 12.8 – Transmission Projects Included in the Utah 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

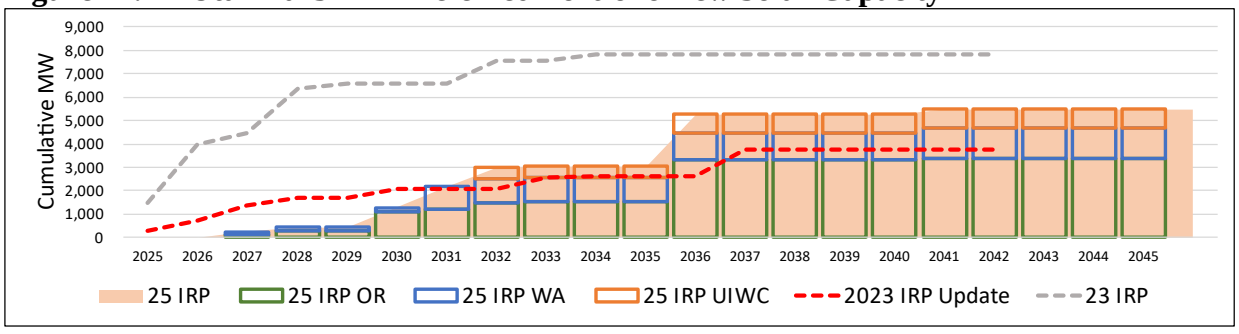
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

New Solar Resources

The Utah 2025 IRP preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and more than 5,492 MW by the end of 2045, as shown in Figure 12.2.

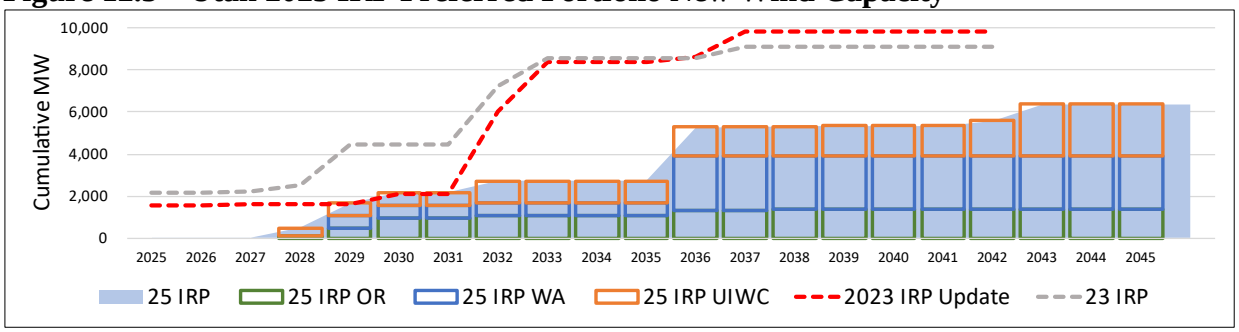
Figure 12.2 – Utah 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 12.3, PacifiCorp's Utah 2025 IRP preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379 MW of cumulative new wind by the end of 2045.

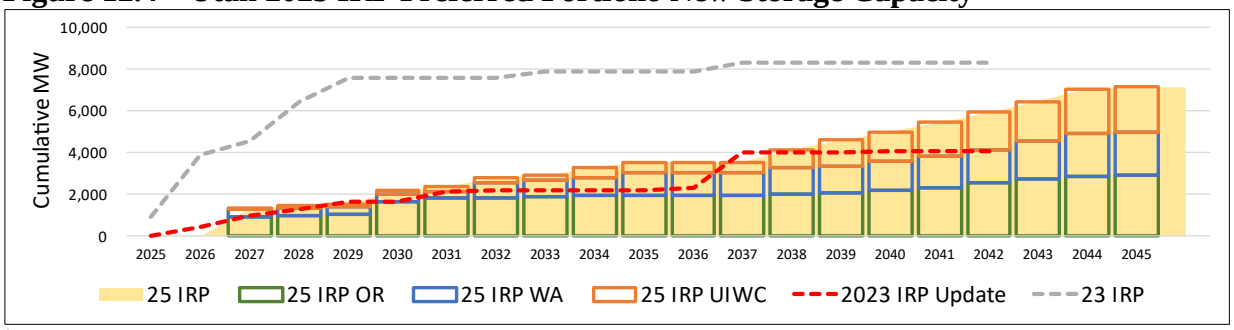
Figure 12.3 – Utah 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the Utah 2025 IRP preferred portfolio are summarized in Figure 12.4. The Utah 2025 IRP preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4 and 8-hour lithium-ion storage. By year-end 2030, the 2025 draft IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the Utah 2025 IRP preferred portfolio includes 7,668 MW of new storage.

Figure 12.4 – Utah 2025 IRP Preferred Portfolio New Storage Capacity[1]

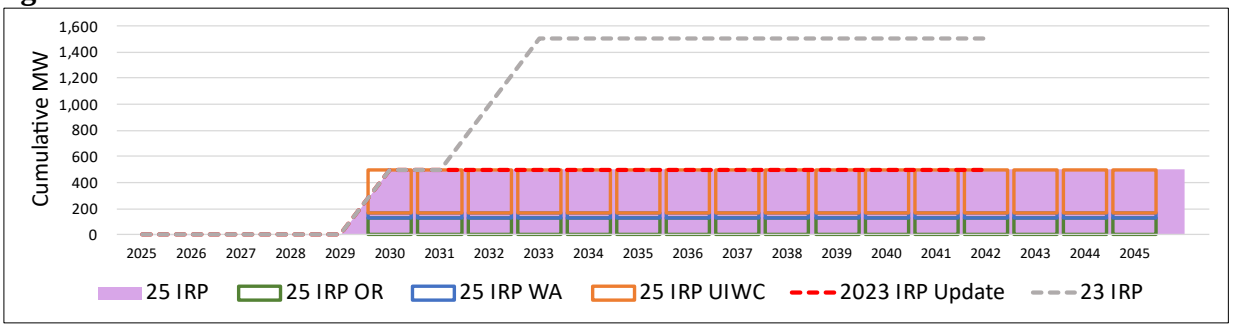


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The Utah 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 12.5, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by summer 2030.

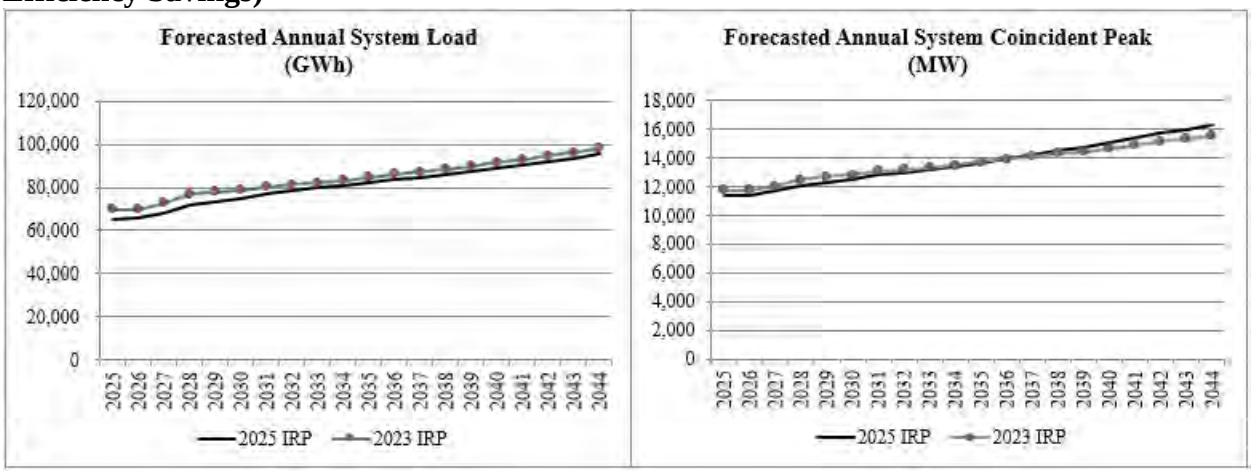
Figure 12.5 – 2025 IRP New Nuclear



Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 12.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, lowering the commercial forecast.

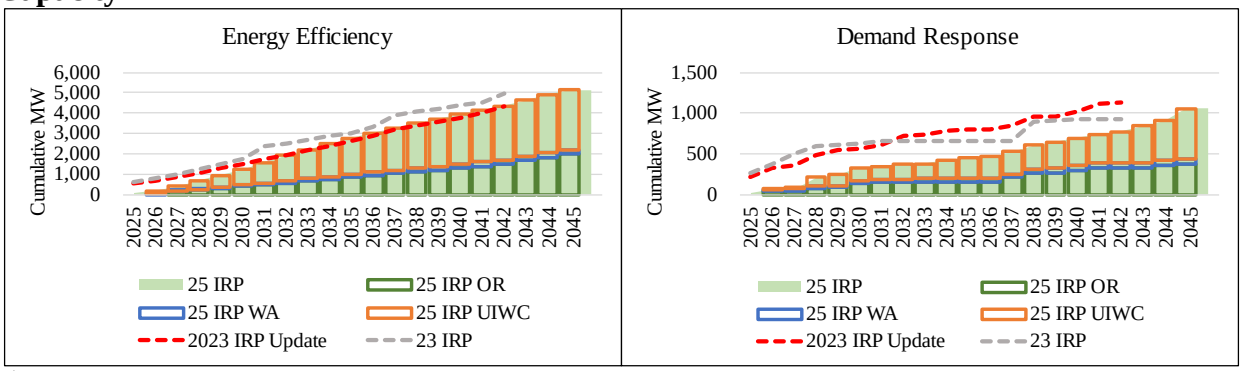
Figure 12.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 12.7 compares total energy efficiency capacity savings in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and includes 5,149 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 12.7 compares cumulative demand response program capacity in the Utah 2025 IRP preferred portfolio relative to the 2023 IRP Update preferred portfolio and does not include capacity from existing programs. The 2025 draft IRP has a cumulative capacity of demand response programs reaching 695 MW by 2040. By year-end 2045, the Utah 2025 IRP preferred portfolio has a cumulative capacity of demand response programs reaching 1,052 MW, a 6.3% decrease from the cumulative capacity of demand response programs by the end of the planning horizon in the 2023 IRP Update (1,123 MW).

Figure 12.7 – Utah 2025 IRP preferred portfolio Energy Efficiency and Demand Response Capacity

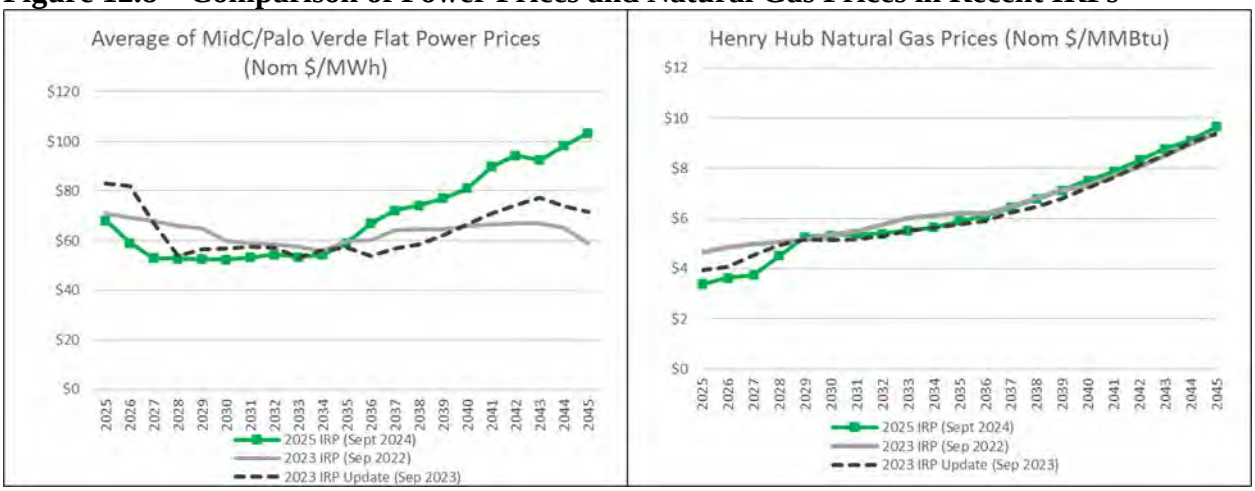


[1] Energy efficiency and demand response in the 2023 IRP Update began escalating two years prior to when escalation begins in the 2025 draft IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 draft IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP Update, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 12.8 illustrates that the Utah 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 12.8 reports that the Utah 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

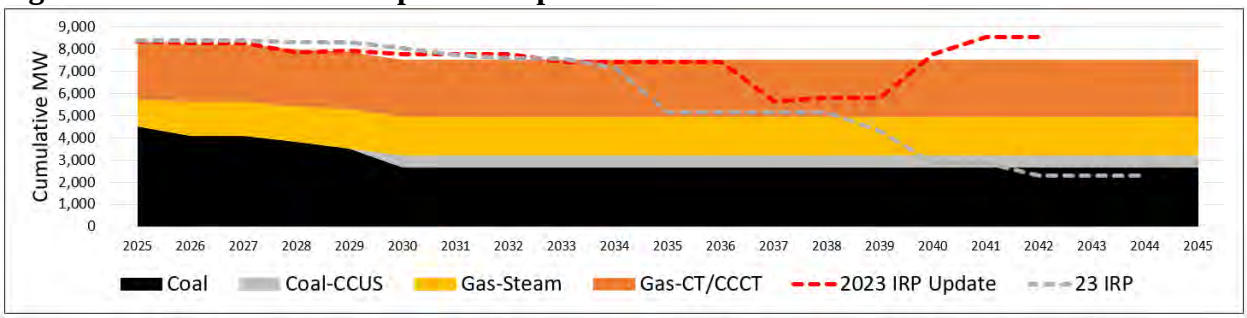
Figure 12.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be reasonably available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 12.9, the Utah 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386.2 MW of minority-owned coal, and an additional 220 MW of majority-owned coal by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 12.9 – Utah 2025 IRP preferred portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the Utah 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 12.9. In addition to these

coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[3]

Table 12.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal			
Unit	Utah 2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	Not retired (Alt. fuel conv. 2030)	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	7 (Gas conversion 2024)
Jim Bridger 3 & 4	Not retired (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Carbon Dioxide Equivalent Emissions

The Utah 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, storage and transmission advancements; and Regional Haze compliance that capitalizes on flexibility.

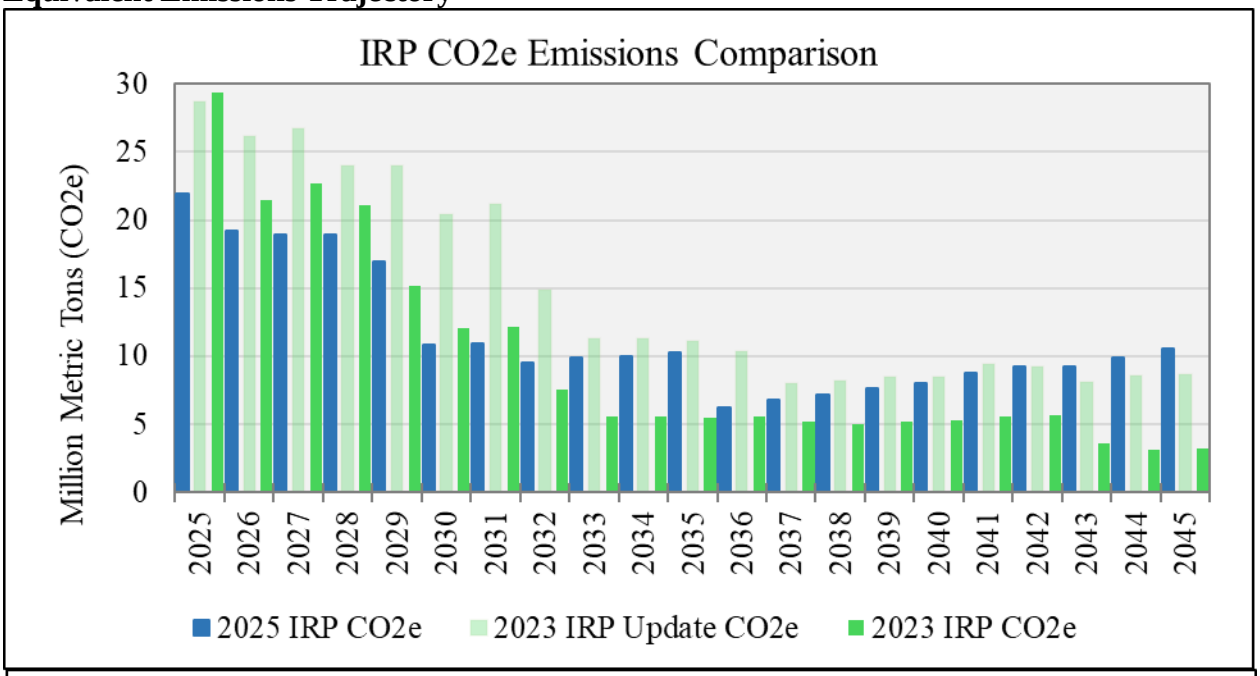
The chart on the left in Figure 12.10 compares projected annual CO_2e emissions across the Utah 2025 IRP, 2023 IRP, and 2023 IRP Update preferred portfolios and is inclusive of emissions attributed to market purchases. The Utah 2025 IRP delivers greater emission reductions between 2025 to 2032 outperforming both the 2023 IRP and 2023 IRP Update, with average annual CO2e emissions down 8% by 2030 relative to the 2023 IRP. After 2032, emissions are forecasted to rise moderately above the 2023 IRP due in part to a higher load forecast in the Utah 2025 IRP and the expiration of existing contracted resources. The difference in emissions from the 2023 IRP also reflects the Utah 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing

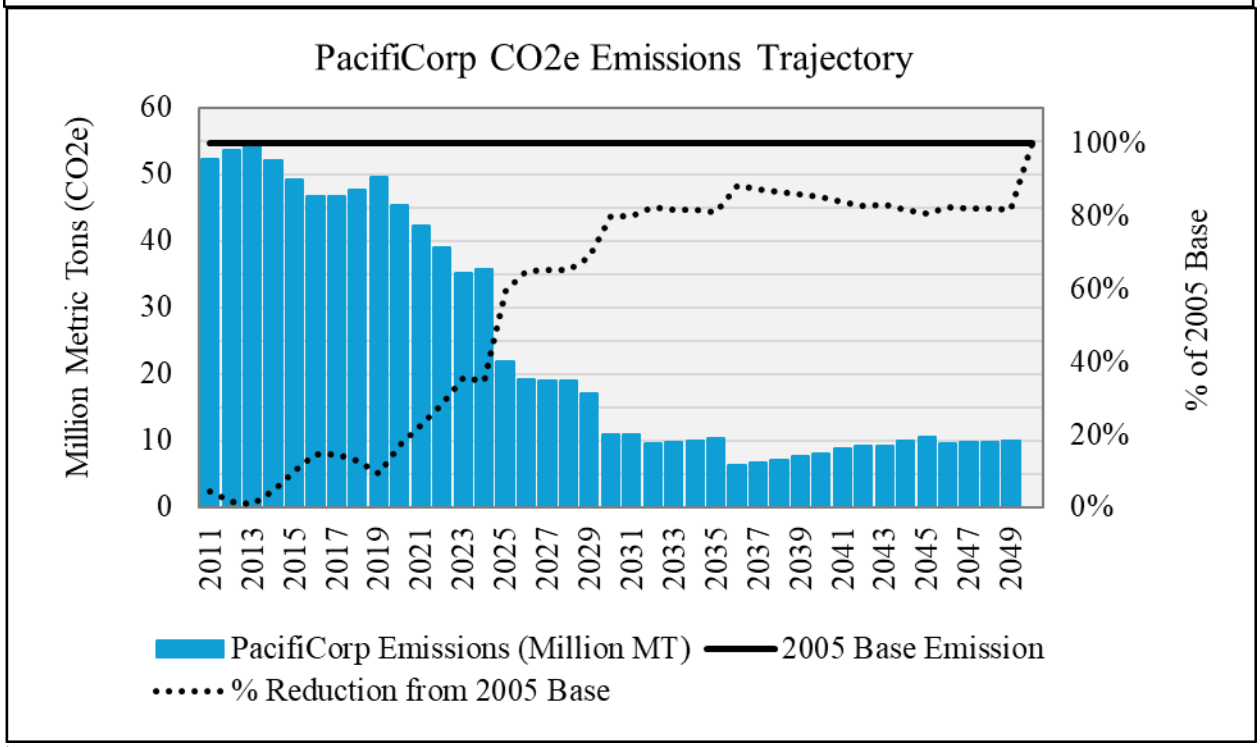
[3] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

existing coal plants to operate through the planning period at a reduced capacity. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals. By the end of the planning horizon, system CO2e emissions are projected to fall from 22.0 million metric tons in 2025 to 10.6 million tons in 2045—a reduction of 52 percent.

The chart on the right in Figure 12.10 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that, relative to a 2005 baseline of 54.6 million metric tons, system CO2 equivalent emissions are down 60 percent in 2025, 80 percent in 2030, and 85 percent in 2040.

Figure 12.10 – Utah 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]





[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. 2023 emissions have yet to be updated for actuals and 2024 emissions were not forecasted in the 2025 IRP. Therefore both 2023 and 2024 reflect the forecast from the 2023 IRP. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the Utah 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2045, emissions reflect the rolling average emissions of each resource from the Utah 2025 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

Renewable Portfolio Standards

PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the Utah 2025 IRP preferred portfolio.

Capacity and Energy

Figure 12.13 and Figure 12.14 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[4] On an energy basis, coal generation drops below 20 percent in 2026, falling below 10 percent in 2036, and remaining below 10 percent through the end of the planning period. On a capacity basis, coal resources drop to 12 percent. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources and DSM resources.

[4]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 12.11 – Projected Energy Mix with Preferred Portfolio Resources

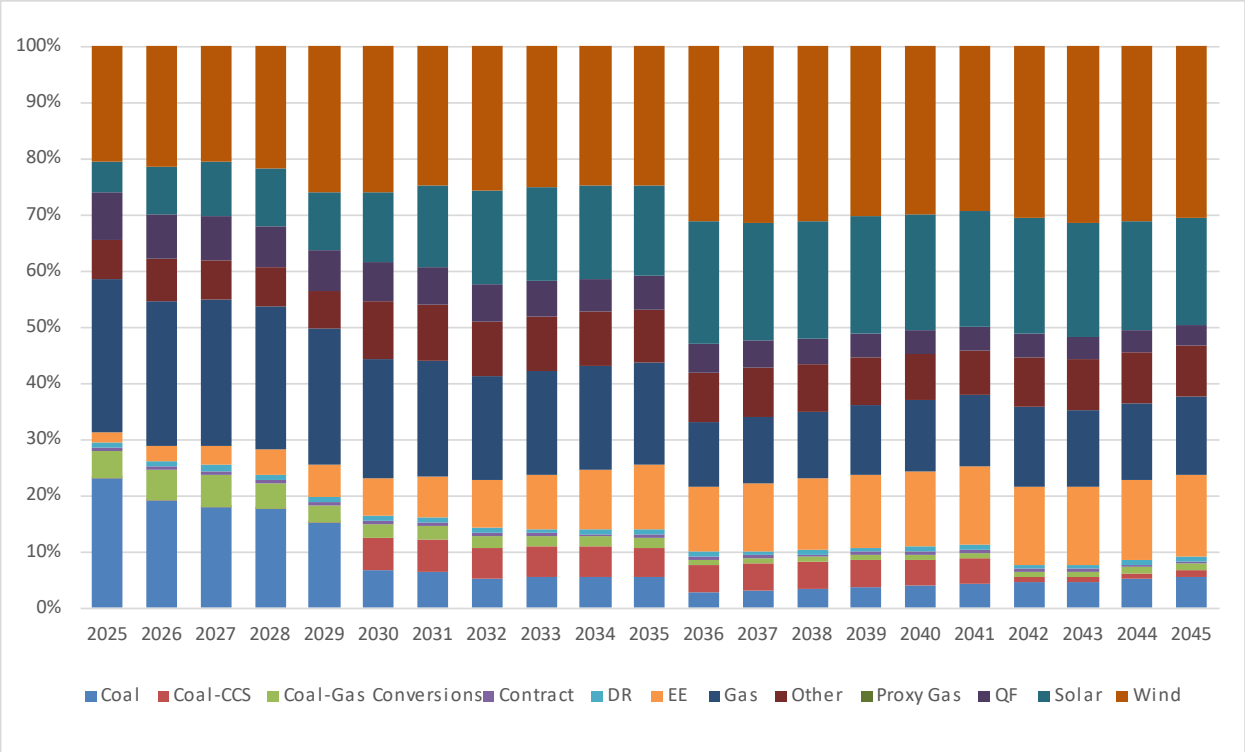
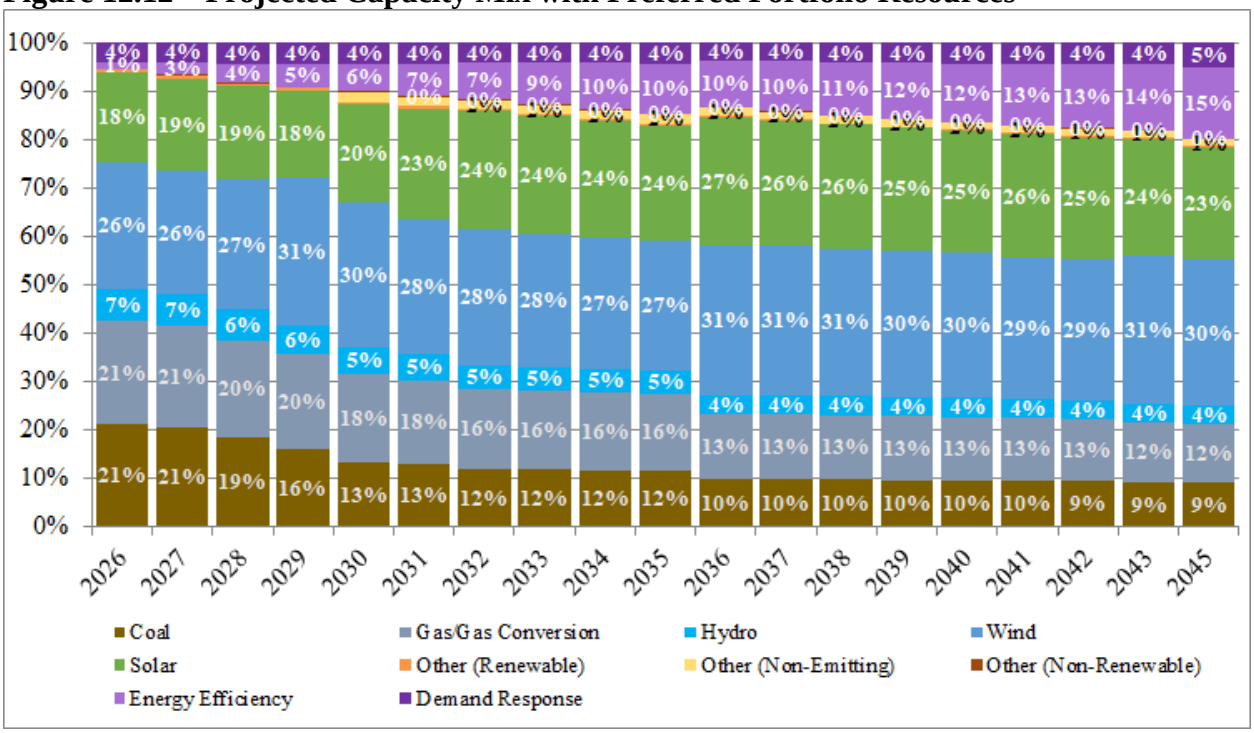


Figure 12.12 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 12.10 provides line-item detail of PacifiCorp's Utah 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon.

Table 12.11 and Table 12.12 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon.

Table 12.13 and Table 12.14 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

Table 12.10 – PacifiCorp's Utah 2025 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239	5,149
DSM - Demand Response	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144	1,052
Renewable - Wind	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-	4,071
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-	2,308
Renewable - Utility Solar	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-	5,492
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15	4,383
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	(2)	(52)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,792**	**961**	**1,426**	**1,966**	**1,212**	**2,144**	**455**	**735**	**535**	**5,061**	**235**	**893**	**747**	**652**	**516**	**989**	**1,630**	**710**	**456**	

Table 12.11 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,959	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,295	3,469	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	246	224	218	211	205	189	168	162	157	151
Solar	342	499	488	476	464	453	441	429	418	406
Other Renewable	46	45	44	42	41	40	38	37	36	34
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	413	404	395	386	377	368	359	348	334	323
Demand Response	305	300	295	290	286	281	276	271	266	262
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	0	(639)	(822)	(627)	(335)	(1,131)	(1,021)	(595)	(628)	(494)
East Existing Resources	**8,373**	**8,709**	**8,480**	**8,434**	**8,567**	**7,549**	**7,598**	**7,975**	**7,889**	**7,974**
Additional Proxy/Short-Term Purchases	190	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	85	185	268	263	273	267	263
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	136	160	220	867	1,029	1,049	1,139	1,224
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**190**	**0**	**137**	**319**	**499**	**1,543**	**1,701**	**1,751**	**1,836**	**1,947**
East Total Resources	**8,563**	**8,710**	**8,617**	**8,753**	**9,065**	**9,092**	**9,299**	**9,726**	**9,725**	**9,920**
Load	7,734	7,947	7,952	8,230	8,667	8,855	9,050	9,335	9,335	9,284
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(515)	(354)
Energy Efficiency	(92)	(191)	(234)	(346)	(457)	(566)	(561)	(852)	(880)	(996)
East Total obligation	**7,485**	**7,613**	**7,532**	**7,651**	**7,924**	**7,948**	**8,089**	**8,025**	**7,940**	**7,934**
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	15.0%	21.2%	22.5%	25.0%
West										
Coal	140	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	229	224	212	207	198	194	188	178	174	170
Demand Response	60	59	58	58	57	56	55	55	54	53
Transfers	0	639	822	627	335	1,131	1,021	595	628	494
West Existing Resources	**1,927**	**2,551**	**2,719**	**2,516**	**2,212**	**2,868**	**2,745**	**2,307**	**2,332**	**2,191**
Additional Proxy/Short-Term Purchases	2,145	1,711	568	720	1,079	166	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	64	64	64	112	112	111
Solar	0	0	133	225	218	627	1,031	1,363	1,333	1,285
Storage	0	0	847	920	908	923	912	1,186	1,171	1,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**2,145**	**1,718**	**1,559**	**1,907**	**2,313**	**1,825**	**2,055**	**2,710**	**2,665**	**2,815**
West Total Resources	**4,072**	**4,269**	**4,278**	**4,423**	**4,525**	**4,693**	**4,799**	**5,017**	**4,998**	**5,006**
Load	3,672	3,826	3,938	4,121	4,271	4,482	4,609	4,828	4,946	4,887
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(244)	(148)
Energy Efficiency	(63)	(41)	(123)	(157)	(191)	(227)	(231)	(229)	(334)	(364)
West Total obligation	**3,560**	**3,731**	**3,740**	**3,866**	**3,955**	**4,102**	**4,195**	**4,386**	**4,368**	**4,376**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%
System										
Total Resources	12,635	12,978	12,895	13,175	13,590	13,785	14,099	14,743	14,723	14,926
Obligation	11,045	11,345	11,272	11,517	11,879	12,050	12,284	12,410	12,308	12,310
Planning Reserves (14.4%)	1,590	1,634	1,623	1,658	1,711	1,735	1,769	1,787	1,772	1,773
Obligation + Reserves	12,635	12,978	12,895	13,175	13,590	13,785	14,053	14,197	14,081	14,082
System Position	0	0	0	0	0	0	45	546	642	844
Reserve Margin	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.8%**	**18.8%**	**19.6%**	**21.3%**

Table 12.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926
Gas	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	145	140	134	128	122	117	81	77	73	69	65
Solar	395	383	343	332	322	311	300	290	279	246	236
Other Renewable	33	32	30	11	11	10	9	9	8	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	314	302	240	231	223	211	204	196	189	182	176
Demand Response	257	252	247	243	238	233	228	223	218	214	209
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(469)	(310)	(491)	(366)	(567)	(653)	(663)	(627)	(708)	(607)	(765)
East Existing Resources	**7,950**	**8,060**	**7,749**	**7,811**	**7,564**	**7,430**	**7,346**	**7,339**	**7,216**	**7,252**	**7,047**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	258	641	628	621	609	596	583	601	691	675	658
Solar	0	316	306	297	287	278	268	258	249	239	230
Storage	1,288	1,286	1,284	1,605	2,064	2,371	2,690	2,688	2,947	3,273	3,350
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,022**	**2,726**	**2,711**	**3,024**	**3,494**	**3,789**	**4,095**	**4,116**	**4,484**	**4,799**	**4,943**
East Total Resources	**9,972**	**10,786**	**10,460**	**10,835**	**11,058**	**11,219**	**11,441**	**11,454**	**11,700**	**12,051**	**11,990**
Load	9,411	9,557	9,767	9,935	10,083	10,201	10,339	10,480	10,664	10,745	10,883
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(1,110)	(1,151)	(1,024)	(1,333)	(1,462)	(1,515)	(1,580)	(1,315)	(1,562)	(1,583)	(1,613)
East Total obligation	**7,916**	**7,990**	**8,298**	**8,129**	**8,118**	**8,156**	**8,202**	**8,581**	**8,492**	**8,528**	**8,610**
East Reserve Margin	26.0%	35.0%	26.1%	33.3%	36.2%	37.6%	39.5%	33.5%	37.8%	41.3%	39.3%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0	0
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	143	138	133	129	125	121	100	96	94
Demand Response	52	52	51	50	49	49	48	47	46	46	45
Transfers	469	310	491	366	567	653	663	627	708	607	765
West Existing Resources	**2,159**	**1,992**	**2,153**	**2,021**	**2,213**	**2,293**	**2,276**	**2,235**	**2,293**	**2,187**	**2,341**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	111	111	110	110	109	109	109	108	108	107	107
Solar	1,235	1,444	1,382	1,320	1,259	1,197	1,208	1,140	1,074	1,008	942
Storage	1,466	1,444	1,431	1,569	1,551	1,576	1,617	1,881	2,001	2,130	2,102
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,861**	**3,048**	**3,008**	**3,106**	**3,027**	**3,010**	**3,071**	**3,270**	**3,325**	**3,415**	**3,327**
West Total Resources	**5,020**	**5,040**	**5,161**	**5,127**	**5,240**	**5,303**	**5,347**	**5,505**	**5,618**	**5,603**	**5,668**
Load	4,944	5,009	5,082	5,189	5,258	5,330	5,397	5,473	5,660	5,651	5,730
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(394)	(426)	(378)	(502)	(457)	(461)	(475)	(399)	(473)	(463)	(471)
West Total obligation	**4,388**	**4,406**	**4,512**	**4,481**	**4,581**	**4,635**	**4,674**	**4,812**	**4,910**	**4,897**	**4,955**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%
System											
Total Resources	14,992	15,826	15,621	15,961	16,299	16,522	16,788	16,959	17,318	17,653	17,658
Obligation	12,304	12,396	12,810	12,610	12,699	12,791	12,876	13,393	13,403	13,425	13,564
Planning Reserves (14.4%)	1,772	1,785	1,845	1,816	1,829	1,842	1,854	1,929	1,930	1,933	1,953
Obligation + Reserves	14,076	14,181	14,654	14,426	14,528	14,633	14,730	15,321	15,333	15,358	15,518
System Position	917	1,645	967	1,536	1,771	1,888	2,059	1,638	1,985	2,295	2,141
Reserve Margin	**21.8%**	**27.7%**	**21.9%**	**26.6%**	**28.3%**	**29.2%**	**30.4%**	**26.6%**	**29.2%**	**31.5%**	**30.2%**

Table 12.13 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,733	3,733	3,498	3,184	3,014	3,014	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	2,037	1,929	1,836	1,748	1,616	1,456	1,377	1,300	1,226	1,154
Solar	77	104	101	98	95	92	89	86	83	80
Other Renewable	41	39	38	37	35	34	33	31	30	28
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	177	171	167	162	155	150	130	125
Demand Response	139	135	132	129	125	122	119	116	112	109
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,281)	(1,299)	(1,403)	(1,600)	(1,600)	(1,176)	(1,225)	(1,002)
East Existing Resources	**8,062**	**7,890**	**8,104**	**7,749**	**7,379**	**6,841**	**6,748**	**7,083**	**6,931**	**7,070**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	225	484	691	672	688	666	645
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	90	113	173	821	983	1,003	1,093	1,178
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**0**	**0**	**90**	**412**	**750**	**1,920**	**2,063**	**2,120**	**2,188**	**2,283**
East Total Resources	**8,062**	**7,890**	**8,194**	**8,161**	**8,129**	**8,760**	**8,811**	**9,202**	**9,119**	**9,353**
Load	5,724	6,099	6,174	6,448	6,759	6,698	6,869	7,153	7,223	7,397
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(63)	(116)	(174)	(243)	(311)	(385)	(403)	(528)	(613)	(695)
East Total obligation	**5,659**	**5,981**	**5,997**	**6,201**	**6,443**	**6,306**	**6,459**	**6,617**	**6,601**	**6,693**
East Reserve Margin	42.5%	31.9%	36.6%	31.6%	26.2%	38.9%	36.4%	39.1%	38.1%	39.7%
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	61	59	57	54	52	50	47	45	43
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	68	68	60	60	57	56	56	55	55	55
Demand Response	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,281	1,299	1,403	1,600	1,600	1,176	1,225	1,002
West Existing Resources	**3,341**	**3,339**	**3,010**	**3,026**	**3,124**	**3,171**	**3,167**	**2,740**	**2,787**	**2,561**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	64	64	64	112	111	111
Solar	0	0	34	57	55	158	259	340	331	316
Storage	0	0	1,102	1,197	1,180	1,200	1,182	1,538	1,517	1,770
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**0**	**6**	**1,146**	**1,297**	**1,343**	**1,466**	**1,553**	**2,039**	**2,008**	**2,248**
West Total Resources	**3,341**	**3,345**	**4,156**	**4,322**	**4,467**	**4,637**	**4,720**	**4,778**	**4,794**	**4,809**
Load	3,711	3,577	3,676	3,859	4,025	4,478	4,541	4,421	4,477	4,526
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(45)	(79)	(118)	(157)	(199)	(246)	(236)	(328)	(370)	(407)
West Total obligation	**3,665**	**3,498**	**3,558**	**3,701**	**3,825**	**4,230**	**4,303**	**4,091**	**4,105**	**4,117**
West Reserve Margin	-8.8%	-4.4%	16.8%	16.8%	16.8%	9.6%	9.7%	16.8%	16.8%	16.8%
System										
Total Resources	11,404	11,235	12,350	12,484	12,596	13,397	13,531	13,980	13,913	14,161
Obligation	9,324	9,479	9,555	9,902	10,268	10,537	10,762	10,708	10,706	10,810
Planning Reserves (16.8%)	1,566	1,593	1,605	1,663	1,725	1,770	1,808	1,799	1,799	1,816
Obligation + Reserves	10,891	11,072	11,160	11,565	11,993	12,307	12,570	12,507	12,505	12,626
System Position	513	163	1,190	919	604	1,091	960	1,474	1,408	1,536
Reserve Margin	**22.3%**	**18.5%**	**29.3%**	**26.1%**	**22.7%**	**27.2%**	**25.7%**	**30.6%**	**30.0%**	**31.0%**

Table 12.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,082	1,014	948	883	820	674	621	570	522	474	429
Solar	77	74	71	68	66	63	60	57	46	44	41
Other Renewable	27	26	24	8	8	8	7	6	6	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	121	103	98	95	91	87	83	79	75	72	68
Demand Response	106	103	99	96	93	89	86	83	80	76	73
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(911)	(1,183)	(1,390)	(789)	(927)	(938)	(950)	(1,006)	(965)	(865)	(921)
East Existing Resources	**7,078**	**6,712**	**6,426**	**6,936**	**6,725**	**6,558**	**6,481**	**6,365**	**6,339**	**6,375**	**6,265**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	625	1,530	1,476	1,436	1,383	1,329	1,273	1,286	1,447	1,378	1,311
Solar	0	81	78	75	71	68	65	62	59	55	52
Storage	1,242	1,239	1,234	1,552	2,008	2,312	2,628	2,623	2,880	3,203	3,277
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,342**	**3,334**	**3,281**	**3,564**	**3,996**	**4,254**	**4,521**	**4,540**	**4,983**	**5,247**	**5,345**
East Total Resources	**9,420**	**10,046**	**9,707**	**10,500**	**10,721**	**10,812**	**11,001**	**10,905**	**11,322**	**11,622**	**11,610**
Load	7,321	7,508	7,595	7,732	7,856	7,991	8,169	8,340	8,450	8,525	8,664
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(580)	(891)	(834)	(824)	(879)	(926)	(1,042)	(979)	(1,305)	(1,268)	(1,195)
East Total obligation	**6,730**	**6,606**	**6,749**	**6,896**	**6,964**	**7,052**	**7,113**	**7,347**	**7,131**	**7,242**	**7,453**
East Reserve Margin	40.0%	52.1%	43.8%	52.3%	54.0%	53.3%	54.7%	48.4%	58.8%	60.5%	55.8%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	41	39	36	34	32	30	28	26	24	22	20
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	53	53	52	51	51	50	50	49	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Transfers	911	1,183	1,390	789	927	938	950	1,006	965	865	921
West Existing Resources	**2,467**	**2,736**	**2,940**	**2,336**	**2,471**	**2,480**	**2,489**	**2,542**	**2,499**	**2,397**	**2,451**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	111	110	110	109	109	109	108	108	107	107	106
Solar	301	349	331	312	294	276	274	254	235	215	195
Storage	1,893	1,865	1,845	2,021	1,997	2,027	2,076	2,412	2,564	2,722	2,685
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,355**	**2,374**	**2,372**	**2,549**	**2,508**	**2,539**	**2,596**	**2,914**	**3,048**	**3,213**	**3,162**
West Total Resources	**4,822**	**5,109**	**5,312**	**4,886**	**4,979**	**5,018**	**5,085**	**5,456**	**5,547**	**5,610**	**5,613**
Load	4,773	4,920	4,989	4,941	5,062	5,136	5,276	5,289	5,398	5,345	5,467
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(642)	(543)	(439)	(755)	(796)	(837)	(919)	(614)	(645)	(538)	(658)
West Total obligation	**4,128**	**4,374**	**4,548**	**4,183**	**4,263**	**4,297**	**4,353**	**4,671**	**4,749**	**4,803**	**4,805**
West Reserve Margin	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
System											
Total Resources	14,241	15,155	15,018	15,386	15,700	15,830	16,086	16,361	16,869	17,232	17,223
Obligation	10,858	10,980	11,297	11,079	11,227	11,348	11,466	12,018	11,880	12,045	12,258
Planning Reserves (16.8%)	1,564	1,581	1,627	1,595	1,617	1,634	1,651	1,731	1,711	1,735	1,765
Obligation + Reserves	12,422	12,561	12,924	12,674	12,843	12,983	13,117	13,749	13,591	13,780	14,023
System Position	1,820	2,594	2,095	2,711	2,857	2,848	2,969	2,612	3,278	3,452	3,200
Reserve Margin	**31.2%**	**38.0%**	**32.9%**	**38.9%**	**39.8%**	**39.5%**	**40.3%**	**36.1%**	**42.0%**	**43.1%**	**40.5%**

Integrated Portfolio Resource Comparisons by Technology and Year

Table 12.15 through Table 12.25 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 12.26 through Table 12.28 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology.

Table 12.15 – New Gas[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	489	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.16 - Nuclear[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.17 – Renewable Peaking[1]

Study	Cumulative Energy, Gwh																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.18 – DSM – Energy Efficiency

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239
MR Base	89	89	238	259	266	285	338	329	308	282	265	249	250	239	227	214	210	235	286	271	239
MN - No Coal Post 2032	89	89	238	259	266	281	336	329	303	282	265	248	250	234	220	208	201	232	283	269	240
MN - No CCS	89	89	238	262	270	285	343	329	308	282	270	255	250	234	220	208	202	232	287	272	239
MN - No Nuclear	89	89	238	262	275	289	345	331	308	283	265	252	250	233	227	214	207	235	286	275	239
MN - Offshore Wind	89	89	238	259	270	285	338	329	308	283	265	252	250	233	219	208	207	232	283	271	236
LN Base	89	89	237	257	265	280	334	328	307	281	264	254	249	232	218	206	199	225	276	266	227
HH Base	89	89	244	268	276	291	347	333	312	286	268	268	261	243	229	217	210	235	286	272	240
SC Base	89	89	244	265	272	286	347	333	310	283	265	258	252	240	227	209	210	234	286	271	235

Table 12.19 – DSM – Demand Response

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144
MR Base	18	40	11	126	43	76	12	39	2	46	16	12	80	80	42	48	48	34	71	43	62
MN - No Coal Post 2032	18	40	11	141	32	60	47	27	2	46	16	12	66	84	42	48	48	34	71	62	43
MN - No CCS	18	40	11	139	38	81	13	36	2	46	24	12	66	76	45	48	60	68	23	153	53
MN - No Nuclear	18	40	19	126	53	94	23	21	18	39	16	1	136	28	42	77	23	29	72	62	144
MN - Offshore Wind	18	40	23	135	38	49	7	37	18	30	24	1	136	47	42	72	24	28	79	61	43
LN Base	18	40	25	138	53	34	13	36	18	31	16	21	85	76	43	50	46	33	72	118	88
HH Base	18	40	23	134	45	34	13	36	2	50	16	12	105	25	39	104	50	19	81	28	65
SC Base	18	40	13	27	115	21	82	26	2	46	16	1	32	91	94	30	67	27	77	27	40

Table 12.20 – Utility Scale Wind[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	1,417	594	-	-	451	-	-	3	2,954	187	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	1,077	594	153	78	350	-	-	2	3,132	178	-	-	-	-	-	-	-	-
MN - No CCS	-	-	439	970	602	-	-	-	-	-	273	2,634	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	422	834	-	-	412	-	-	199	1,374	616	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	452	792	-	200	-	41	-	270	864	1,126	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	594	-	-	-	-	-	3	3,015	-	-	-	-	-	-	-	-	-
HH Base	-	-	1,187	721	975	233	-	451	-	-	3	2,492	-	-	-	-	-	-	-	-	-
SC Base	-	-	1,417	-	594	-	-	451	-	-	297	3,236	152	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.21 – Small Scale Wind[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-
MR Base	-	-	-	-	-	745	-	60	52	-	-	300	98	9	9	-	-	552	28	414	40
MN - No Coal Post 2032	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No CCS	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No Nuclear	-	-	-	-	-	246	7	-	-	-	21	207	111	17	9	-	-	-	-	105	211
MN - Offshore Wind	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	-	79	1	-	-
LN Base	-	-	-	-	500	349	34	26	-	29	29	29	41	33	9	109	-	-	-	194	660
HH Base	-	-	-	-	133	876	89	-	-	-	14	172	76	75	49	-	402	486	120	125	37
SC Base	-	-	20	-	302	616	35	89	1	-	8	215	32	103	119	-	-	875	92	-	454

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.22 – Utility Solar[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-
MR Base	-	-	137	107	-	505	794	1,081	522	1	-	2,736	2	406	-	-	237	-	-	-	-
MN - No Coal Post 2032	-	-	245	182	-	848	896	805	87	5	480	4,291	4	-	-	-	237	-	-	-	-
MN - No CCS	-	-	245	182	-	848	896	805	567	5	-	4,291	2	-	-	-	237	-	-	-	-
MN - No Nuclear	-	-	290	237	-	44	181	451	521	2	2,079	2,103	4	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	297	101	-	385	411	634	521	4	-	405	4	-	-	670	-	-	393	-	-
LN Base	-	-	136	317	49	683	985	452	522	300	105	1	4	6	-	-	231	-	-	-	-
HH Base	-	-	419	411	-	546	2,865	452	4	1	-	2,648	800	406	-	-	237	-	-	-	-
SC Base	-	-	336	500	-	281	1,156	415	55	1	66	3,363	1,584	564	139	-	237	793	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.23 – Small Scale Solar[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	61	-	110	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	591	-	1	26	17	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	731	55	72	-	-	3	165	54	8	9	-	-	-	-	-	244
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,121
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.24 – Battery Storage [1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15
MR Base	-	520	1,135	26	181	390	108	537	37	197	277	-	176	341	73	81	79	651	589	639	15
MN - No Coal Post 2032	-	520	1,297	116	-	19	4	639	12	71	365	-	56	602	220	422	128	227	242	411	17
MN - No CCS	-	520	1,297	16	43	19	4	464	14	242	389	-	438	417	65	488	214	214	355	592	15
MN - No Nuclear	-	520	734	124	318	879	110	317	15	309	148	-	-	314	14	861	174	95	108	43	96
MN - Offshore Wind	-	520	1,360	328	220	558	140	69	122	118	47	-	-	127	10	1,067	322	405	313	244	15
LN Base	-	520	1,235	160	3	-	-	401	6	242	546	156	368	245	412	863	211	456	380	851	9
HH Base	-	520	1,133	66	108	347	141	452	141	12	200	-	74	50	12	193	136	505	399	276	34
SC Base	-	520	1,011	98	-	708	2	592	91	14	181	-	13	313	307	94	393	41	370	695	139

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.25 – Long Duration Storage [1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80
MR Base	-	-	-	-	-	378	-	-	-	-	-	-	-	60	167	496	261	50	108	71	-
MN - No Coal Post 2032	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No CCS	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No Nuclear	-	-	251	109	-	123	249	97	-	258	126	-	36	152	120	277	229	246	160	104	33
MN - Offshore Wind	-	-	45	15	79	166	-	31	-	339	178	-	-	382	675	305	206	274	327	362	122
LN Base	-	-	93	-	2	803	151	66	102	58	-	-	-	58	94	554	89	109	257	345	23
HH Base	-	-	-	-	-	243	-	-	-	86	131	-	274	375	106	555	-	-	135	346	90
SC Base	-	-	-	-	-	197	-	-	-	103	78	-	24	-	14	399	130	469	373	108	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 12.26 – Majority Owned Coal Retirements[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Negative values indicate retirement of coal capacity.

Table 12.27 – Carbon Capture and Sequestration Selections

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(264)
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 12.28 – Coal to Gas Conversion Selections

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	357	-	-	205	2,397	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	357	-	-	205	3,097	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 9 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. As a consequence, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS.

Table 12.29 – Preferred Portfolio Variant Studies

Variant	Description
No CCS	No coal units are able to select CCS technology
No Nuclear	No nuclear resources are eligible for selection
No Coal 2032	All coal must retire or gas convert by January 1, 2032
Offshore Wind	Counterfactual to the Preferred Portfolio selection
All Coal End of Life	Current coal units cannot gas convert OR select CCS
No New Gas	Proxy gas plants are not eligible for selection
Force All Gas Conversions	All coal plants that can gas convert, must
No Forward Technology	Nuclear, Hydrogen and Biodiesel units are not eligible

Table 12.30 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no CO_2) price-policy scenario.

Table 12.30 – Initial and Variant Cases Under Medium Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	22,930	0	1	220,325	66,013	5
Integrated No Coal Post 2032 MN	23,844	914	4	154,979	668	2
Integrated No CCS MN	23,199	269	3	218,003	63,691	4
Integrated Offshore Wind MN	29,231	6,301	6	216,728	62,417	3
Integrated No Nuclear MN	24,295	1,365	5	239,932	85,621	6
Integrated Base MR	22,985	55	2	154,311	0	1

Table 12.31 below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero CO_2) price-policy scenario.

Table 12.31 – Initial and Variant Cases Under Low Gas/ Zero CO_2

Case - LN	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN**						
Integrated Base MN	20,981	101	2	215,698	38,760	5
Integrated No Coal Post 2032 MN	21,598	718	4	178,027	1,089	2
Integrated No CCS MN	21,470	589	3	204,546	27,608	3
Integrated Offshore Wind MN	27,395	6,515	6	208,244	31,305	4
Integrated No Nuclear MN	22,085	1,205	5	235,603	58,664	6
Integrated Base MR	20,880	0	1	176,938	0	1

**The Integrated LN Base case was not able to be evaluated in ST prior to publishing the draft. The comparative data for this table will be provided prior to final publication.

Table 12.32 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high CO_2) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

Table 12.32 – Initial and Variant Cases Under High Gas/ High CO_2

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	25,554	0	1	121,431	0	1
Integrated Base MN	27,549	1,995	5	141,740	20,308	6
Integrated No Coal Post 2032 MN	27,315	1,760	3	129,468	8,037	2
Integrated No CCS MN	27,351	1,797	4	132,543	11,111	4
Integrated Offshore Wind MN	33,701	8,146	7	140,389	18,957	5
Integrated No Nuclear MN	29,601	4,047	6	147,714	26,283	7
Integrated Base MR	26,776	1,222	2	130,846	9,414	2

Table 12.33 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

Table 12.33 – Initial and Variant Cases Under Medium Gas/ Social Cost of CO_2

	ST Value			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	29,603	0	1	61,102	0	1
Integrated Base MN	30,766	1,163	3	68,506	7,404	5
Integrated No Coal Post 2032 MN	30,773	1,170	4	62,173	1,071	3
Integrated No CCS MN	30,665	1,062	2	61,948	847	2
Integrated Offshore Wind MN	36,933	7,330	6	66,925	5,823	4
Integrated No Nuclear MN	32,606	3,003	5	71,961	10,859	6

Initial and Variant Cases Under Medium Gas/ Federal Regulation (MR)

The only variant cases which would be compliant under the current language in EPA 111(d) are the MR case and the No Coal Post 2032 case. The Base MR portfolio is $807 million less in PVRR than the No Coal Post 2032 portfolio when dispatched under the MR gas and market pricing structure. CO_2 emissions are 972 tons higher in the Base MR portfolio than the No Coal post 2032 portfolio.

Variant Study Analysis

No CCS Variant

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were not to be commercially viable at these locations.

Figure 12.15 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Given the lower capacity factor of coal plants without CCS, additional resources are needed over the course of the horizon to generate enough energy to meet retail demand. This results in 1,447 MW of additional wind, 2,588 MW of additional solar and 1,420 MW of additional storage as compared to the integrated MN view.

Figure 12.13 - Increase/(Decrease) in Proxy Resources with No CCS

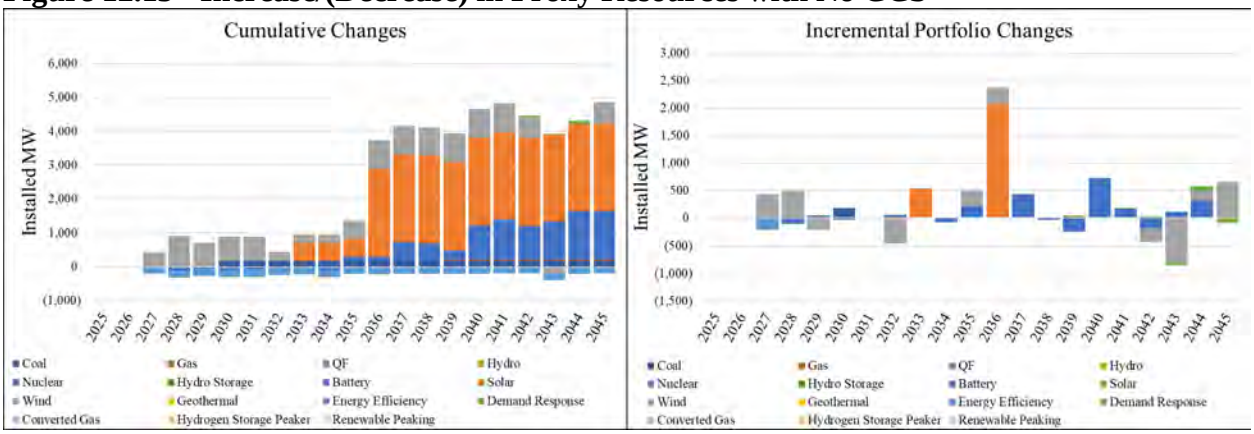
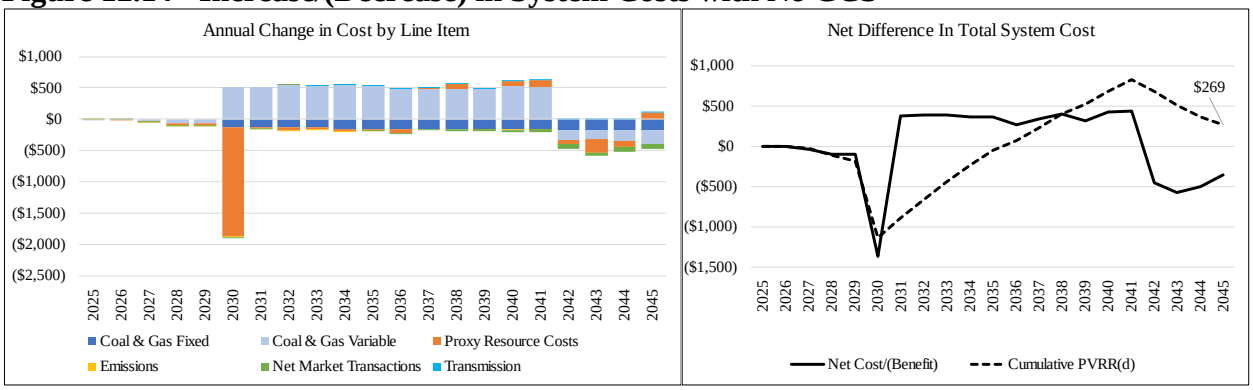


Figure 12.16 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $269 million increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 12.14 - Increase/(Decrease) in System Costs with No CCS



No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2030. Additionally, this variant does not allow any other nuclear to be selected as a potential replacement of the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the Natrium™ demonstration or other nuclear project prove not to be commercially viable.

Figure 12.17 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Given the currently selected nuclear siting at Naughton, overall portfolio changes are somewhat smaller than

in cases where significant coal changes are tested. The variant case selects 40 MW of new gas peaking resources, an additional 468 MW of energy efficiency, 998 fewer MW of wind which is offset by 1,293 additional MW of solar. Finally, an additional 81 MW of storage is selected.

Figure 12.15 - Increase/(Decrease) in Proxy Resources with No Nuclear

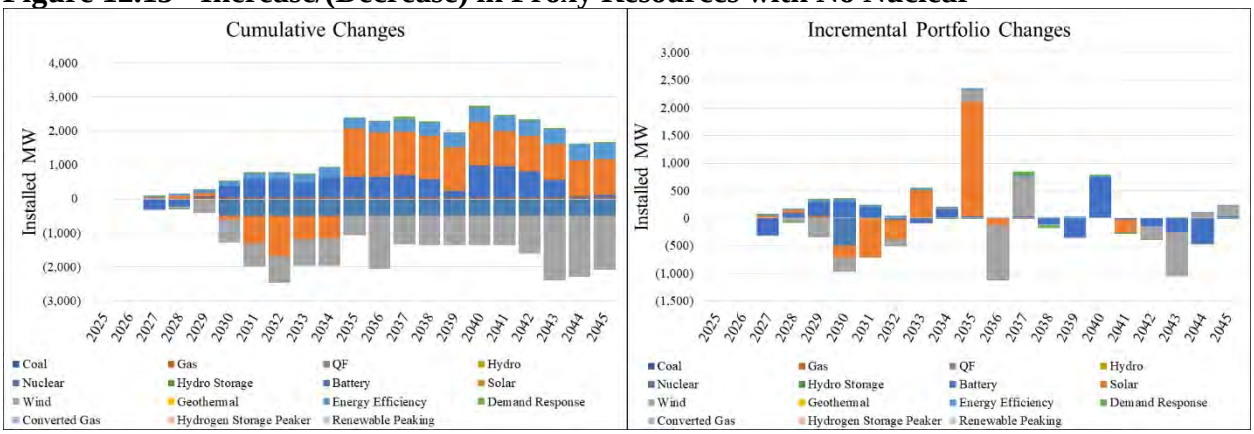
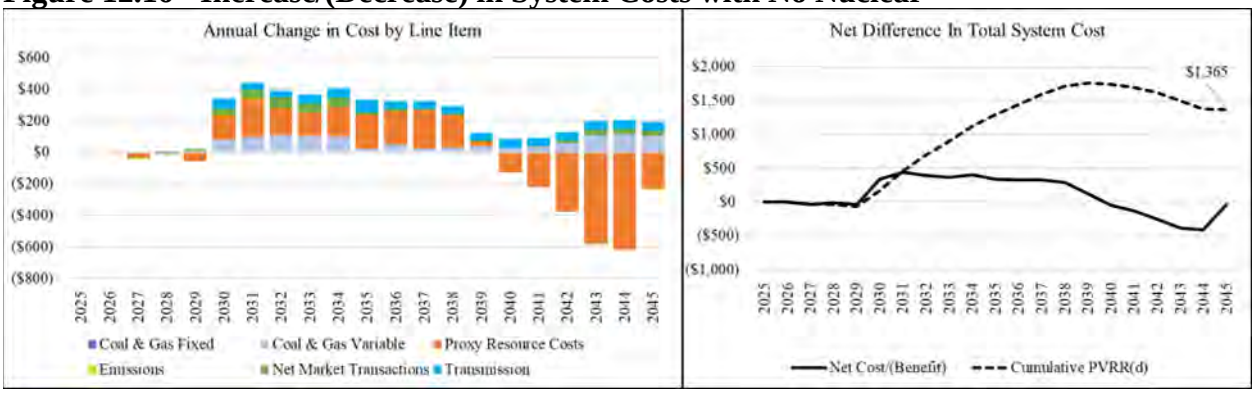


Figure 12.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.365 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.18 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 12.16 - Increase/(Decrease) in System Costs with No Nuclear



No Coal Post 2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS.

Figure 12.19 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects new gas peaking resources whereas the integrated MN view does not. Additionally, more solar and wind is selected in the variant, and less long duration storage is partially offset by additional 4-hour storage.

Figure 12.17 - Increase/(Decrease) in Proxy Resources with No Coal Post 2032

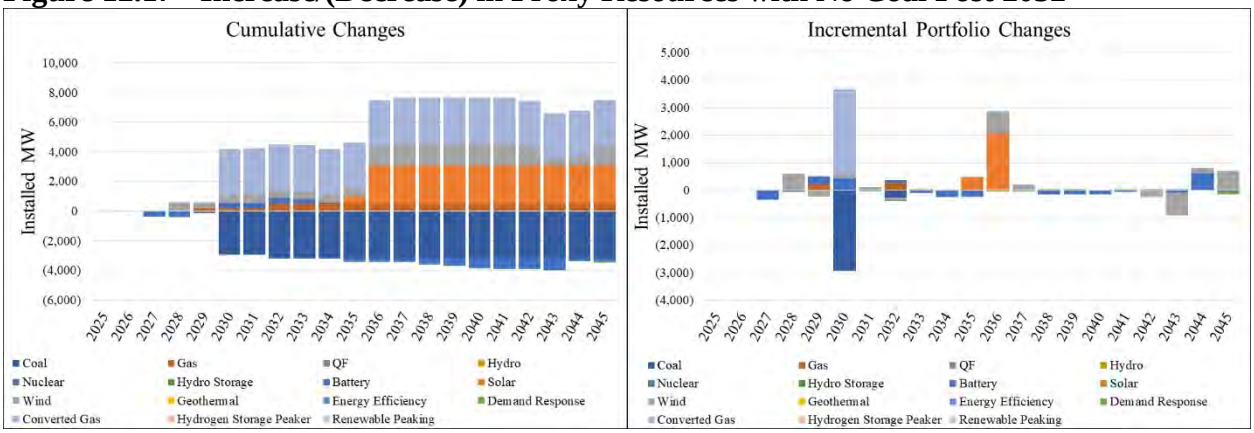
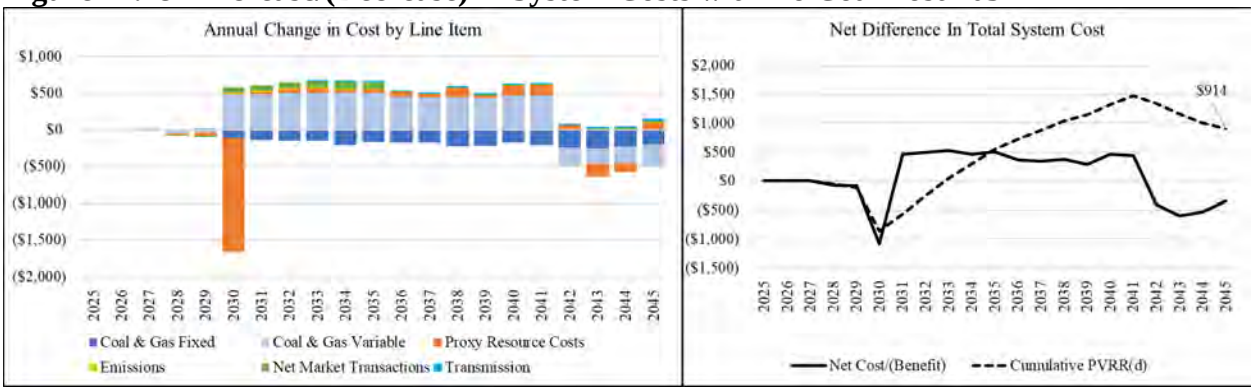


Figure 12.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or gas converted by 2032, the resulting portfolio has a $914 million increase in costs compared to the preferred portfolio.

As seen in Figure 12.20 below, like in the No CCS case, the loss of 45Q tax credits more than offsets the reduced capital cost to install CCS. Additionally, this case has higher levels of market purchases, and additionally has higher proxy resource costs in nearly all years of the study horizon.

Figure 12.18 - Increase/(Decrease) in System Costs with No Coal Post 2032



Force Offshore Wind

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 12.21 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The higher capacity factor of the offshore wind resource results in 300 MW less utility scale wind being selected in the portfolio compared to the preferred portfolio. Additionally, the portfolio has 1,669 MW less utility scale solar. Less small-scale wind is offset by more small scale solar. For capacity and reliability needs, 1,824 more MW of storage is selected in the offshore wind case, 1,603 MW of which is 4-hour storage. Retirements are the same between the studies.

Figure 12.19 - Increase/(Decrease) in Proxy Resources with Offshore Wind

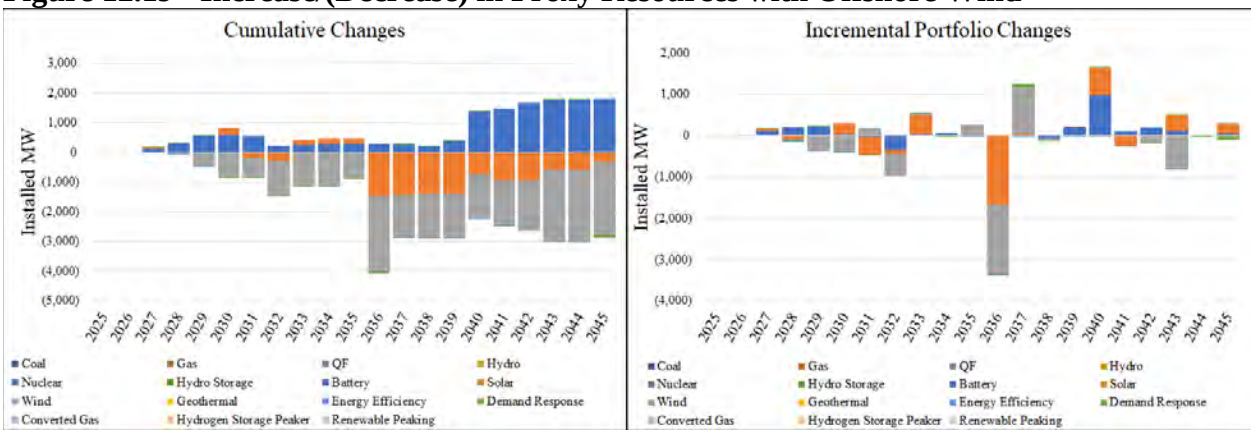
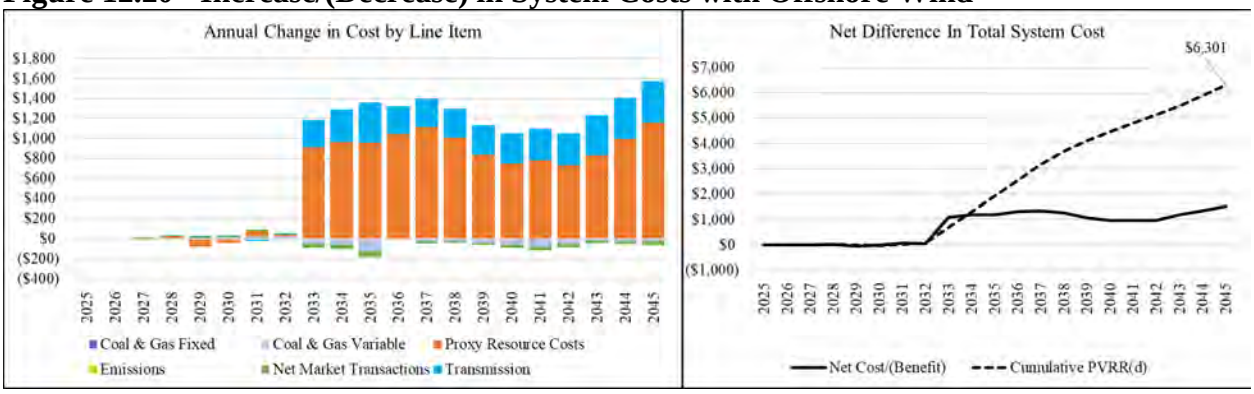


Figure 12.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $6.301 billion increase in costs compared to the preferred portfolio.

As seen in Figure 12.22 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

Figure 12.20 - Increase/(Decrease) in System Costs with Offshore Wind



CHAPTER 13 – UTAH ACTION PLAN

ORDER ISSUED IN DOCKET NO. 23-035-10

- Chapters 11, 12 and 13 are provided in compliance with the Utah Order issued in Docket No. 23-035-10.[1] Per the order, modeling input and assumption changes were locked down as of the publication of the Draft 2025 IRP on December 31, 2024:
    - "For the 2025 IRP cycle, the Data Lockdown Date is January 1, 2025; PacifiCorp shall not further alter modeling inputs after that date. . ."
    - "PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025."
- If the Public Service Commission of Utah wishes to consider updated data and analysis, Chapters 1, 9 and 10 represent the most recent available results corresponding to three Utah-specific Chapters 11 through 13.
- As the Utah Order does not restrict *non*-model inputs and assumptions, Chapters 2 through 8 and all Appendices A through Z represent the most up-to-date information.

CHAPTER HIGHLIGHTS

- The Utah 2025 Integrated Resource Plan (IRP) action plan identifies steps, determined when the analysis was conducted, that PacifiCorp would pursue over the next two-to-four years to deliver resources aligned with the Utah preferred portfolio.
- PacifiCorp's Utah 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[2]
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's Utah 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The Utah 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp

[1] https://pscdocs.utah.gov/electric/23docs/2303510/3356352303510o9-24-2024.pdf

[2] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the Utah 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the Utah 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the Utah 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The Utah 2025 IRP Action Plan

The Utah 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – Utah 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the Utah 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
1f	**Natrium™ Demonstration Project:** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.

1g	**Ozone Transport Rule Compliance:** • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** • The Utah 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** • EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** • PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • In light of the differentiated resource needs by jurisdiction identified in the Utah 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

Action Item	4. Demand-Side Management (DSM) Actions
4a	**Energy Efficiency Targets:** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP. • PacifiCorp will pursue cost-effective energy efficiency resources. • PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.

Action Item	5. Market Purchases
5a	**Market Purchases:** • PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.

6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the Utah 2025 IRP action plan. The status for all action items from the Utah 2025 IRP is summarized in Table 10.2.

Table 10.2 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	**Naughton Units 1 and 2 Gas Conversion:** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.	• PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. • Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.

1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by the end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• PacifiCorp received an approval order on December 7, 2023 from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. • PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023. • Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024.
1e	**Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:** • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits.

		• PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to the second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the Natrium™ project and expects to finalize these arrangements by the end of 2025.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective.	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

	• Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	
Action Item	**2. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	**<u>2025 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the Utah 2025	The Utah 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	IRP preferred portfolio that can achieve commercial operations by the end of December 2030. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on the final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027.	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities.

	• In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on the final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.	• EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource procurement needs coming out of the 2022 All-Source Request for Proposals. • PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals.
Action Item	3. **Transmission Action Items**	**Status**
3a	**Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	The Energy Gateway South transmission project is in-service.
3b	**Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	**Boardman-to-Hemingway (500 kV transmission line):** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date.

	• Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. **Demand-Side Management (DSM) Actions**	Status
4a	**<u>Energy Efficiency Targets:</u>** PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	• PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and is on track to achieve its 2024 Class 2 DSM target. • PacifiCorp has launched a number of new demand response programs in 2022 and 2023. Additionally, the company is currently expanding its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023 incremental

		capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs.
Action Item	5. **Market Purchases**	**Status**
5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. **Renewable Energy Credit (REC) Actions**	Status
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the Utah 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the Utah preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the Utah 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the Utah 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[4] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[4] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

A full acquisition path analysis relevant to all jurisdictions is presented the Chapter 10 (Action Plan), Table 10.3.

Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable and resilient grid operations. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the Utah 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Resource Procurement Strategy

To acquire resources outlined in the 2023 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2023 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFP to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, define specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[5]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on the size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings, and has continued Wattsmart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

[5] Class 1 DSM is most commonly referred to as "demand response" in the 2023 IRP; Class 2 DSM is most commonly referred to as "energy efficiency". Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

Small Scale Renewable Energy Supply

In order to fulfill Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is addressed in PacifiCorp's 2023 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. While the level of imputation associated with long-term contracts is expected to be lower than the debt associated with owned resources, it still may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal

frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit H: Salt River Project, *2023 Integrated Systems Plan*

Delivering water and power®

2023 INTEGRATED SYSTEM PLAN

2023 INTEGRATED SYSTEM PLANNING CONTENTS

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SECTION 1

Executive Summary

Salt River Project (SRP) is a community-based, not-for-profit organization with a mission to provide reliable, affordable and sustainable water and energy to more than 2 million people in central Arizona. To ensure we can continue to carry out this mission as we have for over a century, we regularly perform long-term power and water planning to anticipate and meet future needs. Recently, we completed an Integrated System Plan (ISP), an industry-leading, multidisciplinary effort to identify strategies to help guide our power system planning through 2035.[1]

The world is changing in dramatic ways that will directly and indirectly impact the power system. Key forces of change that are reshaping our industry include:

- Growing electricity demand driven by migration to the region, increasing levels of large customers such as manufacturers and data centers, and the rapid adoption of electric vehicles (EVs), which is also exacerbated by the increasing and prolonged severity of extreme heat due to climate change and urban heat effects;
- Rising costs and extended development timelines for new infrastructure projects as a result of the lingering effects of inflation and supply chain disruptions that began during the COVID-19 pandemic;
- The anticipation that the Inflation Reduction Act will encourage deployment of clean energy resources and accelerate research and development of innovative technologies;

[1]The ISP focuses exclusively on power system planning. SRP plans the water system through separate processes.

- Increasing momentum behind decarbonization efforts, including customer demand for sustainable energy, retirement of coal plants and expansion of renewable and storage resources throughout the West, and electrification of transportation and buildings; and
- Growing tightness in regional electricity markets as significant quantities of aging baseload generators receive additional regulatory scrutiny and approach the end of their operating lifetimes.

The past several years provide a powerful reminder of how suddenly — and unexpectedly — change can occur. In such a dynamic environment, we must plan for a range of potential outcomes in order to develop effective strategies that can stand up to the pressure of unanticipated changes while allowing for flexibility and adaptation.

Simply put, SRP's customers expect the same quality of service from us despite the changing and increasingly complex landscape. Meeting customers' needs over the next decade will require a complete transformation of our power system, including:

- How, when and where we generate and store electricity
- How we deliver electricity over our transmission and distribution systems
- How we engage with our customers through rate design and customer programs

Successfully transforming our power system and achieving our 2035 Sustainability Goals depends on our ability to plan in an integrated fashion, allowing for close coordination and collaboration among groups to identify the best systemwide solutions for customers. By planning together, we can best meet customers' needs and ultimately ensure a more reliable, affordable and sustainable future despite the challenges and uncertainties ahead.

The primary outcome of our first ISP is a set of seven interdependent **System Strategies**. These strategies will guide the actions of our planning teams and help establish a common vision for how we plan the system of the future. They will also help our teams ensure that their specific near-term actions — including siting, engineering, permitting, procurement, development, construction, operations, workforce development, etc. — are consistent with the common strategic vision.

Based on the System Strategies, SRP has already identified some of these near-term actions — the **ISP Actions** — which are summarized later in this section. While the System Strategies provide direction for planning the system, they are also developed with flexibility in mind. Because the future is difficult to predict, SRP cannot lock in all decisions through 2035 today. However, we can adapt and respond to these changing conditions while using the System Strategies to guide us.

Significant changes to SRP's power system are already underway. By the mid 2020s, we will add more than 2,000 megawatts (MW) of solar projects and more than 1,000 MW of battery storage. By 2032, we will retire more than 1,300 MW of capacity at four coal plants, replacing this capacity with new lower-carbon-emitting resources. We are also actively exploring regional market initiatives and have already committed to joining the Western Resource Adequacy Program (WRAP), a regional program designed to ensure there is enough resource capacity to maintain system reliability.

Need for Integrated System Planning

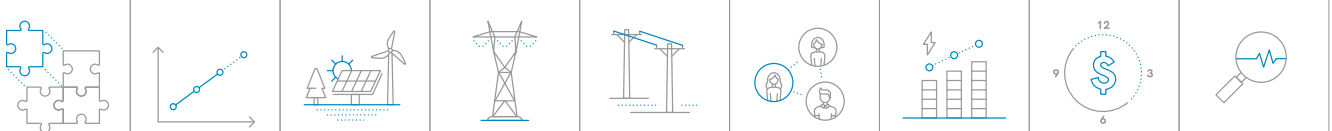
Historically, many of the planning functions that have existed within power utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan, has traditionally focused on future generation choices with limited insight into how those choices might impact all parts of the system.

Given the rapid pace of disruptive change in the power sector, planning decisions across the system must be coordinated from end to end to identify the best path forward for customers. For example:

- Adoption of EVs will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if SRP can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, this can limit the amount of new infrastructure investment needed.
- Many of the new large-scale generation resources that SRP will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of transmission and renewable resources.
- As the share of solar generation in SRP's portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative framework that includes all of SRP's key planning areas. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary and advanced engineering questions that will confront utilities in the coming decade. It will also help us ensure that the solutions we identify are robust given the many uncertainties for the future. A more in-depth overview of SRP's current system and the forces driving the need for an ISP is provided in Section 2.

KEY CONTRIBUTING DEPARTMENTS



Integrated System Planning & Support	Forecasting & Load Research	Resource Planning & Development	Transmission Planning, Strategy & Development	Distribution Planning & Strategy	Customer Programs	Financial Planning & Analysis	Pricing	Strategic Research & Insights

Our Planning Objectives

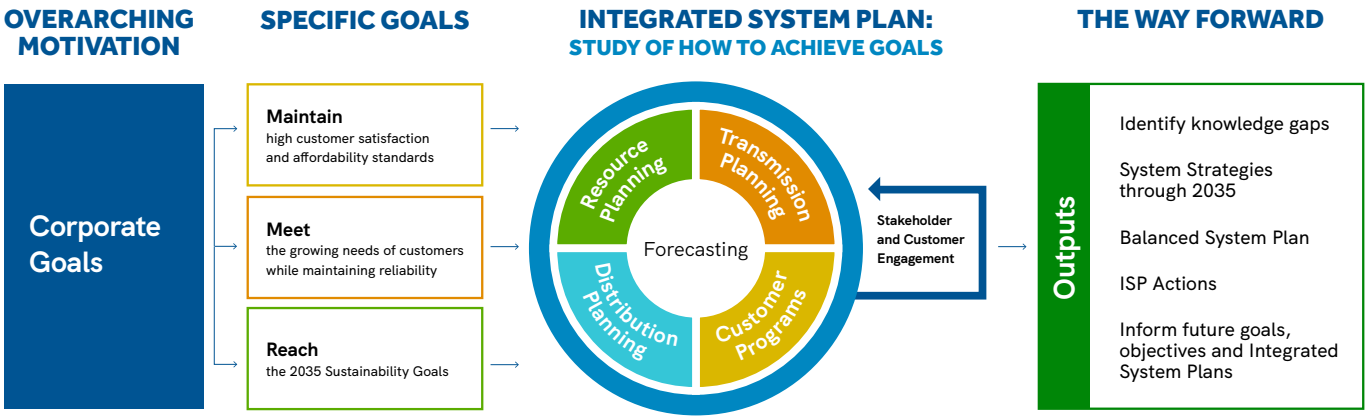
Reliability, affordability and sustainability are the cornerstones of SRP's 2035 goals, which in turn guide our planning efforts. Each of these is essential to upholding our mission and commitment to our customers.

Reliability: We are committed to maintaining electric reliability for our customers who depend on uninterrupted service, especially on the hottest days of the year.

Affordability: We recognize that electric bills represent a large cost to households and businesses. As many of our customers are facing mounting financial hardship and rising prices elsewhere in the economy, it is imperative that we strive to limit future increases to the cost of service.

Sustainability: We understand that our actions today will have far-reaching consequences for generations to come and recognize the importance of environmental stewardship to our community. These priorities are reflected in our comprehensive set of 2035 goals for minimizing our environmental footprint.

In the ISP, our teams performed rigorous systemwide modeling to identify viable pathways through 2035 to meet these goals. In addition to modeling, we engaged with customers and community stakeholders to inform and gather feedback on the ISP, while also building support for the ISP outcomes. The key deliverables of the ISP included the System Strategies approved by the Board, the Balanced System Plan and the ISP Actions. This first ISP also helped us identify opportunities to improve planning in future iterations. A more in-depth overview of the ISP process is provided in Section 3.



Stakeholder & Customer Engagement

A core component of the ISP effort included engaging our customers and stakeholders throughout the entire process, including study design, review of key findings, and development of strategies and actions. Since SRP delivers power to diverse communities, individuals and organizations, we took great care to ensure that we heard varying perspectives on how to design a first-of-its-kind ISP and how we should chart a path forward in planning the power system.

To engage our customers and stakeholders, we created an Advisory Group, which included 32 representatives from 23 different community organizations. This group met 18 times over the course of two years and provided feedback on all aspects of the ISP. We co-developed the ISP study design with the Advisory Group based on their feedback on how the future could unfold, how SRP could consider planning choices, and what aspects of planning the future power system were most important to capture. We also convened a Large Stakeholder Group, including over 140 organizations, eight times to inform a wider group of stakeholders and to receive feedback at key junctures throughout the process. In addition to engaging stakeholders, SRP convened groups of industry experts through four Technical Working Sessions to gather diverse industry perspectives on several key topics that are emerging in the industry. Through these three engagement tracks, customers, stakeholders and industry experts provided incredibly valuable feedback and played a key role in shaping the ISP study process and the final outcomes of the ISP. SRP greatly appreciates their participation and contributions throughout the entire process.

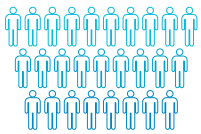
ISP PLANNING PROCESS **FAST FACTS**

NUMBER OF ADVISORY GROUP MEMBERS:

32
community representatives

from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



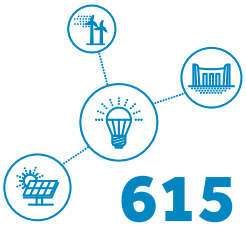
250
community representatives from
143
organizations

1,349
SLIDES PRESENTED

NUMBER OF MEETINGS:

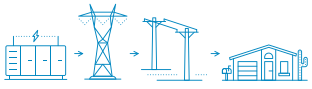
31 stakeholder meetings

totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED

4 **90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED**

STAKEHOLDER QUESTIONS ANSWERED:
588

In addition to convening stakeholders, SRP performed research in partnership with external research consultants to better understand the perspectives of residential customers. Residential customers have a diverse range of preferences, and it is challenging to capture these perspectives through a stakeholder meeting process given the time commitment required for those customers to meaningfully participate. To make sure that these diverse preferences were considered adequately within the ISP, we performed residential customer research. This customer research consisted of several focus groups and surveys of over 1,400 SRP customers, which SRP and its consultants ensured was a representative sample of residential customers based on demographics. Along with the stakeholder group meetings, this additional information provided us with a more complete picture of customers' desires and how the power system can help satisfy them.

Transparency was essential in the development of the ISP. To ensure visibility for interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the process. These can be found on our ISP webpage at srp.net/isp.

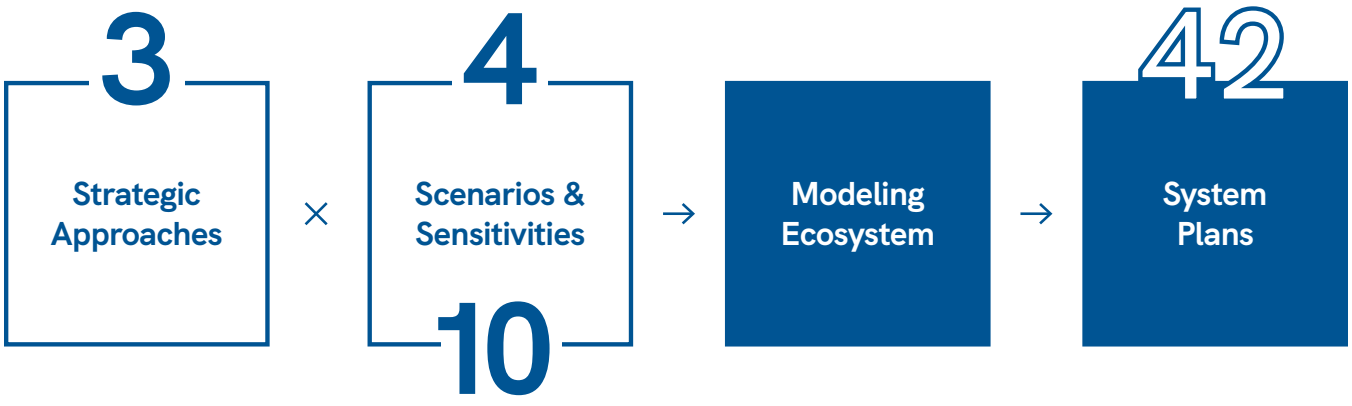
An Integrated Modeling Ecosystem

One of the principal challenges we encountered in implementing an ISP was designing an analytical framework with the appropriate level of detail to represent all parts of the system — from our biggest power plant to an individual customer's meter and every point in between. As the largest machine ever built by humans, the electric power system is incredibly complex. There is no single planning model with the capability to analyze the entirety of the electric power system as it undergoes transformative change over a long period of time. Instead, we sought to harmonize the models and tools currently used by each of our planning functions by utilizing common scenario definitions and consistent input assumptions. Additionally, we worked to improve the linkages between the models in such a way that information flowed fluidly between different analysis platforms. The result of these efforts is SRP's ISP modeling ecosystem that relies on common planning assumptions and connects tools used by each planning function with an unprecedented level of cohesion. This allows us to develop and analyze plans for the entire system.

Scenario-Based Analysis Framework

To identify solutions that benefit our customers across a wide range of uncertainties, we employed a scenario-based planning framework in the ISP. The planning framework included three key elements: scenarios, sensitivities and strategic approaches. A **scenario** represents a plausible future state of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions — generally, factors that are outside of SRP's control. A **sensitivity** modifies one assumption in a scenario to isolate the impact of that assumption. A **strategic approach** represents a decision or set of decisions that are within SRP's control as we develop the power system of the future. A detailed description of the scenarios, sensitivities and strategic approaches is provided in Section 4.

Studying each strategic approach under a range of scenarios and sensitivities provided a framework for understanding how different decisions stand up against the uncertainty of the future. The ISP analyzed three strategic approaches across four scenarios and 10 sensitivities, producing a total of 42 unique system plans. The methodology employed to develop these system plans is discussed in Section 5.



Each of the 42 system plans comprised specific plans for customer programs, distribution investments, transmission investments, and generation additions and retirements from 2025 to 2035. Additionally, for each system plan, SRP evaluated a variety of metrics that measured impacts to reliability, affordability, sustainability and customer value. Assessing strategic approaches across a variety of futures allowed us to identify strategies that work well across various scenarios and helps mitigate future risks. This also allows us to take advantage of potential opportunities, thereby creating a plan that is adaptive yet resilient to the forces of change.

Key Findings from Analysis

SRP gained new insights from performing systemwide analyses of the 42 system plans. This ISP showed how customer needs, infrastructure buildout and operations could evolve under a wide range of future scenarios and uncertainties. We also learned how our actions can influence reliability, affordability and sustainability while also helping to manage future risks and uncertainties. SRP distilled these insights into a list of key findings below. A detailed description of the analysis results is provided in Section 6 of the report.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how our customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers, while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity at an unprecedented pace in the next decade to serve customers while achieving reliability and sustainability goals.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230-kilovolt (kV) transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet infrastructure needs, supply chain and development solutions are essential to managing costs and to meeting the needed pace of transformation.

These key findings from the analysis underscore the tremendous transformation of SRP's power system over the next 10-plus years. Making this transformation a reality will be a significant undertaking requiring additional planning beyond the ISP to ensure there are detailed, sound engineering and operational plans in place for any additional infrastructure or changes to the system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc.

While the analysis provides insights into how to plan the future power system and tradeoffs for different approaches, SRP ultimately needs a plan that is specific enough for our planning groups,

communities and stakeholders to plan the power system. The plan also needs to be flexible, given uncertainties about the future and the potential for innovation. The plan should include strategies that are no-regrets across all futures, while also making tradeoffs between different objectives and identifying strategies that achieve an appropriate balance between reliability, affordability and sustainability. The next sections describe SRP's vision for how to plan the future power system, including System Strategies, an illustrative Balanced System Plan and ISP Actions.

System Strategies

SRP developed seven interdependent **System Strategies**, representing long-term strategies for planning and operating all parts of the power system, including customer programs, distribution, transmission, generating resources, pricing and system operations. The strategies were approved by SRP's Board on Oct. 2, 2023, and will guide planning through 2035 and beyond. Each strategy is anchored to key findings from the ISP and relies on the other strategies also being in place to ensure success and achievability. To develop these strategies, we synthesized a range of metrics and outputs across scenarios, sensitivities and strategic approaches. We also incorporated feedback from the ISP Advisory Group before finalizing and receiving Board approval.

Each strategy will require that we take action today. Some will take longer than others to implement, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 goals and beyond, manage costs for customers, achieve an adequate and reliable power system, and adapt toward a more sustainable future regardless of what that may be in 2035. The System Strategies are summarized below, and a full description is provided in Section 7.

Energy Investments
Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

Capacity Investments
Invest in firm generation, including natural gas, to support reliability and manage affordability, while also supporting advancement of emerging firm technologies.

Proactive Transmission
Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

Distribution Innovation
Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

Partnerships & Suppliers
Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

Evolution of Customer Programs & Pricing
Evolve pricing and customer programs to improve economy-wide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

Strategic Investment & Reinforcement of Existing Assets
Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

Balanced System Plan

The System Strategies set the direction for SRP's planning efforts through 2035. To provide an illustration of how the system could look in 2035, following implementation of the System Strategies, SRP developed a **Balanced System Plan**. The Balanced System Plan provides an illustration of power generation, transmission, distribution and customer program plans, as well as reliability, affordability, sustainability and customer focus metrics, through 2035. To develop this plan, we drew upon the key findings from the analysis and residential customer research and built out a system plan consistent with the System Strategies.

The Balanced System Plan adds a significant quantity of resources, more than doubling SRP's total installed capacity by 2035 relative to today. This includes adding:[2]

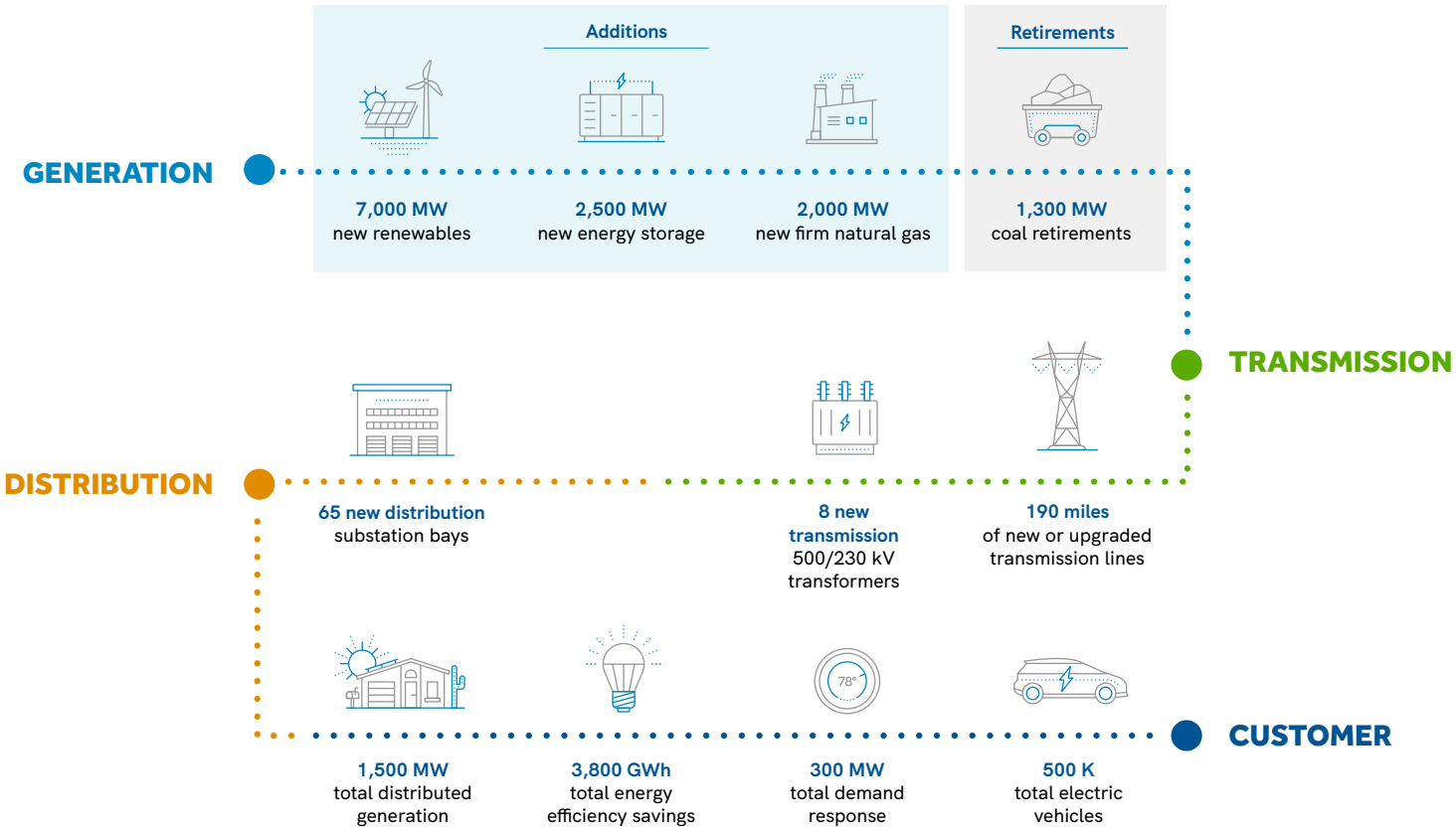
- 7,000 MW of new renewables
- 1,000 MW of new long-duration pumped hydro energy storage
- 1,500 MW of new battery storage
- 2,000 MW of new firm natural gas

This additional capacity, along with resources that are already contracted and planned to come online in the next few years, makes up for the loss of 1,300 MW of retired coal capacity and a retiring agreement with a natural gas plant. It also helps SRP keep pace with a greater than 40% growth in energy demand by 2035 and marks a significant increase of clean energy resources in the future power supply.

To deliver generation from these new resources and to accommodate the increase in energy demand, the plan includes more than 190 miles of new or upgraded high-voltage transmission lines, as well as eight 500/230 kV transformers. This infrastructure can take several years to site, engineer, permit, construct and energize, so it is crucial that SRP takes a proactive approach to ensure transmission is in place to enable future growth. The plan also includes more than 65 new distribution substation bays across existing and new distribution substations which is necessary to accommodate increasing energy demand.

Customers play a significant role in the transformation of the system in the Balanced System Plan. Customers' total energy demand is expected to increase significantly due to new large industrial customers, migration to the Valley and the growing popularity of EVs. However, this growth is mitigated to an extent due to customer adoption of distributed generation, like solar and batteries, and customer participation in SRP's energy efficiency and demand response programs. Moreover, as the power system evolves, we believe that customers can play a central role in achieving that transition through participation in future time-of-use price plans, electric vehicle managed charging programs and other offerings that have yet to be rolled out. The graphic on the next page shows the key elements of the Balanced System Plan, including power generation, transmission, distribution and customer program components.

[2] MW additions reflect the mix of resources determined to best balance reliability, affordability and sustainability needs. However, actual additions may change over time as external conditions change, such as load growth and technology costs.



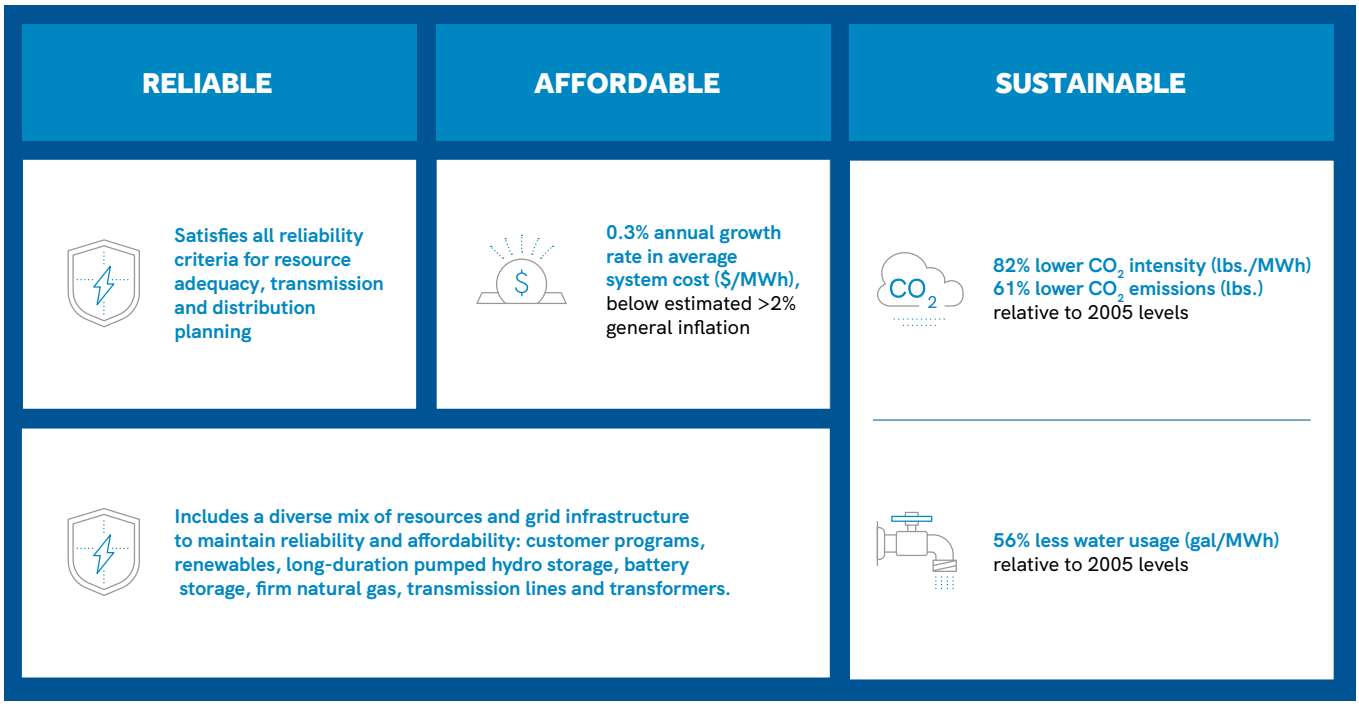
As mentioned earlier, the Balanced System Plan allows SRP to achieve important goals related to reliability, affordability and sustainability.

Reliability: By investing across the system — including new firm generation, long-duration and short-duration storage, renewables, transmission, distribution and customer programs — SRP will ensure strong reliability performance across the system.

Affordability: Due to the diverse mix of investments and programs, average system costs for this plan are projected to increase by less than 0.3% per year, well below projected general inflation. Ultimately, the driving force behind our plan is to meet customers' future energy needs at the best overall value. We believe this plan delivers on that goal.

Sustainability: As SRP retires coal capacity and adds significant amounts of clean energy resources, CO_2 emissions intensity is projected to decline by 82% (relative to 2005) and water usage intensity is projected to decline by 56% (relative to 2005), in both cases surpassing SRP's 2035 Sustainability Goals.

We are excited by the performance of this plan. However, as mentioned earlier, this illustration supports a common vision of what the future may look like based on what is known today. As expectations change — such as economic development forecasts, technology cost projections, or the implementation of new laws and regulations — the system plan will need to adapt and evolve accordingly. The Balanced System Plan is described in more detail in Section 8.



ISP Actions

Our planning processes do not stop with the ISP. In many ways, the conclusion of the ISP represents new beginnings as our teams start to execute the System Strategies. As a first step, SRP has defined 10 **ISP Actions**, which we have already started to implement. The ISP Actions will also help enhance our planning capabilities, establish a roadmap to implement the System Strategies and further our progress toward meeting our 2035 goals. The ISP Actions are summarized below, and a full description is provided in Section 9.

ISP Action #1: Residential Time-of-Use Pilot: Execute a residential time-of-use price plan pilot and perform customer research to evaluate customer response to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform SRP's load forecast for long-term system planning and SRP's price process.

ISP Action #2: Time-of-Use Evolution: Engage commercial, small business, large industrial and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods. Develop a roadmap for implementing new time-of-use periods, including the following elements: undertake a pricing process informed by the ISP as to how time-of-use plans need to evolve and develop a communication plan for all customer types and segments to educate them about any new time-of-use price plans.

ISP Action #3: Customer Programs: Continuously refresh program plans and drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from SRP's initial 2035 Sustainability Goal for energy efficiency.

ISP Action #4: EV Management: Develop a roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing EV charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.

ISP Action #5: Electrification: Analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on SRP operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.

ISP Action #6: Distribution Enablement Roadmap: Continue implementing SRP's Distribution Enablement (DE) Roadmap, including the following elements: deploy the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024; continue implementing advanced locational planning tools; advance the interconnection process; execute the Distribution Enablement Research & Development plan; and share the Distribution Enablement Strategy with external stakeholders.

ISP Action #7: Resource Selection: Issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that SRP can agnostically select resource technologies that minimize total system costs while meeting SRP's reliability and 2035 Sustainability Goals.

ISP Action #8: Coal Transition Action Plan: Develop a coal repurposing action plan, including the following elements: coordinate with co-owners to develop a path forward for the Springerville Generating Station; prepare a plan or plans for repurposing the Coronado Generating Station site; develop solutions that preserve transmission following the retirement of coal plants; and test strategies for minimizing emissions from coal power plants.

ISP Action #9: Proactive Siting: Develop and initiate collaborative community engagement, land, resources and transmission siting research to proactively identify, prepare and preserve options for feasible future system infrastructure sites.

ISP Action #10: Regional Transmission: Pursue transmission projects that would enable SRP to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.

The completion of the ISP Actions will significantly advance SRP's planning and development of the future power system. The ISP Actions related to time-of-use price plans, customer programs, EV management, electrification and the Distribution Enablement Roadmap will ensure that SRP continues to provide customers with the best options for managing their energy costs, adopting clean energy technologies and helping SRP achieve the future transformation of the power system. The ISP Actions related to resource selection, the coal transition action plan, proactive siting and regional transmission will ensure that SRP takes a proactive approach to managing the transition of existing coal assets, maintaining a reliable power grid, accessing the best available resource options and driving improved sustainability. Like the System Strategies, these ISP Actions work together to help SRP achieve its reliability, affordability and sustainability goals. To keep SRP's Board, customers and stakeholders informed on progress made toward the ISP Actions, SRP will provide annual updates.

Beyond the First ISP

SRP is excited to have completed this first ISP. It was a first-of-its-kind effort that required creative thinking in how to plan the entire system in a coordinated manner and led to a comprehensive set of System Strategies and ISP Actions that will allow us to take concrete steps to transform our power system. Given that this effort was trailblazing in many regards, there were challenges in doing end-to-end modeling of the entire system across so many different futures. However, upon reflecting on this effort, we are more confident than ever that an integrated system planning framework is the best way to plan the future power system. By planning for the entire power system within one process, we can identify solutions across the entire system and how those solutions must work together to allow us to achieve reliability, affordability and sustainability goals at the best value to our customers.

The first ISP is just a starting point. SRP has learned a lot about how to perform systemwide planning through this effort and plans to continue to improve upon it in future iterations of the ISP. This will provide us with opportunities to update scenarios as new information becomes available and consider any adjustments to strategies, a balanced plan and actions based on updated systemwide analysis. In the meantime, we will use findings from the ISP to support other ongoing efforts at SRP, including annual planning activities, procurement of new resources through all-source requests for proposals (RFPs), and our 2035 Sustainability Goals update process.

SECTION 2

SRP Overview and Background

About SRP

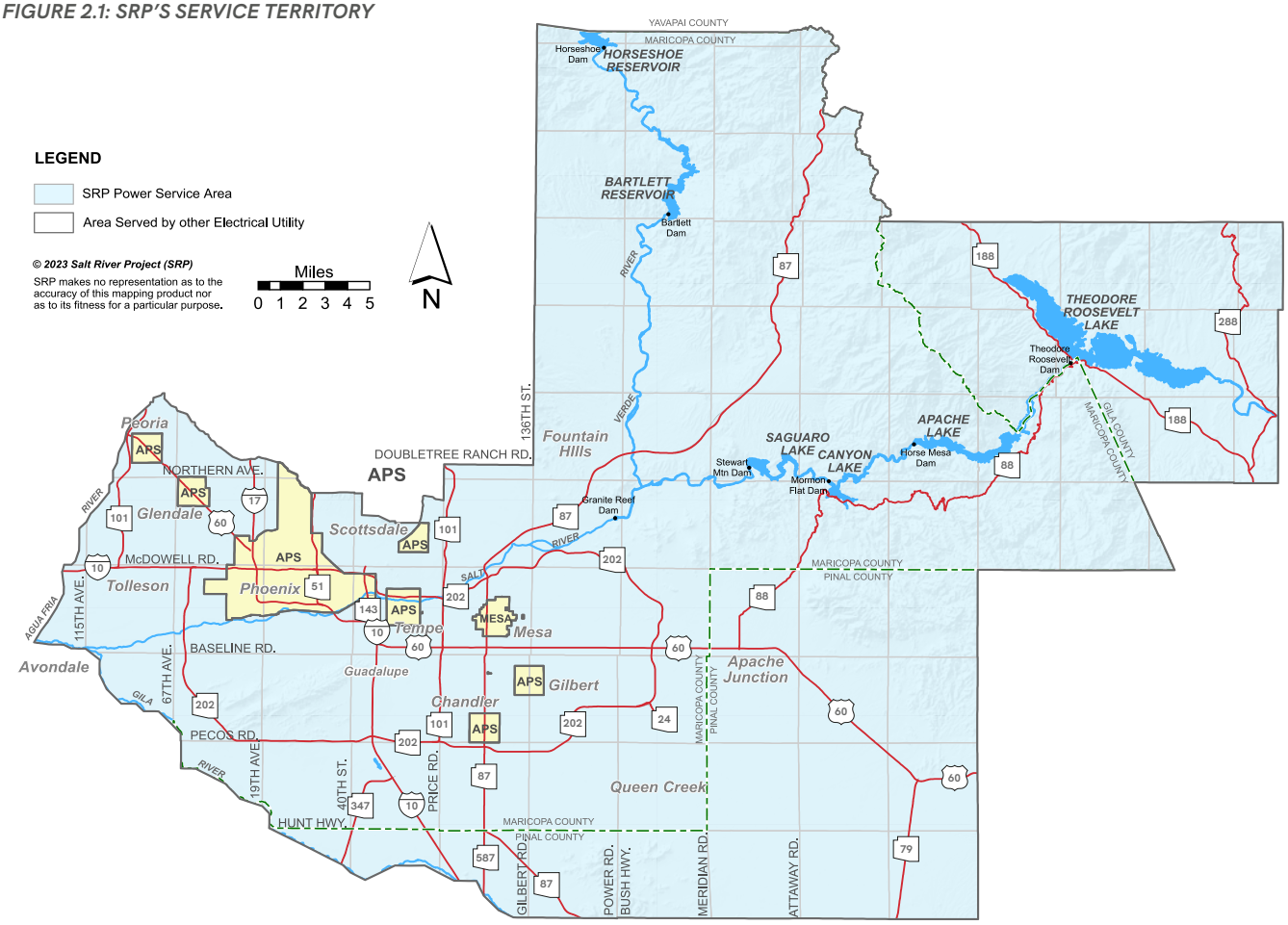
Salt River Project (SRP) is the oldest multipurpose federal reclamation project in the United States and one of the nation's largest public power utilities. As a community-based not-for-profit organization, SRP's mission is to serve our customers and communities by providing reliable, affordable and sustainable water and energy. Our long history, beginning in 1903, predates Arizona's statehood.

SRP comprises two separate organizations: the "Association," a private water corporation founded in 1903, and the "District," an electricity provider formed as an agricultural improvement district and a political subdivision of the State of Arizona in 1937.

SRP has helped and will continue to help the Phoenix metropolitan area develop and thrive by providing these essential water and power resources. Our guiding principles have remained the same since our founding: to act in the best interest of the people we serve and strive to help build a better future for Arizona.

For over a century, SRP has focused on building strategic partnerships and innovative solutions to meet the Phoenix metropolitan area's ever-changing needs. In the years ahead, we will continue to lead the way by applying a forward-thinking approach and new technologies to address energy supply challenges.

FIGURE 2.1: SRP'S SERVICE TERRITORY



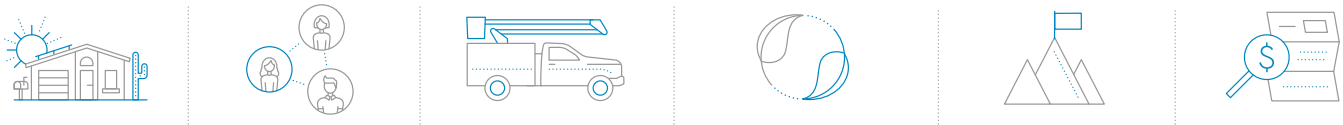
Electric Customers

SRP takes great pride in serving over 1 million electric residential, municipal, large commercial, industrial and small business customers. Residential customers are households that use electricity for their daily needs, such as lighting, heating and cooling. Municipal customers are local governments that use electricity to power public facilities, such as streetlights, traffic signals and water treatment plants. Small business customers are businesses that consume a relatively small amount of electricity, such as small shops and restaurants. Large commercial customers, such as shopping malls, hospitals and universities, consume a significant amount of electricity. Industrial customers are businesses that use electricity to power heavy machinery and equipment, such as factories and manufacturing plants.

J.D. Power recently ranked SRP highest in customer satisfaction in the western United States among large electric utilities for the 22nd time in the 23 years that J.D. Power has been surveying residential electric customers — and the 20th year in a row. Among large electric utilities (500,000-plus households), customers ranked SRP as the top-performing large electric provider in the West in all six customer satisfaction factors: power quality and reliability, price, billing and payment, corporate citizenship, communications, and customer service.

SRP's 2035 Goals

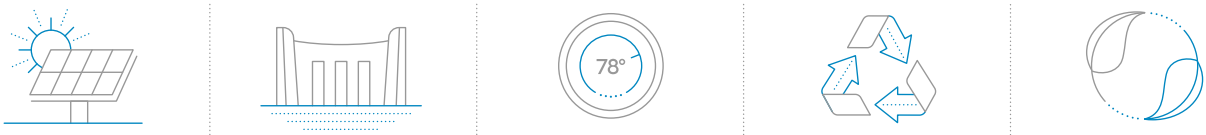
For over 120 years, SRP has fulfilled its mission to deliver reliable, affordable and sustainable water and energy. Our 2035 Corporate Goals define what we want to achieve over the long term in order to continue delivering on our mission. The categories for our corporate goals are shown below. These goals provide us with a purposeful structure for planning strategically as a company. They also allow us to anticipate and respond to the many ways in which our customers' expectations are changing, new technologies are emerging and advancing, and the energy sector is transforming.



CUSTOMERS | **COMMUNITY** | **WORKFORCE** | **SUSTAINABILITY** | **LEADERSHIP** | **FINANCES**

A subset of goals within the 2035 Corporate Goals are sustainability targets that impact SRP's future resource and customer program planning. They include Carbon Footprint and Water Resiliency Goals related to generating resources and Customer and Grid Enablement Goals related to customer programs.

SRP SUSTAINABILITY GOALS



Carbon Footprint | **Water Resiliency** | **Customer & Grid Enablement** | **Supply Chain & Waste Reduction** | **Customer, Community & Employee Engagement**

Carbon Footprint & Water Resiliency Goals:

- Reduce carbon emissions from generation intensity reaching 65% reduction by 2035 and 90% by 2050.
- Achieve a 20% reduction in generation-related water use intensity across all water types.
- Eliminate or offset power generation groundwater use in Active Management Areas (AMAs).

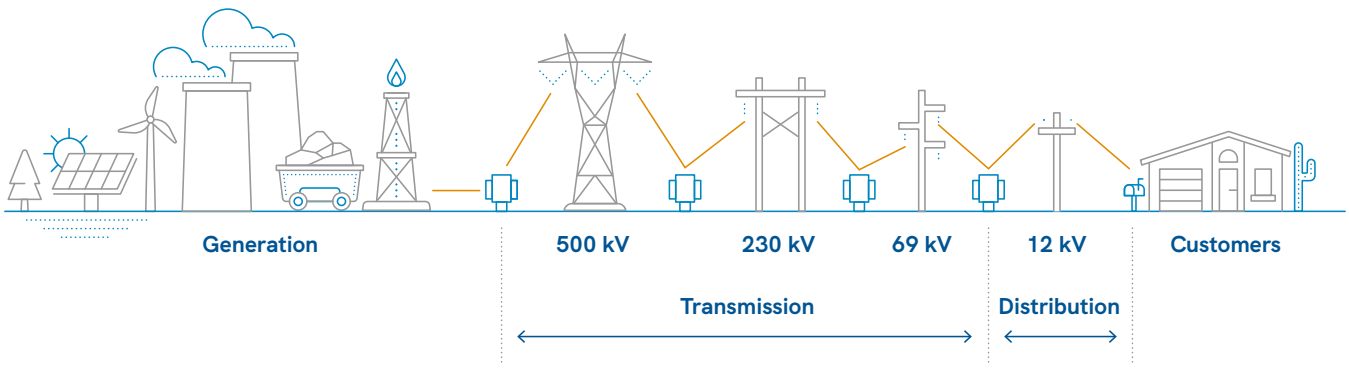
Customer & Grid Enablement Goals:

- **Energy Efficiency:** Deliver over 3 million megawatt-hours (MWh) of annual aggregate energy savings.
- **Demand Response:** Deliver at least 300 megawatts (MW) of dispatchable demand response and load management programs.
- **Electric Transportation:** Support the enablement of 500,000 electric vehicles (EVs) in SRP's service territory and manage 90% of EV charging through price plans, dispatchable load management, original equipment manufacturer integration, connected smart homes, behavioral and other emerging programs.
- **Electric Technologies:** Expand the electric technology (non-EVs) program portfolio to deliver 300,000 MWh of annual aggregate energy impact.
- **Grid Enablement:** Enable the interconnection of all customer-sided resources, including solar photovoltaic (PV) and battery storage, without technical constraints while ensuring current grid integrity and customer satisfaction.

The 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders. To learn more about SRP's 2035 Sustainability Goals, visit srp.net/2035.

Existing Power System

SRP is a vertically integrated utility that owns and plans for all-electric energy supply chain levels, including generation, transmission, distribution and customer programs. As a vertically integrated utility, SRP owns and controls the electricity supply chain's generation, transmission and distribution components. We are responsible for producing, transmitting and distributing electricity to our customers. We also design customer programs and pricing to ensure we meet customers' evolving needs and signal customers when to use electricity.



Being a vertically integrated utility, SRP has some advantages when planning, including greater flexibility in designing and implementing customer programs and pricing plans that meet the specific needs of our customers and our system. We can use our oversight of the entire electricity supply chain to ensure that our customer programs are integrated with our operations. This can help improve the reliability and efficiency of SRP's operations, ultimately benefiting customers by reducing costs and improving service quality.

Historically, many of the planning functions that have existed within vertically integrated utilities like SRP have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing.

Generation Overview

Resource planning at SRP determines what generation resources we need to add to our system to maintain reliability and achieve SRP's 2035 Sustainability Goals. SRP's generation resources can be viewed as capacity or energy sources. Capacity is the maximum output a generating resource can physically produce or export at a single point in time, measured in megawatts (MW). This output helps serve high peak demand hours and when the system has critical needs. Not all resources have the same capability to produce power at full capacity for all hours of the day and year. Demand resources, such as Demand Response and Energy Efficiency, are measured by their capacity to reduce demand, also in MW.

Energy is the amount of electricity a generator produces over a specific period of time, measured in MWh. Many generators do not operate at their full capacity all the time. A generator's output may vary according to conditions at the power plant, the availability of fuel, variability of wind and sun, or dispatch instructions from the utility due to changes in fuel costs or market prices. To maintain a balanced grid, SRP must constantly match demand with supply at any given instant.

Think of capacity like the lanes on a freeway and the maximum number of vehicles it can allow. Commuters need enough lanes to accommodate the number of vehicles during rush hour traffic. This means several of the lanes may be empty during lighter traffic times of the day, but the additional lanes are necessary for vehicles during a peak traffic time. Think of the energy as the flow and number of vehicles traveling on the freeway over a given period of time.

ANALOGY

Capacity: Maximum number of cars that can fit on an interstate during rush hour.

Energy: Number of cars per year traveling on that same interstate.

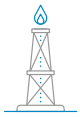
Previously, SRP used an Integrated Resource Plan (IRP) to determine the generation resources needed to meet our forecasted demand. Using this IRP process, SRP could understand how different resource choices and energy portfolios performed in various scenarios and future business environments. Our past IRPs aimed to analyze possible critical uncertainties and the generation of resources available to navigate them. This process involved evaluating current and future energy needs and developing a resource plan to meet those needs in a cost-effective, sustainable and reliable manner. The IRP process included a variety of analyses, such as load forecasting, resource planning and economic analysis. The IRP process aimed to ensure that the utility can provide reliable and affordable electricity to its customers while minimizing environmental impacts.

Once the IRP was completed, SRP would then develop specific plans linearly based on annual load forecasts, starting with a resource plan, then transmission, distribution, and customer programs and pricing. The resource plan was based on the resulting strategic directions from the IRP process, inclusive of annual load growth projections. Then, each subsequent plan was developed and designed to meet SRP sustainability and corporate goals. On an annual basis, between IRP cycles, we monitored and evaluated our operations and adjusted individual planning area plans to ensure that we met our goals and continued providing reliable, affordable and sustainable electricity to our customers.

The overall objective of the IRP was to incorporate a flexible resource plan that could embrace the challenges, uncertainties and growing energy requirements of tomorrow's world. The following are the concluding strategic directions from the 2017-2018 IRP.

Coal Generation: Reduce the amount of energy in SRP's portfolio produced by coal generation.

Nuclear Generation: Preserve option for new nuclear generation in the mid-to-late 2030s with a focus on small modular technology.

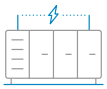


Natural Gas Generation: Develop flexible natural gas generation options to meet peak demand and integrate renewables.

Customer Programs: Continue the promotion of energy efficiency programs and technologies that help customers save energy and money.

Renewable Energy: Grow SRP's renewables portfolio to reduce CO_2 intensity and manage costs; expand opportunities for customer-dedicated projects.

Market Resources: Implement Energy Imbalance Market participation as planned and seek opportunities to expand participation in other regional markets.



Energy Storage: Add cost-effective energy storage to support additional renewable energy integration.

New Technologies: Pursue pilot projects and research and development efforts for innovative applications of new power generation, load management, energy storage and electrification.

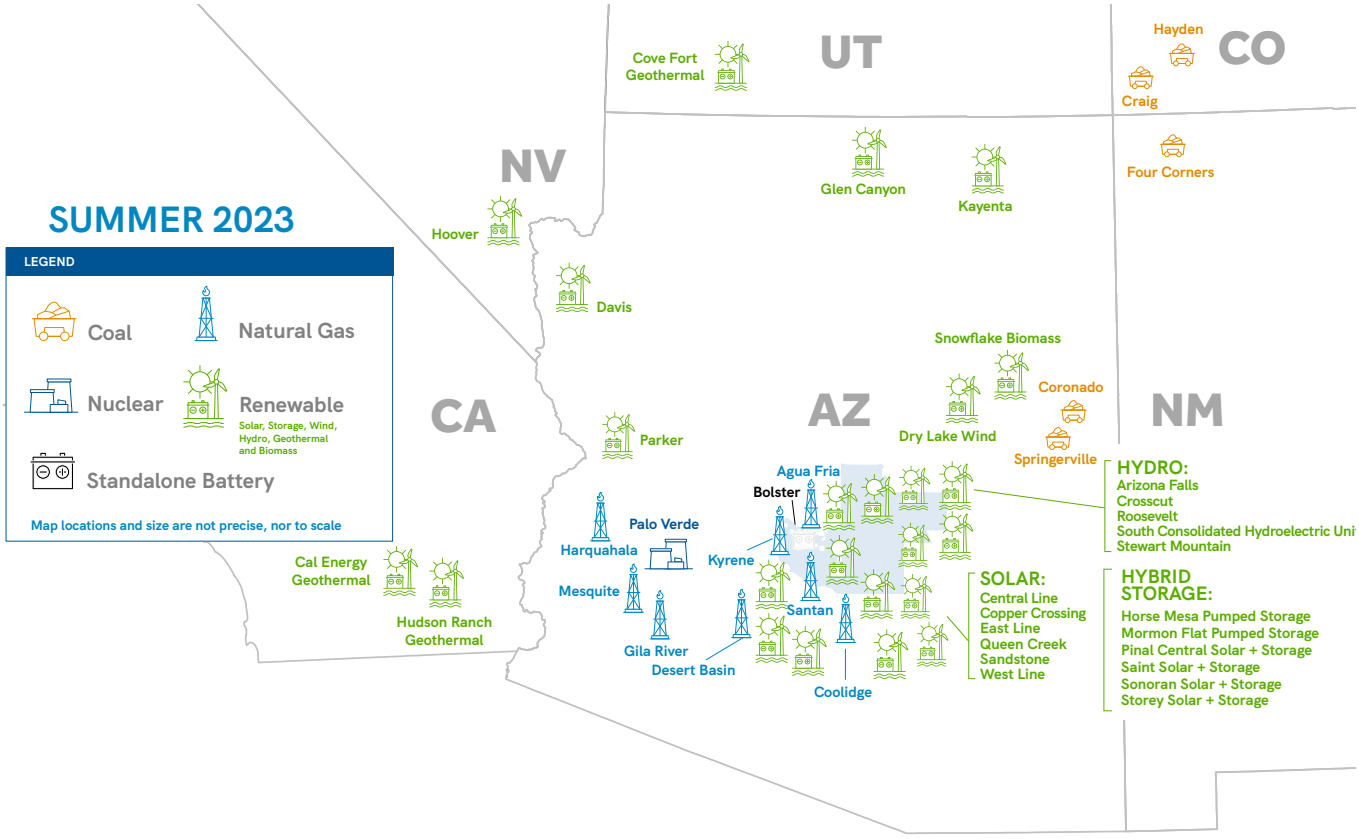
Featured in the next section are brief overviews of each planning area, where they are today and what we must consider when planning for the future.

SRP's Generation Sources Today

Over the past few years, SRP's service area has been experiencing significant and unprecedented growth in demand. In 2023, SRP served a multiday record peak for electricity demand. On several days, power demand reached over 8,000 MW, and SRP served its highest peak demand of 8,163 MW on July 18, 2023. The 2023 peak was 7% higher than last summer.

Where Does SRP Power Come From?

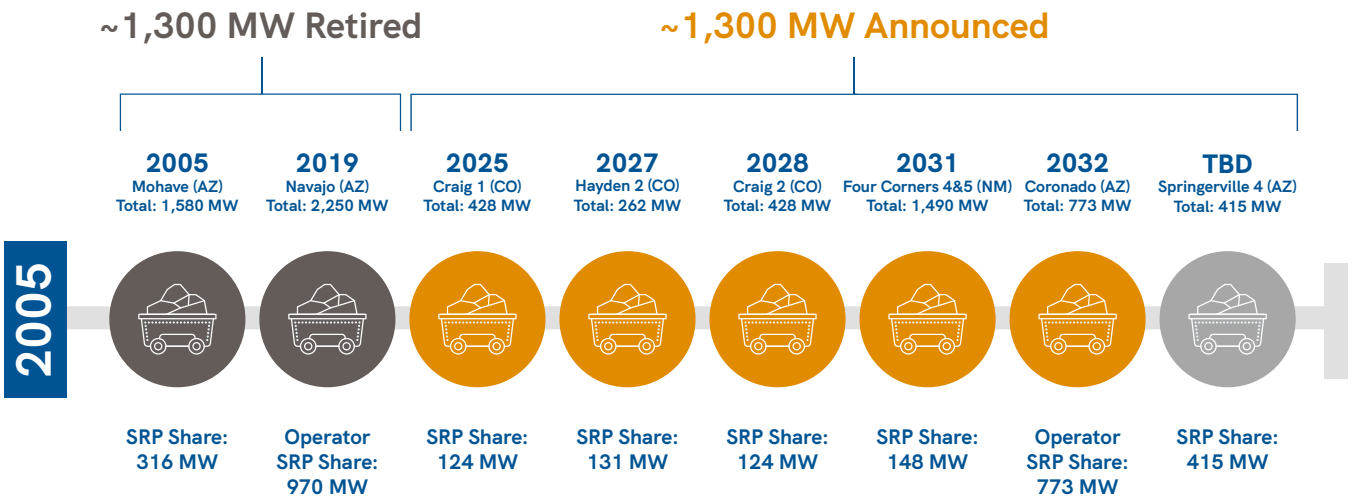
SRP generates electricity from renewable, traditional fossil fuel and carbon-free sources. The renewable sources include solar, geothermal, biomass, wind and hydropower. Traditional fossil fuel sources include coal and natural gas, and carbon-free sources include nuclear generation. Below is a graphic that displays what and where SRP generation sources are today.



To address growing demand and enable the achievement of our 2035 carbon reduction goals, SRP has been positioning its resource portfolio in alignment with the IRP strategic directions that would allow for a lower-carbon future by retiring coal plants, adding new renewable resources, integrating storage, adding flexible natural gas and acquiring existing zero-carbon nuclear resources.

Progress in Reducing Coal

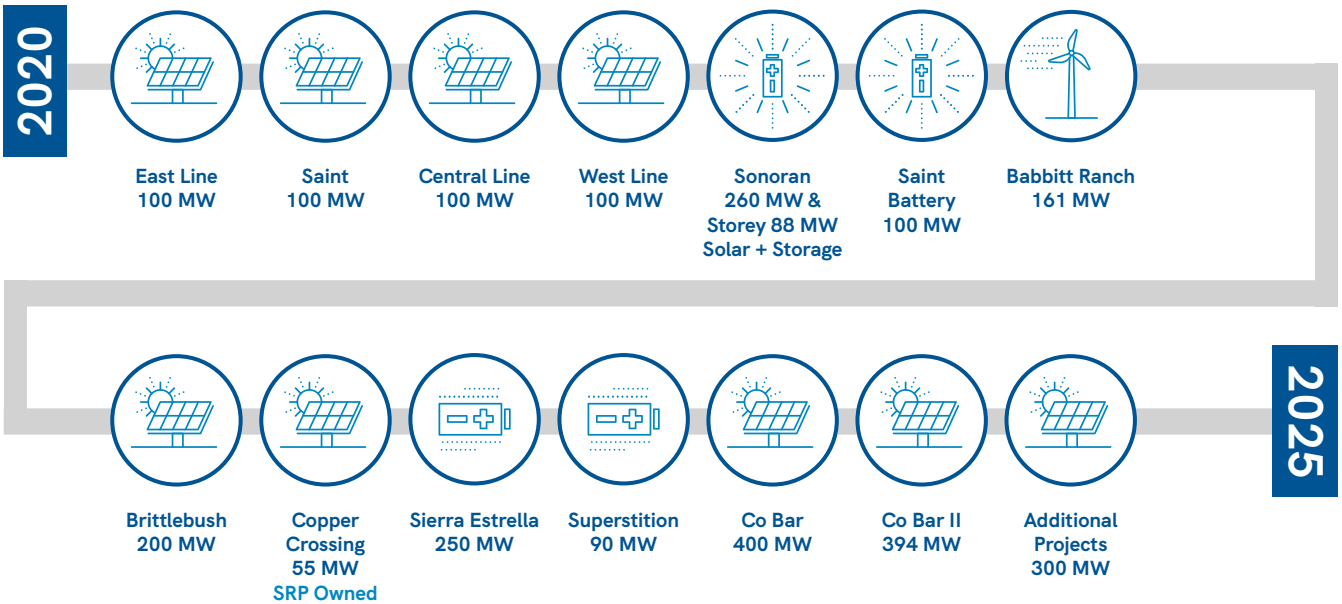
Since 2005, SRP has taken action to retire approximately 1,300 MW of coal generation. By 2032, SRP will retire an additional 1,300 MW from four coal plants already announced for retirement that will be replaced with new lower-carbon resources.



Increase carbon-free resources

In fiscal year 2023 (FY23), SRP added 104 MW of carbon-free generation from Palo Verde and has contracted an additional 10 MW in 2024 for a total of 114 MW. With this purchase, SRP increases the carbon-free energy delivered to our customers by up to 1,000,000 MWh annually, over 2.5% of our annual retail electricity.

SRP also prioritized additional renewable resources by adding 400 MW of new solar and has contracts in place for an additional 1,697 MW and continues to work with developers to implement 1,088 MW of storage and 161 MW of wind under contract.



Develop long-lead carbon-free resources

We have made great efforts to develop the capability to effectively integrate utility-scale storage technologies into our system to provide the optimal value to SRP and our customers, improve our ability to decarbonize with greater amounts of low-cost intermittent renewable resources, and potentially avoid or defer adding conventional generation or power delivery infrastructure while mitigating life-cycle environmental impacts. In addition to new lithium-ion storage technology, we have initiated early development of a Pumped Hydro Storage Project for up to 2,000 MW with a 10-hour duration. Pumped storage can provide utility-scale storage resource diversity and is a proven technology that SRP has had decades of experience owning and operating.

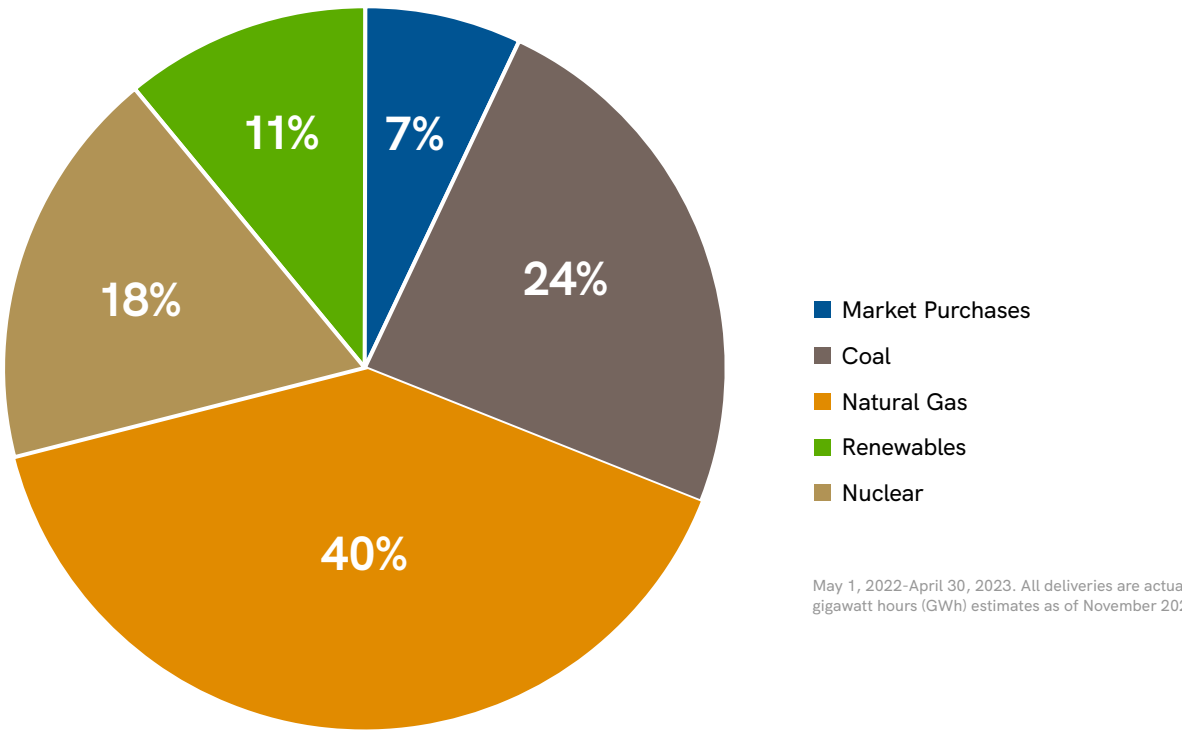
Adding flexible firm resources for future renewable integration and reliability

Without sufficient generation resources and power system stability, SRP customers may experience power shortages. Firm resources are sources of electricity (generation resources) that the utility can dispatch to meet system needs. Characteristics of a firm resource include reliable capacity in all seasons and over long durations. Natural gas is a firm resource that provides flexibility to balance ramps caused by intermittent resources (such as solar and wind) and fast response during emergencies. In 2023, we obtained an Amended Certificate of Environmental Compliance (CEC) authorizing SRP to build the natural gas peaking Coolidge Expansion Project to help integrate intermittent renewable resources.

SRP's Energy Mix

SRP's resource mix is constantly evolving to meet growing customer demands. The chart in Figure 2.2 summarizes SRP's latest energy mix delivered to customers from FY23.

FIGURE 2.2: ENERGY DELIVERED TO CUSTOMERS



May 1, 2022-April 30, 2023. All deliveries are actua
gigawatt hours (GWh) estimates as of November 20

Transmission System Overview

Transmission and distribution refer to the various stages of delivering electricity, from generating resources to a "load" such as a home or a business. The primary distinction between transmission and distribution is the voltage level at which electricity moves. At SRP, transmission refers to energized facilities at 69 kilovolts (kV) (69,000 volts) or higher.

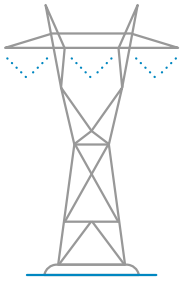
The transmission system is like the "interstate highway" of electricity delivery. It comprises three primary components: substations, switchyards and transmission lines. Both substations and switchyards are connection points where two or more transmission lines connect to form an "intersection."

The transmission lines are responsible for getting large quantities of electricity from the generation resources over long distances to the distribution system to deliver to customers. In some instances, larger energy customers connect directly to the transmission system.

SRP's transmission system is also part of a more extensive transmission network called the Western Interconnection, which ties SRP to other regional utilities and allows SRP to participate in wholesale power markets. The SRP transmission system is just a portion of this more extensive system with solely owned and co-owned lines with neighboring utilities. Being part of the Western Interconnection enables utilities to share generating resources to help balance the region's needs. Transmission Planning at SRP determines what new transmission infrastructure is needed to deliver energy reliably to SRP's service territory.

Transmission System Today

As of April 2023, SRP owns and/or operates and maintains about 3,333 circuit miles of three-phase power lines at 69 kV–525 kV voltages. Of these power lines, SRP owns approximately 955 miles of 69 kV, 263 miles of 115 kV, 493 miles of 230 kV and 361 miles of 525 kV. SRP jointly owns about 36 miles of 230 kV and 1,103 miles of 525 kV. These power lines and additional equipment, including over 1,200 circuit breakers and 72 transformers, make up the SRP transmission system today.



3,333 CIRCUIT MILES

Transmission Planning for the Future

As the demand for electricity in the Phoenix metropolitan area continues to grow, the need for new and upgraded transmission infrastructure also increases. Transmission infrastructure is planned to construct facilities and place them in service before they are needed. One of the significant challenges with planning the transmission system is the uncertainty around the location of the new electric demand and future generation resources. SRP proactively identifies and develops effective transmission solutions for current and future electric customers.

SRP is integrating low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts the transmission system. Some of the transmission-related challenges facing utilities are system voltage control, greater fluctuations in frequency, and increased risk of interruption due to forest fires. To best prepare for these transmission-related issues, we are shifting our planning practices to integrate consideration for all key planning areas. These new efforts will aid in developing plans to address grid needs across all of our planning areas holistically. This move also bolsters our efforts to achieve our 2035 Corporate Goals.

Distribution System Overview

The distribution electrical system includes the distribution substations and the infrastructure required to bring power safely and reliably to SRP customers. Distribution Planning is responsible for ensuring that we can serve the energy needs of current and future customers safely and reliably. This is accomplished by developing short- and long-term load growth plans and designing a highly configurable, robust looped system, allowing us to serve customers by multiple paths. If service from one path gets interrupted, we can still serve the customer from a secondary path. This configuration also allows us to reconfigure the system for optimal use of existing capacity.

This commitment to providing reliable power is why SRP has been ranked highest in customer satisfaction in the western United States among large electric utilities 22 times in the past 23 years that J.D. Power has been surveying residential electric customers.

Distribution System Today

As of 2023, SRP provides power to more than 1.1 million customers in a 2,900-square-mile service area. More than 1,198,000 advanced meters are serving SRP customers. Some of our customers are becoming increasingly involved with their energy future now more than ever by taking more of a prosumer role of consuming as well as producing electricity. In total, 51,287 customer-owned distributed energy resources (DERs) are interconnected with the SRP grid, including standalone solar generation, solar paired with battery storage, and standalone battery storage. Of those DERs, 50,468 are residential and 819 are commercial. These DERs provide a total generation capacity of 472 MW and a battery storage capacity of almost 16 MW.

Most of SRP's distribution system is looped, meaning there is more than one path that electricity can travel to serve a customer, but only one path at a time. SRP operates and maintains 21,736 circuit miles of lines that comprise the SRP distribution system, which entails 1,428 distribution circuits.

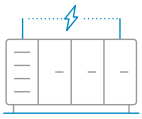
SRP operates and maintains 286 substations, including 191 distribution substations that transform power to the 12 kV voltage level to serve neighborhoods and other customers. A substation can accommodate one to four transformers, each serving 2,000–3,000 customers, depending on load requirements.

SRP is committed to providing reliable power, which is why we have ranked in the top 10 in the nation for our low System Average Interruption Duration Index (SAIDI) among all electric utilities with more than 500,000 customers every year for at least the past 10 years. This metric tracks the number of minutes customers are without power for more than five minutes averaged over all SRP retail customers. This includes any loss of customer load, planned or unplanned. SAIDI is an industry metric commonly used to assess overall power reliability.

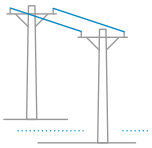
1.1 MILLION+ CUSTOMERS

2,900-SQUARE-MILE SERVICE AREA

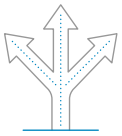
16 MW
DER BATTERY STORAGE CAPACITY



21,736
CIRCUIT MILES



286
SUBSTATIONS



Distribution Planning for the Future

The SRP distribution system is experiencing unprecedented growth due to a wide variety of new and expanding customers, including tech firms and advanced manufacturing. As more DERs, including solar generation and battery storage, are added to the distribution system, the possibility of voltage issues increases. The system is also experiencing an increase in electrification (EV adoption, smart appliances, etc.) that draws more of the load.

When we consider these factors, it becomes clear that we need to enhance our projection models of the distribution system and increase our ability to collect and analyze data. These efforts to plan for the changing grid will enable distribution planning to work collaboratively with other planning areas at SRP through an improved planning process.

Customer Programs Overview

Providing customers with reliable, affordable and sustainable service includes helping them understand and manage their energy usage through energy efficiency, demand response, electrification, EV and grid enablement programs. Customer programs enable us to effectively limit power plant emissions, lower costs, manage current demand and plan for future growth.

SRP has developed and fielded innovative customer programs and price plans to meet changing patterns in electricity use and customer needs. Demand Response (DR) programs such as smart thermostat and EV-focused programs and price plans encourage customers to shift energy usage to times energy is abundant and affordable. Looking to the future, we must evolve our programs to match the changing grid. Distributed energy programs enable the interconnection of thousands of customer-owned solar and battery systems each year. For customers unable to invest in their own renewable energy projects, SRP has invested heavily in system-scale solar and battery storage projects to offer unique solar energy programs that take advantage of economies of scale to help customers large and small achieve their individual sustainability goals. Customer programs will continue to meet evolving customer needs while spurring the transition to low-carbon energy for all customers.

Forecasting SRP customers' future energy demand (load) is one of the most important considerations for any long-term planning. We need to understand our customers' unique needs in order to plan for and maintain the reliability of SRP's transmission and distribution systems and have enough generating resources online to meet that load.

Customer Programs Today

For fiscal year 2023, SRP maintains a robust and comprehensive portfolio of customer programs; SRP's energy efficiency (EE) portfolio remains one of the largest and most cost-effective in the Southwest and across the country. For the 10th consecutive year, SRP was awarded the EPA's 2023 ENERGY STAR® Partner of the Year award with Sustained Excellence in recognition of outstanding delivery of Energy Efficiency programs.

Aside from EE and DR, SRP's growing Transportation Electrification programs are working to support the adoption of EVs and tackle the challenge of managing EV charging demands to avoid future on-peak hours. Electric Technology programs further support the electrification of fossil fuel-served loads today. In contrast, Distributed Energy programs support customer access to

utility-scale renewable energy projects and the interconnection of customer-owned solar and battery systems. SRP has also committed to developing programs like the Sustainable Energy Offering and others to partner with large customers with sustainability goals to reduce carbon emissions on a grand scale.

In fiscal year 2023, SRP's programs helped customers:

- Save 616,847 MWh — enough to power 37,000 homes annually — by:
    - Completing 70,000-plus residential efficiency upgrades and 1,200-plus commercial efficiency projects
    - Moving into 15,000-plus new, efficient homes and commercial spaces
    - Learning more about efficient, cost-saving behaviors (94,000 SRP Energy Scorecard™ and 148,000 SRP M-Power® participants)
    - Planting 5,300-plus drought-tolerant shade trees
- Develop 128 MW of dispatchable demand response capacity by:
    - Subscribing 87 MW of capacity through 76,143 smart thermostats in the residential SRP Bring Your Own Thermostat Program™
    - Enrolling more than 500 business customer facilities to deliver 41 MW of DR capacity
- Adopt 40,585 EVs within SRP's service territory and:
    - Install Level 2 or better charging for 3,300-plus EVs (581 business ports, 2,020 residential ports and 763 EV-ready homes)
- Electrify 15,897 MWh of business equipment load
- Achieve renewable energy goals by:
    - Commissioning 11,925 solar PV or PV+battery storage systems
    - Matching 100% of the electricity needs for 33 large commercial customers with 300 MW of dedicated solar energy through SRP's Sustainable Energy Offering (trimming carbon pollution in Arizona by 1.6 million tons)
    - Connecting 6,544 residential and small business customers to system-scale solar through the SRP Solar Choice™ program
- Avoid the consumption of 250 million-plus gallons of water through avoided generation and water efficiency embedded in the programs

Cutting carbon emissions by 1.6 million tons is equivalent to taking 300,000 cars off the road for a year!

SRP is committed to delivering programs and price plans that continually evolve to align with customer needs while maintaining a reliable, affordable and increasingly sustainable system. Despite recent achievements, there is a future need for even more energy efficiency to help maintain affordability by reducing customer energy consumption and pacing infrastructure investments. SRP has committed to accelerating its energy efficiency plans and goals while expanding demand response initiatives to help achieve established 2035 DR targets.

Customer Programs of the Future

As the population of SRP's service territory expands, we remain committed to meeting the growing needs of the communities we serve while staying focused on our 2035 Sustainability Goals. During our transition to a more sustainable future, the types and availability of low-cost resources will change with the increased adoption of renewables. As these changes occur, we will remain focused on striking the right balance of reliable, affordable and sustainable power for our customers. SRP continues to adapt its customer programs to meet changing patterns in electricity

use and needs by maintaining the acceleration of Energy Efficiency and Demand Response program plans to help address the significant load growth and capacity constraints SRP faces over the next several years.

As we plan further into the future, we must maintain affordability for our customers by continuing to leverage the existing infrastructure upgrades and expansion of customer program strategies to help reduce the need for costly new capital investments to meet near-term capacity needs. We must monitor how customers' energy usage and needs evolve and change as the digital economy drives how and when customers use power. Lastly, we must ensure customer programs will continue to help SRP cost-effectively meet growing customer needs while helping to address load growth and reliability challenges.

Uncertainties Facing SRP Today

While SRP's power system is transforming, other external factors also impact our planning efforts, including explosive load growth in SRP's service territory, evolving customer needs, supply chain volatility, regulatory policy uncertainties and resource adequacy uncertainty in the West. This section covers the significant drivers and trends we observed during our ISP planning efforts.

Explosive Load Growth & Evolving Customer Needs

The Phoenix metropolitan area continues to rank high in population growth nationally. For SRP, this growth means more customers, higher energy demand and increased peak demand. This demand is coming rapidly, putting pressure on us to develop solutions quickly. Demand has increased by 1.7% per year during the last decade, and these trends are expected to continue. While the SRP service area experienced extraordinary residential growth in the early mid-2000s, SRP is now experiencing unprecedented growth in the commercial and industrial sectors, including high-energy users such as semiconductor manufacturing, data centers and other high-tech industries.

Additionally, customers' energy usage and needs continue to evolve and change as the digital economy drives an evolution in how and when customers use power. These new customers not only need 24/7 power but also have specific power quality needs and an increased need for reliable power delivery. Large and small business customers are also driving renewable energy development needs for SRP, with an increased desire for partnership opportunities to help them achieve their sustainability goals.

Supply Chain Volatility

Volatility within the global supply chain impacts each group involved in SRP's integrated system planning process. COVID-19 exposed how quickly the interconnectedness of the global supply chain can lead to fewer suppliers, longer lead times, higher prices, material shortages and logistics challenges. Russia's war with Ukraine further exacerbated the disruptions to an already taxed supply chain and added to the uncertainty. Additionally, as inflation continues to rise, we can expect it to play a significant role in pricing in the future. Supply chain uncertainties are an essential factor in future planning and budgeting, as collectively or individually they can change the direction of our planning. Continuing to work jointly with our Supply Chain organization will enable us to find the flexible solutions needed to support our customers.

Regulatory Policy Uncertainty

Shifts in regulatory policies make it more difficult for SRP to make decisions because it is difficult to assign probabilities to possible future states confidently. Two policy developments that have a high potential impact on SRP's long-term planning efforts are the Inflation Reduction Act and the proposed EPA 111(b) and 111(d) rules.

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) was passed by Congress and signed into law by President Biden. SRP has traditionally contracted for renewable and energy storage projects through power purchase agreements (PPAs) with developers who could take advantage of previous tax credits. The IRA now provides SRP and other public power entities with access to direct pay credits for the first time, which may create the opportunity for SRP to receive federal incentives for self-built renewable and energy storage resources. The IRA could provide several potential benefits to power utilities; however, there are uncertainties about how the domestic supply chain will ramp up to meet increasing demand and what specific requirements must be met to qualify for IRA credits, given implementation guidance has not yet been issued.

Proposed EPA 111(b) and 111(d) rules

In May 2023, the EPA released its proposed carbon pollution standards for new, modified, reconstructed and existing power plants under sections 111(b) and 111(d) of the Clean Air Act. The regulatory package proposed standards for new gas-fired combustion turbines, existing coal and gas-fired steam plants, and certain large and frequently used existing gas-fired combustion turbines. The proposed standards are based on control methods and technologies (e.g., limited capacity factor, combusting hydrogen and installing carbon capture) that can be applied directly at electric generating units. If finalized, the 111(b) and 111(d) rules could help decarbonize the energy sector. Still, uncertainty remains regarding the availability and timing of the control technologies that the EPA relies on to reduce emissions.

Resource Adequacy in the West and the Impacts of Climate Change

SRP must maintain the ability to meet customers' energy demands at all times of the day and across a variety of system conditions. This resource adequacy requirement is becoming more complex as the utility industry transitions from conventional generating technology to renewables and storage. Reliable electricity supply is also becoming increasingly important to society as recent extreme weather events triggered regional outages that impacted customers and communities across the electric system. SRP routinely monitors the current trends affecting the desert Southwest region to understand better how to plan our investments and resources amidst uncertainty.

Because SRP is connected to an extensive grid system that includes neighboring utilities, the entire regional grid is at risk when one area or utility is not resource-adequate. Extreme temperatures also put pressure on utilities to maintain reliability by driving up customers' demand for more energy and fueling natural disasters such as wildfires that can damage the transmission system and limit utilities' ability to move power where their customers need it. The climate change impacts experienced over the last few years are expected to continue.

In light of the dramatic transition in the utility industry and the importance of regional resource adequacy, the SRP Board in January 2023 approved SRP's participation in the Western Resource Adequacy Program (WRAP), which is the first regional program of its kind in the history of the West. WRAP will deliver a regionwide approach to assessing and addressing resource adequacy. It will help ensure that entities use consistent planning approaches as utilities become increasingly reliant on variable resources like solar, wind and battery storage.

Technology Advancements

To achieve continued decarbonization while maintaining a highly reliable grid, SRP is monitoring, developing and deploying advanced low- and zero-carbon firm technologies such as clean hydrogen, long-duration storage and small modular nuclear. Accelerating the deployment of firm low-carbon energy solutions is required to continue to provide reliable and sustainable energy for SRP customers. Significant progress is being made around new nuclear technologies and long-duration storage that could provide reliable, safe and carbon-free generation in the future. Unfortunately, the current development timeline for some of these resources is over a decade. While today's market is experiencing some obstacles, a combination of new technologies, efficiencies in permitting and lower financial risk during construction may provide a compelling option for these resources in the future. Therefore, it is important for SRP to continue to pursue activities that preserve varying resource options, such as potential site locating and early permitting.

Planning for the Future

The electric power industry has undergone a dramatic transformation in recent years, and that transformation is expected to accelerate, driven by a variety of factors mentioned above, including:

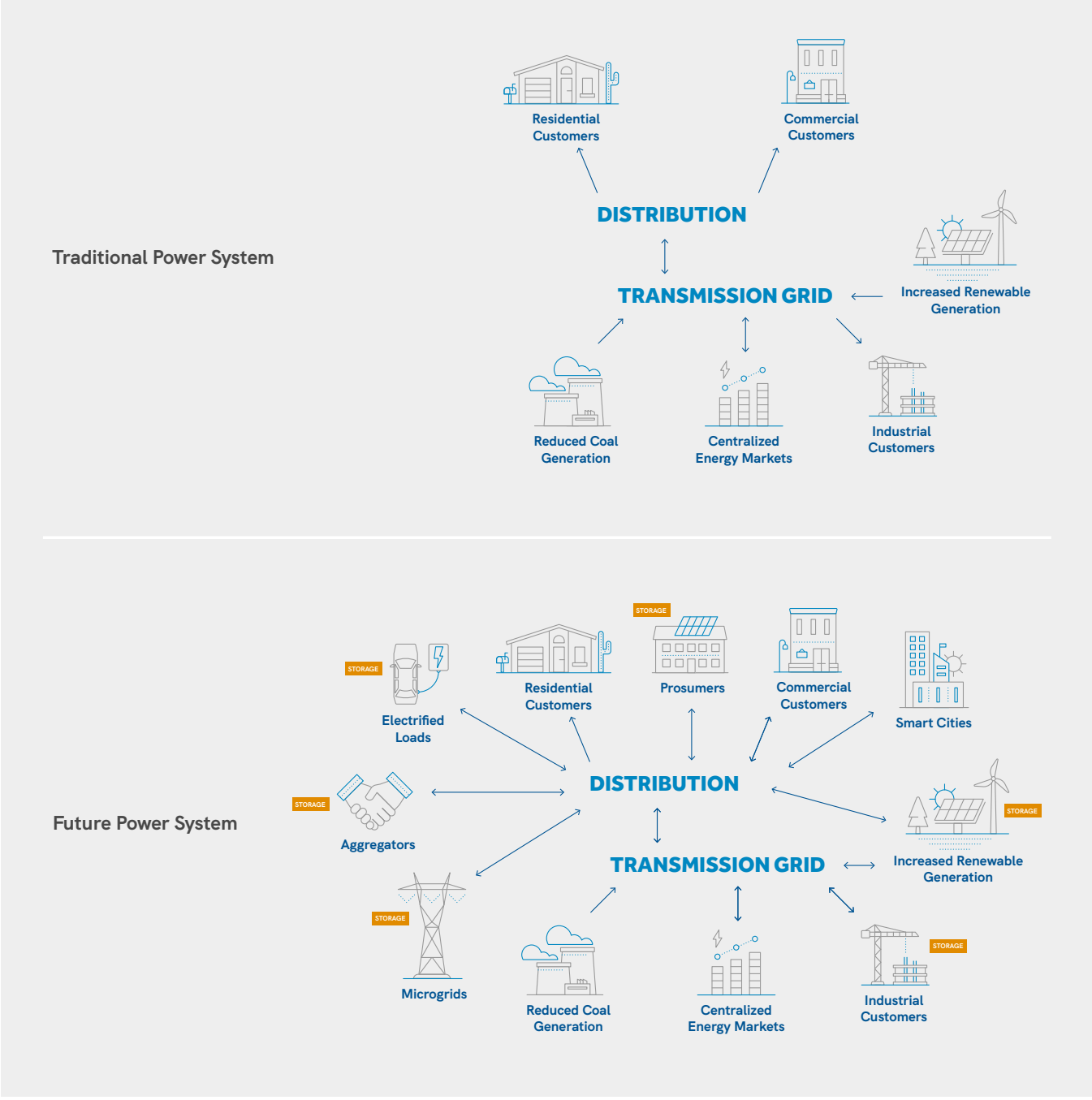
- Rapid deployment of large-scale variable energy resources (VERs) such as solar and wind
- The growth of distributed energy resources (DERs) like rooftop solar and residential battery storage
- Dramatic advances in digital energy and communications technologies
- Persistent low natural gas prices
- Increased reliance on just-in-time delivery of natural gas to support gas-fired generation
- Growing awareness of the electric sector's potential role in achieving environmental goals

While all of these external factors are changing, SRP is also evolving by integrating a significant number of low-carbon resources, such as solar, to meet our customers' growing electricity demand and replace retiring generation assets. This shift in our resource mix also impacts operations and the grid. Some of the transmission-related challenges facing utilities are system voltage control, more significant fluctuations in frequency, and increased risk of interruption due to forest fires. With these changes, traditional planning methods are increasingly insufficient to optimally develop a safe, reliable, affordable and environmentally responsible power system. Meeting our customers' needs over the next decade will require a complete transformation of the power system that touches all aspects of our business: how, when and where we generate and store electricity; how we deliver electricity over our transmission and distribution systems; and how we engage with our customers through rate design and customer programs. Our success

in this transformation depends on our ability to plan the system in an integrated fashion, allowing for close coordination and collaboration to identify the best solutions for our customers.

Integrated Resource Planning to Integrated System Planning

In the past, Integrated Resource Plans guided SRP's ability to plan long-term generation resource decisions by conducting structured analyses assessing risk and uncertainty. Given the many ongoing changes in the power sector, we must adapt these traditional planning methods to optimally develop a safe, reliable, affordable and environmentally responsible power system.



To best prepare for these impacts, SRP has transitioned from a conventional Integrated Resource Plan (IRP) solely focused on resource planning to a more holistic and comprehensive Integrated System Plan (ISP), including forecasting, resources, transmission, distribution and customer programs, to achieve our 2035 Corporate Goals.

An integrated system planning approach is necessary to meet changing customer needs, such as enabling two-way power flow for rooftop solar additions, managing charging of EVs, and anticipating the power system transition to a lower-carbon, increasingly complex grid. Given the effort needed to implement a holistic ISP, we focused on the period from 2025–2035 for our first-ever ISP, which will be covered in more detail in the next section.

SECTION 3

ISP Overview and Process

Why Integrated System Planning?

Historically, many of the planning functions that have existed within utilities have operated independently from one another. While planning processes for generation, transmission, distribution and customer programs have relied on some common data sets and exchanged some information, planning cycles are often asynchronous, focus on different objectives and planning horizons, and lack direct visibility into how quickly other parts of the system are changing. The most prominent of these planning processes, the utility Integrated Resource Plan (IRP), has traditionally focused exclusively or primarily on future generation choices with limited insight into the implications of those choices for other aspects of the utility's systems.

Given the rapid pace of change in the power sector, we identified a need to integrate planning within a single process — the Integrated System Plan (ISP) — to optimally develop a safe, reliable, affordable and sustainable power system. Planning decisions across the system must be coordinated to identify the best path forward for customers. For example:

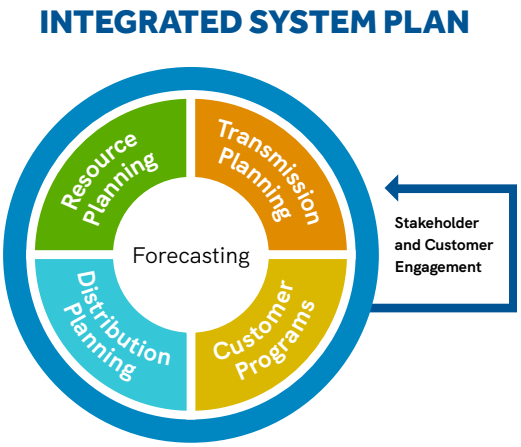
- Adoption of electric vehicles (EVs) will increase electricity demand, requiring additional investments in new power generation and delivery infrastructure. But if we can provide pricing signals to customers that encourage them to charge their vehicles during periods that are more advantageous for the overall system, we can limit the amount of new infrastructure investment needed. The most advantageous periods for charging will depend on future resource, transmission and distribution needs.
- Many of the new large-scale generation resources that we will consider — particularly renewables — will be located in areas where the existing transmission system may not be able to accommodate their delivery. Studying how the location of these new resources will impact the transmission system will provide a leading indicator of where new investment may be needed and may also allow for proactive siting of renewable resources to take advantage of transmission opportunities.
- As the share of solar generation in our portfolio increases over time, daytime energy will become increasingly abundant and lower the value of conservation during this period. This will have direct impacts on how we think about the value of future customer programs and the design of our future time-of-use price plans.

With this first ISP, we have transitioned to a holistic and collaborative planning framework that includes all key planning areas at SRP. By planning for the entire power system within one process, we are positioning ourselves to answer the most difficult multidisciplinary questions that will confront utilities in the coming years.

What is the Integrated System Plan?

SRP's ISP is a holistic power system roadmap that considers evolving customer needs for reliability, affordability and sustainability while achieving our 2035 Corporate Goals. The ISP includes all elements of meeting future customer demand: forecasting, power generation, transmission, distribution and customer programs. The ISP will help SRP plan for a future power system while maintaining a high standard of customer service from 2025 to 2035.

Before initiating the objective setting phase of the ISP, SRP retained Energy and Environmental Economics (E3), an energy consulting firm that works with utilities, regulators, policymakers, developers and investors to tackle the most pressing, difficult questions facing the electric industry. In our ISP — one of the first comprehensive efforts in the industry to initiate a systemwide planning process — E3's combination of broad experience, technical expertise and creative problem-solving made their support invaluable to our success. Further, having worked with each of Arizona's three largest utilities in support of integrated resource planning processes, E3 brought an understanding of our state's unique utility planning landscape that made their advice throughout the process germane and direct. At every step of the process, E3 was a vital partner for SRP, providing full-service support in the following areas: scoping the planning process; designing the analytical and stakeholder engagement frameworks; overseeing analysis and validation; and providing modeling support for the ISP process.



Objectives for the ISP

In April 2021, the SRP ISP project team and E3 concluded the objectives phase of the ISP after conducting many interviews and holding alignment workshops with SRP leadership. Through this process, the ISP project team received direction from senior leaders on the vision and objectives of the first ISP and received approval to develop a more detailed study plan.

ISP Vision Statement and Objectives

This vision, the goals and SRP's 2035 Corporate Goals guided the development of the ISP vision statement and objectives below.

"An ISP is a data-driven, collaboratively developed plan for generation, transmission, distribution and customer-sided resources to meet SRP's 2035 Corporate Goals and prepare for SRP's 2050 ambitions and system needs."

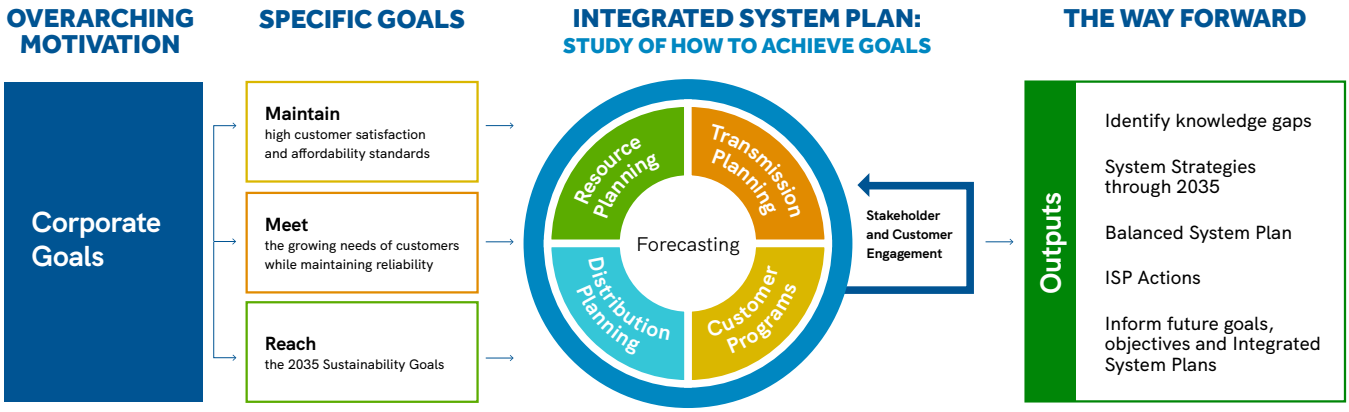
ISP objectives are to identify:

- Viable pathways for achieving SRP's 2035 Corporate Goals
- Costs, risks and trade-offs of these different pathways
- System solutions that are valuable across different pathways
- New capabilities or tools required to plan and operate as the system evolves effectively
- Activities SRP should undertake in the next six years to plan for these system solutions

SRP's 2035 Corporate Goals have been updated. The ISP leveraged goals established in 2019 and was completed prior to the 2024 updates.

Process for the ISP Development

The ISP process begins with SRP's Corporate Goals which establish the specific performance objectives of SRP and the motivation for the ISP. The ISP objectives relate to reliability, affordability and sustainability ("the what"), and the ISP determines how best to meet those objectives ("the how"). The ISP analytical process then combines the power system planning functions into an integrated planning framework to ensure that investments across the functional areas contribute together to support the corporate goals and objectives. In addition to the analysis, the ISP process included a comprehensive engagement process with customers and stakeholders to inform and gather input on the ISP and build support for the ISP outcomes. Key outputs of the ISP include a set of ISP Actions and longer-term System Strategies that help guide the development of SRP's power system through 2035.



The ISP analytical process, or "framework," was developed as part of the ISP objective setting process and involves conducting scenario analysis across the system functions to evaluate the cost and performance trade-offs and risks in achieving SRP's Corporate Goals. The process steps included:

1. Establishing an appropriate set of scenarios that evaluate key drivers of uncertainty outside of SRP's control.
2. Evaluating system needs for each scenario, subject to minimum reliability planning criteria.
3. Developing alternative solutions to meet the system needs for each scenario that consider key SRP decisions.
4. Synthesizing the scenario analysis to develop an illustrative Balanced System Plan that depicts the execution of ISP outputs, including System Strategies and ISP Actions, considering costs, performance and risk trade-offs metrics.

The objective development phase also included a stakeholder and customer engagement approach. SRP obtained the services of Kearns & West, a collaboration and strategic communications firm with experience in similar projects for other power utilities and an impartial approach to outcomes. Kearns & West offered input on establishing stakeholder groups and engagement methods, facilitated and documented meetings with stakeholders, and provided feedback on other aspects of stakeholder engagement. SRP, E3 and Kearns & West established a communications team, closely collaborating to create this approach. The communications team designed and executed all ISP stakeholder engagements, including scheduling, material

preparation and coordinating discussions with stakeholders internally and externally. The process included a review of best practices and lessons learned at SRP and other utilities. The effort also reviewed how other utilities capture residential and small commercial viewpoints in planning activities and consulted with SRP's Community, Communications and Marketing (CCM) organization to identify existing research resources and explore future approaches for gaining residential and small commercial customer input. Finally, the team consulted the CCM organization on best practices and options for stakeholder information sharing and regularly consulted SRP's 2017 IRP and Sustainability 2035 leads.

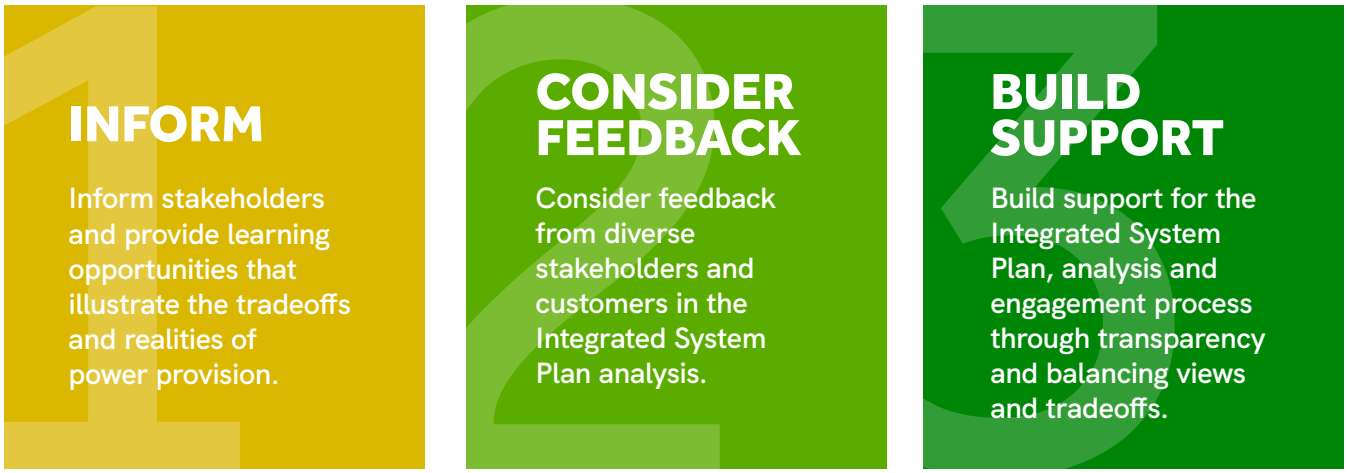
The stakeholder groups and customer engagement approaches are depicted below. SRP, E3 and Kearns & West also worked together to develop the details of the engagement approaches, including stakeholder group membership, roles, meeting topics and information sharing.

Stakeholder Group	Engagement Method
Advisory Group	• Focused engagement from a smaller diverse group • Regular meetings • ~20 representatives from diverse organizations • Role(s): Inform, Consult and Involve
Large Stakeholder Group	• Large-scale public platform • Eight meetings • Over 140 organizations • Role(s): Inform and Consult
Technical Working Sessions	• Small groups convened on specific topics with topical experts • Single sessions scheduled as needed around topics of interest • Role(s): Consult
Customer Research	• Multipronged approach to include the customer's voice • Surveys, customer preference elicitation, focus groups • Role(s): Consult

Role of the ISP Stakeholder Groups

A vital aspect of the ISP is developing and implementing a robust plan to actively engage customers and external stakeholders. SRP delivers power to diverse communities, individuals and organizations, and these stakeholders may hold varying views of the future and preferences for SRP's path forward. Providing information to stakeholders about the challenges SRP faces and collecting feedback on these challenges helped us roadmap a viable path forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped build support for the ISP process underlying SRP's strategic decisions. Much of the stakeholder and customer engagement efforts were planned to interact with the development of the ISP at specific touchpoints. These engagement efforts had the following three Global Goals:

FIGURE 3.1: ISP ENGAGEMENT GLOBAL GOALS



Transparency was essential in the development of the ISP. We designed the process to engage customers and other stakeholders and be responsive to their questions and input. In our best effort to keep transparency with all interested SRP stakeholders and customers, we posted all ISP stakeholder engagement materials publicly, including pre-reads, agendas, presentations and meeting summary reports, throughout the entirety of the project. These can be found on our ISP webpage at srp.net/isp.

Where We Needed Stakeholder Input for the ISP Process

Through the engagement tools described in the section below, SRP obtained input from stakeholders, including residential customers, regarding the questions proposed below. Their input helped shape all elements in the ISP study plan and informed the design on the final ISP outputs.

- Looking to 2035, what are Arizona's major sources of uncertainty relative to electricity generation, delivery, consumption and affordability?
- What system options should SRP include in its planning analyses for the future power system through 2035?
- What does success look like from your perspective when evaluating reliability, affordability and sustainability?

- What is the scope of the first ISP and which topics of interest should be considered for further research and future ISPs?
- What are the methods for balancing the trade-offs between reliability, affordability and sustainability?
- How might SRP improve our approach to stakeholder engagement for future ISP processes?

Stakeholder and Customer Engagement Tools

The ISP included customer research, technical working groups, large stakeholder group meetings, one-on-one discussions with interested stakeholders and the formation of an Advisory Group. This portfolio of engagement tools helped to achieve all three Global Goals described in Figure 3.1 on the previous page. Some groups focused more on bilateral dialogue, considering feedback and building support, whereas others focused on providing information to stakeholders and the public. The objectives and a brief description of each tool are given below.

The **Advisory Group** is made up of over 20 diverse community organizations and over 30 customer interest representatives. The group contributed wide-ranging expertise and perspectives to the ISP, which helped SRP produce a plan that reflects the diverse interests and values of the customers and communities we serve. Below are the mission and objectives of the ISP Advisory Group. For more information, please reference SRP's ISP Advisory Group Charter.

Mission Statement

The charge of the Advisory Group is to contribute wide-ranging expertise and perspectives to the ISP, resulting in an end product that integrates the diverse interests and values of the customers and communities SRP serves.

Objectives

- Create a dialogue around the ISP.
- Include diverse perspectives as input, guidance and review for the ISP.
- Provide a forum for deep and technical discussion of the trade-offs in energy system planning and the various perspectives to build support around the strategic directions and resource, transmission, distribution and customer program action plans.
- Focus communication for the Large Stakeholder Group.

Choosing a balanced and diverse group of stakeholders for the Advisory Group was critical to ensure that all perspectives were represented and that a single viewpoint was not dominant. To maintain balance, SRP chose members that were representative of one or more of the following stakeholder categories:

Local or special interest groups

- Community Advocates
- Equity Representatives
- Native American Interests
- Environmental Advocates
- SRP Resource Communities
- Public Interest Groups

Customer groups

- Commercial Customers
- Residential Customers
- Small Business Customers

Industry groups

- Energy Efficiency Industry Representatives
- Electric Vehicle Industry Representatives
- Renewable Energy Industry Representatives

Advisory Group Modeling Subgroups – Modeling subgroups were arranged as needed during the ISP process. Advisory Group members who were intensely interested in diving deeper into the ISP analysis self-selected into these subgroups. Efforts were made to include Advisory Group members who span stakeholder interests. Subgroup meeting discussions were reported in subsequent Advisory Group meetings. The Advisory Group's input, questions, ideas and concerns guided and initiated modeling subgroup meetings. If more than 50% of Advisory Group members were interested in participating in a specific subgroup, SRP would consider integrating the subgroup discussion content into the regular Advisory Group meeting series.

Large Stakeholder Group – This group of over 140 organizations was invited to eight meetings throughout the process. The meetings addressed informing stakeholders and considering feedback.

Mission Statement

To provide transparent communication to stakeholders regarding SRP's planning initiatives and allow for stakeholders to ask questions and provide feedback.

Objectives

- Keep stakeholders informed of SRP's planning initiatives in a transparent and proactive way.
- Build understanding of the trade-offs SRP faces and emerging trends in energy markets, regulations and technology.
- Provide opportunities for stakeholders to ask questions and receive answers from SRP experts.
- Provide feedback opportunities for stakeholders and consider their perspectives when balancing trade-offs while developing the ISP.

The Large Stakeholder Group was made up of over 140 organizations and 200 individuals, including representatives from SRP's customers and communities; 120 organizations were initially invited based on their existing relationships with SRP, standing within the Arizona community and diversity of perspectives. Types of organizations also included local and special interest groups, customer groups and industry groups. Throughout the process, SRP received many requests from individuals and entities to join the ISP Large Stakeholder Group outside of the initial organizations invited. They were all accepted and integrated into the process, resulting in a total of over 140 organizations at the end of the process. SRP strove to maintain inclusivity and representativeness within the Large Stakeholder Group so that the group reflected the diverse interests and values of the customers and communities SRP serves.

Technical Working Sessions – These sessions addressed specific technical topics of interest that arose throughout the ISP process and were attended by both external and internal SRP experts. The sessions leveraged external technical expertise for advice on the analytical methods used in

the ISP. The objectives of the Technical Working Sessions addressed considering feedback and building support and were to:

- Create a structured forum for external experts to give deep technical input to the most complex challenges in future planning.
- Build support around the ISP methodologies by leveraging external best practices.

Customer Research – This was a multipronged research approach that focused on understanding the preferences and perspectives of residential customers with the overarching goal of reflecting diverse customer voices and perspectives in the ISP. Customer focus groups and surveys were conducted to collect the preferences of SRP customers on balancing reliability, affordability and sustainability in potential energy futures. This data allowed SRP to consider the customer's perspective when choosing the best path forward. Customer research addressed bilateral dialogue, considering feedback and building support from our residential customers through the achievement of the specific following objectives:

- Co-create learning opportunities about the ISP and SRP's strategies, decisions and initiatives with customer input.
- Understand the energy/utility programs customers participate in and why.
- Understand customers' concerns about the future of Arizona, the economy and the United States.
- Align how customers plan for their futures and how secure they feel in their lot with the process and messaging of the ISP.
- Understand customer perspectives on power, reliability and potential trade-offs with sustainability.
- Understand the diverse perspectives and opinions on SRP's route to sustainability and how these opinions evolve.
- Include customer input into the ISP analysis and the balancing of trade-offs.

Guiding ISP Principles

These principles were developed in collaboration with ISP team and ISP Advisory Group members. The purpose of the Guiding ISP Principles was to balance all important considerations in developing an ISP. SRP strove to understand the inherent trade-offs between reliability, affordability and sustainability for the principles and sought to establish an ISP in accordance with these Guiding ISP Principles.

Integrated Long-Term View

Develop a holistic view, including resources, transmission, distribution and customer program perspectives, for meeting evolving customer needs and achieving our Corporate Goals for 2035 and beyond. The long-term view ensures that SRP is making the right decisions today to support its customers and stakeholders in the future.

Transparency

Engage customers and other stakeholders in a system planning process that is responsive to questions and input.

Measure Success Through the Eyes of Our Customers

Maintain industry-leading customer satisfaction by responding to evolving customer needs by providing safe, reliable, affordable and sustainable power while equitably recognizing the different needs, challenges and perspectives of our customers.

Manage Costs

Deliver exceptional system and energy value by minimizing impacts from additional grid needs and future uncertainties to average retail prices while maximizing customer value through diligent long-term-oriented cost management.

Build an Adequate and Reliable Power System

Meet (and in some cases exceed) industry standards to provide a dependable supply of electricity to all SRP customers. Provide a reliable grid that is able to prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability.

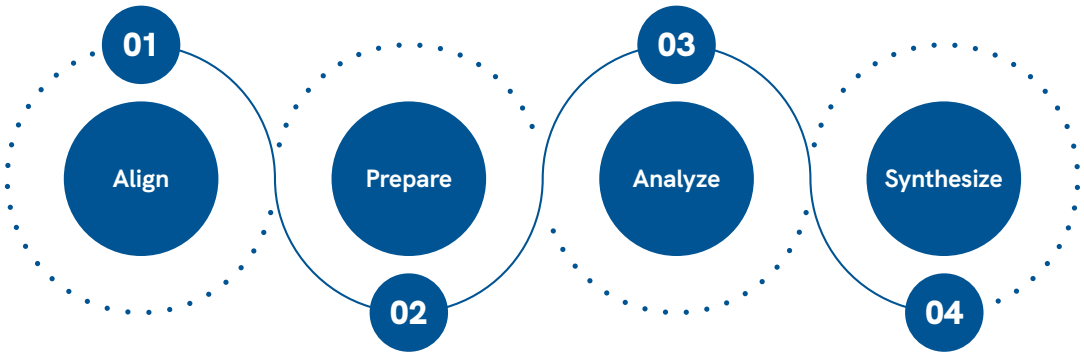
Adapt Toward a More Sustainable Future[1]

Meaningfully reduce carbon emissions and generation water usage to achieve SRP's 2035 Sustainability Goals to help address climate change and create less waste.

ISP Stakeholder Engagement Overview

Below is a summary of the stakeholder engagement process in the ISP and how we gathered and used internal and external stakeholder input to inform this first-of-its-kind planning effort in accordance with the above Guiding ISP Principles.

FIGURE 3.2: SRP ISP ROADMAP - STAKEHOLDER ENGAGEMENT



SRP ISP ROADMAP

Stakeholder Engagement

Align on Objectives of the first ISP

Collaboratively develop Study Plan:

Scenarios & Sensitivities Strategic Approaches Metrics

Gather input data

Perform system analysis

Validate and share results

Recommend new SRP system strategies

Recommend near-term actions

[1]The 2035 Sustainability Goals are being revised in 2024 in collaboration with community stakeholders. The next iteration of the ISP will focus on achieving and exceeding those revised goals.

Advisory and Large Stakeholder Group Engagements

For the initial Align Phase of the ISP depicted in Figure 3.2 on the previous page, SRP hosted four Large Stakeholder Group meetings over the summer of 2021. The SRP Summer Stakeholder Series was an opportunity to update, educate and engage with valued community stakeholders regarding SRP's efforts to transition from a traditional generation resource-focused Integrated Resource Plan (IRP) to a more holistic, comprehensive ISP inclusive of forecasting, customer programs, resource, transmission and distribution planning.

As shown in Figure 3.2, the Prepare Phase of the ISP stakeholder engagement strategy focused on creating a bilateral dialogue with stakeholders where they could comment, provide feedback and contribute their perspectives to the ISP analysis. This phase included customer research, one-on-one discussions with interested stakeholders, technical working groups, Large Stakeholder Group meetings and forming an Advisory Group. Together with community stakeholders, SRP set up a study plan that incorporated principles of scenario planning. This looked at how the future might unfold by analyzing key drivers, as well as the policy choices SRP could make and how those might perform in the future. We presented the co-created study plan for SRP's first-ever ISP to the Large Stakeholder Group on April 29, 2022.

Following along with the Figure 3.2 ISP Roadmap, at the end of April 2022, SRP kicked off the Analyze Phase of the ISP and conducted modeling through 2023. During this phase, SRP provided regular updates on ISP analysis to the Advisory Group as well as a final key findings presentation on April 21, 2023. Final key findings were presented to the Large Stakeholder Group on May 12, 2023.

As indicated in Figure 3.2, the final phase of the ISP was the Synthesize Phase, where SRP discussed with stakeholders and answered questions on viable pathways for meeting growing customer needs and achieving our 2035 Corporate Goals. SRP provided information to stakeholders about the trade-offs SRP faces, and collecting feedback helped SRP design a pathway moving forward. Inclusive, transparent and proactive dialogue with SRP stakeholders helped to build support for the first-ever ISP that will help guide major SRP strategy decisions.

Technical Working Sessions

In response to stakeholder feedback received throughout the objectives setting phase of the project, SRP developed Technical Working Sessions around topics of interest that stakeholders wanted to explore further. Starting in January 2021, SRP hosted four Technical Working Session webinars where experts from SRP and from around the country explored special topics. During 2022, SRP surveyed stakeholders to gauge their interest in different technical topics to help inform the topics for these sessions. The four sessions included the Inflation Reduction Act, inverter-based resources, regional market developments, and evolving time-of-day use programs.

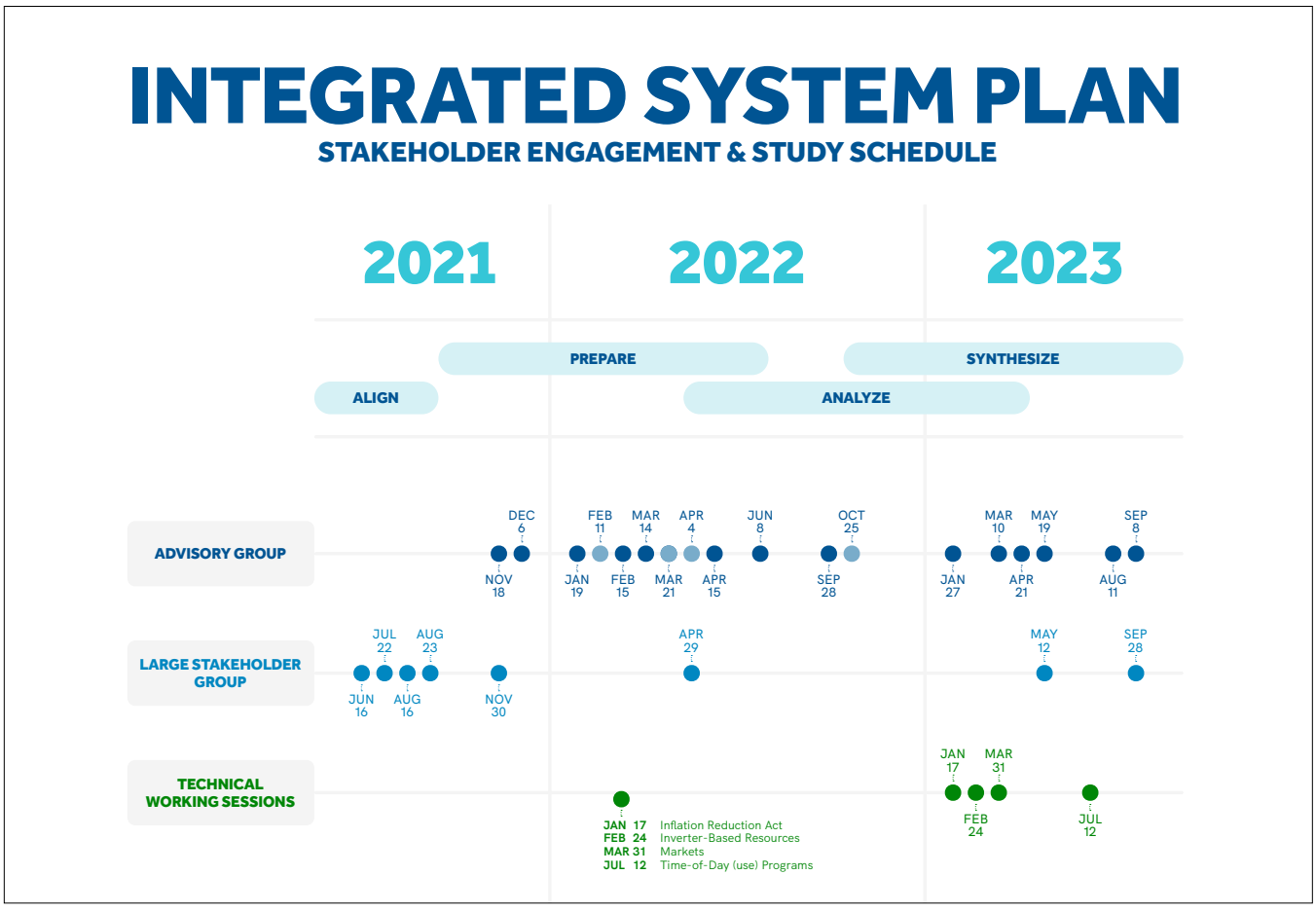
During these sessions, SRP shared work that has been done to date by our team in relevant areas. Each Technical Working Session featured a moderated panel discussion where external experts in relevant areas from around the country were invited to share leading industry experience and discuss potential enhancements SRP could undertake in future planning activities. Through these webinars, we had the opportunity to learn alongside stakeholders, gather input from these stakeholders, collect expert opinions in relevant topical areas and discuss potential enhancements applicable to SRP's system.

Customer Research

Throughout the process, SRP partnered with research consultant Bellomy Market Intelligence to execute the effort to bring the voice of SRP's residential customers into planning the future power system. Bellomy is a full-service market research firm that partners with healthcare, retail, financial, energy and consumer product companies to identify insights and strategic business implications derived from those insights. Having been immersed in the industry for over 25 years, Bellomy understands utility and energy clients' unique needs in regulated and deregulated landscapes. The customer research was a three-phased approach that started with phase 1, virtual focus groups (December 2021), followed by phase 2, quantitative confirmation survey (March 2022). The first two phases of research results were provided to Advisory Group members for consideration in designing the ISP study plan elements. Finally, for phase 3, a choice exercise was executed (May 2023). This research was designed to understand how customers think about reliability, affordability and sustainability related to power provision and gauge their reactions to a potential energy plan. All customers included in the research were SRP residential customers who were considered to be energy decision-makers and who did not work for a competing industry and were over 18 years old.

By using these engagement tools, SRP effectively collaborated with stakeholders and customers to build support for a shared vision for the future of the power system with 31 stakeholder meeting engagements executed and a multipronged residential customer research effort throughout the process, depicted in the timeline below.

FIGURE 3.3: ISP ENGAGEMENT TIMELINE



Transparent and Engaging ISP Process

SRP considered customers and community stakeholders essential partners in building a reliable, affordable and sustainable future power system. The holistic study plan was developed with input from SRP subject matter expert, customer and stakeholder feedback. The SRP project team, consisting of representatives from Forecasting, Resource Planning, Transmission Planning, Distribution Planning, and Customer Programs, performed a first-of-its-kind systemwide scenario analysis that allowed SRP to test strategies for building the future power system across a wide range of futures. Based on learnings from that analysis, the project team developed and shared with stakeholders the ISP key findings that identified costs, risks and trade-offs to consider when planning the future power system.

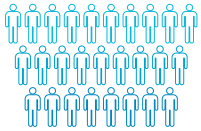
ISP PLANNING PROCESS FAST FACTS

NUMBER OF ADVISORY GROUP MEMBERS:

32
community representatives

from **23** organizations

NUMBER OF LARGE STAKEHOLDER GROUP MEMBERS:



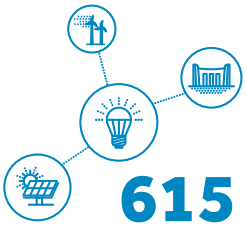
250
community representatives from
143
organizations

SLIDES PRESENTED

NUMBER OF MEETINGS:

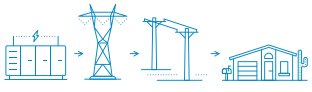
31 stakeholder meetings

totaling over **62.5** hours of content



615
POINTS OF FEEDBACK COLLECTED AND INTEGRATED INTO THE ISP

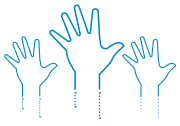
1,411
RESIDENTIAL CUSTOMER SURVEYS CONDUCTED



42
SYSTEM PLANS CROSS-FUNCTIONALLY ANALYZED

4
90-MINUTE RESIDENTIAL FOCUS GROUPS CONDUCTED

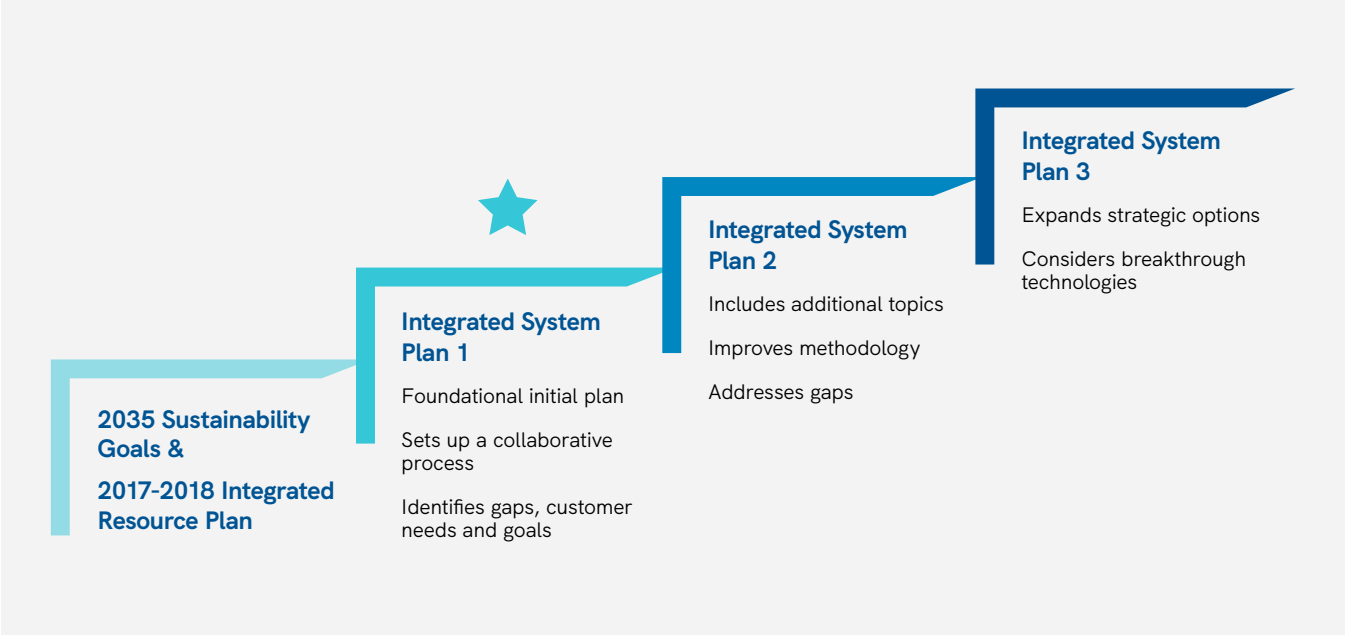
STAKEHOLDER QUESTIONS ANSWERED:
588



ISP Evolution

The scope of the ISP will evolve as SRP's planning groups gain experience and develop new capabilities. Participants in the objective development phase explored and discussed both the long-term vision and initial scope of ISP. Planning groups aligned on the importance of tackling a reasonable scope for the first ISP and building toward a long-term vision over time. One vision for what that evolution could look like is depicted below in Figure 3.4.

FIGURE 3.4: ISP LONG-TERM VISION



The initial ISP, or ISP 1, includes three key enhancements to current planning practices agreed to by the ISP team. The enhancements include consistent scenario and sensitivity analysis across the planning areas, incorporating transmission capacity headroom and expansion costs with supply-side resource planning, and expanding and enhancing the avoided cost framework to better evaluate customer programs. The process could evolve in future ISPs as new capabilities and tools are developed to be more cyclical. The pace and scale of ISP evolution will largely be determined by the experiences and lessons learned with ISP 1 and continued SRP exploration. The ISP enhancements for ISP 2 and ISP 3 in Figure 3.4 are illustrative and reflect stepwise progress of the potential elements identified in the long-term ISP vision.

Lastly, as part of the objective development engagement, the ISP team began a preliminary exploration of how the existing planning and sustainability processes might integrate with the ISP process in the future and the related issue of the cadence or frequency of the ISP. Consistent with the measured approach to the scope of ISP 1, the group generally agreed that gaining experience through ISP 1 would be helpful to inform future discussion on these topics.

The remainder of the report will describe the ISP 1 methodology, analytical framework, modeling results and critical findings that helped shape the concluding ISP deliverables, including System Strategies, ISP Actions and an illustrative Balanced System Plan.

SECTION 4

Scenarios, Sensitivities and Strategic Approaches

Scenario Framework

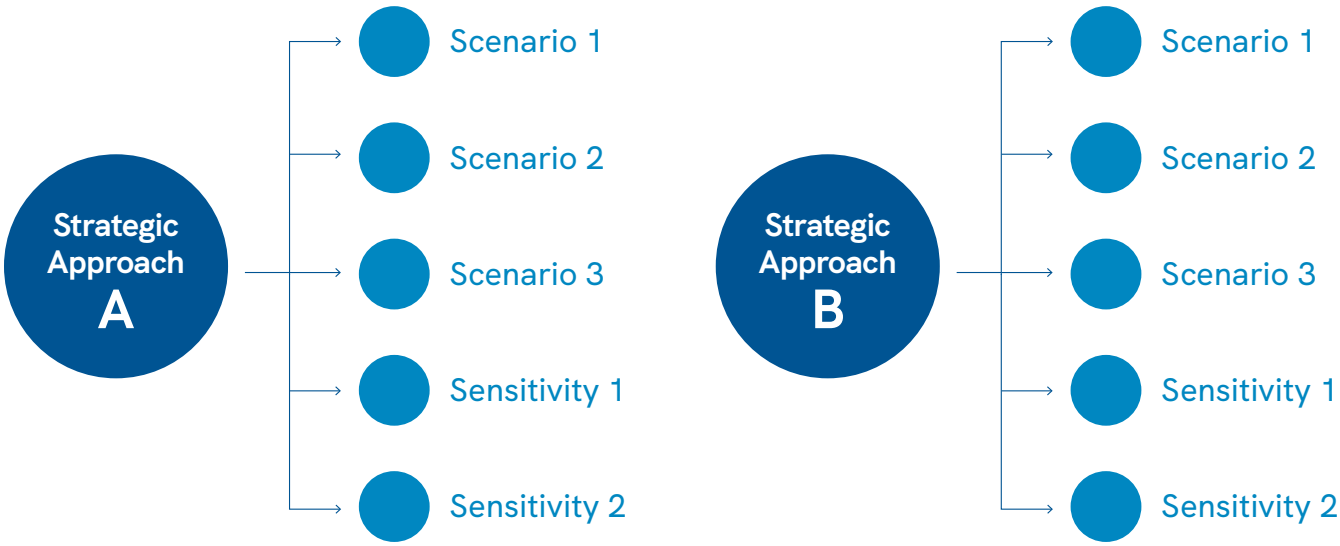
The decisions SRP makes today must withstand the risks and uncertainties of any future. Therefore, we utilized a scenario planning framework to test how different strategic decisions perform in an uncertain future.

The scenario planning framework used for the Integrated System Plan included three key elements: scenarios, sensitivities and strategic approaches. Scenarios defined plausible future states of the world around us, reflecting societal, technological, economic, environmental and political trends and conditions. These factors are outside of our control and reflect the unpredictable nature of the future that needs to be accounted for in SRP's planning activities. Sensitivities, like scenarios, capture future states of the world around us but vary a single planning assumption. Finally, strategic approaches represented possible decisions that we could make in planning the future power system. These decisions are fully within our direct control.

FIGURE 4.1: SCENARIO DESIGN FRAMEWORK

In the Integrated System Plan, each strategic approach was tested against each of the future scenarios and sensitivities. This allowed us to examine the performance of each strategic approach under different futures and identify the components that best achieved SRP's goals, supporting the development of a robust system plan that positions SRP to take advantage of opportunities and react quickly as changes occur.

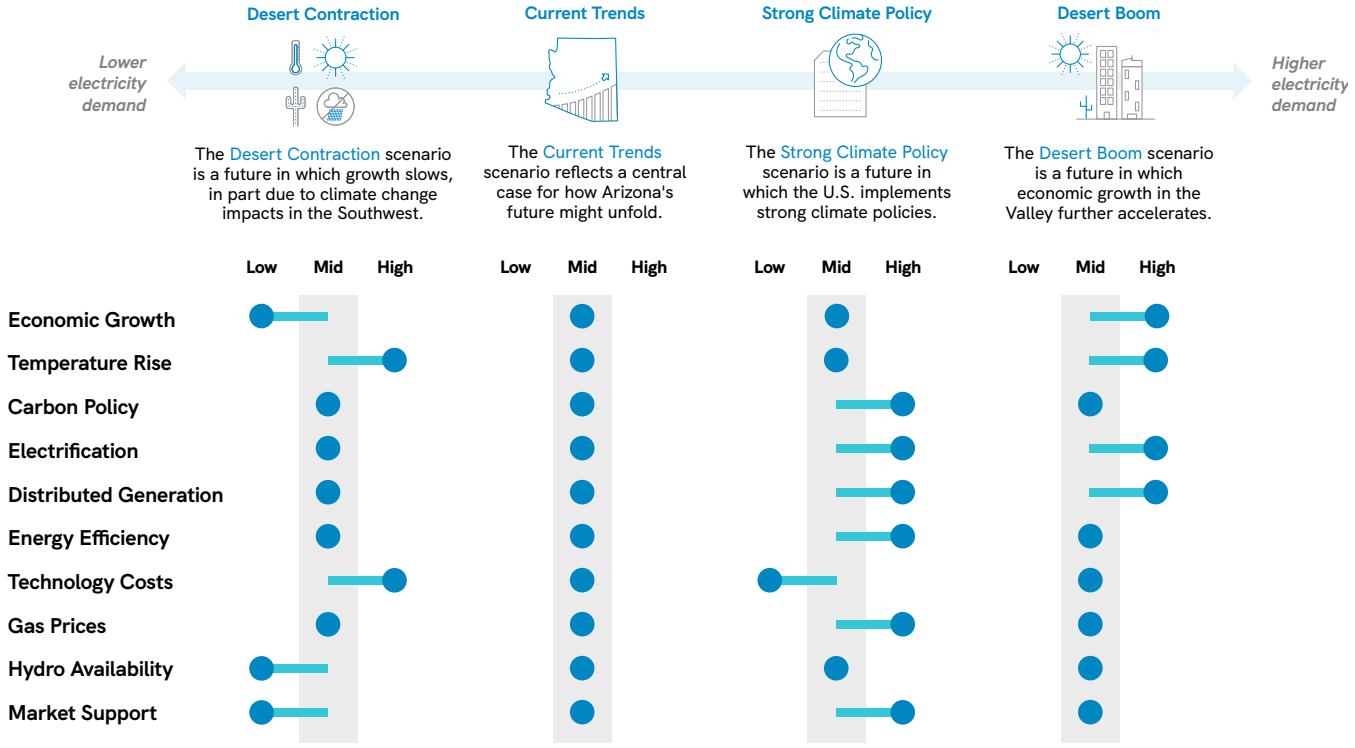
FIGURE 4.2: SCENARIO ANALYSIS



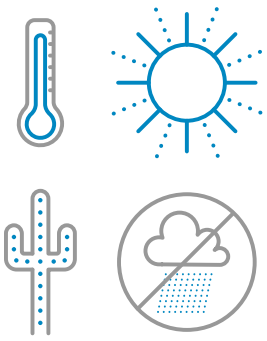
Scenarios

In collaboration with community stakeholders and based on results from customer research efforts, we developed four scenarios to analyze in the first Integrated System Plan: Desert Contraction, Current Trends, Strong Climate Policy and Desert Boom. The four scenarios considered many of the different external factors that can affect SRP's business environment and were designed to reflect a range of diverse yet plausible futures. Figure 4.3 below shows the four scenarios including how each external driver changed across the scenarios.

FIGURE 4.3: SCENARIOS



The following subsections describe each scenario in more detail and the key drivers associated with each scenario.

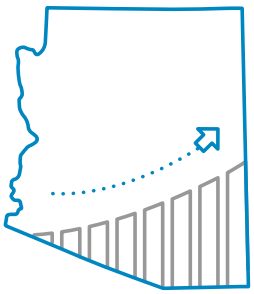


Scenario: Desert Contraction

The Desert Contraction scenario envisions a future where Arizona becomes a less desirable place for people and businesses due to a slowing economy and worsening climate conditions, which negatively impact residential and commercial growth. Additionally, global competition and consolidation initiates an exodus of large industry from the Valley, creating a cascading effect for the state's population. As a result, electricity demand in SRP's service area falls well short of current projections. Climate change also affects the region's watersheds, as declining rainfall throughout the West leads to lower reservoir levels along the Colorado River.[1] The corresponding reductions in generating capacity at large hydroelectric power plants significantly stress power markets, especially during peak demand periods.

[1]The Salt and Verde watersheds are more resilient to climate change and are unaffected in this scenario.

Key Drivers	Descriptions
Economic Growth	Higher summer temperatures and water supply issues stifle growth in the Southwest, limiting new migration and reversing expected growth trends. Large commercial and industrial customers emigrate out of Arizona and population growth levels off over time.
Climate Change	The Southwest experiences accelerated temperature rise consistent with the Intergovernmental Panel on Climate Change's (IPCC's) pessimistic Representative Concentration Pathway (RCP) 8.5 scenario, resulting in warming to the region that is more severe (0.91°F increase per decade). These conditions exacerbate current regional drought conditions, resulting in Lake Powell dropping below minimum power production levels for hydrogeneration from Glen Canyon Dam starting in 2025.
Policy	A worsening climate and intense global competition increase economic pressure on governments, resulting in a failure around the globe to adopt more consistent and aggressive carbon emission reduction regulations. While SRP remains committed to its 2035 Sustainability Goals, no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Spurred by the worsening impacts of climate change and the lack of cohesive federal climate action, more and more Arizonans prioritize sustainability. Therefore, adoption rates for electric vehicles (EVs), heat pumps, and distributed solar and batteries increase. Growing adoption rates for these customer-sided technologies are tempered by lower overall population growth.
Technology	Increased global market competition, prolonged supply chain issues and stagnant economic growth in the Southwest raise material and labor costs, slowing the decline of renewable and storage costs. Tax credits provided through the Inflation Reduction Act help to reduce costs, although a stretched labor market makes qualifying for such credits expensive.
Market Dynamics	Extreme heat waves, wildfires and the loss of power capacity at Glen Canyon Dam as well as other hydrogeneration in the West lead to constrained regional markets that cannot be relied upon during peak periods.

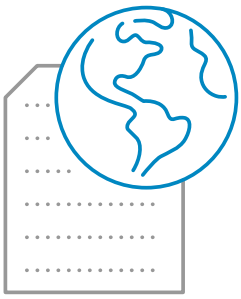


Scenario: Current Trends

The Current Trends scenario presumes that the large-scale changes currently underway in society, the region and the utility sector continue, resulting in substantial changes for SRP and Arizonans by 2035. Population in the Valley grows at a steady pace as the affordable cost of living and pleasant weather most of the year in the Phoenix area continue to attract new residents from California and surrounding states. With land availability, a competitive workforce, a geographical location in the middle of large markets (including California, Texas and Mexico), and with local and federal support of industries such as domestic semiconductor manufacturing, Phoenix becomes increasingly attractive to large commercial and industrial businesses. Data centers and manufacturing companies continue to move into the Valley, creating more jobs and bringing even more growth for Arizona. Some of these companies have significant load requirements measured in the hundreds of megawatts, much larger than those seen in the past. EVs gain popularity due to the broadening availability of vehicle models and improving charging infrastructure across the nation.

Key Drivers	Descriptions
Economic Growth	Continued growth is sustained in the greater Phoenix area, driven by continued migration and expansion in commercial and industrial business activities.
Climate Change	Climate change impacts are consistent with the projected RCP 4.5 scenario modeled by the IPCC, which envisions global emissions dropping below 2005 levels by 2100. Temperatures increase moderately (0.67°F per decade), while current drought conditions in the West persist but do not worsen throughout the study period.
Policy	While the Inflation Reduction Act provides a strong, sustained economic stimulus to support clean energy development, further federal action on climate policy is limited: Partisan politics continue to create a gridlock that prevents adoption of any comprehensive federal climate policy. In the absence of federal policy, state governments, utilities and corporations continue to drive advancements toward clean energy and sustainability goals. Like many other utilities in the region, SRP continues its independent efforts to meet voluntary sustainability goals.

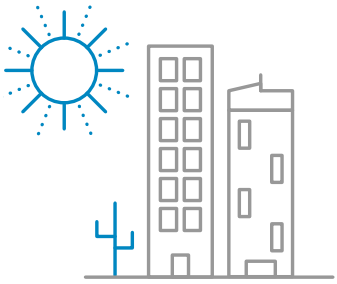
Customer Participation (EE, DG, electrification)	SRP continues to be a regional leader in offering energy efficiency and demand response programs to customers. The number of light-duty EVs increases significantly by 2035, benefiting from strong federal policy support provided in the Infrastructure Investment and Jobs Act, and consistent with SRP's current 2035 Sustainability Goals. Cost declines of distributed solar and batteries drive increased adoption by residential and commercial customers.
Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits provided through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting increased demand.



Scenario: Strong Climate Policy

The Strong Climate Policy scenario reflects a future where political consensus is reached on the need for swift and decisive action to combat climate change, resulting in several new policies and measures at the U.S. federal level. These policies are guided by an economywide net-zero emissions target by the year 2050, resulting in mass-based emissions reductions targets for electric utilities throughout the country by 2035. Decarbonization policies also impact demand: The pace of electrification in the building and transportation sectors accelerates, causing demand for electricity to increase, and government support for energy efficiency measures results in improvements in efficacy, reduction in cost and more widespread adoption. These two effects are offsetting but change the patterns and timing of electricity consumption. Extensive research and development support of clean energy resources advances power companies' operational learning curves and accelerates cost declines. Such cost declines also impact distributed generation on the customer side and create favorable conditions for the adoption of solar and storage systems. A Regional Transmission Organization (RTO) or a regional resource adequacy program would be established in the Southwest, allowing power companies to better take advantage of load and resource diversity in the region.

Key Drivers	Descriptions
Economic Growth	Growth is sustained as large commercial and industrial customers continue to migrate to the Valley. Furthermore, electricity demand is accelerated by rapid electrification of the building and transportation sectors.
Climate Change	Through 2035, temperatures in the Southwest remain consistent with the IPCC's RCP 4.5 scenario. Temperature increases moderately (0.67°F per decade), while current drought conditions in the West continue throughout the study period.
Policy	The U.S. federal government implements a suite of comprehensive policies to address climate change. These policies are designed around an economywide net-zero emissions target by 2050.
Customer Participation (EE, DG, electrification)	Stronger federal codes, standards and incentives lead to high energy efficiency growth. Technology improvements and rapid cost declines drive accelerated distributed solar and battery adoption among SRP's residential and commercial customers. The number of light-duty, medium-duty and heavy-duty EVs as well as heat pumps increases significantly, with federal support for these technologies.
Technology	Additional federal tax incentives, research and development investments, and increased deployment of clean energy resources advance learning curves, driving significant cost declines for renewables and storage and accelerating the commercialization of emerging technologies. Domestic manufacturing is able to keep up with demand, and no price increases from supply chain constraints are expected.
Market Dynamics	Federal policy support, incentives and subsidies drive increased transmission buildout across the nation. An RTO or a regional resource adequacy program would be established in the Southwest region, and system planning is conducted at a regional level. The regional planning paradigm and operational coordination allow the Balancing Authority Areas in the region to better take advantage of regional load and resource diversity, lowering the planning reserve margin SRP requires. More aggressive policies related to the natural gas supply chain increase natural gas prices.



Scenario: Desert Boom

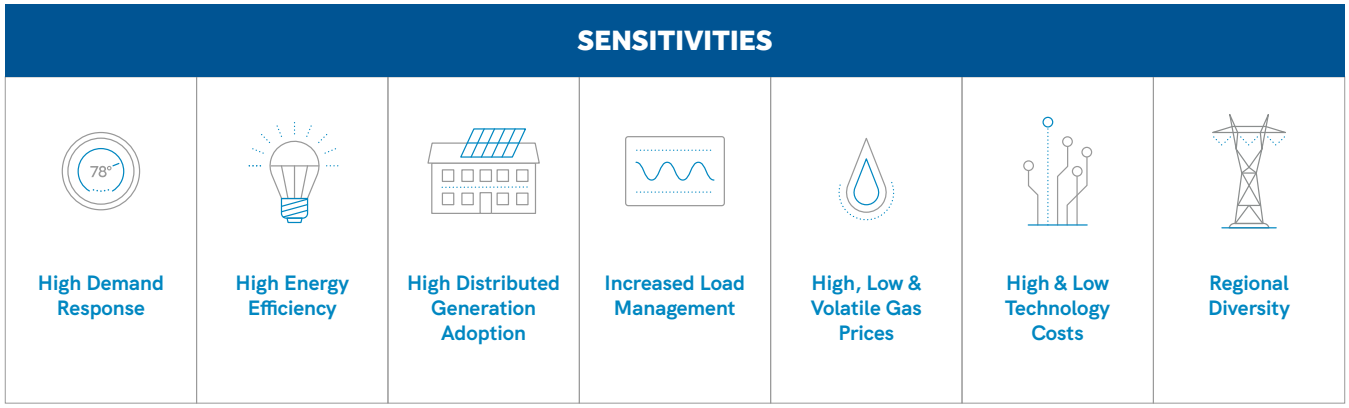
The Desert Boom scenario is characterized by explosive growth in SRP's service territory. Arizona becomes a regional energy, technology and manufacturing hub, creating a second "Silicon Valley" in the Phoenix metropolitan area. Economic growth in the Phoenix metropolitan area accelerates far beyond current projections and is led by a strong global technology industry and a supportive environment in Arizona. Electricity demand increases significantly with accelerated economic activity, growth in energy-intensive businesses and increased energy exports. Arizona's central location, affordable cost of living and skilled workforce attract an influx of people and businesses to the area. Strong economic growth supports accelerated EV and heat pump adoption, adding more electrification loads to the grid. Increased availability of distributed solar and battery technology helps mitigate system demand but not at the scale needed to provide full grid backup.

Key Drivers	Descriptions
Economic Growth	Growth accelerates significantly as Arizona becomes a regional energy, technology and manufacturing hub.
Climate Change	Climate change accelerates around the globe due to both climate policy inaction and strong global economic activity. Greater temperature rise occurs (0.91°F per decade) consistent with the Intergovernmental Panel on Climate Change (IPCC)'s pessimistic Representative Concentration Pathway (RCP) 8.5 scenario while current drought conditions in the West continue throughout the study period.
Policy	Governments around the globe prioritize economic growth over carbon emission reductions in the midst of an economic boom. SRP is committed to its 2035 Sustainability Goals, and no federal or state sustainability policies are passed that supersede these goals.
Customer Participation (EE, DG, electrification)	Population growth and higher incomes accelerate adoption of light-duty EVs, heat pumps, and distributed solar and batteries.

Technology	Renewable and storage technologies continue to advance over time, leading to sustained cost declines. Tax credits through the Inflation Reduction Act make carbon-free resources even more competitive, but the cost reductions are partially offset by continued supply chain constraints driven by a large spike in demand. Emerging technologies such as small modular reactors, natural gas power plants equipped with carbon capture, and green hydrogen production become commercially available in the 2030s.
Market Dynamics	Diversity in load and generation resources across different Balancing Authority Areas in the Southwest allows SRP to rely on market purchases to meet part of its electricity demand when necessary and economical. Natural gas prices increase moderately over time, reflecting continued demand growth and declining supply.

Sensitivities

In addition to the scenarios, SRP also analyzed 10 sensitivities under the Current Trends scenario. A **sensitivity** varied a single assumption in the Current Trends scenario, allowing SRP to understand the impact of the assumption on the overall system plan. Sensitivities were analyzed under the Current Trends scenario to assess the impact of varying individual assumptions on the system plan at a central case of potential future load growth. Details on the assumptions used for each sensitivity are included in Section 5: Methodology.



In the graphic above, the "High, Low & Volatile Gas Prices" icon encompasses three sensitivities, including High Gas Prices, Low Gas Prices and Volatile Gas Prices. The "High & Low Technology Costs" icon encompasses two sensitivities, including High Technology Costs and Low Technology Costs.

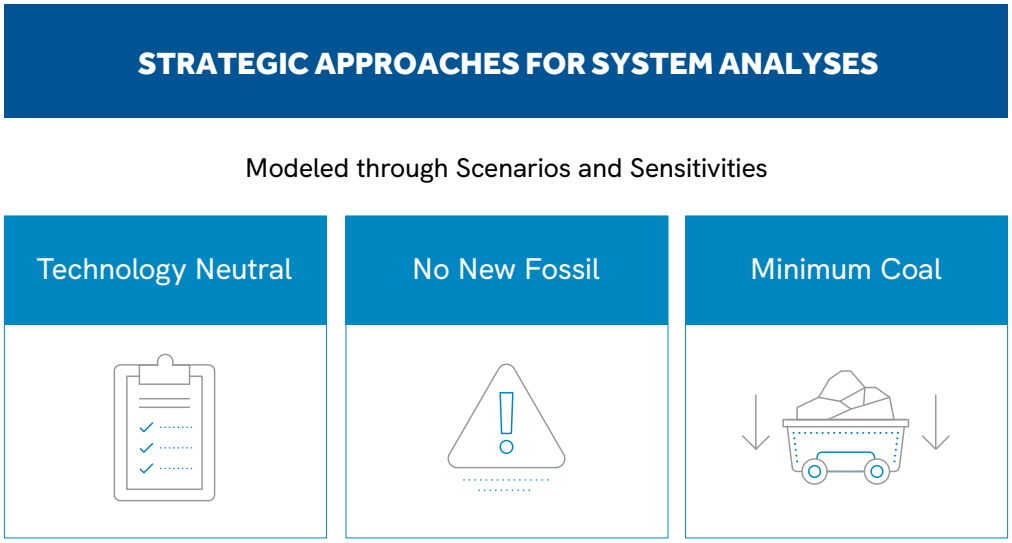
Strategic Approaches

SRP developed three strategic approaches to analyze in the Integrated System Plan. The three strategic approaches were analyzed across each of the scenarios and sensitivities described above.

The **Technology Neutral** strategic approach aims to develop future system plans on a least-cost basis to meet reliability and sustainability goals without any preferences for or restrictions upon the specific technologies included in the portfolio.

The **No New Fossil** strategic approach seeks to meet future system needs with exclusively carbon-free resources, excluding investment in new natural gas resources from consideration. Existing natural gas units remain in service and are still used to meet customer needs. Further, no changes to planned coal retirement dates are included in this strategic approach.

The **Minimum Coal** strategic approach aims to reduce power generation from coal in SRP's system by testing operational changes to SRP's coal resources, including seasonal operations and the full retirement of coal by 2035. This strategic approach builds upon the No New Fossil approach described above, meaning that all new generation resources must not rely on fossil fuel technologies.

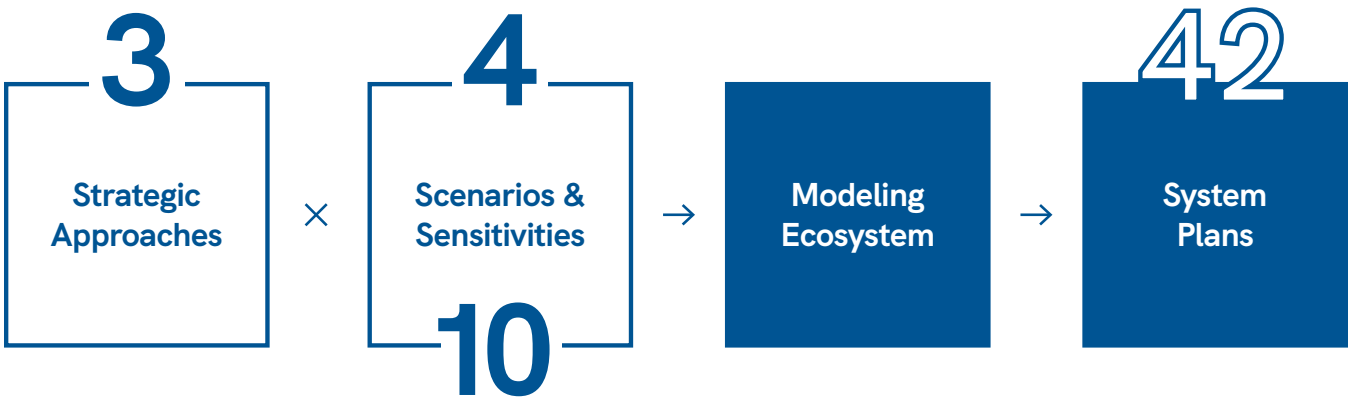


SECTION 5

Methodology

Methodology Overview

As discussed in Section 4, the ISP tested three strategic approaches across four scenarios and 10 sensitivities to evaluate 42 different planning cases. For each of these planning cases, SRP developed a system plan for the years 2025–2035 which included customer programs, distribution investments, transmission investments and resource additions.

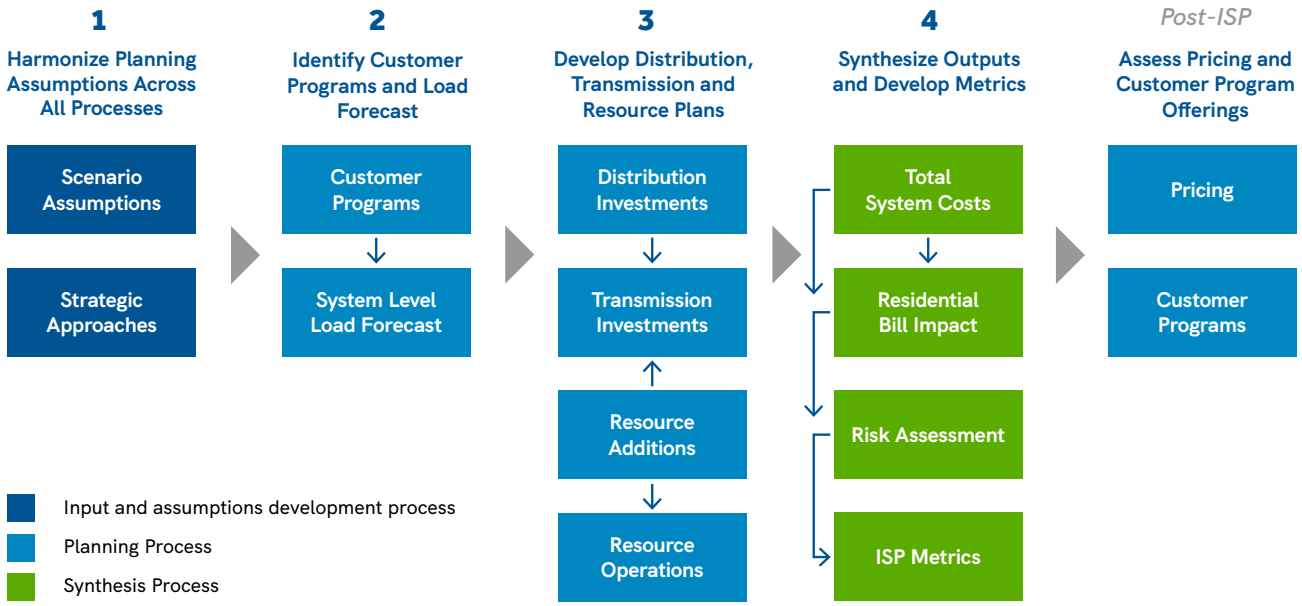


Our team evaluated and compared these plans by developing metrics to understand how each strategic approach performs across different futures and to identify the system components that could help SRP deliver a reliable, affordable and sustainable future power system. While we cannot know what the future will hold, assessing system plans across a variety of potential futures allowed us to identify strategies to mitigate future risks and take advantage of potential opportunities. This section describes the modeling ecosystem, key modeling inputs and metrics that we utilized to develop and evaluate each of the system plans.

Modeling Ecosystem

This first-of-its-kind ISP required a new approach to perform comprehensive system planning. Because there was no single planning model available that we could use to analyze all parts of the system simultaneously, we needed to develop an analytical ecosystem that included multiple planning processes, each with its own model(s). Each planning process utilizes the same planning assumptions, and then results from one planning process feed into other planning processes to help us create integrated system plans. An overview of this modeling ecosystem is shown in Figure 5.1.

FIGURE 5.1: MODELING ECOSYSTEM OVERVIEW



For a given planning case, we utilized the same scenario and strategic approaches across all planning processes (Step 1). We then forecasted energy demand during all times of the year, including the adoption of customer programs and customer-sited generation (Step 2). We next identified distribution investments, transmission investments and resource additions to meet future needs through 2035 (Step 3). The Distribution Investments planning process identified where the load would grow on the distribution system and the distribution infrastructure required, while the Resource Additions planning process identified which resources would be added. These results fed into the Transmission Investments planning process, which determined what transmission investments would be needed on SRP's system to connect large-scale resources to serve customers' energy demand. In addition, the Resource Operations process simulated how the future system could operate. We then leveraged all of these outputs to develop reliability, affordability, sustainability and customer-focused metrics (Step 4).

We will use this information to inform the design of customer programs and pricing plan offerings following the first ISP. These planning processes and metrics are described further in the following sections.

Due to time constraints, we could not perform every modeling process for all 42 planning cases. For the Transmission Investments, Residential Bill Impact and Risk Assessment processes, we performed modeling for a subset of the 42 planning cases, as detailed further below. We quantified all metrics for the 12 "core system plans" (three strategic approaches evaluated against four scenarios) and assessed all 42 system plans when developing key findings, as discussed in Section 6.

Customer Programs and End-Use Technologies

We developed customer program and end-use technology forecasts for energy efficiency, demand response, electrification (transportation and other technologies) and distributed

generation — including distributed solar and distributed batteries — for scenarios and sensitivities. These forecasts served as inputs into the load forecasts, which subsequently served as key inputs for each of the planning processes. The demand response forecast served as a direct input for the Resource Additions process.

Methodology Overview

To meet customers' diverse needs and the overall system needs, we developed a cost-effective portfolio of programs that achieve SRP's 2035 Sustainability Goals for energy efficiency, demand response, transportation electrification and electric technologies. In addition, we developed forecasts for customer adoption of other end-use technologies, including distributed generation in alignment with SRP's 2035 Sustainability Goal for grid enablement.

We developed customer program and end-use technology forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Demand Response (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Across these scenarios and sensitivities, we assumed that external factors drive customer adoption differences relative to the Current Trends scenario. For example, in the Strong Climate Policy scenario, we assumed that increased federal support for decarbonization efforts drives an expansion in energy efficiency, electric vehicles, building electrification and distributed generation.

Key Inputs

Key inputs for the customer programs and end-use technologies planning process included SRP's 2035 Sustainability Goals, assumptions for specific measures and programs, and market drivers.

2035 Sustainability Goals

SRP has established 2035 Sustainability Goals for various customer program offerings. In all ISP cases, we included customer program projections that met or exceeded these levels by 2035. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

- Energy efficiency: 3 million MWh
- Demand response: 300 MW
- Transportation electrification: 500,000 EVs
- Electric technologies: 300,000 MWh
- Grid enablement: Enable all distributed energy resources that customers choose to install

SRP Customer Program Planning Assumptions

SRP offers customer programs for energy efficiency, demand response, transportation electrification and electric technologies. The assumptions for these programs reflect the suite of customer program opportunities available to SRP, as well as their performance and costs.

SRP has implemented a continuous improvement process over many years to refine planning assumptions for specific measures for energy efficiency, demand response and electric technology programs. SRP's Measurement & Evaluation team and third-party consultant Guidehouse formally evaluate a subset of programs each year to continually refine assumptions for the measures included in each program. Based on this process, we have defined planning assumptions for each of the following measures:

- Reduction in energy demand during peak hours (kW)
- Reduction in energy demand during the entire year (kWh)
- Timing of energy demand reduction on an hourly basis
- Useful life over which SRP can expect energy savings
- Incremental cost, which serves as the basis for rebate design

Market Research

SRP regularly performs market research to understand the market activity and customer willingness to participate in different programs and to adopt various end-use technologies. In addition to speaking with customers, SRP gathers information from implementation partners, trade allies and third-party research. To develop the distributed generation forecast, we relied on historic and recent trends for distributed generation installations within SRP's power system area as well as advanced metering infrastructure data for the historic and recent generation of the systems already installed. To develop the electric vehicle forecast, we relied on information from the Electric Power Research Institute (EPRI) related to feasible EV adoption rates and supplemented this with internal research on EV load impacts within SRP's service area. We then leveraged this market research information, along with historical trends, to inform the forecast of future customer participation in SRP programs and adoption of end-use technologies.

Key Outputs

Below are the key outputs from this planning process.

Output	Description	Output Units
Energy Efficiency and Electrification Impacts on Annual Load	Forecast of energy efficiency and electrification (transportation and other technologies)	MWh

Demand Response Capacity	Forecast of the amount of capacity on the system that is available to provide demand response services	MW
Distributed Generation Adoption	Forecast of customer-sited solar and batteries	MW
Customer Program Costs	Forecast of program costs for SRP customer programs	$

Load Forecast

In the load forecasting process, we forecasted customer energy demand on an hourly basis through 2035. The forecast reflects typical patterns in energy demand throughout the year and across the hours within a given day, including during peak energy demand periods. This information served as a key input for determining future system needs in the ISP.

Methodology Overview

First, our team created a baseline forecast for the Current Trends scenario. We then employed the Statistically Adjusted End-Use (SAE) model (developed by Itron) to forecast electricity demand from customer end uses. We updated this model to align with inputs related to economic growth, end-use saturation and efficiency trends, adoption of customer programs, adoption of distributed generation, adoption of electric vehicles, and temperature trends. Finally, we used the outputs of this model to determine the hourly energy demand through 2035.

To develop additional forecasts for each of the four planning scenarios and two of the sensitivity cases, we modified one or more key assumptions. We developed load forecasts for the following scenarios and sensitivities:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

Key Inputs

The following sections describe the key inputs for the Load Forecast process, including economic growth and temperature increase. In addition to these inputs, we factored in changes in customer energy usage from energy efficiency, electrification and adoption of distributed generation. These inputs are the results of the Customer Programs and End-Use Technologies process and are discussed in Section 6.

Economic Growth

We developed economic growth projections for all four scenarios to determine key inputs, such as change in population and growth in energy demand from large customers. To do so, we developed an economic outlook for the Phoenix metro area by creating a composite forecast from a variety of external economic forecast providers, including University of Arizona, Arizona State University, Moody's, Woods & Poole Economics, and R.L. Brown Construction. We also developed an outlook for large customer growth by leveraging information from a variety of sources, including SRP's Strategic Energy Managers, SRP Economic Development, the Greater Phoenix Economic Council, state and local commerce authorities, and observed historical trends.

Figures 5.2 and 5.3 show the population and incremental large customer load growth forecasts for the four scenarios. In the Current Trends and Strong Climate Policy scenarios, the population and new industrial loads increase markedly, consistent with recent trends in migration and expansion of business activity. In the Desert Boom scenario, there is even greater growth as Arizona develops further as a regional energy, technology and manufacturing hub. In the Desert Contraction scenario, there is limited new migration and a significant slowing of large customer growth trends.

FIGURE 5.2: PHOENIX METRO POPULATION

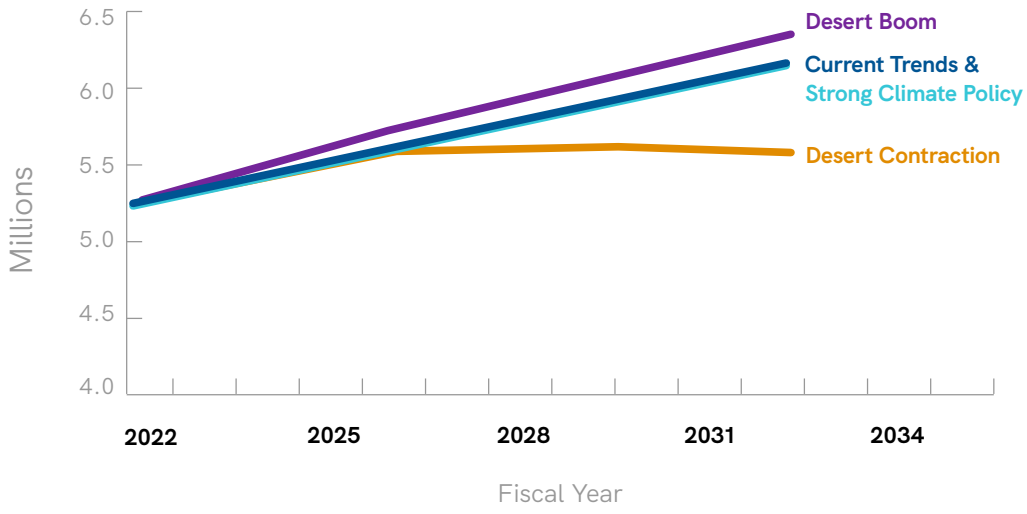
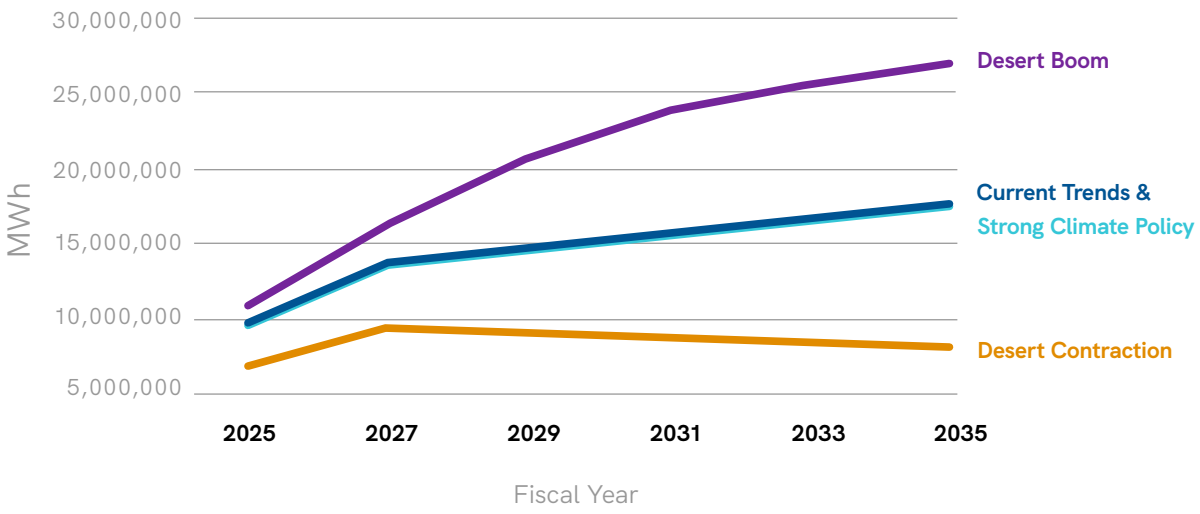


FIGURE 5.3 INCREMENTAL LARGE CUSTOMER LOAD GROWTH



Temperature Increases

In all scenarios, we considered the impacts of global warming. To characterize the future temperature increases, we relied on data from the Intergovernmental Panel on Climate Change (IPCC). For the Current Trends and Strong Climate Policy scenarios, we used the Representative Concentration Pathway (RCP) 4.5 trajectory, which corresponds to a temperature increase of 0.67°F per decade. For the Desert Boom and Desert Contraction scenarios, we used the RCP 8.5 trajectory, which corresponds to an even greater temperature increase of 0.91°F per decade. We then translated these changes in temperature into changes in cooling degree hours and heating degree hours (see figures 5.4 and 5.5), which are metrics that are correlated with energy demand from cooling and heating buildings.

FIGURE 5.4: COOLING AND HEATING DEGREE HOURS

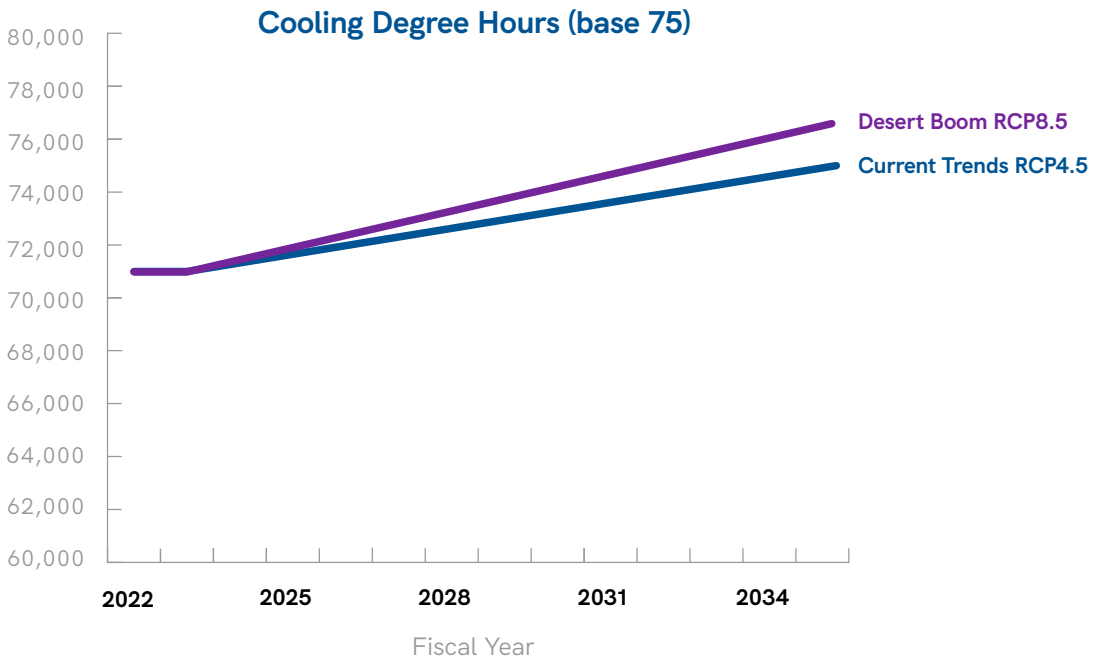
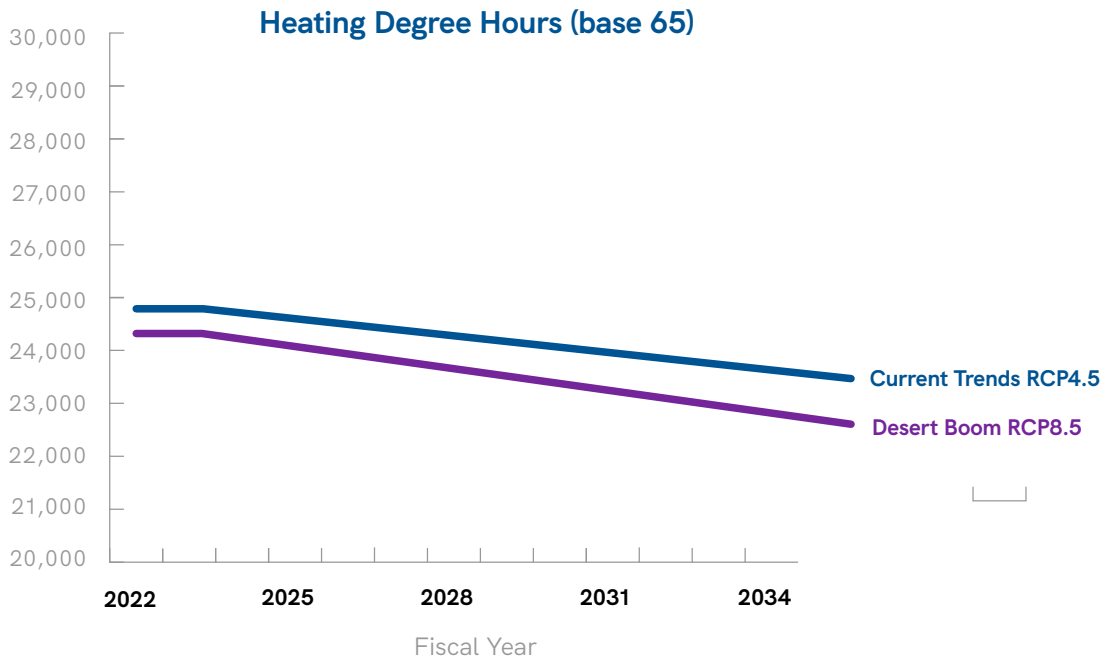


FIGURE 5.5: COOLING AND HEATING DEGREE HOURS



Key Outputs

SRP developed the following outputs, which served as inputs for other planning processes.

Output	Description	Output Units
System Load Forecast	System peak load and hourly energy demand forecast	MW
Transmission-Level Forecast	Peak load forecast for customers that connect directly to the high-voltage transmission system	MW
Distribution-Level Forecast	Peak load forecast for customers that connect to the lower-voltage distribution system	MW

Distribution Investments

In the Distribution Investments planning process, we determined which investments are needed on the distribution system to accommodate growth in customer energy demand, including the impacts from adoption of electric vehicles and customer-sited generation, while ensuring reliability.

Methodology Overview

First, we allocated the system-level load forecast (described in the Load Forecast section) to granular localized levels of the distribution system. We utilized LoadSEER (developed by Integral Analytics), which is a distribution forecasting and planning tool that allocates the system-level load to individual substations based on geographic, economic and historical customer usage data. This resulted in a peak load forecast for each substation, allowing us to understand where customer demand is changing and how the system may need to adapt.

After we allocated the system-level load forecast to the localized levels of the distribution system, SRP analyzed capacity-constrained locations and evaluated applicable infrastructure solutions to alleviate these constraints. Due to modeling limitations and time constraints, we focused on substation equipment and did not evaluate individual distribution lines that connect to the substations. We utilized the following reliability planning criteria, consistent with SRP's distribution planning practices:

- A distribution substation bay may not exceed 85% of its emergency rating.
- The total distribution system load should not exceed 70% of the total distribution system capacity.

One way we addressed an overloaded substation was by shifting loads to adjacent substations, which was possible if the neighboring substation had available capacity. This ensured the existing distribution infrastructure was used efficiently. In areas that were significantly capacity-constrained and existing distribution infrastructure could not be utilized, SRP strategically placed new substations, adding capacity to an area to address as many overloads as possible.

We performed this analysis for the following scenarios and sensitivities, which covered all planning futures in which load and customer programs change and could impact distribution investment needs:

- Current Trends
- Desert Boom
- Desert Contraction
- Strong Climate Policy
- High Energy Efficiency (sensitivity)
- High Distributed Generation Adoption (sensitivity)

For the two sensitivity analyses, the team estimated the required number of substation bay additions through interpolation by calculating the relationship between forecasted load and

resultant substations required in the four major scenarios. This relationship was then applied to the forecasted load for the two sensitivity cases. This process resulted in a high-level estimate of substation bay addition requirements for each sensitivity case, and it assumes that these technologies are adopted evenly throughout the service territory.

Key Outputs

The modeling process resulted in a plan detailing the location of each substation addition for each year as well as the load for each substation in each year.

Output	Description	Output Units
Substation Load Forecast	Projects addition of new substations and allocation of load between substations.	MW
Distribution Investments	Specification of substation additions or upgrades to meet system requirements, as well as associated costs.	$

Resource Additions

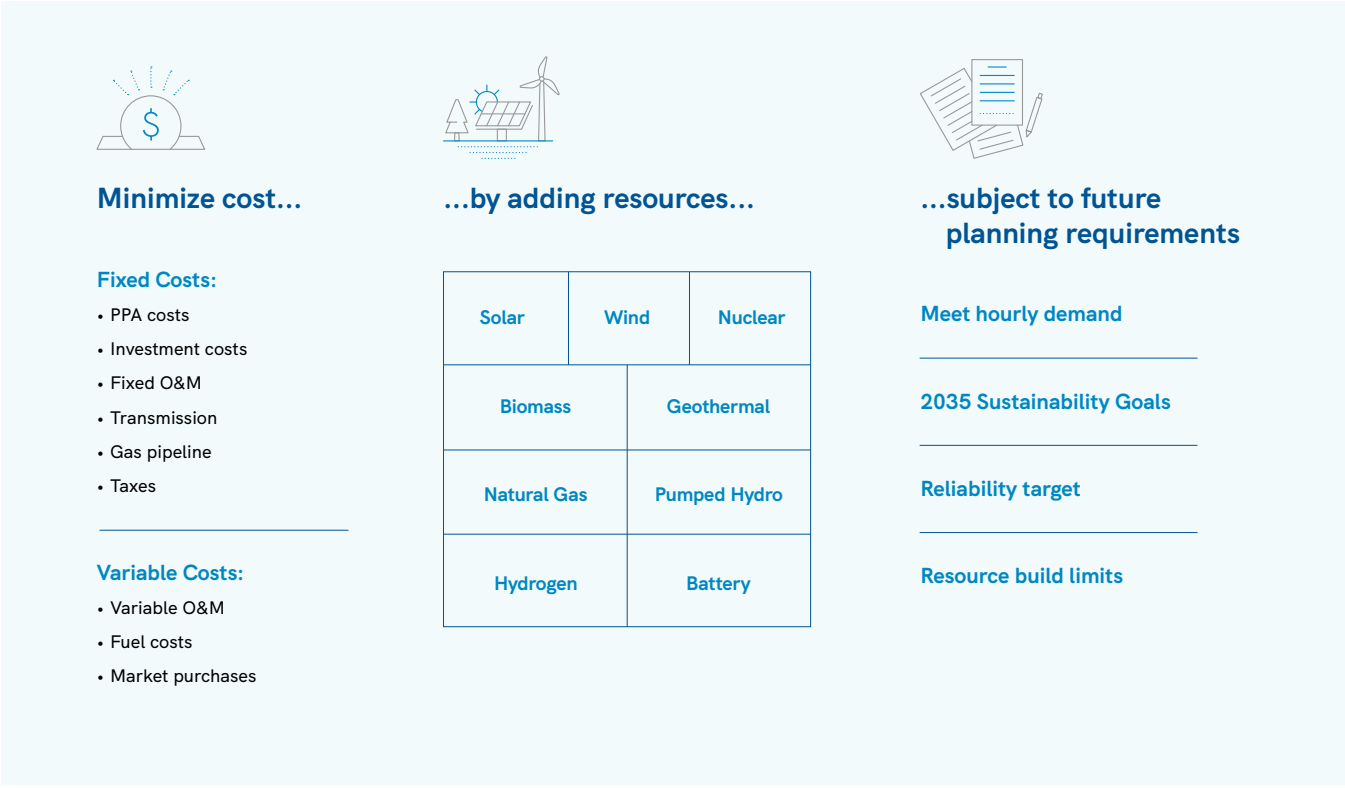
In the Resource Additions planning process, we determined the least-cost resource additions needed to meet future energy demand while ensuring reliability and meeting SRP's 2035 Sustainability Goals related to carbon dioxide emissions and water usage.

Methodology Overview

During this process, our team assessed future resource additions through a resource portfolio optimization analysis that identified the least-cost long-term combination of generation investments subject to reliability, policy and technical constraints.

To perform the analysis, we engaged Energy and Environmental Economics Inc. (E3) to deploy a long-term capacity expansion model, PLEXOS (developed by Energy Exemplar), which we had not leveraged in prior resource planning efforts. PLEXOS considers investment costs, fixed costs and production costs to simultaneously select new resources and simulate system operations over a long planning horizon (see Figure 5.6).

FIGURE 5.6: OVERVIEW OF THE RESOURCE ADDITIONS MODELING FRAMEWORK



E3 produced optimized resource portfolios for all cases presented in the ISP, except for the volatile gas price sensitivities[1], totaling 39 cases. Each portfolio identified resource additions through 2035.

Key Inputs

The key inputs for this analysis included the system load forecast (see Load Forecast section), resource options, resource and transmission costs, reserve margin requirements, fuel prices, reliability requirements and sustainability requirements.

Resource Options

The ISP considered a wide range of resource options to meet future needs, including renewable, storage and thermal resources.

Renewable Resource Options

The ISP considered several renewable resource options, including biomass, geothermal, solar and various wind options that vary by location and transmission path.

[1]The volatile gas price sensitivities are intended to evaluate the impact of gas prices unexpectedly changing over short time periods without SRP being able to change decisions around resource additions. Therefore, SRP evaluated the volatile gas price sensitivities in the Resource Operations analysis, using the same resource additions as in the Current Trends scenario.

FIGURE 5.7: RENEWABLE RESOURCE OPTIONS

Resource	State	First Available Year	Capacity Factor[2]
Biomass	Arizona	2025	Varies
Bioenergy with Carbon Capture and Storage	Arizona	2035	Varies
Geothermal	California	2031	90%
Solar	Arizona	2025	32.2%
Wind – Existing SRP Transmission	Arizona	2033	31.3%
Wind – Existing non-SRP Transmission	Arizona	2025	31.3%
Wind – New Transmission	Arizona	2031	31.3%
Wind – New Transmission	New Mexico	2026	45.5%
Wind – New Transmission	Wyoming	2029	55.4%
Wind – Existing Transmission	Wyoming	2029	55.4%

To ensure that the resource additions identified reflect realistic plans that SRP can execute, the ISP included build limits for the renewable resource options to reflect development limitations in being able to bring such new resources online. Below are the total build limits by 2035 for each resource:

- **Biomass –** SRP assumed up to 150 MW of new additions, based on the amount of fuel that SRP assumed could be made available from forest-thinning projects such as those in the SRP Healthy Forest Initiative™.
- **Bioenergy with Carbon Capture and Storage (BECCS) –** SRP assumed up to 100 MW of new additions, given that the CCS component of this resource is not widely commercialized today and has a certain degree of uncertainty in terms of availability and cost.

[2]Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.

- **Geothermal –** SRP assumed up to 1,000 MW of new additions. Based on SRP's assessment of regional transmission, SRP expects that access to new geothermal resources in the Salton Sea area in California — which has high-quality geothermal energy — would require development of new long-distance transmission between the Salton Sea area and the Phoenix metropolitan area. SRP assumed that new transmission could be put in service as early as 2031 and that this would allow SRP to access up to 1,000 MW of geothermal resources. For details on the cost of this transmission, see the Transmission Costs section. In the Strong Climate Policy scenario, SRP assumed that increased federal support for regional transmission could accelerate the availability of this resource from 2029 to 2031.
- **Solar –** SRP effectively did not limit solar additions. In total, the model could add up to 20,000 MW of solar by 2035, but that threshold was never constraining.
- **Wind –** For wind, assumptions varied according to current and potential transmission availability. For more details on the cost of transmission, see the Transmission Costs section.
    - **Wind (AZ), Existing SRP Transmission —** SRP estimated that 800 MW of transmission would become available in 2033 following the retirement of the Coronado Generating Station and an additional 450 MW in 2034 in the Minimum Coal strategic approach following the retirement of the Springerville Generating Station.
    - **Wind (AZ), Existing Non-SRP Transmission —** SRP estimated that 50 MW of non-SRP transmission is currently available for new wind generation in Arizona.
    - **Wind (AZ), New Transmission —** SRP assumed a new transmission line could be added from eastern Arizona by 2035, which would provide access to approximately 500 MW of wind generation.
    - **Wind (NM), New Transmission —** SRP assumed new transmission could be added between a region in New Mexico with high-quality wind and the Valley by 2035. SRP assumed this transmission would enable SRP to access up to 1,500 MW of wind generation.
    - **Wind (WY), Existing Transmission —** SRP estimated that 100 MW of transmission could become available in 2029 following the retirement of the Craig and Hayden coal plants in Colorado.
    - **Wind (WY), New Transmission —** SRP assumed one or more new transmission lines could be added between Wyoming and southern Nevada by 2025, and that SRP could then utilize approximately 300 MW of existing transmission to deliver wind in Wyoming to the Phoenix metropolitan area.

For solar and wind resources, we developed hourly generation profiles by using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). The solar profile reflects a project with single-axis tracking in Arizona, while the wind profiles reflect differences in generation profiles across the different states.

Storage Resource Options

The ISP also considered energy storage resources, including lithium-ion batteries and pumped hydro storage, which can help integrate renewable resources on the system. For battery storage, the ISP considered both stand-alone storage and hybrid storage that is co-located with solar.

FIGURE 5.8: STORAGE RESOURCE OPTIONS

Resource	First Available Year	Duration (hours)	Round-Trip Efficiency
Battery	2025	4	85%
Pumped Hydro	2033	10	80%

As was done for renewable resources, SRP included build limits for storage resources to reflect development limitations in being able to bring new resources online. Below are the total build limits by 2035 for each resource:

- **Battery –** SRP assumed up to 8,500 MW of new additions, above and beyond the battery storage resources that are already contracted.
- **Pumped Hydro –** SRP assumed up to 1,150 MW of new additions, which corresponds to one large new project.

Thermal Resource Options

In addition to renewable and storage resources, the ISP considered several thermal resource technologies. We modeled conventional natural gas technologies, including combined cycle, combustion turbine (both frame and aeroderivative) and reciprocating engine technologies. We also modeled a few emerging technologies, including combined cycle with carbon capture and storage (CCS), combustion turbine that burns 100% green hydrogen (Hydrogen 100),[3] combustion turbine that burns a blend of natural gas and an increasing share of hydrogen (Hydrogen Transition), and nuclear small modular reactors (SMR). The ISP also considered biomass and geothermal as thermal resource options. Those resources are discussed in the Renewable Resource Options section above.

FIGURE 5.9: THERMAL RESOURCE OPTIONS

Resource	First Available Year	Fuel
Combined Cycle (1x1)	2028	Natural Gas
Combined Cycle (2x1)	2028	Natural Gas
Combustion Turbine (Frame)	2027	Natural Gas
Combustion Turbine (Aero)	2025	Natural Gas

[3] Green hydrogen is produced from 100% renewable energy.

Reciprocating Engine	2025	Natural Gas
Hydrogen Transition	2030	Blend (Green Hydrogen and Natural Gas)
Combined Cycle with CCS	2030 or 2035 depending on scenario	Natural Gas
Hydrogen 100	2034 or post-2035 depending on scenario	Green Hydrogen
Nuclear SMR	2034 or post-2035 depending on scenario	Uranium

The resource availability assumptions reflect the time required to site, permit and construct resources. For emerging technologies, including combined cycle with CCS, hydrogen and nuclear SMR resources, we considered the uncertainty of when these resources would become available, given that they have not yet reached widespread commercialization. See Figure 5.10 for the availability assumptions for emerging technologies. We excluded these resources from consideration within the planning horizon under most scenarios. However, to test an alternative scenario in which these technologies progress more rapidly following government support, we accelerated SRP's availability in the Strong Climate Policy scenario.

FIGURE 5.10: FIRST YEAR AVAILABLE FOR EMERGING TECHNOLOGIES

Resource	Strong Climate Policy Scenario	Other Scenarios
Combined Cycle w/ CCS	2030	2035
Hydrogen 100	2034	Post-2035
Nuclear SMR	2034	Post-2035

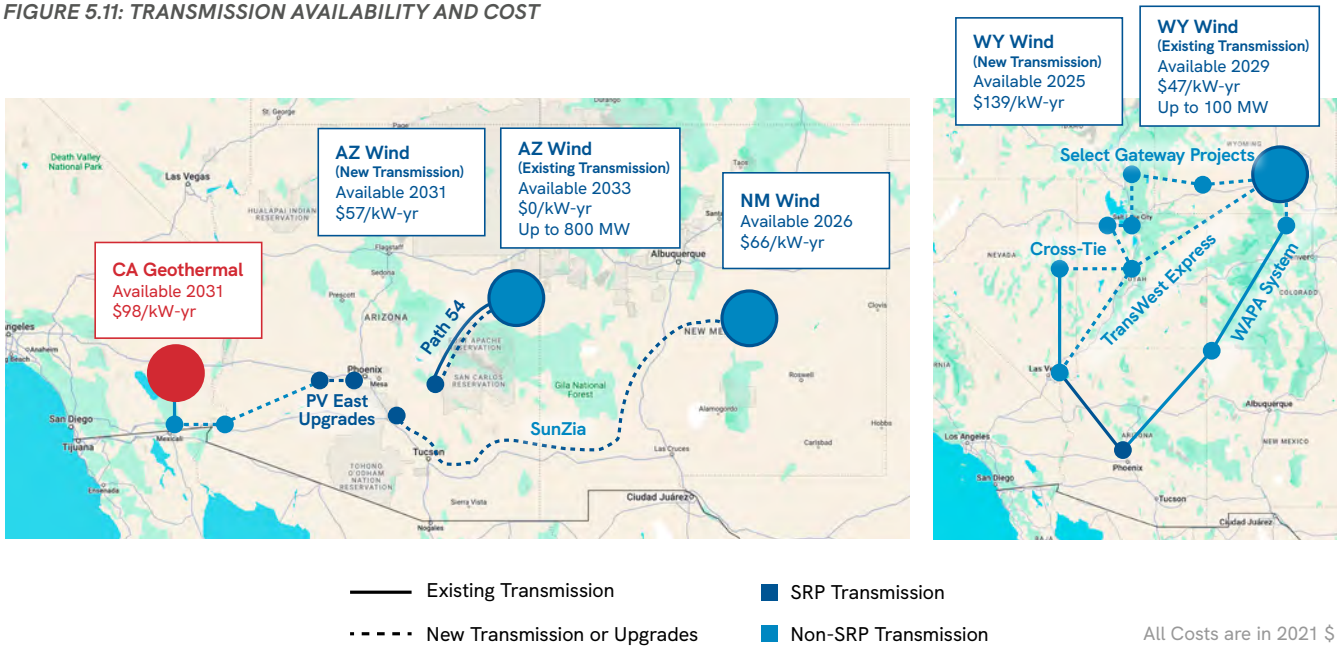
Transmission Costs

Several wind resource options, as well as the geothermal resource option, required consideration of transmission availability and costs of potential transmission expansion or upgrades. The Resource Additions planning process considered this availability and cost information when determining which resources to add.

See Figure 5.11 for the transmission availability and transmission cost adder for each resource option. For transmission paths that would require new or upgrades to transmission, we estimated the cost of this transmission and levelized the cost over the life of the transmission to determine

the transmission cost adder for those wind and geothermal resources. For existing transmission, we estimated how much transmission capacity would be available without further upgrades.

FIGURE 5.11: TRANSMISSION AVAILABILITY AND COST



Resource Costs

Our team forecasted future resource costs under different scenarios by relying on public data. We leveraged the 2022 NREL Annual Technology Baseline (ATB) for renewable and storage resource costs and the Energy Information Administration (EIA) 2022 Annual Energy Outlook (AEO) for thermal resource costs.

The fixed costs for resources included the following components: upfront capital, interconnection, property taxes, transmission (for remote resources, described in previous section), gas transportation (for gas resources), and fixed operations and maintenance costs. For upfront costs, we levelized these costs over the useful lifetime of each resource.[4] The variable costs for resources included fuel expense and variable operations and maintenance costs. This subsection focuses on the fixed costs, which don't vary with operations, while the Fuel Prices section below discusses fuel prices.

In August 2022, as our team was partway through the ISP analysis, Congress passed the Inflation Reduction Act (IRA), which provided an unprecedented federal investment in clean energy and created new federal tax credits for clean energy resources. Because of the significant nature of the IRA, we revised the cost of new resources to reflect these tax credits in all ISP scenarios and used these updated assumptions for the final ISP modeling. These revised costs were in part informed by the Technical Working Session SRP held with a group of industry experts on Jan. 17, 2023, to better understand the IRA.

[4]SRP utilized a lifetime of 15 years for battery storage resources, which was different from the NREL 2022 ATB but is consistent with the NREL 2023 ATB. SRP established this assumption based on experience with contracting for storage resources and after having conversations with members of the NREL ATB team to understand the underlying assumptions for battery lifetimes.

TECHNICAL WORKING SESSION ON THE INFLATION REDUCTION ACT

On 1/17/23, SRP held a Technical Working Session to better understand the impacts and uncertainties of the Inflation Reduction Act (IRA) and how to incorporate this into SRP's planning. Given the significant complexity of the IRA, SRP convened a group of experts with a wide range of viewpoints:

- Christine Turner, Solar Energy Manufacturers for America Coalition
- Mitch Rapaport, Nixon Peabody LLP
- Michael Mace, Public Financial Management (PFM)
- Hanson Wood, EDF Renewables North America

The experts highlighted a few ways in which the IRA could spur significant new clean energy investment:

- Provides significant incentives to grow domestic manufacturing, which could mitigate impacts from supply chain challenges experienced in recent years.
- Provides longer certainty for clean energy credits, through at least 2032 and likely longer.
- Expands eligibility of tax credits to a wider range of technologies, including standalone storage, nuclear, carbon capture and storage, and hydrogen.
- Creates an option for tax credit bonuses for domestic content and location within an Energy Community.
- Allows public power utilities like SRP to take advantage of tax credits via direct pay provisions, increasing feasibility of public power project ownership.

The experts also highlighted a few sources of risk and uncertainty:

- Greater guidance and certainty are needed from the Internal Revenue Service (IRS) for many of the IRA provisions to mitigate risks.
- Public power utilities like SRP must meet domestic content provisions to qualify for a direct pay credit.
- It is too early to tell whether projects will qualify for bonus tax credits, how much it will cost to monetize tax credits, and how tax credit savings will be split between developers and offtakers.
- Increased demand for clean energy demand could put increased pressure on supply chains in the near-term.
- Lack of support for new transmission in the IRA may lead to increased congestion, curtailment, and limitations in renewable resource growth.

Figure 5.12 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for renewable and nuclear resources in terms of levelized cost of energy (LCOE).[5] The LCOE metric expresses the levelized annual cost of a resource relative to its expected annual generation. One caveat in interpreting this metric is that it only reflects the cost of a resource and does not reflect the value that a resource provides to the system, nor does it reflect any renewable curtailment, which would increase the LCOE.

[5]Resource cost assumptions for the other scenarios and sensitivities are provided in Appendix A: [ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES].

FIGURE 5.12: RENEWABLE RESOURCE COSTS (2023 $/MWH)

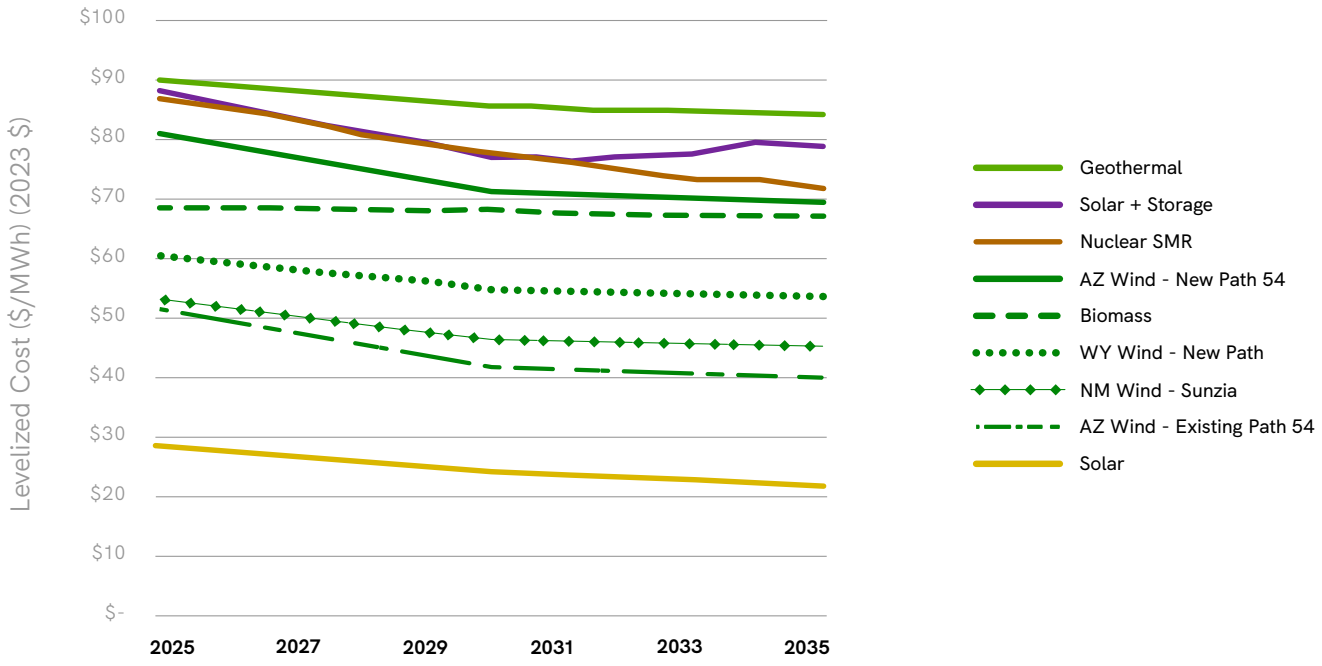
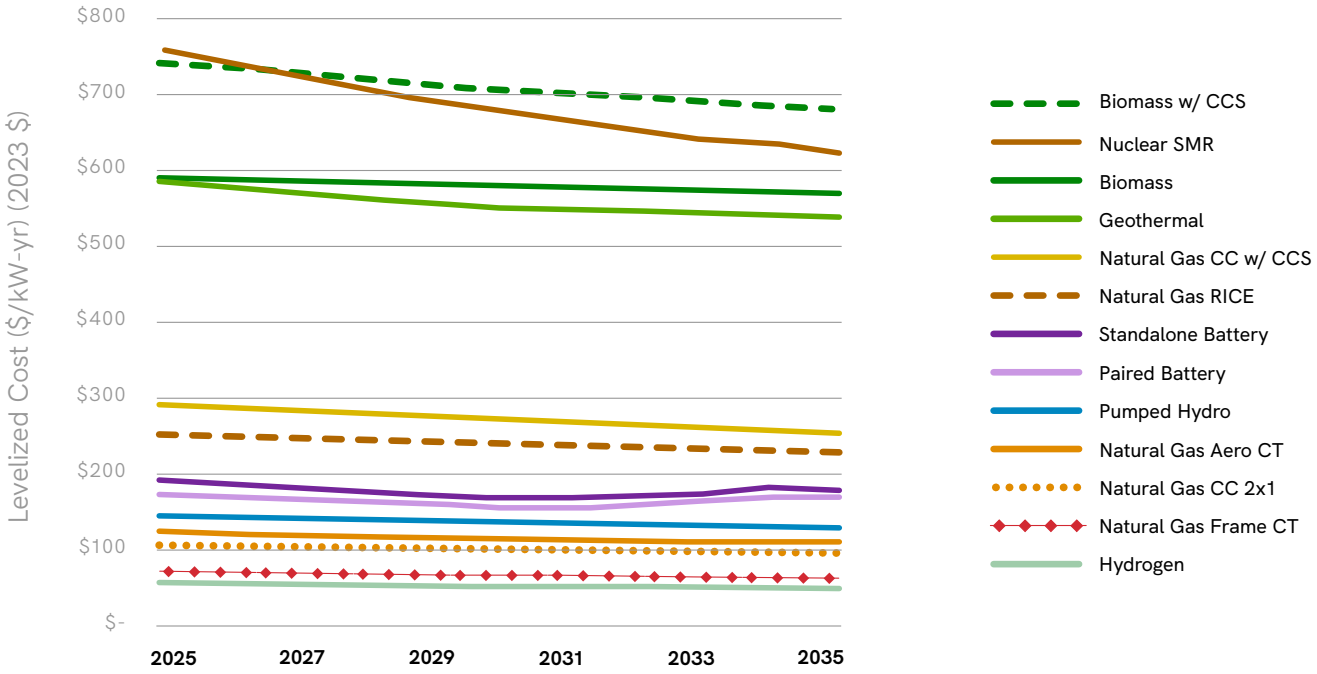


Figure 5.13 shows the resource cost forecasts for the Current Trends and Desert Boom scenarios for thermal and storage resources in terms of levelized fixed cost. Note that the LCOE metric used above is not commonly used for thermal and storage resources because the annual utilization of these resources can vary widely from one scenario to another or even year to year, while the LCOE metric assumes a fixed annual utilization.

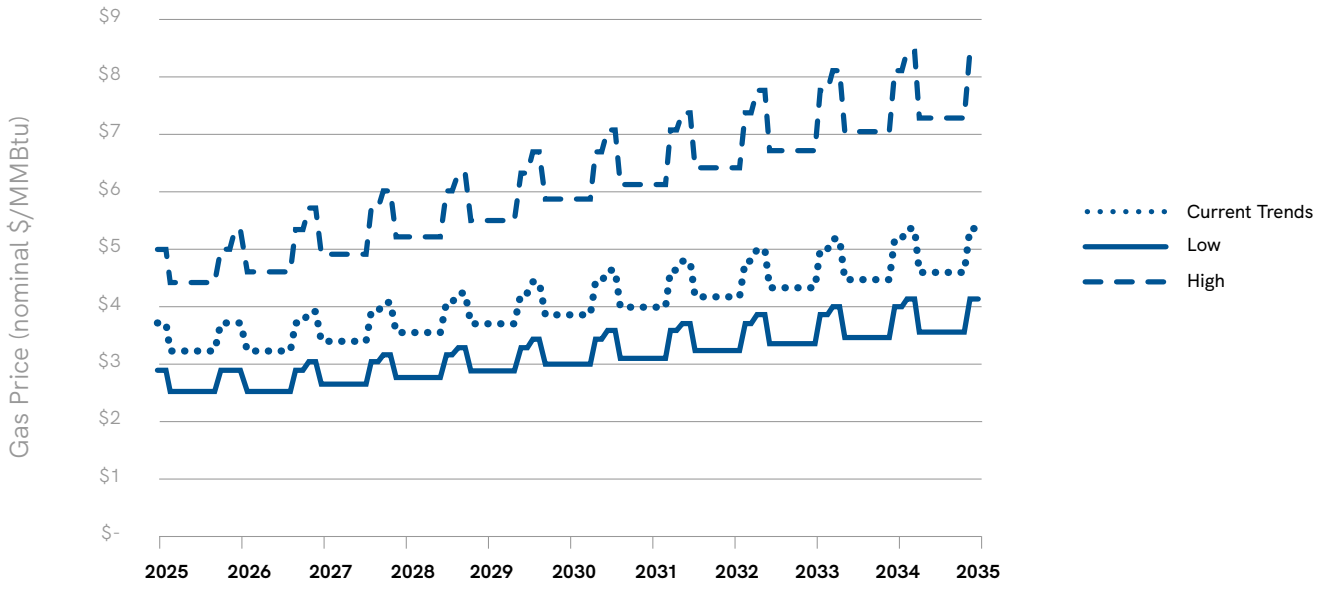
FIGURE 5.13: DISPATCHABLE RESOURCE COSTS



Fuel Prices

Fuel prices for the ISP were derived from several data sources. Natural gas forecasts were derived from the EIA 2022 AEO, with certain scenario trajectories regionalized based on SRP's gas supply. The gas price forecast varies by scenario and across the gas price sensitivities, reflecting low, mid, high and volatile trajectories. The low case reflects AEO's High Oil & Gas Supply Case; the mid case reflects AEO's Reference Case; the high case reflects AEO's Low Oil & Gas Supply Case; and the volatile gas case reflects observed volatility from 2000–2010 for the 2025–2035 analysis period. Figure 5.14 shows the Low, Current Trends (Mid) and High monthly forecasts through the 2025–2035 period.

FIGURE 5.14: GAS PRICE FORECASTS



Green hydrogen price forecasts were developed by E3, assuming electrolysis of hydrogen using an alkaline electrolyzer that is powered by solar energy (with solar resource costs as defined in this report). Hydrogen electrolyzer costs are derived from the California Energy Commission (CEC) publication on hydrogen production costs.[6] Hydrogen storage costs are derived from Department of Energy (DOE) project ST-001 costs.[7] Hydrogen transport costs are derived using Argonne National Laboratory's Hydrogen Delivery Scenario Analysis Model (HDSAM).[8] A $3/kg Production Tax Credit (PTC) is applied to all hydrogen produced through 2032. Market resource costs are derived and provided by internal SRP forecasts.

Reliability

To ensure system reliability, SRP must procure sufficient capacity to exceed annual peak demand over the entire planning horizon. In addition to serving the peak, a planning reserve margin (PRM) must be added to the amount of firm capacity on the system to ensure resource adequacy and avoid loss-of-load events while accounting for the potential for exceptional extreme loads, resource forced outages, uncertainties in load forecasting, and the operator's need to maintain a margin of operating reserves.

[6] https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf
[7] https://www.hydrogen.energy.gov/pdfs/review22/st001_ahluwalia_2022_p.pdf
[8] https://hdsam.es.anl.gov/index.php?content=hdsam

In most ISP cases, SRP applies a PRM of 16%, meaning that in each year of the planning horizon, SRP must have reliable capacity in an amount equal to or greater than 116% of forecast peak demand. In the Strong Climate Policy scenario and Regional Diversity sensitivity, the PRM is reduced to 13% as a proxy to represent the assumption that expanded transmission and regional coordination allows for increased resource and load diversity.

Due to high cooling loads, SRP has a summer-peaking system. Thermal generators are assumed to provide a PRM contribution (firm capacity value) equal to their summer monthly rating. Wind and pumped hydro storage resources contribute a fixed percentage of capacity (18% and 80%, respectively) to the PRM. Battery resource contributions to PRM decline with increasing battery penetration. New stand-alone solar resources are assumed to provide no firm capacity to SRP's system, but solar storage resources do contribute to the PRM due to the storage component.

CO_2 Emissions Target

SRP has established a goal of reducing carbon emissions intensity (lbs./MWh) by 65% by 2035 and by 90% by 2050, relative to 2005 levels. The carbon emissions intensity is the amount of carbon dioxide emissions (in pounds) from emitting power plants expressed relative to the amount of total generation (in megawatt-hours) across all power plants. In 2005, SRP's emissions rate was 1,576 lbs./MWh. In 2035, the CO_2 emissions target is 550 lbs./MWh. The ISP analysis capped CO_2 emissions to ensure that the future resource additions and operations are consistent with SRP satisfying its 2035 Sustainability Goals. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

Key Outputs

The following table reports the key outputs of the Resource Additions analysis:

Output	Description	Output Units
Resource Installed Capacity	Installed capacity of the generator, including new investments.	MW
Resource Contribution to Reliability	Firm capacity of the generator. For renewable resources options, this will equal the effective load carrying capability (ELCC) times the installed capacity.	MW
Resource Fixed Costs	Total fixed costs, including annualized build costs, fixed O&M and fixed charge (pipeline and/or fuel deliverability) costs.	$
Reliance on Emerging Technologies	Installed capacity and firm capacity for emerging technologies.	MW

Resource Operations

In the Resource Operations planning process, we simulated generating resource operations. For each future year, we simulated resource operations in each hour to understand how resources operate to meet total system demand and to understand the implications for cost, emissions, water usage and interactions with the regional power market. This information helped us evaluate the trade-offs between different system plans. This modeling process is sometimes referred to as production cost simulation in the industry.

Methodology Overview

Although the Resource Additions planning process considered resource operations when determining which resources to add in the future, that planning process did not have the same level of granularity as the Resource Operations planning process. In this planning process, SRP modeled every hour of the year (rather than a representative sample) and factored in more detailed operating characteristics for generators, which can influence operations. This refinement allowed SRP to say with more confidence how resource operations could evolve over time and what that would mean for affordability and sustainability metrics.

During this process, our team performed modeling for all 42 system plans. We used the Aurora model (developed by Energy Exemplar) to simulate future system operations, including existing resources and any new resources selected through the Resource Additions planning process. For the Volatile Gas Prices sensitivity cases, which did not vary the resource additions relative to the corresponding Current Trends cases, we only modified the gas prices and market prices over time to understand the impact of a volatile fuel price environment on system operations, affordability metrics and sustainability metrics.

Key Inputs

For this modeling process, we leveraged most of the same inputs utilized in the Resource Additions modeling process. Whereas the Resource Additions modeling process determined which resources to add to the system, the Resource Operations modeling process took the resource additions as fixed and then simulated future system operations. Therefore, this modeling process did not utilize the inputs related to resource additions or reliability given the system already had sufficient resources to meet future reliability needs. The Resource Operations process utilized the resource addition results as inputs and then leveraged the same data for these inputs:

- Load forecast
- Renewable generation profiles
- Variable operations and maintenance costs
- Fuel price forecast
- Market price forecast
- CO_2 emissions target

Because the Resource Operations modeling process simulated future system operations in a more granular manner, it also incorporated additional key inputs:

- Detailed operating characteristics for thermal generators
    - Minimum stable operating level
    - Startup time
    - Ramp rate
    - Minimum runtime
    - Minimum downtime
- Startup and shutdown costs for thermal generators
- Operating reserve requirements

Key Outputs

This planning process generated detailed system operations data for all 42 system plans. The table below summarizes the key outputs:

Output	Description	Output Units
Fuel, Operations and Maintenance Costs	Hourly fuel use, operations and maintenance costs	$
Market Purchase Costs	Costs of procuring external electricity generation outside of SRP	$
SRP Carbon Emissions (Mass)	Carbon emissions from generating resources during the planning period	Tons CO_2
SRP Carbon Emissions (Intensity)	Carbon emissions per MWh generation emitted during the planning period	Lbs. CO_2 per MWh
Carbon-Free Generation (%)	Percentage of total generation that was carbon-free	%
Water Use	Total water use during resource operation	Gallons
Criteria Pollutants (NO_x, SO_2, PM, VOC)	Criteria pollutant emissions from generation during the planning period	Tons
Thermal Plant Capacity Factor	Capacity factors for thermal plants during resource operation	%

Transmission Investments

In the Transmission Investments planning process, we studied the forecasted load and resource additions, determined future transmission needs and identified transmission investments to meet those needs. For the year 2035, we simulated transmission operations under different load and resource assumptions to understand which transmission investments were needed and at what cost.

Methodology Overview

For the ISP, we analyzed the portion of the transmission system rated 115 kV and above. We focused on this part of the transmission system for two reasons. First, transmission investments at these higher voltages require longer lead times for siting, engineering, permitting and construction, so there is more value in identifying investment needs for these assets through 2035. Second, analyzing the 69 kV system was not feasible due to limited resources over this study period. While we did not analyze the 69 kV system, we did estimate investment costs for the 69 kV system based on the number of new distribution substations.

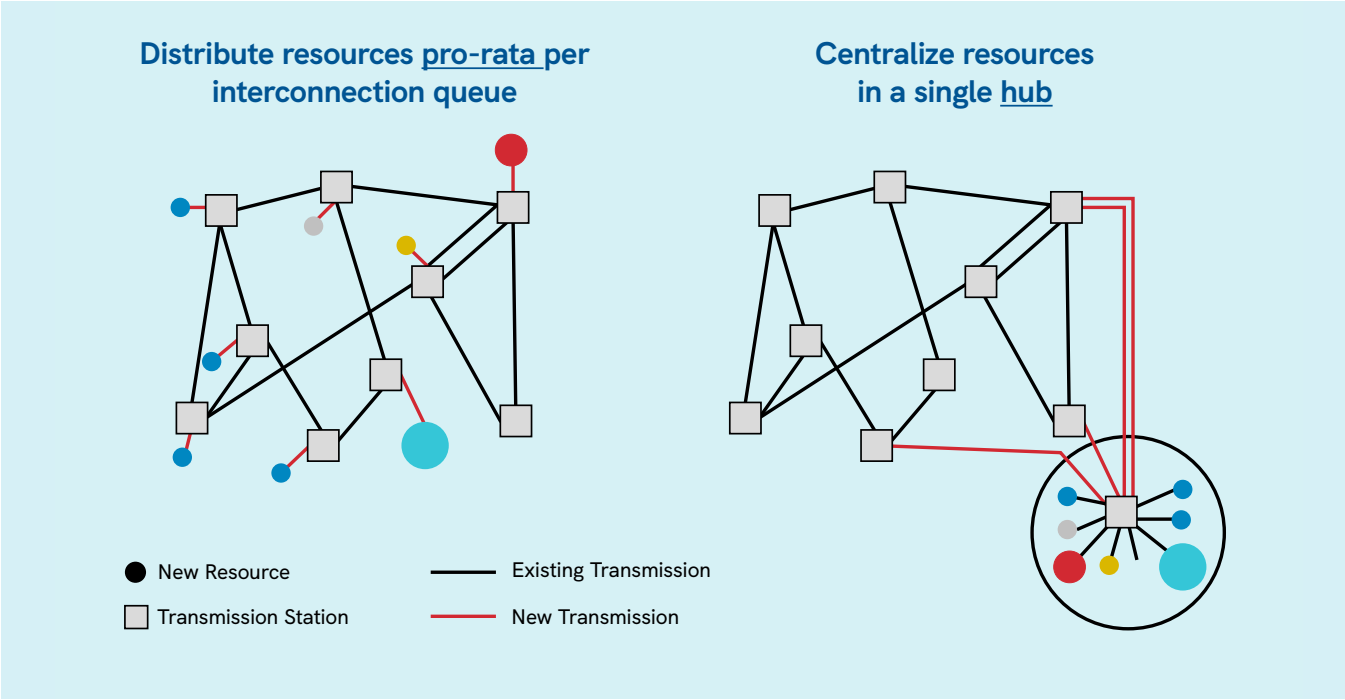
During this process, our team performed power flow analysis for the year 2035 to understand how power would flow across the transmission system and how the voltage would respond under certain conditions. We evaluated whether any element of the transmission system would be overloaded or be outside its acceptable voltage range. We also evaluated whether any element of the transmission system would be overloaded or fall outside its acceptable voltage range if other transmission elements were unavailable. We then identified transmission investments to mitigate the identified issues until none remained.

We studied two different operation hours for each case analyzed: the summer peak load hour, during which energy demand is greatest, and a summer peak renewables hour in which generation from solar, wind and other renewable resources are at maximum output. By studying these two conditions, we confirmed that the transmission system could meet the peak energy demand and accommodate renewable generation during peak production periods. For each case analyzed, we identified transmission investments that mitigated all issues across both operating conditions.

One of the key uncertainties in transmission planning is the location of future resources. Currently, developers decide where to site projects, submit interconnection requests and bid to provide energy to SRP or other utilities. As a result, we do not know where future resources will interconnect. The location of these resources can have a significant impact on the need for new transmission projects.

In the ISP, we chose to evaluate two resource location options: Pro-Rata and Hub (see Figure 5.15). The Pro-Rata option envisions new solar and battery resources being added across the system in proportion to the resources currently in SRP's interconnection queue. The interconnection queue served as a proxy for where developers would site future projects. With the Hub option, SRP would develop a new 500 kV switchyard southeast of the Valley and would encourage development of new gas, solar and battery storage resources at the hub. The Pro-Rata option represents a continuation of current practices in which developers locate throughout SRP's system, while the Hub option represents a potential alternative in which SRP concentrates development of resources in one location and connects that location to the rest of the system.

FIGURE 5.15: RESOURCE LOCATION OPTIONS



Our team identified transmission investments for the following cases under both the Pro-Rata and SRP Hub options. Due to time constraints through the ISP analysis, we could not perform detailed transmission analysis on all cases. Instead, we chose to analyze the following cases because they represent a wide range in both load growth and resource additions.

- Technology Neutral, Current Trends
- Technology Neutral, Desert Boom
- Minimum Coal, Current Trends

Key Inputs

For this modeling process, our team leveraged outputs from different planning processes, including Load Forecasting, Distribution Investments, Resource Additions and Resource Operations. As the transmission system acts as the link between utility-scale resources and customers, inputs related to loads and resources from these other planning processes were key inputs in determining transmission investment needs.

Because SRP's system is connected to other power systems in the Western Interconnection, we utilized models that represent the entire Western Interconnection. On an annual basis, SRP coordinates with neighboring utilities to develop "heavy summer" transmission models for up to 10 years into the future. For the ISP, we adapted the "2032 heavy summer" model to perform analysis for the different transmission cases through 2035.

Energy Demand

The projected energy demand at different locations on the transmission system came from two sources. First, the Load Forecasting modeling process identified the future energy demand for customers that connect directly to the transmission system. Second, the Distribution Investments modeling process identified the energy demand at each existing and new distribution substation to represent those customers connected to the distribution system. These inputs allowed SRP to identify the energy demand for each location on the transmission system.

Resource Locations

Figure 5.16 shows the location assumption for each new resource in the Pro-Rata and Hub options. For natural gas resources under the Pro-Rata option, we identified five potential locations based on preliminary gas siting screening efforts that were recently performed. For solar and battery storage resources under the Pro-Rata option, we allocated them to different substations in proportion to the interconnection queue. For the Hub option, we located new natural gas, solar and battery storage resources at the hub. The locations for other resources did not vary between the Pro-Rata and Hub options because the locations were already determined by the location of the underlying resource. The locations for wind and geothermal resources are discussed above in the Resource Additions section.

FIGURE 5:16: NEW RESOURCE LOCATIONS IN THE PRO-RATA AND HUB OPTIONS

New Resource	Pro-Rata	Hub
Natural Gas	Split across five locations	Placed at hub
Solar	Pro-rata allocation	Placed at hub
Battery Storage	Pro-rata allocation	Placed at hub
Pumped Hydro	Northeast of SRP service territory	
Wind	Varies by resource	
Geothermal	California, wheeled to Arizona, and injected at Hassayampa	
Biomass	Coronado	

Resource Operations

For the resource operations, our team identified the expected generation from all existing and planned resources for the peak load hour, so the transmission peak hour models reflected the planned resource outputs. This also included an economic dispatch order that was used to develop the peak renewable output hour scenarios.

Key Outputs

This planning process determined transmission investments. The table below summarizes the key outputs:

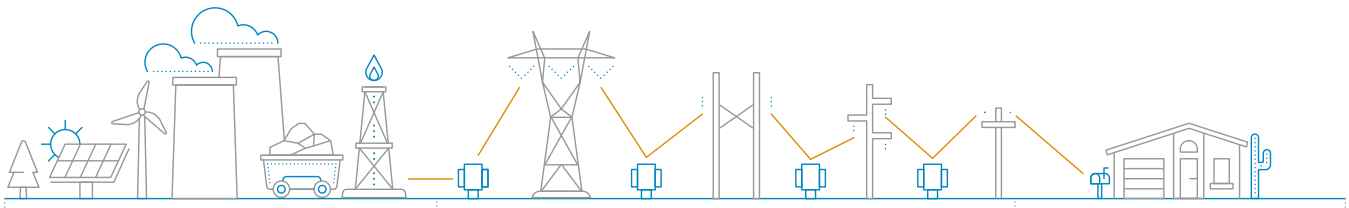
Output	Description	Output Units
Transmission Investments	Transmission projects to meet system requirements and associated upfront investment costs	$

Total System Cost

In this process, we performed simplified financial modeling to develop an annual total system cost metric for every case analyzed in the ISP. The purpose of this analysis was to provide indicative affordability metrics to compare system plans to one another and understand trade-offs between different system strategies. While the total system cost metric is helpful for these comparisons, it is not intended to provide a forecast of future rates for SRP customers or reflect SRP's financial outlook.

See Figure 5.17 below. We developed the total system cost by estimating system costs for generation, transmission, distribution, customer programs and other costs. These costs included costs of existing investments, new investments, operations and an estimate of system costs not modeled explicitly in the ISP. Many of these costs were outputs from the other modeling processes in the ISP.

FIGURE 5.17: COSTS INCLUDED IN TOTAL SYSTEM COST



Generation

Fuel

Market purchases and sales

Power purchase agreements

Existing and new investments

Operations and maintenance

Non-SRP transmission cost

Transmission & Distribution

Existing and new investments

Operations and maintenance

Customer Programs

Program and market enablement costs

Other

General & Administrative

Customer systems (metering, billing, customer service, etc.)

Telecom

Taxes

Assumed constant across all cases

Methodology Overview

For this methodology, our team first established a set of "base" costs that do not change across system plans. We forecasted the costs associated with existing generation, transmission and distribution assets, including the recovery of investment and maintenance costs. In addition, we forecasted other costs that do not relate to generation, transmission, distribution and customer programs, such as general and administrative costs. We held all of these "base" costs constant across cases.

We then determined the costs for investments that differed across the system plans and leveraged the outputs from the different planning processes to determine any incremental investments. To determine the annual costs for these investments, we applied straight-line depreciation and assumed a cost of capital consistent with SRP's weighted average cost of capital. SRP also estimated property taxes for these investments based on previously observed tax rates. Lastly, we leveraged the outputs from the planning processes to forecast operating expenses.

Generation

The Resource Additions process identified incremental generation investments, operation and maintenance fixed costs, and power purchase agreement costs. The Resource Operations process identified all variable operating costs associated with generation, including fuel expense, net market purchase costs, and variable operations and maintenance costs.

Transmission

The Transmission Investments process identified any incremental transmission system investments for the three cases analyzed. SRP further differentiated these costs by investments that are generation-driven versus load-driven to estimate costs in other cases. Using the three transmission cases analyzed, we calculated a linear relationship between (1) generation-driven costs and interconnected capacity additions, and (2) load-driven costs and peak load growth. We then applied those relationships to interconnected capacity additions and peak load growth observed in each of the remaining cases.

Distribution

The Distribution Investments process identified incremental distribution system investments, including transformers to serve new customers, new substations and substation upgrades. SRP identified these investments for each scenario as well as the high distributed generation and high energy efficiency sensitivities. The investment types and estimated costs remained consistent across the three strategic approaches.

Customer Programs

The Customer Programs process identified the incremental customer program operating costs. These costs reflected the cost of Energy Efficiency and Demand Response programs.

Key Outputs

The Total System Cost process generated annual cost estimates for all 42 system plans. The table below summarizes the key outputs. These outputs served as key inputs in calculating residential bill impacts across cases (see the Residential Bill Impact section below).

Output	Description	Output Units
Total System Cost	Total system costs across generation, transmission, distribution and other	$
Average System Cost	Total system cost divided by retail sales	$/MWh

Residential Bill Impact

In this process, we applied a simplified method to estimate the bill impacts over time for residential customers. While the Total System Cost process estimated how total costs could evolve over time, this process estimated how these changes could impact residential customers specifically and developed a residential bill impact metric.

This bill impact analysis does not necessarily reflect how future costs may be allocated and recovered from customers and therefore should not be considered as a projection of customer rates. SRP will carry out pricing processes in the future to determine future cost allocation and rates. Nevertheless, this metric provides a means for comparing cases to understand relative differences.

Methodology Overview

We leveraged information from our most recent Cost Allocation Study (CAS) to allocate costs in the ISP to residential customers. The CAS determined how the energy usage of residential customers differed from other customer classes (e.g., commercial and industrial) and developed cost allocators for different system cost components (e.g., generation and fuel). Because different system cost components are driven by different factors (e.g., total annual energy use, peak hour energy usage), the cost allocators differ by system cost component. This ensures that each customer class pays its fair share of system costs, based on the cost of serving those customers.

Below is the methodology we used in the ISP to allocate costs for different system components to residential customers:

- **Generation –** Generation-related costs, including operations and maintenance (O&M) costs, power purchase agreement (PPA) costs and recovery of investment costs, are allocated based on a blend of two factors: the share of annual delivered energy (in kWh) and the share of energy demand (in MW) during overall system peak periods.

- **Fuel –** Fuel costs, including natural gas, coal and (in some ISP cases) hydrogen fuel costs, are allocated based on the share of total annual energy demand (in kWh), calculated as the total annual delivered energy less any energy exported to the grid.
- **Transmission –** Transmission costs, including O&M costs and recovery of investment costs, are allocated based on the share of energy demand (in MW) during overall system peak periods.
- **Distribution –** Distribution costs, including O&M costs and recovery of investment costs, are allocated based on the peak hourly energy demand of the customer class (in MW) — not necessarily during the overall system peak period — relative to the peak hourly energy demands of other customer classes.
- **Customer Service, Billing and Metering –** Customer service, billing and metering costs are allocated based on the share of the total number of customers served by SRP.
- **Other Costs –** Other costs, including net market purchase expenses and any other costs not described above, are allocated according to the share of total generation, transmission and distribution costs.

To determine the average residential customer cost (in ¢/kWh), SRP divided the total costs allocated to residential customers by the total annual energy demand (in kWh). SRP then compared these average residential costs to the actual costs for residential customers in November 2022 to show the change through 2035.

Key Outputs

The key output of this process is the average residential bill impact:

Output	Description	Output Units
Average Residential Customer Cost	Average residential customer cost for each ISP case.	¢/kWh

Development and Operational Risk Assessments

Our team evaluated the development and operational risk factors for different system plans. While the various planning processes identified future infrastructure additions based on least-cost optimization analysis, as well as future operations based on simulations, there are many real-world risks to consider that could impact SRP's ability to develop and operate these system plans.

There are risks and challenges in developing new infrastructure, including risks related to permitting, siting, constructing and acquiring new infrastructure. As we have observed over the last few years, third-party projects can be delayed or even cancelled due to supply chain challenges. Supply chain issues have also led to increased timelines for acquiring new transmission and distribution infrastructure. There are also risks in developing large new infrastructure projects, which may depend on multiple regulatory approvals and therefore come with uncertainty. Because each of the ISP system plans requires significant development

of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems.

There are also risks and challenges in operating the power system in new ways. While the production cost model simulated future operations based on hourly optimization analysis, many real-world risks cannot be captured fully in that analysis and could potentially impact SRP's operations. There are risks related to more variable system operations, fuel availability, wear and tear on generating resources, etc. Because each of the ISP system plans requires a meaningful shift in the future operations of the system, we performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems.

Methodology Overview

Our team developed qualitative development and operational risk ratings for each system plan to understand the relative risks between different system plans. This approach is used to assess uncertainty in factors where it is not easily quantified and is known as the expert opinion method.

First, because the ISP assessed many planning cases, and some of the resulting system plans were relatively similar across cases, we clustered some plans together when performing the risk assessment.[9] The clustered system plans were representative of the 12 core system plans (three strategic approaches evaluated against four scenarios). We then convened an internal group of subject matter experts from various departments to assess the development and operational risks for each of the system plans. After the group assessed the different system plans independently, SRP held a joint workshop during which the group discussed findings, identified risks, discussed mitigation factors and developed risk ratings.

To develop a quantitative risk rating, each participant rated each cluster of system plans on a scale from 1 to 5, with 1 being lowest risk and 5 being highest risk. We identified a reference plan (Tech Neutral, Current Trends) to correspond to a risk rating of 3 to calibrate a point of reference. The participants rated each cluster of system plans based on how the risk factors for that plan compared to the risk factors identified for the reference plan, and SRP averaged these ratings to develop a final risk rating for each system plan.

Development Risk Assessment

To evaluate the development risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Resource Planning, Acquisition and Development**, consisting of engineers and analysts responsible for acquiring and developing power generation resources (renewable and thermal) to meet system needs
- **Distribution Planning**, consisting of engineers who plan distribution infrastructure
- **Innovation & Development**, consisting of engineers who support research into emerging generation technologies (e.g., hydrogen, nuclear small modular reactors, and carbon capture and storage)

[9] For the development risk assessment, SRP clustered system plans based on resource additions across different technologies. For the operational risk assessment, SRP clustered system plans based on multi-hour ramping needs, natural gas fuel consumption, market purchases, solar additions, wind additions, battery storage additions, and curtailment.

- **Power Delivery**, consisting of engineers and planners who support generation interconnection and plan, site and build necessary transmission infrastructure
- **Land**, consisting of analysts responsible for acquiring necessary land for new projects
- **Supply Chain Management**, consisting of analysts managing procurement of long-lead-time equipment
- **Supply and Trading & Fuels**, consisting of power and natural gas traders and analysts focused on market operations
- **Customer Programs**, consisting of analysts who develop and manage customer programs (e.g., energy efficiency, electrification)
- **Environmental Services**, consisting of engineers and scientists who support site permitting and ensure compliance with environmental regulations
- **Community Partnerships**, consisting of community strategists who work with and support the communities that SRP operates within

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following development risk factors:

- Permitting, siting and land acquisition
- Supply chain challenges
- Long lead times to develop infrastructure
- Interconnection of new resources
- Natural gas pipeline development
- Reliance on emerging technologies
- Reliance on customer adoption of end-use programs (such as energy efficiency and distributed generation)

Operational Risk Assessment

For the operational risk assessment, we followed a process similar to that used for the development risk assessment. To evaluate the operational risks for different system plans, we convened an internal group of subject matter experts from the following groups within SRP:

- **Supply and Trading & Fuels**, consisting of electricity and natural gas traders and analysts focused on markets and operations
- **Operations Planning**, consisting of analysts focused on modeling the market, optimal dispatch and maintenance planning
- **Transmission & Generation Operations**, consisting of real-time power dispatchers
- **Operational Readiness**, consisting of engineers leading the processes for enabling additional solar and batteries onto SRP's system
- **Generation Engineering**, consisting of engineers analyzing the maintenance needs of generation plants

We provided each of these groups with the outputs for different system plans and then tasked them with evaluating the system plans based on the following operational risk factors:

- System ramping needs and capabilities
- Renewable curtailment
- Thermal unit operations (capacity factor, starts and hours of operation)
- Reliance on market purchases for electricity
- Natural gas hourly and daily consumption

Key Outputs

Output	Description	Output Units
Development Risk Rating	Risk rating summarizing the degree of development risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)
Operational Risk Rating	Risk rating summarizing the degree of operational risks associated with a given system plan	Likert Scale (1 = lowest risk, 5 = highest risk)

Metrics

We developed metrics for ISP cases to evaluate the performance of each strategic approach across scenarios and sensitivities, provide information to customers and other stakeholders, and to inform the ISP residential customer research. Figure 5.18 lists the metrics we developed to evaluate the performance of different system plans, which include reliability, affordability, sustainability and customer focus metrics.

FIGURE 5.18: ISP METRICS

Reliability

Resource Contribution to Reliability

Reliance on Emerging Technologies

Qualitative Risk Ratings (Development Risk and Operational Risk)

Planning Reserve Margin

Affordability

Total System Costs

Average System Costs

Average Residential Price Impact

Sustainability

CO_2 Reductions

Water Use

Carbon-Free Generation

Capacity Factor for Gas Fleet

Direct Air Emissions (NOx, SO_2, PM, VOC)

Customer Focus

Customer Preference Rating

CO_2 reductions from energy efficiency, distributed generation and electrification

We developed most of these metrics through the modeling processes described above. The Total System Cost and Residential Price Impact processes produced the affordability metrics. The Resource Operations process produced the sustainability metrics. And lastly, the Resource Additions, Development Risk Assessment and Operational Risk Assessment processes produced the reliability metrics.

For the Customer Focus metrics, we completed additional analysis separate from the modeling processes described above. To develop the Customer Preference Rating, SRP engaged Bellomy Market Intelligence to complete the ISP residential customer research. The goal of Bellomy's research was to bring the voice of SRP's residential customers into the planning of the future power system. More specifically, this research was designed to gain an understanding of how customers view and value sustainability, affordability and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems being analyzed in the ISP. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the ISP and ultimately develop the Customer Preference Rating. More details on the specific methodology are included in appendices B and C, which contain reports from all phases of the ISP residential customer research effort.

To develop the CO_2 Reductions metric for various customer programs (including energy efficiency, distributed generation, demand response and electrification), we estimated the amount by which additional amounts of these programs could decrease economywide greenhouse gas emissions. For energy efficiency and distributed generation, we evaluated how much annual emissions would decrease in each planning case if customer adoption increased slightly. For electrification measures (including electric vehicles and heat pumps), we estimated how much annual emissions from electricity generation would increase from customers adopting these measures and increasing energy demand. In addition, we estimated how much emissions would decrease from displaced fossil fuel consumption (in vehicles or home heating systems) to arrive at an estimate for net decrease in economywide emissions for adoption of electrification measures.

Ultimately, planning a future energy system involves trade-offs between different planning goals for the system. No single system plan performed the best in every metric that we quantified. We utilized this suite of metrics to evaluate trade-offs between different strategic approaches and to understand how planning would need to adapt under future planning uncertainties.

SECTION 6

Results

This section presents the modeling results and key findings from the ISP analysis. The analytical results are presented for each planning process described in Section 5, including Customer Programs and End-Use Technologies, Load Forecast, Distribution Investments, Resource Additions, Resource Operations, Transmission Investments, Total System Cost, Residential Bill Impact, Development and Operational Risk Assessment, and Residential Customer Research. Several ISP key findings are highlighted in callout boxes throughout and then summarized at the end of this section.

Results

Customer Programs and End-Use Technologies

Customer programs play an important role in managing SRP's load and are a key input to the load forecast used in the ISP. Also, customer adoption of end-use technologies, such as electric vehicles and distributed generation, have an increasing impact on the load forecast over time. This section presents the forecasts through 2035 for annual energy efficiency savings, demand response capacity, additional electrification load, and customer adoption of distributed generation across each scenario.

Figure 6.1 shows the incremental new energy efficiency savings. Under Current Trends, Desert Boom and Desert Contraction, there is continued expansion in energy efficiency over time, reaching 3,236 GWh of new energy efficiency savings by 2035. Under Strong Climate Policy, expansions to federal codes, standards and incentives lead to even higher energy efficiency growth, reaching 3,896 GWh of total energy efficiency savings by 2035.

Figure 6.2 shows the cumulative demand response capacity through 2035. Under all scenarios, SRP doubles demand response capacity, reaching 300 MW of total demand response by 2035.

FIGURE 6.1: ANNUAL NEW ENERGY EFFICIENCY ASSUMPTIONS

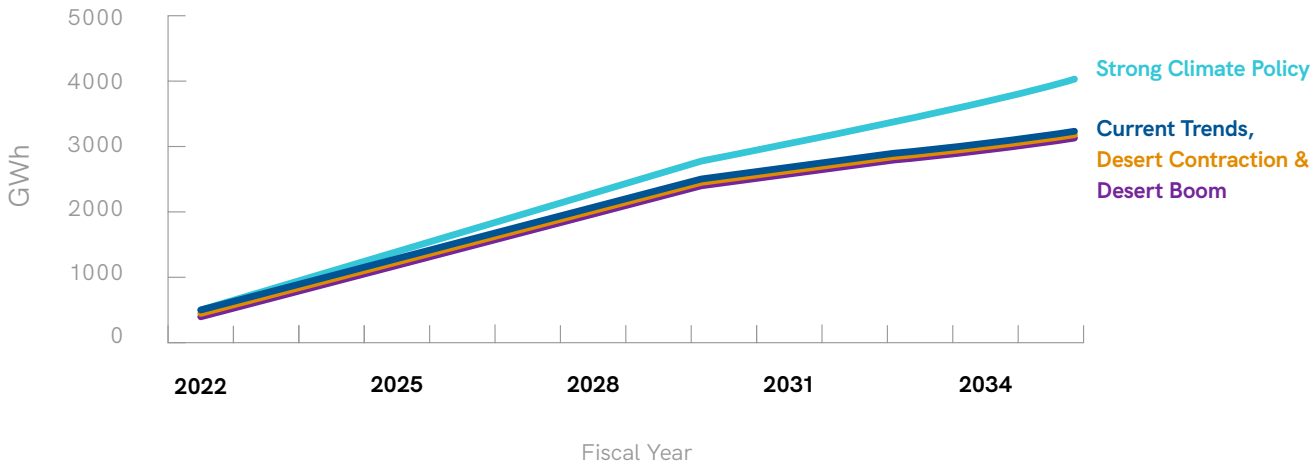
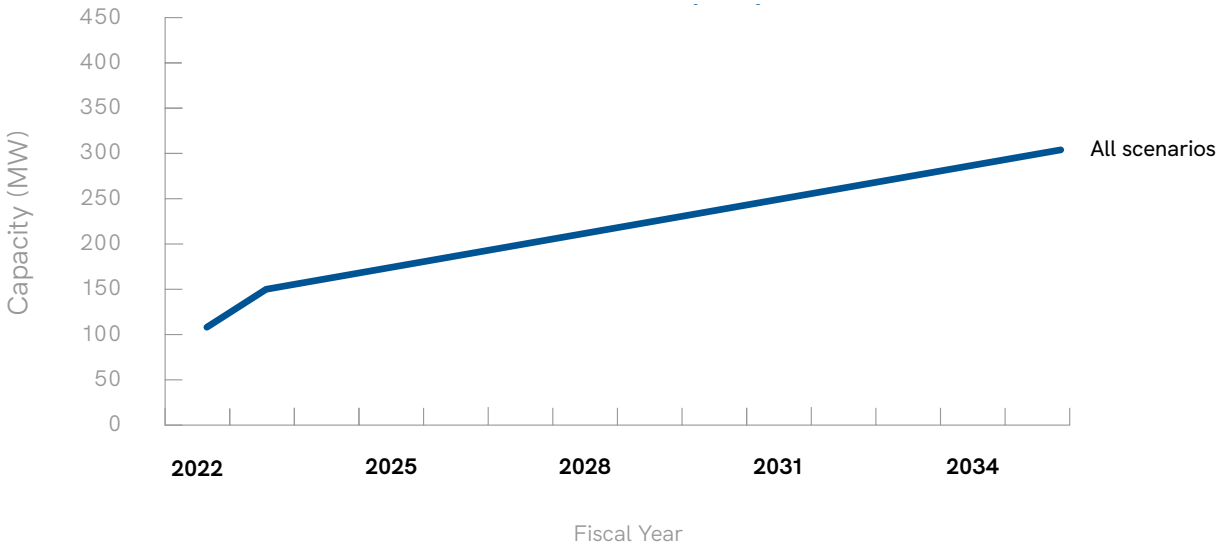


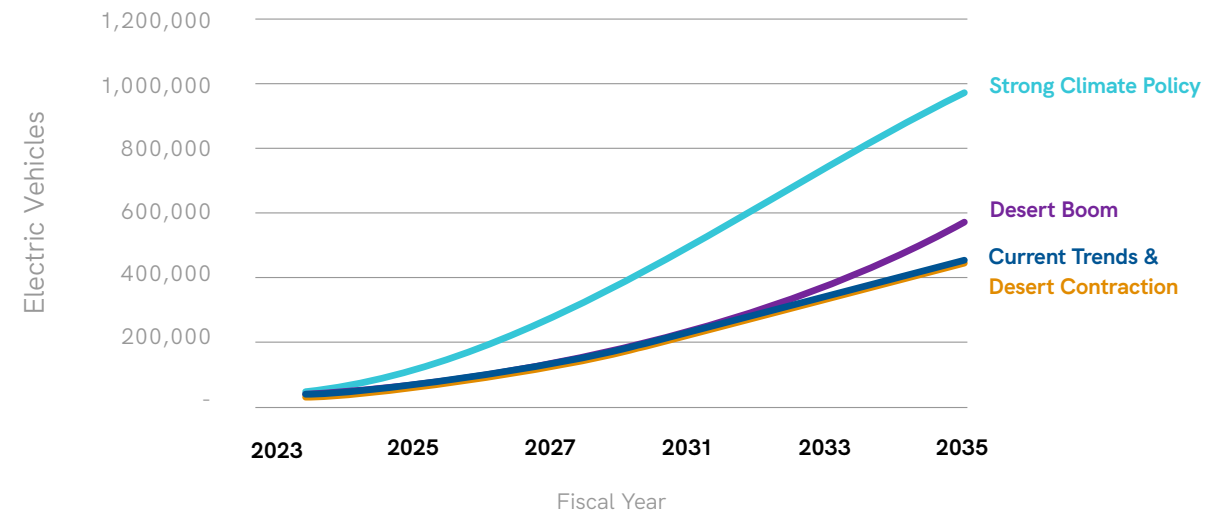
FIGURE 6.2: CUMULATIVE DEMAND RESPONSE CAPACITY ASSUMPTIONS



In addition to the energy efficiency and demand response programs, SRP's electric technologies programs, which serve commercial and industrial customers, grow meaningfully over time. The load impact from these programs grows from approximately 50,000 MWh today to levels consistent with SRP's goal of 300,000 MWh by 2035. The programs are varied and include electrification of material handling equipment (forklifts, scissor lifts, boom lifts, scrubbers, sweepers, etc.), truck stop and truck refrigeration equipment, industrial heating processes (melting, curing, steam, etc.), space and water heating processes, and commercial cooking equipment.

Figure 6.3 shows projected customer adoption of electric vehicles through 2035. Under the Current Trends and Desert Contraction scenarios, customers adopt 500,000 electric vehicles by 2035, consistent with SRP's 2035 goal for electric vehicle adoption. Under the Desert Boom scenario, customers adopt more electric vehicles due to increased economic and population growth. Under the Strong Climate Policy scenario, SRP assumed that increased federal support will result in greater customer adoption of electric vehicles at levels consistent with reaching net-zero economywide emissions by 2050.

FIGURE 6.3: ELECTRIC VEHICLE ADOPTION FORECAST



In addition to customer energy demand, customer adoption of generating resources also impacts the overall forecast for future energy demand. SRP forecasts customer adoption of rooftop solar and batteries to grow, reducing future energy demand (see figures 6.4 and 6.5).

In the Current Trends and Desert Contraction scenarios, rooftop solar and battery adoption increase steadily, reaching 1,296 MW and 75 MW, respectively, by 2035. In the Desert Boom scenario, an increased population and economic growth lead to stronger rooftop solar and battery adoption, reaching 1,804 MW and 157 MW, respectively, by 2035. In the Strong Climate Policy scenario, rooftop solar and battery adoption increase the most due to accelerated technology improvements and cost declines assumed in this scenario. By 2035, solar and battery adoption reach 2,257 MW and 250 MW, respectively, in the Strong Climate Policy scenario.

FIGURE 6.4: ROOFTOP SOLAR ADOPTION NAMEPLATE CAPACITY (MW) FORECAST

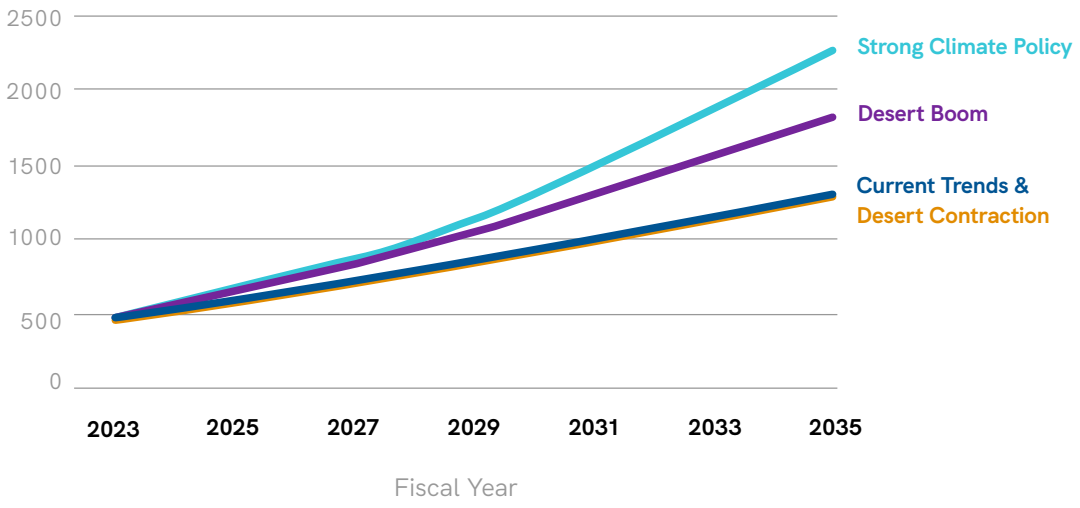
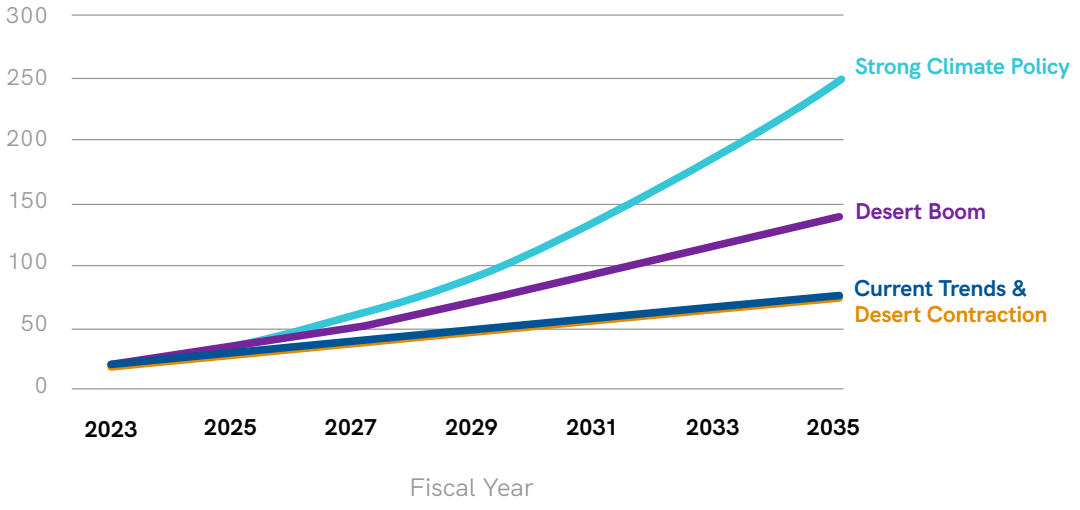


FIGURE 6.5: CUSTOMER-OWNED BATTERY ADOPTION NAMEPLATE CAPACITY (MW) FORECAST



Load Forecast

The load forecast is a key input to all the planning processes, as it is a main driver of future investment needs. This section presents the peak load and annual energy demand forecasts through 2035 for the four scenarios.

KEY FINDING

Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.

Figures 6.6 and 6.7 show peak load and energy demand forecasts for the four scenarios. SRP forecasts rapid load growth in the Current Trends, Desert Boom and Strong Climate Policy scenarios. In the Current Trends scenario, high economic and population growth lead to a substantial increase in both peak load and energy demand. In the Desert Boom scenario, accelerated migration into the Phoenix metropolitan area and increased economic development lead to even higher loads. In the Strong Climate Policy scenario, load growth from rapid electrification is offset by increased customer programs, resulting in a similar, but slightly lower, load forecast as for Current Trends. Across these three scenarios, between 2023 and 2035, peak load grows annually by 2.9%–4.0%, and annual energy demand grows annually by 3.1%–4.8%. The Desert Contraction scenario initially follows a rapid growth trajectory, but then peak load levels off and annual energy demand declines, reflecting a reversal of recent trends in migration and economic growth. Altogether, these load forecasts represent a wide range of future outcomes, from little to no growth in Desert Contraction to accelerated growth in Desert Boom.

FIGURE 6.6: PEAK LOAD (MW) FORECASTS BY SCENARIO

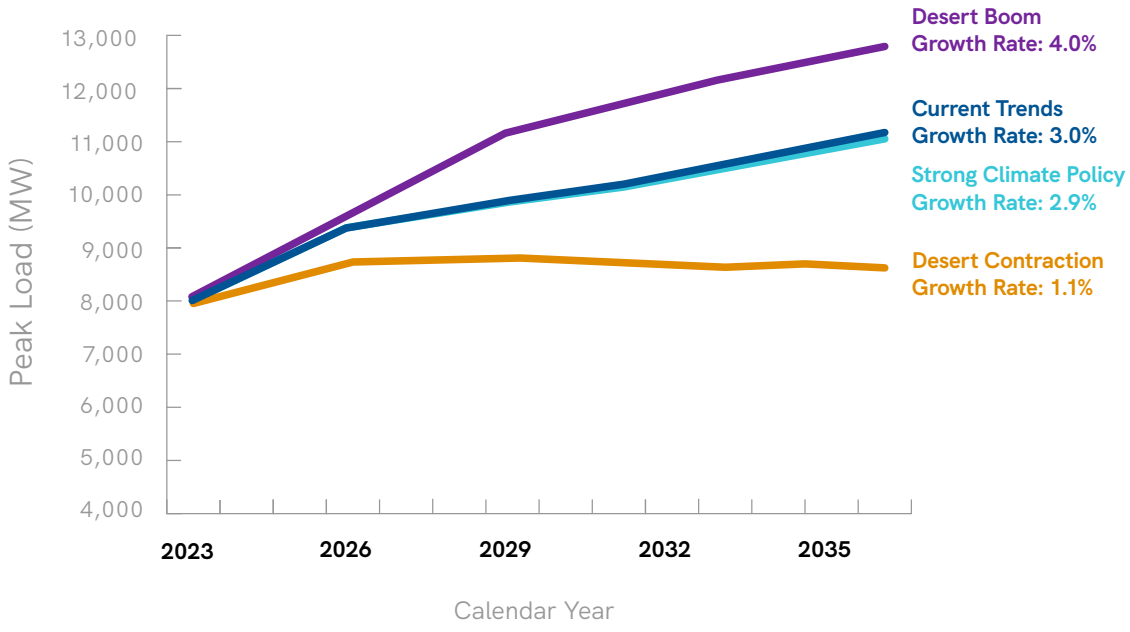
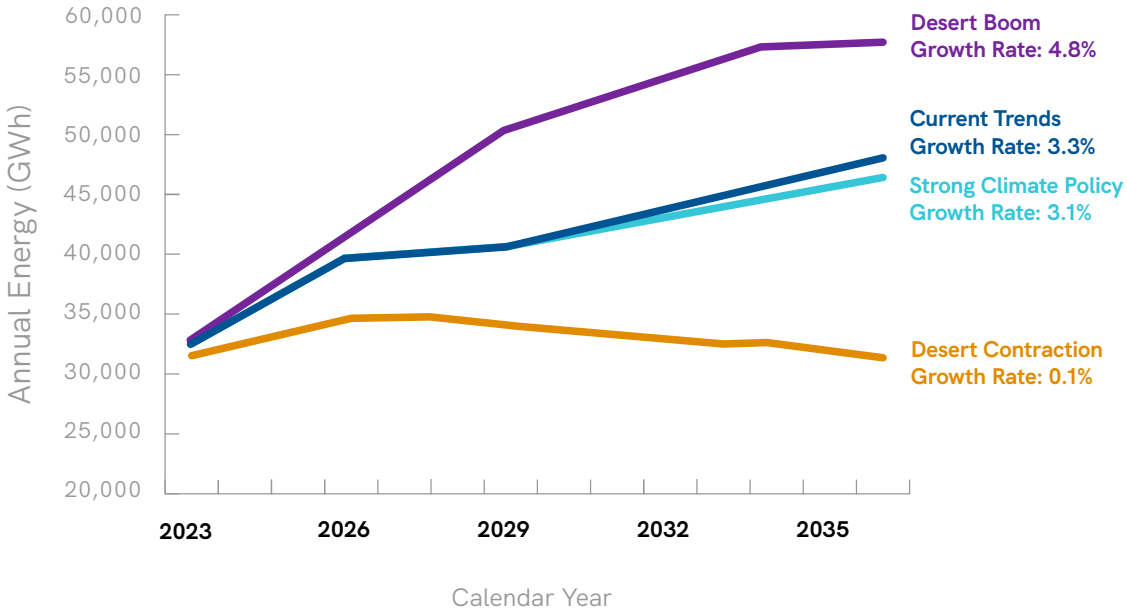


FIGURE 6.7: ENERGY DEMAND (GWH) FORECASTS BY SCENARIO

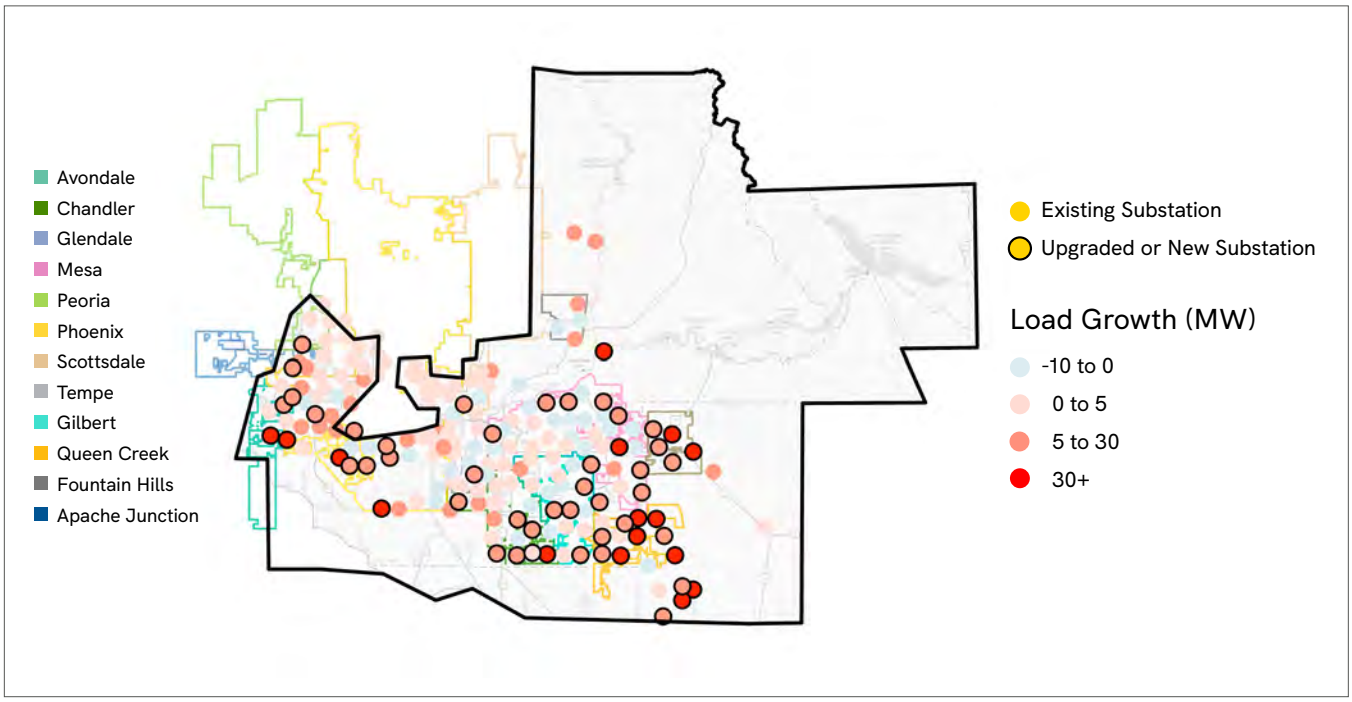


Distribution Investments

Future load growth and customer adoption of new technology increases the demand requirements on SRP's distribution system. SRP adapts to these changes through upgrades to existing infrastructure and investments in new infrastructure, such as distribution substations to serve new loads. This section describes the estimated distribution investments required to reliably serve customers across each scenario.

Figure 6.8 illustrates load growth changes in megawatts (MW) by distribution substation between 2022 and 2035 under the Current Trends scenario, highlighting new substation additions as well as upgrades required at existing substations (i.e., new substation bays added). Load growth and investment needs vary across SRP's service area. The Current Trends scenario results shown below are representative of the other scenarios' results and indicate the most significant load growth would occur in the Southeast Valley, requiring greater investments in that planning region. Additionally, the southwest portion of SRP's service territory sees relatively high load growth, requiring more investments. While these patterns are consistent across scenarios, the level of investments and upgrades needed by 2035 varies with load growth in each scenario, with more investments needed in the Desert Boom scenario and fewer investments needed in the Desert Contraction scenario.

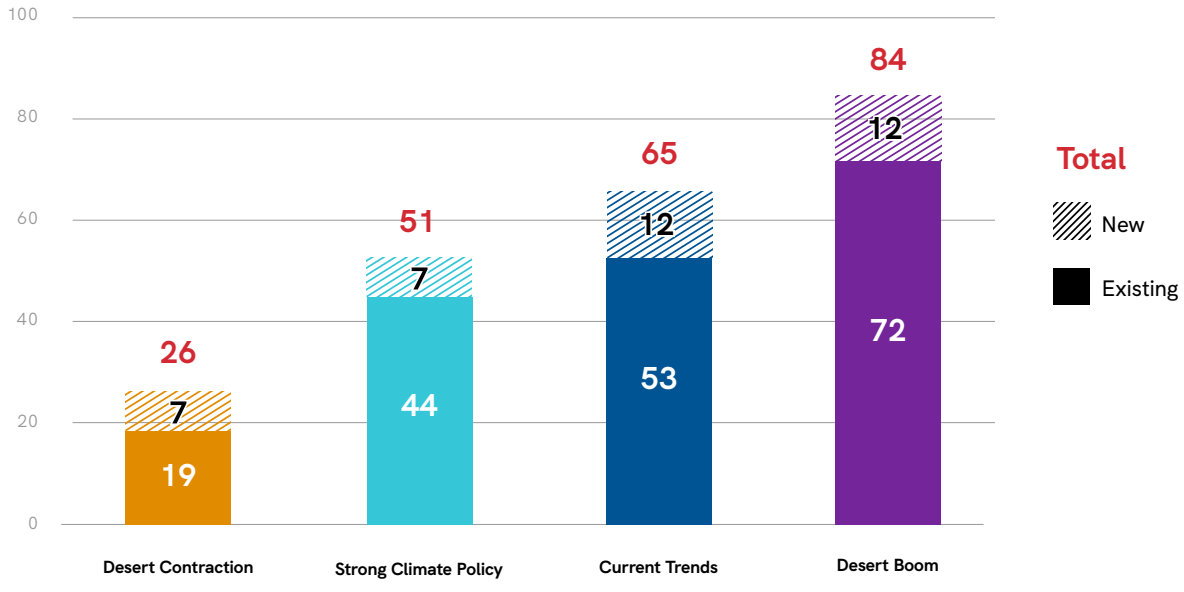
FIGURE 6.8: LOAD GROWTH BY DISTRIBUTION SUBSTATION THROUGH 2035 UNDER CURRENT TRENDS



See Figure 6.9 for the substation bay additions needed through 2035 across each of the scenarios and sensitivities. Across the scenarios, between 26 and 84 new substation bays are needed. A greater need for new distribution infrastructure is correlated with higher load growth across the scenarios. For example, substation bay additions more than triple in the Desert Boom scenario compared to what is required in the Desert Contraction scenario.

As electricity demand continues to grow in SRP's service territory, SRP will need to invest in the distribution system to enable this growth. The level of investments required will depend heavily on the rate of load growth.

FIGURE 6.9: SUBSTATION BAY ADDITIONS AT NEW AND EXISTING DISTRIBUTION SUBSTATIONS BY 2035

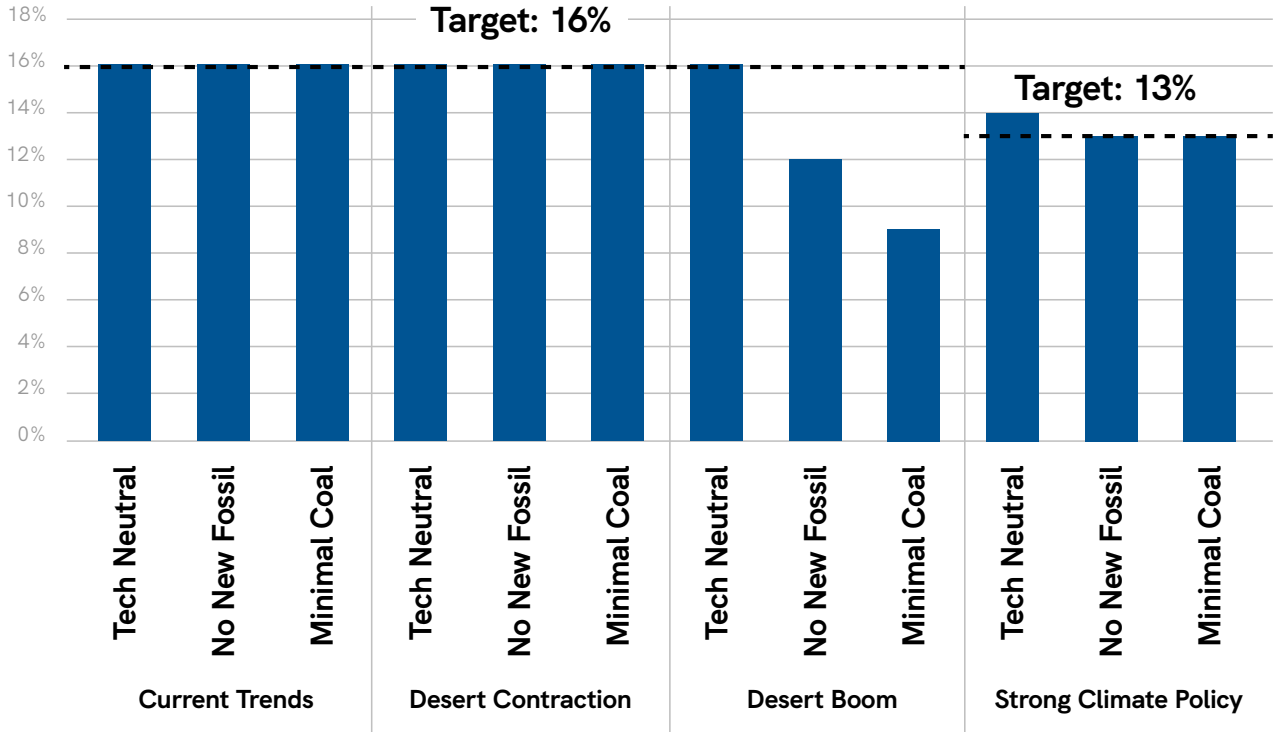


Resource Additions

SRP must add new resources to meet future energy demand, maintain system reliability, and meet the 2035 goals for carbon reduction and water resiliency. This section discusses the least-cost portfolios of generating resources selected by the long-term capacity expansion model across all scenarios and strategic approaches, as well as key reliability metrics.

For SRP to reliably serve customers across a wide range of system conditions, we must build sufficient resources to meet the planning reserve margin (PRM). The PRM is calculated using the load forecast and adding additional capacity to account for contingencies. This is a key metric because a plan that does not meet the PRM requirement is not reliable. Figure 6.10 shows the achieved PRM in 2035 across scenarios and strategic approaches compared with the requirement in each case. SRP's PRM requirement is 16% in all scenarios except for the Strong Climate Policy, where the PRM was reduced to 13% as a proxy to represent the potential benefits from expanded regional markets contributing to reliability.

FIGURE 6.10: ACHIEVED PLANNING RESERVE MARGIN IN 2035



All cases studied satisfy the PRM except for the No New Fossil and Minimum Coal strategic approaches in the Desert Boom scenario. Utilizing these two strategic approaches where firm resource options are limited[1], the accelerated load growth in Desert Boom compromises reliability as early as 2028. In these cases, there is insufficient capacity despite maximizing all available resource options. The third

KEY FINDING

Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.

[1] Firm resources include resources that can generate at sustained output for long periods of time. Firm resources studied in the ISP include natural gas, geothermal, biomass, natural gas with carbon capture and storage (CCS), biomass with CCS, nuclear small modular reactors (SMR), hydrogen and existing coal resources.

case, using a Technology Neutral strategic approach, is reliable in this scenario because it utilizes natural gas technology which was not an option in the No New Fossil and Minimum Coal strategic approaches. Because the No New Fossil and Minimum Coal cases do not meet SRP's reliability requirement, they are not viable in a Desert Boom scenario and were not evaluated further.

Figure 6.11 shows capacity additions through 2035 for all scenarios and strategic approaches. Customer programs, including energy efficiency, demand response and distributed generation, grow in all cases and offset the need for resource additions. Across all cases, renewable and energy storage resources make up a significant share of resource additions. In the Technology Neutral strategic approach, natural gas also accounts for a significant share of additions. In the No New Fossil and Minimum Coal strategic approaches, substantially more capacity is added as renewable and storage because these cases do not allow natural gas. This is because not all technology types contribute to reliability equally. Nearly all the capacity of a firm resource is counted toward the PRM while non-firm resources contribute a smaller portion. With fewer firm generation options, more total resources are needed to ensure reliability.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio.

Due to differences in load growth, the Desert Contraction cases require fewer resources than Current Trends, while the Desert Boom cases require more resources. The Strong Climate Policy cases add significant amounts of renewable and storage resources to meet the stringent federal emissions target in this scenario.

KEY FINDING

If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), SRP would need to significantly accelerate renewable and storage deployment.

FIGURE 6.11: CAPACITY ADDITIONS (MW) SELECTED BY MODEL BETWEEN 2025 AND 2035 UNDER ALL SCENARIOS

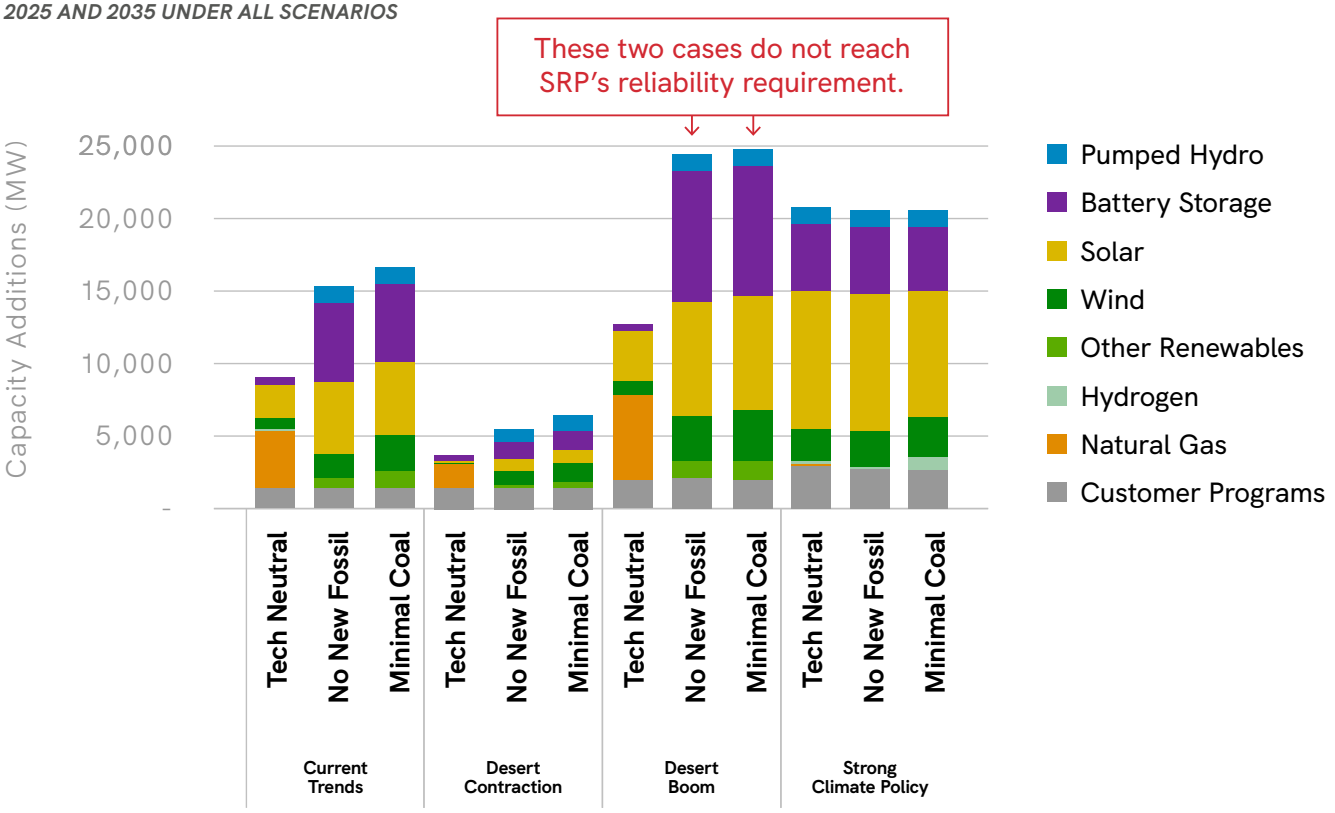


Figure 6.12 shows total installed capacity in 2035 for all scenarios and strategic approaches, as well as installed capacity in 2023 for reference. In the Technology Neutral and No New Fossil cases, more than 1,300 MW of coal capacity will be retired by 2035, with remaining coal capacity making up a small fraction of total capacity in 2035. In the Minimum Coal cases, all coal capacity retires by 2035. Looking across the system plans, there is a significant increase in total capacity between 2023 and 2035. Even the Desert Contraction scenario results in thousands of additional megawatts of capacity, while the other scenarios add more than 10,000 MW of capacity in many cases. Based on these results, SRP will likely need to double or triple its resource capacity in the next decade to serve customers to achieve reliability and sustainability goals, which marks an unprecedented rate of resource additions.

KEY FINDING

SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.

FIGURE 6.12: TOTAL INSTALLED CAPACITY (MW) IN 2023 AND IN 2035 UNDER ALL SCENARIOS

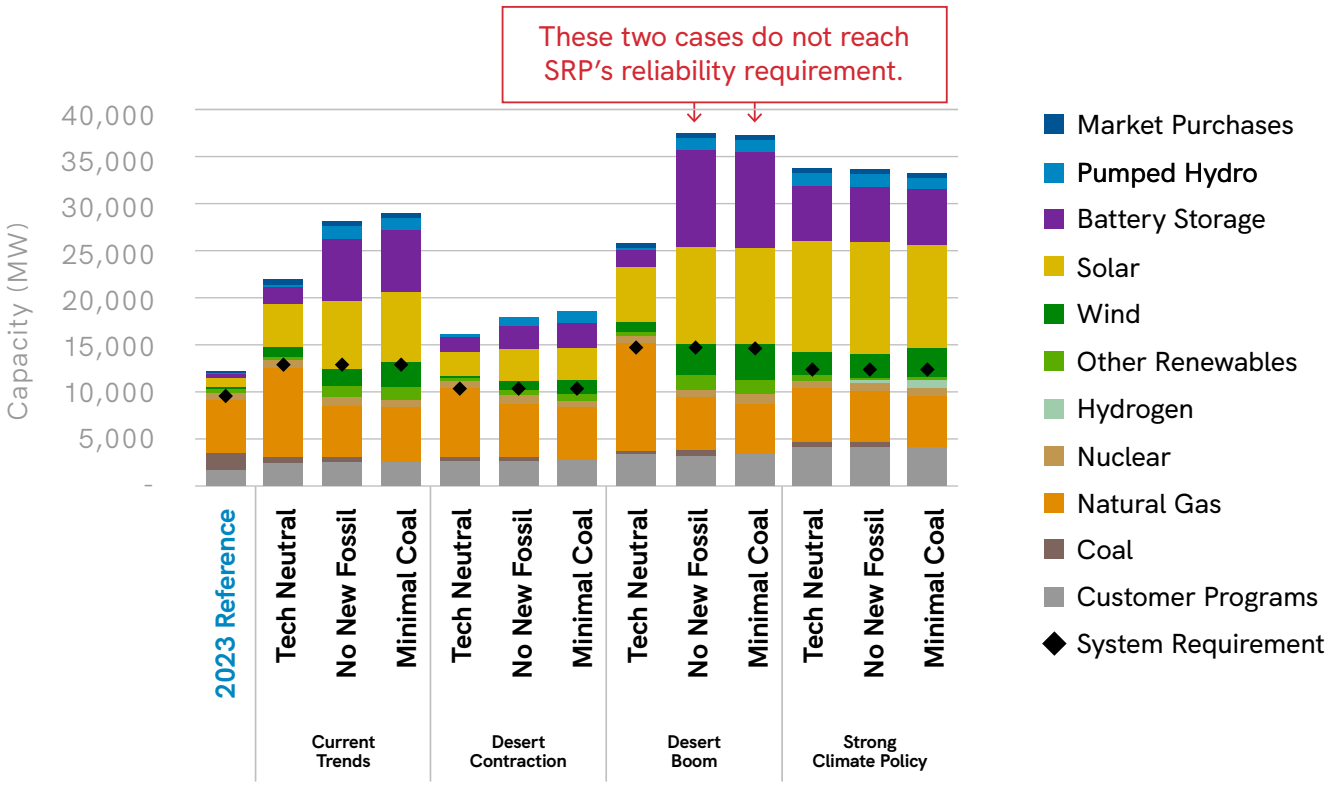
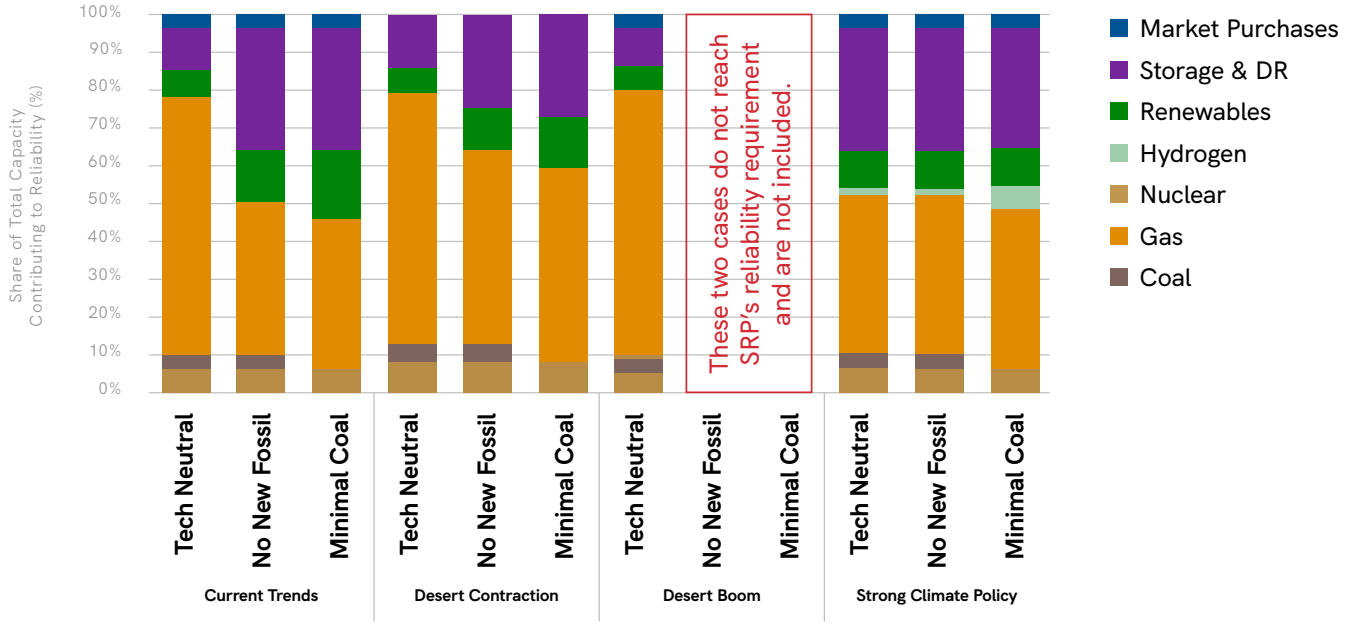


Figure 6.13 shows the contribution share of different resources toward satisfying the PRM requirement in each case. Firm resources are key to maintaining reliability; across all plans, firm resources (nuclear, coal, natural gas, geothermal, biomass and hydrogen) meet at least 55% of reliability needs in 2035, and more so in the Technology Neutral strategic approach. As noted previously, without new firm resources, reliability is compromised by 2028 in the Desert Boom scenario. New renewable and storage resources help contribute to reliability in all cases, and more so in the No New Fossil, Minimum Coal and Strong Climate Policy cases. Lastly, new firm capacity resources (natural gas or hydrogen), when included as an option per the scenario and strategic approach assumptions, are selected to help meet reliability needs at lower cost.

FIGURE 6.13: RESOURCE CONTRIBUTION TO RELIABILITY (RELIABILITY MIX) IN 2035



Note: Renewables includes solar, wind, geothermal, biomass and hydro. Storage & DR includes battery storage, pumped hydro and demand response (DR).

Relying on emerging technology can pose a risk in meeting future customer needs. Figure 6.14 shows the emerging technology selections across cases. The Strong Climate Policy scenario assumes accelerated availability of emerging technologies due to increased government support. Under this scenario, almost 200 MW of hydrogen are added in the Technology Neutral and No New Fossil cases and almost 800 MW in the Minimum Coal case, making up for lost capacity from the early retirement of Springerville Generating Station. This highlights again the value of a firm generation resource option and the potential for emerging technologies like hydrogen to provide firm generation. SRP acknowledges that to deploy 800 MW of hydrogen capacity, significant developments are needed in supply, storage and transportation infrastructure, which would require further advancements in the industry. While the ISP considers carbon capture and storage (CCS) and small modular reactor (SMR) options, these resources are not selected by the model in any of the cases by 2035.

FIGURE 6.14: RELIANCE ON EMERGING TECHNOLOGIES

	STRATEGIC APPROACH		
SCENARIO	Tech Neutral	No New Fossil	Minimum Coal
Current Trends	**No Emerging Technology Additions** Green hydrogen and nuclear SMR not available by 2035 CCS only available by 2035 in Tech Neutral		
Desert Contraction			
Desert Boom			
Strong Climate Policy	**178 MW** Green Hydrogen	**195 MW** Green Hydrogen	**790 MW** Green Hydrogen

Resource Operations

The changes in resource mix from coal retirements and new resource additions have significant implications for resource operations. This section describes the resource operations across cases as modeled in the production cost model, as well as key sustainability metrics.

Figure 6.15 shows the generation mix in 2035 across each scenario and strategic approach, including total generation in megawatt-hours (MWh) as well as the share of total generation for each resource type (%). Coal generation decreases significantly across all cases and only makes up a small share of generation in 2035. Customer programs and renewable generation increase across all cases. The total amounts of renewable and natural gas generation vary most significantly across cases and are explored further below.

FIGURE 6.15: TOTAL GENERATION (GWH) AND GENERATION MIX (%) IN 2035

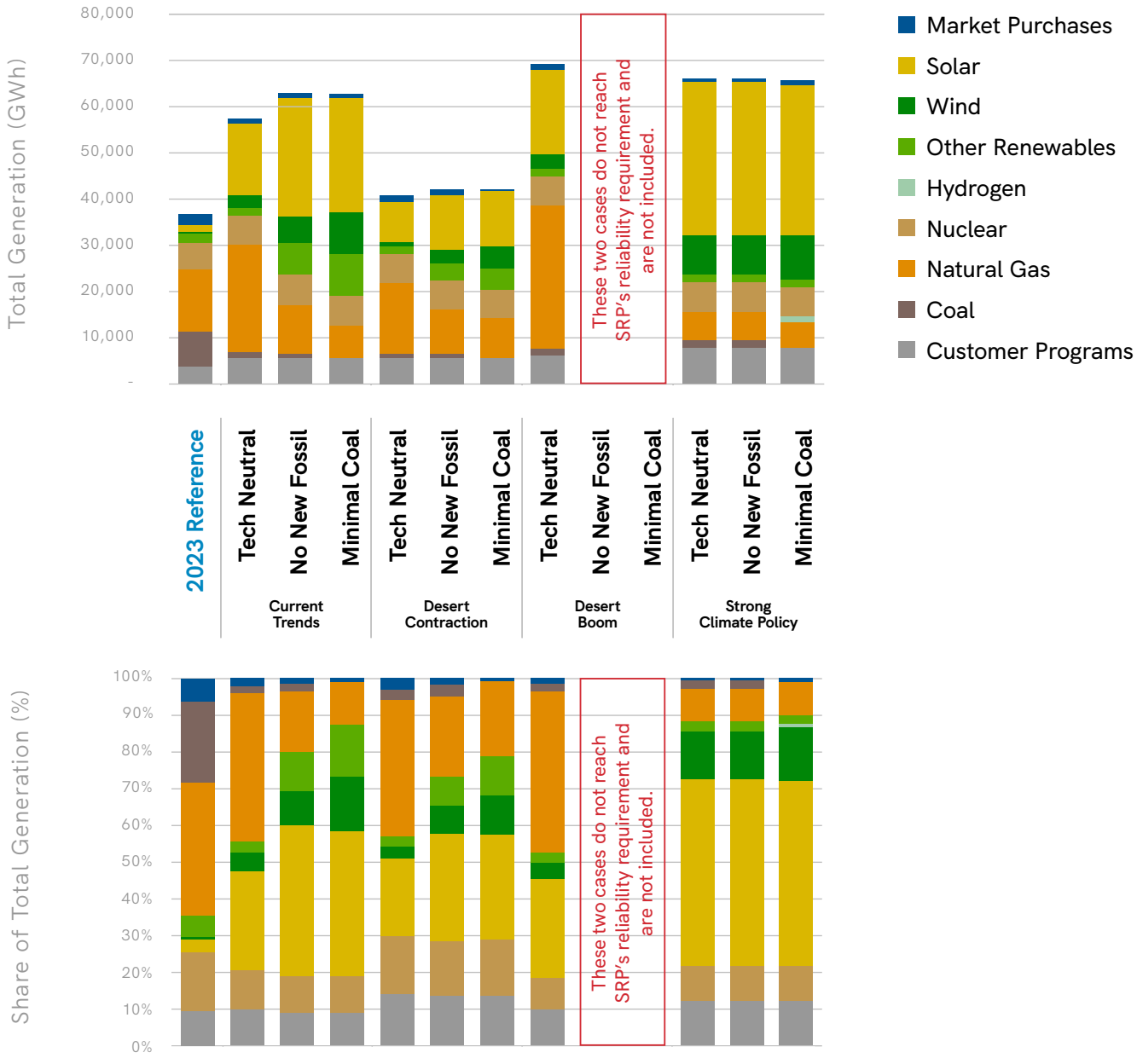
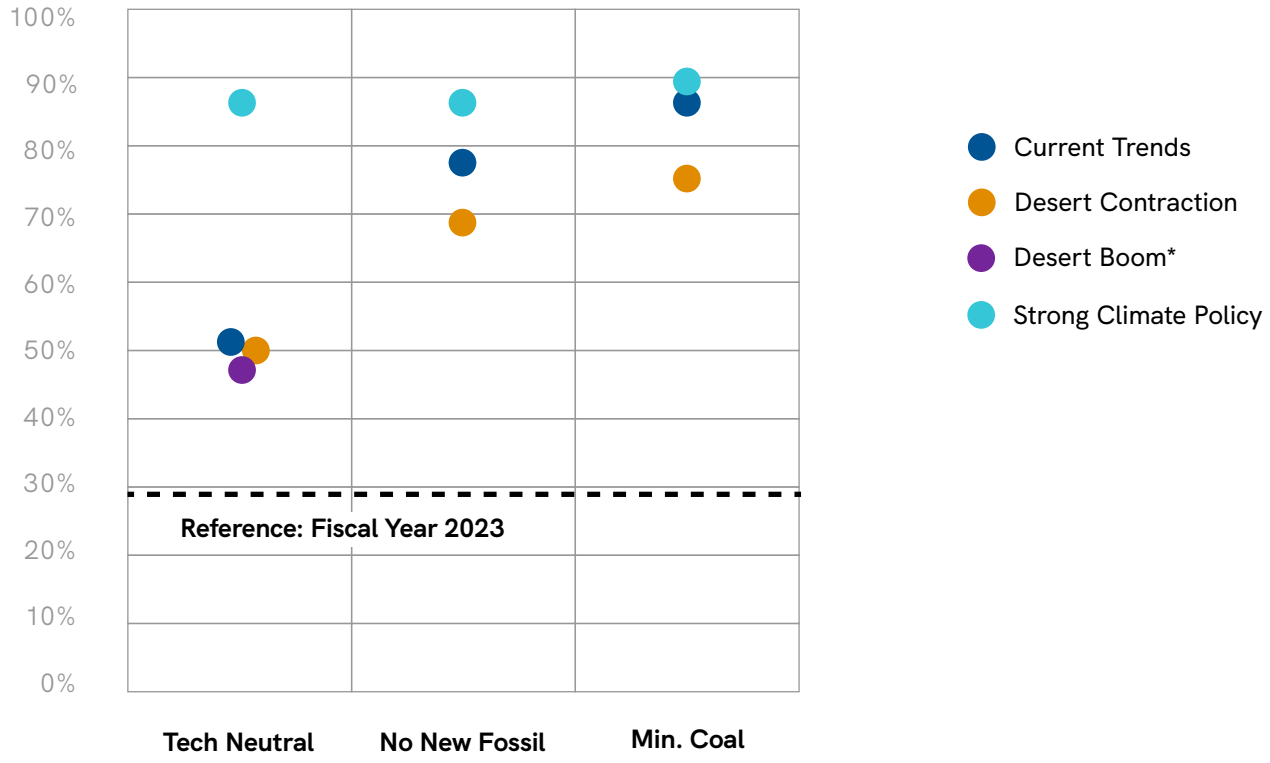


Figure 6.16 shows the percentage of generation coming from carbon-free resources, including nuclear, solar, wind, hydro, geothermal, biomass and hydrogen. Relative to 2023, the share of carbon-free generation increases across all system plans. System plans under the Strong Climate Policy scenario achieve the highest share of carbon-free generation across all strategic approaches, nearing 90%, driven by the more stringent federal emissions target. The No New Fossil and Minimum Coal strategic approaches result in more carbon-free generation compared with Technology Neutral because these cases add more renewable energy and storage to meet the PRM requirement.

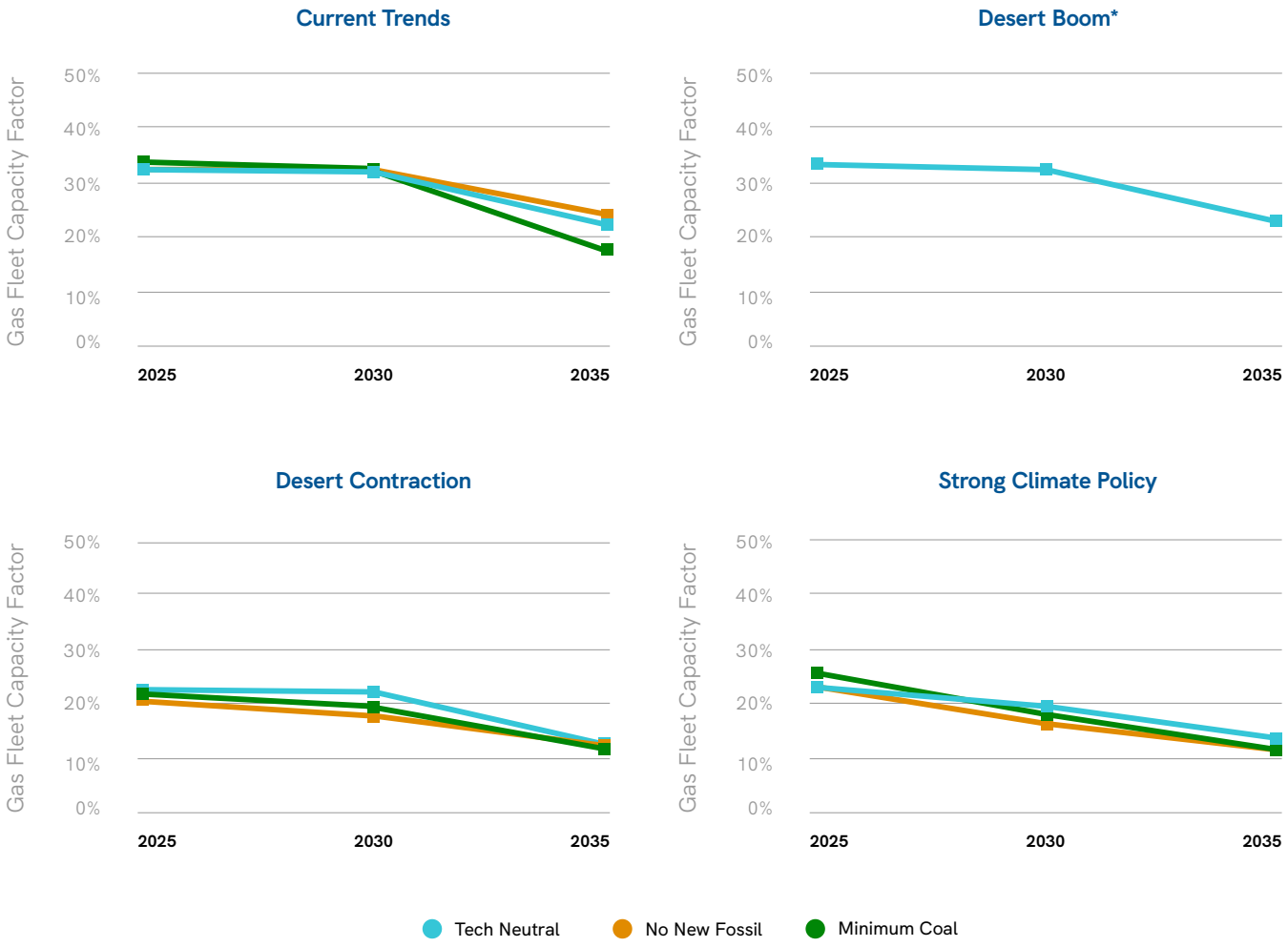
FIGURE 6.16: CARBON-FREE GENERATION BY 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

The extent to which the natural gas-fired power plant fleet is utilized relates inversely to the share of carbon-free generation. Figure 6.17 shows the average capacity factor[2] for SRP's gas fleet[3]. The utilization varies slightly between strategic approaches and scenarios, but in all cases, the average utilization of SRP's gas fleet is projected to decline through 2035 as the system relies increasingly on renewable energy. These resources are available to help ensure system reliability but generate less during the year, in line with integrating more carbon-free resources and decreasing emissions.

FIGURE 6.17: CAPACITY FACTOR FOR GAS FLEET

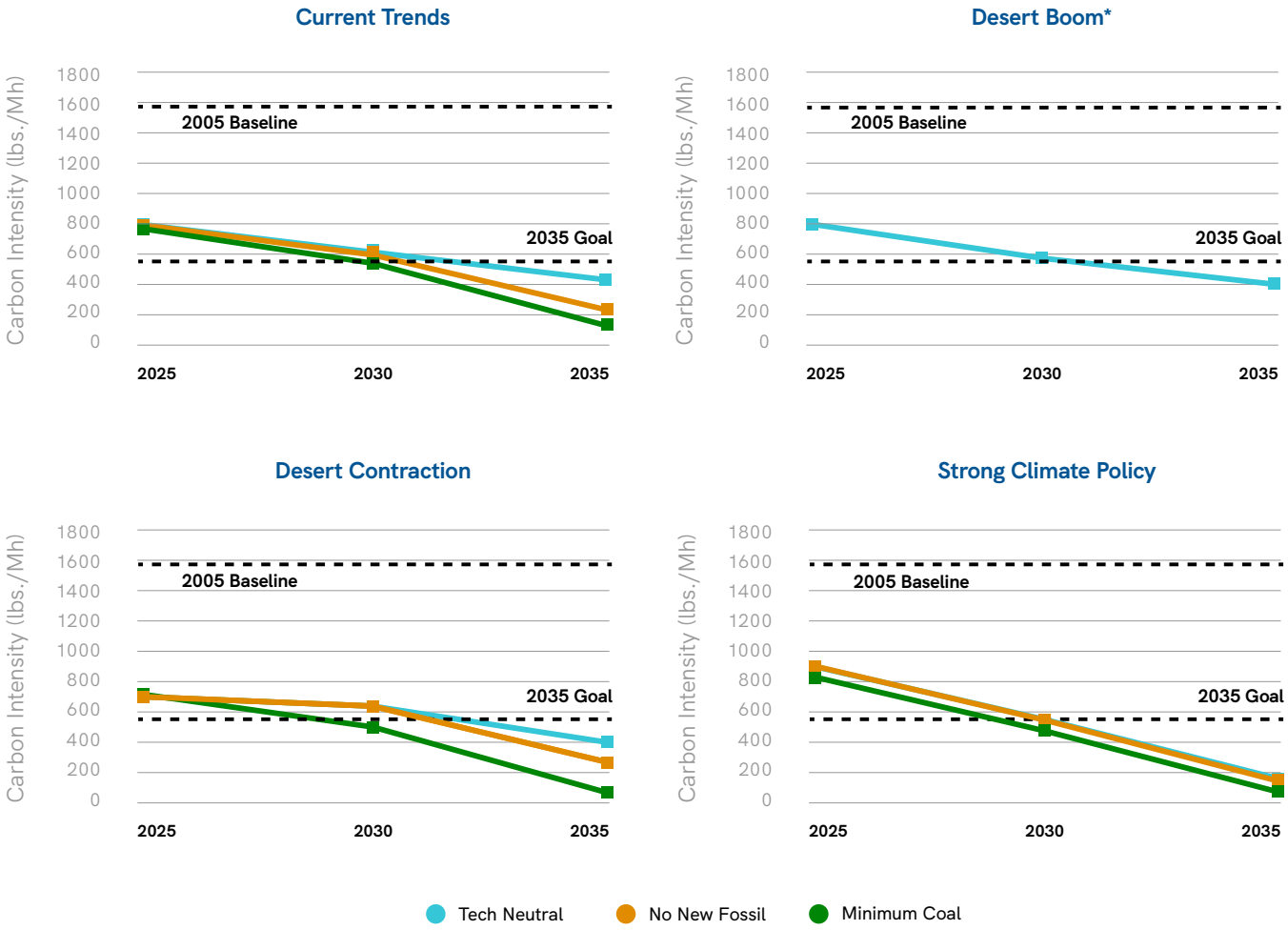


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[2] Capacity factor is a measure of resource utilization and is expressed as a ratio of the actual output over a given period of time compared to the theoretical continuous maximum output over that period.
[3] SRP's gas fleet includes combined cycle units, simple cycle combustion turbines (peakers) and boilers. Capacity factor for each type of gas unit will vary.

A growing share of carbon-free generation offsetting generation from gas and coal-fueled resources drives reductions in system CO_2 emissions. Figure 6.18 shows CO_2 emissions on an intensity basis.[4] All cases exceed SRP's 2035 goal of reducing carbon emissions intensity by 65% relative to 2005 levels. The No New Fossil and Minimum Coal strategic approaches result in greater CO_2 emission reductions, while the Strong Climate Policy scenario results in the most CO_2 emission reductions.

FIGURE 6.18: CO_2 EMISSIONS (INTENSITY BASIS IN LBS. PER MWH)

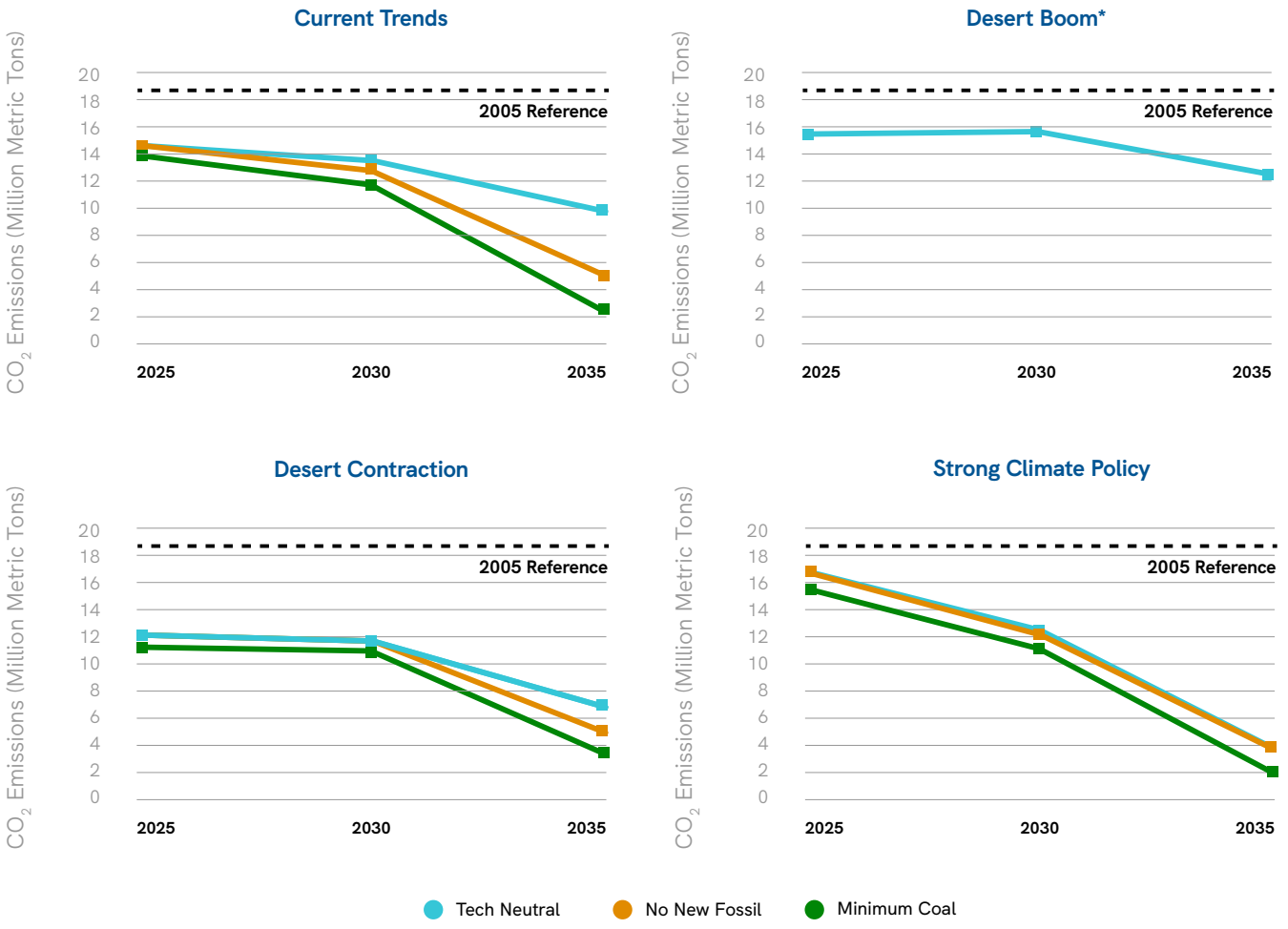


*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[4] Carbon intensity is the amount of carbon dioxide emitted from generating electricity (in pounds), divided by the total generation required to serve SRP's customers (in megawatt-hours).

Figure 6.19 shows total annual CO_2 emissions on a mass basis. The trends within each scenario on a mass emissions basis align with the trends observed with CO_2 emissions intensity. However, the difference across scenarios is more pronounced for total CO_2 emissions because of differences in the load forecast: Higher load growth leads to an increase in total carbon emissions due to an increase in generation, some of which is carbon-emitting (when considering carbon intensity, higher emissions are offset when divided by a greater amount of energy generated). Total CO_2 emissions are higher in Desert Boom because load growth is higher, and emissions are lower in Desert Contraction because load growth is lower.

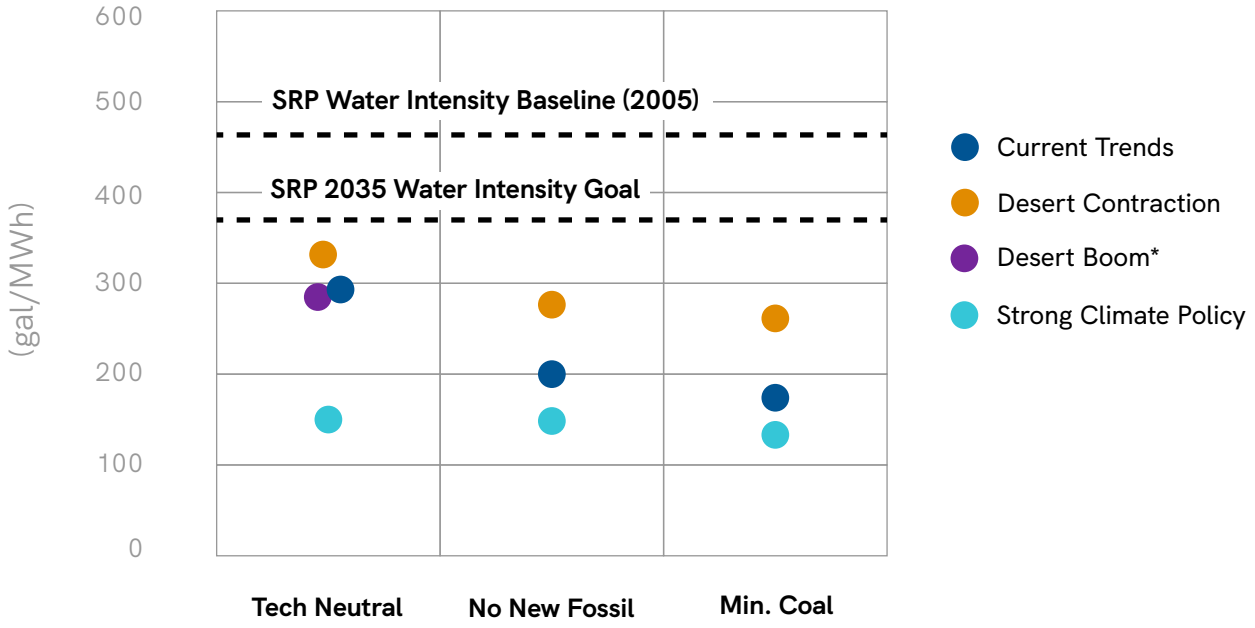
FIGURE 6.19: CO_2 EMISSIONS (MASS BASIS IN MILLION METRIC TONS)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

SRP also projected water consumption from power generation on an intensity basis[5] to evaluate performance with the 2035 goal of reducing water usage intensity by 20% relative to 2005 levels. As shown in Figure 6.20, all cases exceed the 2035 goal. The greatest reductions in water usage intensity occur under the No New Fossil and Minimum Coal strategic approaches, again due to a higher share of carbon-free resources that use little or no water.

FIGURE 6.20: WATER USAGE INTENSITY IN 2035



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

[5] This is the amount of water consumed (in gallons) from generating electricity, divided by the total generation required to serve SRP's customers (in megawatt-hours).

Lastly, in addition to carbon emissions and water usage, SRP estimated direct air emissions from the generation fleet for several criteria air pollutants, and their precursor pollutants, including particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Under all cases, emissions of all pollutants decline substantially by 2035 relative to 2025 levels. However, new biomass causes higher levels of NO_X and SO_2 emissions in the No New Fossil and Minimum Coal system plans.

FIGURE 6.21: DIRECT AIR EMISSIONS IN 2035

*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

System operations change significantly over time in all cases. Coal generation decreases, while customer programs and renewable generation increase across all cases, pushing down natural gas generation across the fleet and improving sustainability metrics. Reductions in carbon intensity ranged from 74% to 96% (compared to SRP's goal of 65%) while reductions in water usage intensity ranged from 31% to 71% (compared to SRP's goal of 20%), both relative to 2005 baseline levels. Cases with less renewable and storage additions resulted in smaller reductions in carbon and water usage intensity, while cases with higher renewable and storage additions resulted in larger reductions. *Note: SRP's 2035 Sustainability Goals are being refreshed in 2024 in collaboration with community stakeholders.*

KEY FINDING

The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.

Transmission Investments

Both load growth and changes in the resource mix influence investment needs for the transmission system. This section describes the transmission investment needs through 2035, including 230 kV lines, 500 kV lines and 500/230 kV transformers.

Figure 6.22 shows the transmission investment needs through 2035 for the three system plans analyzed (Technology Neutral Current Trends, Technology Neutral Desert Boom and Minimum Coal Current Trends) and the two resource location options analyzed (Pro-Rata and Hub). These cases are described in detail in Section 5.

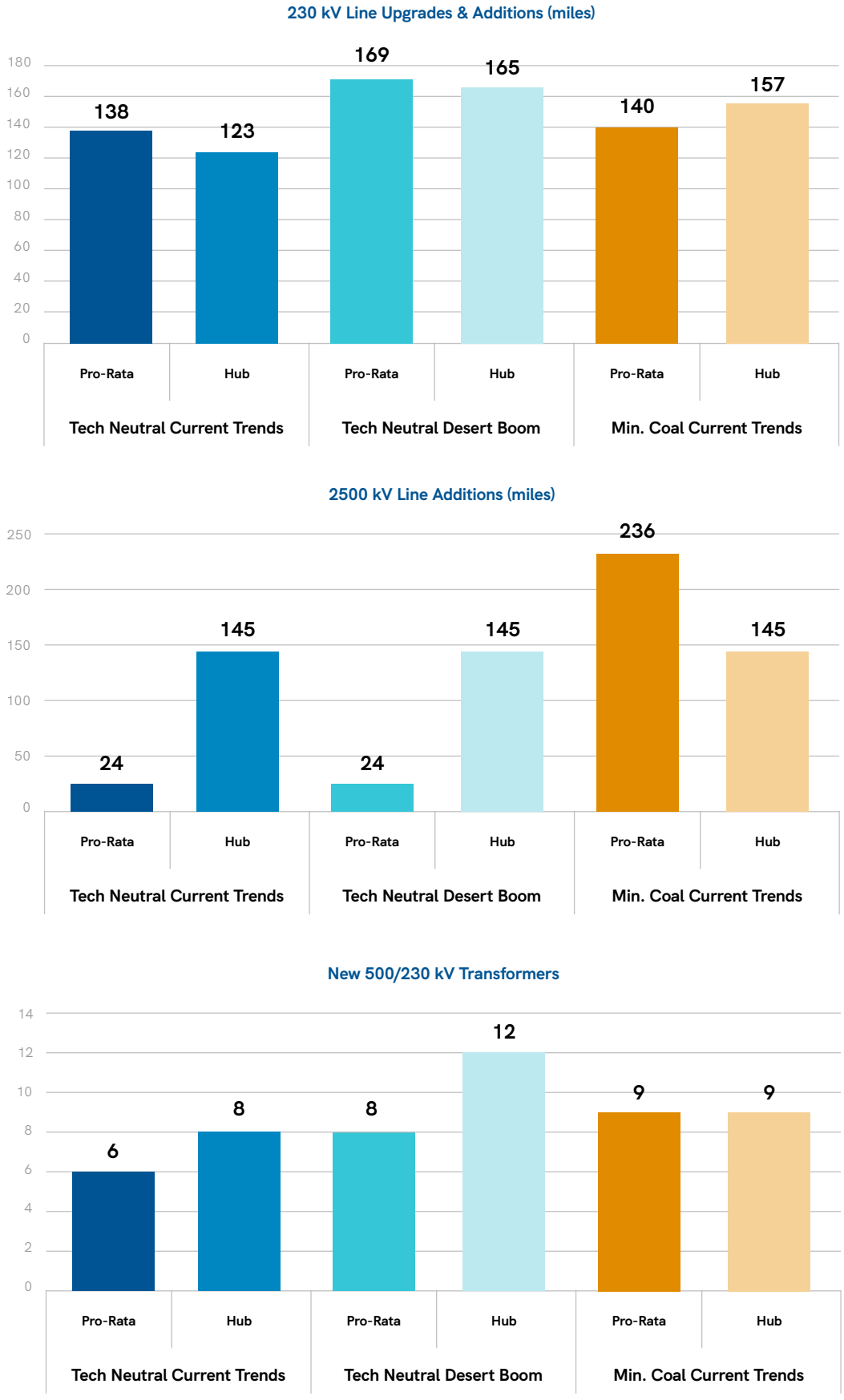
KEY FINDINGS

Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

In all cases, a significant amount of transmission investment is needed by 2035. The investments in 230 kV lines are primarily driven by load growth in all cases; however, where 230 kV lines need to be added and which lines need to be upgraded depends on the resource location assumptions used. The investments in 500 kV lines, as well as the investments in 500/230 kV transformers, vary for each system plan based on the resource location assumptions. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, the Hub resource location assumption requires far more 500 kV line-miles and more 500/230 kV transformers than the same cases using the Pro-Rata resource location assumption. In the Technology Neutral Current Trends and Technology Neutral Desert Boom cases, more investment is needed in the 500 kV system to connect resources at the hub to the rest of the system. By contrast, in the Minimum Coal Current Trends case, fewer 500 kV line-miles are needed under the Hub resource location assumption than under the Pro-Rata resource location assumption. This is driven by the higher levels of solar and battery resources in this case further exceeding existing transmission capabilities when located using the Pro-Rata location assumptions. The differences in results across the Pro-Rata and Hub resource location assumptions highlight how the location of resources has a significant impact on transmission investment needs.

FIGURE 6.22: TRANSMISSION SYSTEM INVESTMENTS BY 2035



KEY FINDING

Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.

The transmission analysis shows that up to 380 miles of new or upgraded transmission lines and 12 new 500/230 kV transformers could be needed over the next decade. The lead times for siting, permitting, building and energizing transmission infrastructure are 5–9-plus years for 500 kV lines, 3–7 years for 230 kV lines and 3–5 years for 500/230 kV transformers. To add the needed transmission infrastructure given these long lead times will require a proactive approach to transmission planning.

Total System Cost

Because maintaining affordability for customers is a fundamental component of SRP's mission, we developed affordability metrics for each system plan analyzed to assess and compare opportunities and risks. This section describes the total system cost and average system cost metrics, while the next section describes the residential bill impact metric.

The total system cost is the estimate of total costs in 2035 to serve customers, including costs related to customer programs, distribution, generation, transmission and normal utility operations. The average system cost is derived by dividing the total system cost by the total retail sales in 2035. Because energy demand growth varies across the scenarios, the average system cost provides a more direct comparison between cases for how costs are changing over time.

While these metrics allow comparison across system plans, they are developed using a simplified ISP analysis model and are not a comprehensive assessment of future financial indicators for SRP. Furthermore, the average system cost metric is not a customer rate metric and should not be interpreted as the rate that customers would pay under different cases. Lastly, differences in results across scenarios reflect scenario assumptions for external factors that are out of SRP's control (e.g., economic growth, fuel prices, resource costs and federal government policy).

Figure 6.23 shows the total system cost in 2035, broken out between generation, transmission, distribution, customer program and other costs. It also provides total system cost in 2025 for reference. Generation costs are the primary driver of differences in cost between cases. Transmission costs follow similar trends as generation costs, as both are influenced by load growth and new resource additions. Distribution costs vary across scenarios due to differences in load growth. Lastly, customer program costs grow through 2035 and continue to mitigate needs for new infrastructure across all cases.

Within the Current Trends and Desert Contraction scenarios, Technology Neutral is the lowest-cost strategic approach. While Technology Neutral allows new natural gas as a resource option, the other strategic approaches (No New Fossil and Minimum Coal) do not have a firm capacity option and thus lead to higher costs due to increased resource additions and transmission investments.

In general, the Desert Contraction cases have lower system costs than Current Trends, and the Desert Boom cases have higher costs, driven primarily by the differences in energy demand. In the Strong Climate Policy scenario, all three strategic approaches have similar costs due to a few factors. First, the aggressive federal emissions requirement in this scenario is a major driver, resulting in significant renewable and storage additions across all three strategic approaches. Second, in this scenario, a firm capacity resource is available in all three strategic approaches due to the accelerated availability of hydrogen. The unavailability of a firm capacity resource was the major driver of cost increases for these two strategic approaches under the other scenarios.

FIGURE 6.23: TOTAL SYSTEM COSTS FOR SRP'S POWER SYSTEM IN 2035 ($ BILLION)

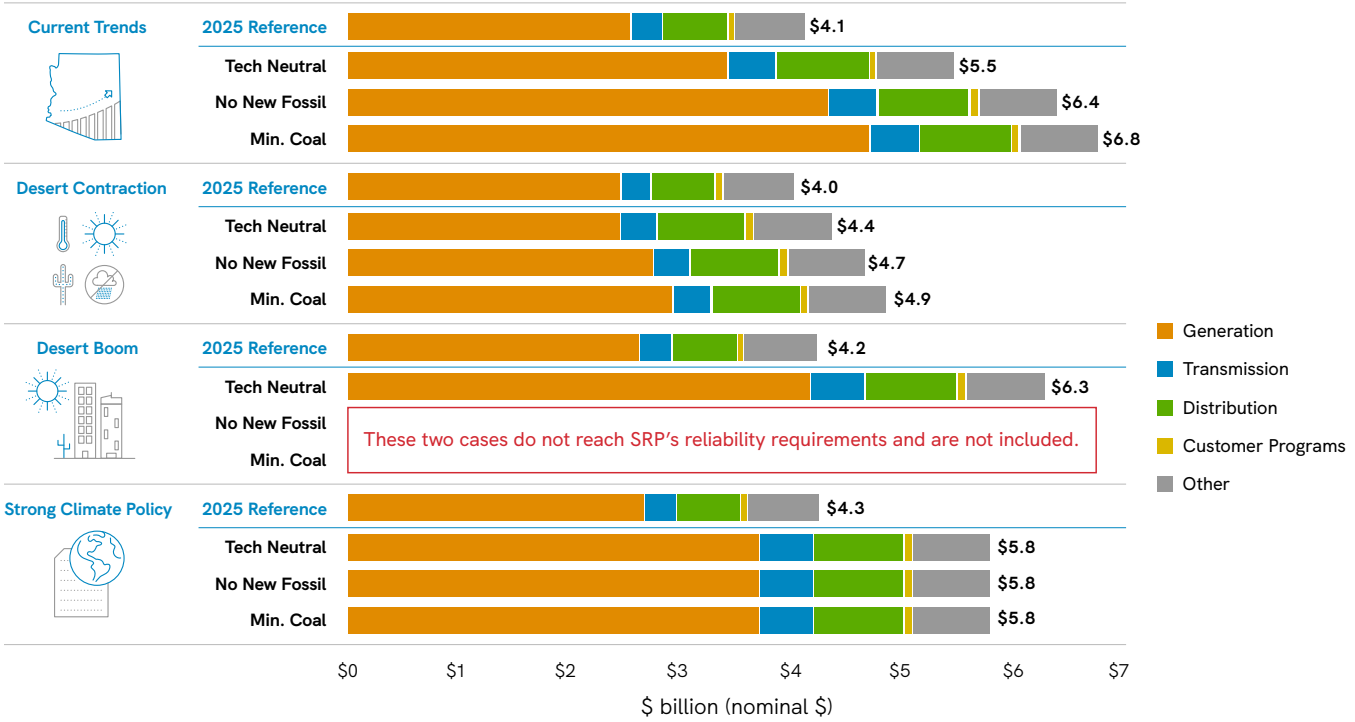
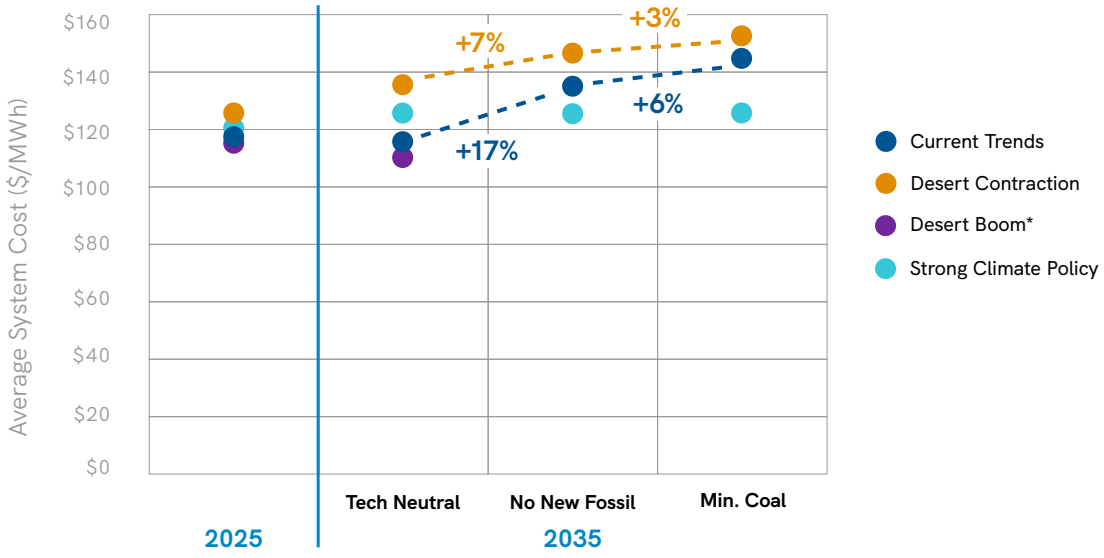


Figure 6.24 shows the average system cost in 2035, with 2025 provided for reference. The Technology Neutral strategic approach results in lower cost than the other strategic approaches with limited firm capacity options. In the Current Trends scenario, the No New Fossil and Minimum Coal approaches result in a 17% and 24% increase, respectively, in average system cost relative to Technology Neutral. In the Desert Contraction scenario, the No New Fossil and Minimum Coal approaches result in a 7% and 10% increase, respectively, in average system cost relative to Technology Neutral. The cost increase in Current Trends is greater than the cost increase in Desert Contraction because the higher load growth in Current Trends makes it more costly to reliably meet customer needs without new firm capacity resources.

FIGURE 6.24: AVERAGE SYSTEM COST ($/MWH)



*For Desert Boom, the No New Fossil and Minimum Coal cases do not reach SRP's reliability requirements and are not included.

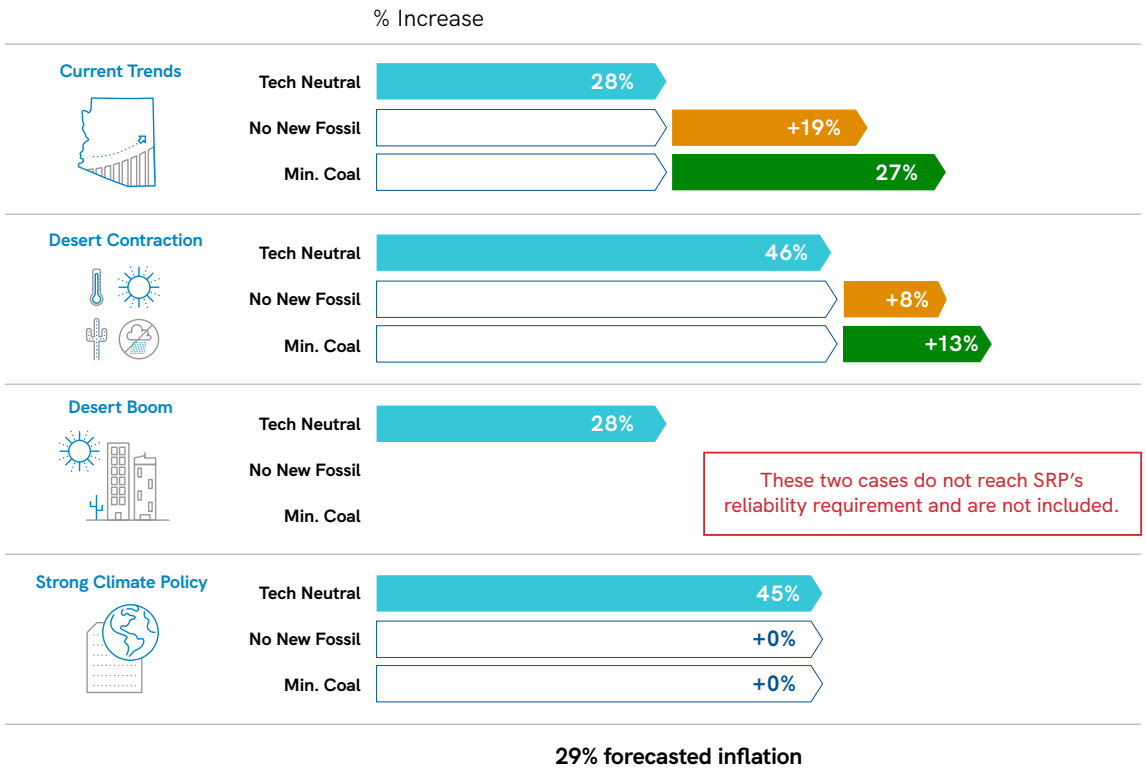
Residential Bill Impact

This section describes the residential bill impact metric across cases. This analysis does not necessarily reflect how future costs would be allocated and recovered from customers and therefore should not be considered a projection of customer rates. SRP will carry out pricing processes in the future that will determine future rates. Nevertheless, this metric is helpful for comparing across cases to understand relative differences.

Figure 6.25 shows the increase in average residential customer rates between 2023 and 2035 along with the forecasted inflation expected over this period for reference. The figure shows the increase in the Technology Neutral strategic approach and then shows the increase in the alternative strategic approaches relative to the Technology Neutral strategic approach. SRP projects the cumulative impact of inflation to be 29% between 2023 and 2035. The Technology Neutral Current Trends approach has an increase of 28% over this same period, meaning that rates increase by less than inflation in this case.

In all scenarios, the Technology Neutral strategic approach results in the lowest impact to average residential rates. The No New Fossil and Minimum Coal approaches are more costly, with the greatest increases relative to Technology Neutral under Current Trends. Under the Current Trends scenario, the No New Fossil strategic approach results in a 19% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 27% increase. Under the Desert Contraction scenario, increases are higher across the cases as the lower load growth leads to less revenue to offset costs. Comparing the cases in the Desert Contraction scenario, the No New Fossil strategic approach results in an 8% increase in customer rates relative to Technology Neutral, and the Minimum Coal strategic approach results in a 13% increase. Under the Strong Climate Policy scenario, the residential bill impact is similar across the three strategic approaches, for the same reasons discussed in the Total System Cost section.

FIGURE 6.25: INCREASE IN AVERAGE RESIDENTIAL CUSTOMER RATES BETWEEN 2023 AND 2035



Risk Assessments

The development and operational risk assessments identified risks and challenges that SRP could face for each of the system plans. It also identified potential mitigation options, which SRP is using to prepare its system and workforce for the future.

Development Risk

Because each of the ISP system plans requires significant development of new resources, we performed a qualitative risk assessment to better understand the risks and challenges in building out these future power systems, as well as mitigation options.

Development Risks and Mitigation Options

KEY FINDING

To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

Supply chain. SRP continues to observe inflation and supply chain disruptions that began during the COVID-19 pandemic. These disruptions led to rising costs and extended development timelines for new infrastructure projects, including solar projects, battery storage projects, transmission infrastructure, distribution infrastructure, etc. Future supply chain disruptions could also impact SRP's ability to develop new infrastructure, impacting ISP system plans with greater infrastructure additions the most. Mitigation steps that SRP is taking to address these risks include ordering key supplies as early as possible and seeking to develop a wider pool of potential suppliers to diversify supply chain risks.

Siting and permitting. Most infrastructure projects take several years for siting, permitting, construction and interconnection. Examples of projects with especially long and complex development processes include nuclear power plants, pumped hydro energy storage, gas pipelines and transmission. On the longer end of development timelines, some transmission projects can take well over a decade to site, permit, construct and energize. There are many variables that can impact the timing of developing projects, including stakeholder consultation, state and/or federal regulatory processes, development of enabling infrastructure (e.g., new transmission or gas pipelines), etc. If development timelines were to extend much longer than expected, this would limit the pace at which SRP can build out the system and put ISP system plans with greater infrastructure additions at more risk. To mitigate this risk, SRP strives to collaborate with government agencies, other utilities and key stakeholders as early as possible. We are also exploring multiple project options so that SRP is prepared to undertake any one of these options more readily should the need arise.

KEY FINDING

With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.

Multistate transmission. While any transmission can have long development timelines and face uncertainty in permitting, these challenges exist even more for transmission that spans multiple states. Such interstate transmission projects may span longer distances and require consultation with more landowners. They also require approvals from different state regulatory bodies and may require approval from multiple federal agencies. The complex nature of developing such projects results in risks to development timelines. These risks are greatest for ISP system plans that add geothermal or wind in states such as California and New Mexico. SRP is working to mitigate this risk by proactively pursuing regional transmission projects that facilitate integration of diverse renewable resources.

Technology maturity. Not all resource technologies have reached full maturity. Lithium-ion battery projects have proliferated in the last five years, but the total amount of capacity deployed is still limited relative to other technologies and they do not have a long track record of performance. Some battery projects, including a project contracted by SRP, have experienced fires that have rendered the resources unavailable. There are other technologies evaluated in the ISP that have not yet reached widespread commercialization, such as power plants powered by 100% hydrogen. There are still uncertainties in the cost, operations and enabling infrastructure for this technology. Given these risks and uncertainties, ISP system plans that rely more on less mature technologies have a greater amount of inherent risk. To mitigate these risks, SRP is actively gaining operational experience with newer technologies and monitoring advancements for emerging technologies. SRP is also balancing the development of newer technologies (e.g., battery storage) with the deployment of more mature technologies (e.g., pumped hydro storage).

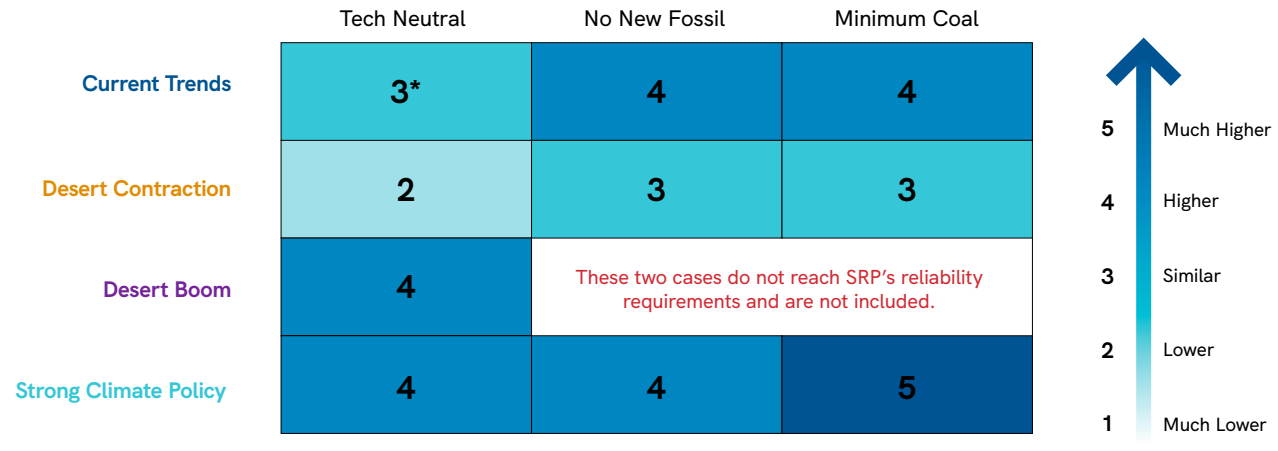
Diversification. The potential impact of any one of these development risks depends in part on the diversification of the system plan. If the system plan relies heavily on only a few technologies, then the entire system plan is at risk if one of those technologies encounters disruptions due to supply chain, permitting or other issues. To mitigate the risk associated with any one technology, SRP is pursuing a diverse system plan.

Development Risk Ratings

SRP identified a development risk rating for each of the core system plans in the ISP, as shown in Figure 6.26, using the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the development risk associated with that plan.

Technology Neutral Desert Contraction has a lower risk level because the system plan adds far fewer generating resources, transmission and distribution than the other plans. For the Desert Contraction scenario, the two other strategic approaches (No New Fossil and Minimum Coal) have a similar amount of risk as the baseline due to the amount of resource additions. All other system plans have higher risk levels due to the very rapid pace of resource additions, with some cases reaching between 25,000 and 35,000 MW of installed capacity. The Minimum Coal Strong Climate Policy case has the highest risk level not only due to the rapid pace of resource additions, but also because of the reliance on almost 800 MW of hydrogen capacity, which would require significant development of hydrogen infrastructure that doesn't currently exist. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

FIGURE 6.26: DEVELOPMENT RISK RATING



*Tech Neutral/Current Trends was the baseline case to which the development risk for all other cases were compared.

Operational Risk

Because each of the ISP system plans requires a meaningful shift in the future operations of the system, SRP also performed a qualitative risk assessment to better understand the risks and challenges in operating these future power systems, as well as mitigation options.

Operational Risks and Mitigation Options

KEY FINDING

A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Variability and uncertainty. The Inverter-Based Resources Integration Technical Working Session highlighted the profound changes that come with moving to a system that relies on more variable renewable generation to meet energy needs. Resources like solar and wind vary in output based on season and time of day. Also, this variability is not perfectly predictable, as the weather can impact solar generation due to cloud cover and wind generation due to changes in wind speed. Managing a system with higher penetrations of variable generation is more complex and comes with new risks in balancing energy demand, supply and market transactions. As a result, ISP system plans with higher penetrations of variable generation resources have greater operational risk. To mitigate these risks, SRP is taking several actions, including improving forecasts for variable renewable generation, increasing reserves to account for uncertainty and variability, pairing variable energy resources with flexible resources (e.g., energy storage) to reduce variability and increase dispatchability, managing resource curtailment to provide more flexibility to the system, and transacting with markets to provide more operational flexibility.

Ramping needs. With higher penetrations of variable generation, especially solar, the system experiences greater ramping needs for dispatchable generation. For example, on a system with a lot of solar generation, there is plentiful generation during the day. However, in the late afternoon and early evening, when electricity demand is high and solar generation rapidly declines, other resources need to ramp up output rapidly. This is a significant change in how the system must operate and creates new challenges. To mitigate these risks, SRP is working to add more flexible resources, such as battery storage, pumped storage hydro and natural gas, to maximize the flexibility from existing resources and from market transactions. SRP is exploring curtailing variable generation to help mitigate ramping needs and provide additional flexibility.

Natural gas plant operations. With increasing amounts of variable generation and increasing ramping needs, natural gas power plants operate differently than they have in the past. When variable renewable generation output is high and energy demand is low, natural gas plants ramp down output or even shut down. When variable renewable generation is low and/or energy demand is high, natural gas plants ramp up output. This may involve shutting down and starting up natural gas plants more frequently than in the past, potentially even daily, which puts increased wear and tear on the generating units. Some natural gas plants may shut down for extended periods of time before starting up again. Systems that cool completely can cause aging seals or fittings to shrink, which can increase risks for more frequent maintenance and repair.

Natural gas fuel transportation. SRP acquires transportation rights on regional natural gas pipelines to secure reliable delivery of natural gas fuel we purchase throughout the year. If natural gas fuel consumption were to increase significantly beyond today's level of consumption, such as in the Technology Neutral Desert Boom system plan, this could create risks in being able to deliver natural gas fuel during critical days for reliability.

Depending on the increase in fuel consumption and how the regional energy landscape evolves, this could require the need for new natural gas pipeline infrastructure. To mitigate this risk, SRP is deploying a diverse mix of additional generating resources such as solar and wind that help to offset natural gas fuel consumption. SRP may also explore fuel storage solutions that can allow natural gas plants to continue to have access to fuel without relying solely on pipelines during critical days.

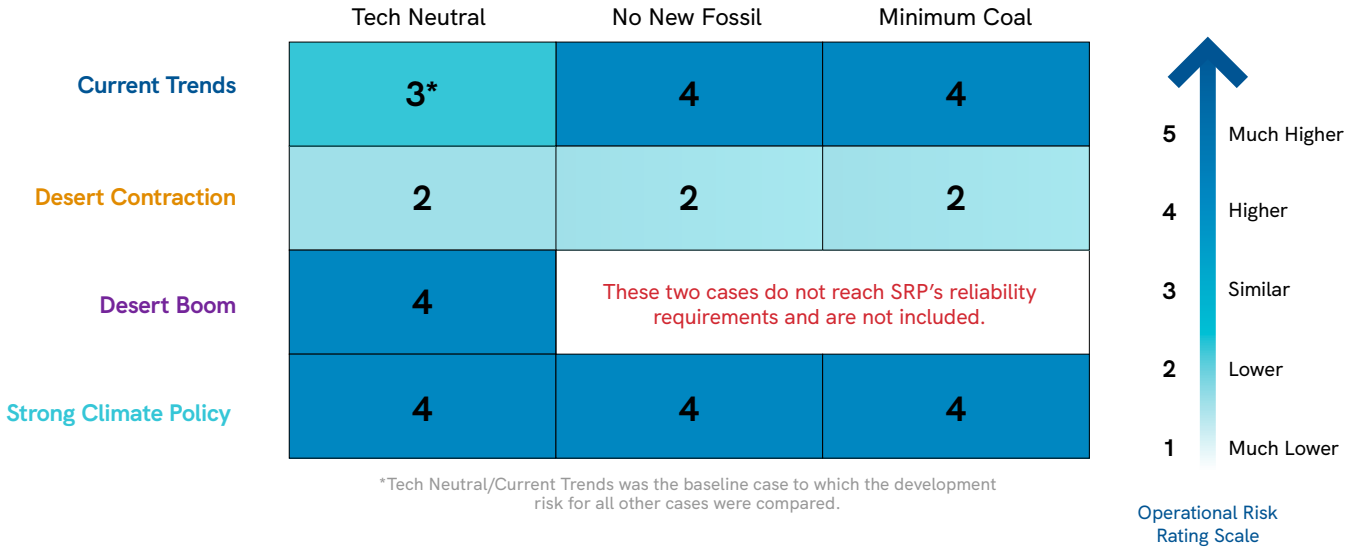
Curtailment. As variable renewable generation increases as a share of SRP's generation mix, there will increasingly be time periods when there is more renewable generation than can be delivered to customers, used to charge energy storage, or sold into markets. For example, during spring months, when energy demand is lower due to milder temperatures, solar generation is relatively high. The West already experiences higher levels of solar curtailment during these months, and this will become more pronounced as SRP and other utilities add more solar capacity. This will require changes in system operations to ensure the grid remains in balance. To accommodate these changes, SRP is making improvements to the dispatch of renewable resources to both curtail their energy production in a way that is most cost-effective and leverages their capabilities, when possible, and to provide ancillary services for controlling small mismatches between customer demand and generation. SRP is also exploring other uses for excess power generation, including storing in long-duration energy storage and generating hydrogen through electrolysis.

Operational Risk Ratings

SRP developed an operational risk rating for each of the core system plans in the ISP, as shown in Figure 6.27, using many of the considerations highlighted above. Technology Neutral Current Trends acted as a baseline, and SRP evaluated all other plans relative to the operational risk associated with that plan.

The three Desert Contraction system plans have a lower operational risk level because annual energy demand is lower, variable generation penetration is lower, and natural gas fuel demand is lower. These three factors mitigate many of the identified operational risks. The three Strong Climate Policy plans have a higher operational risk level because these plans would require a complete transformation of system operations, including a high generation share from variable resources, increased ramping needs, and increased stress for natural gas-fired generators that would need to start up, shut down and ramp up output more frequently. The No New Fossil Current Trends and Minimum Coal Current Trends system plans also have a higher operational risk level for similar reasons, although the operational risk is slightly lower due to a higher share of generation from dispatchable resources. The Technology Neutral Desert Boom system plan has a higher operational risk level because this plan would require increased natural gas fuel consumption to a point that may not be feasible without significant expansion to the regional natural gas delivery system. As discussed above, SRP is employing a suite of strategies to help mitigate risks.

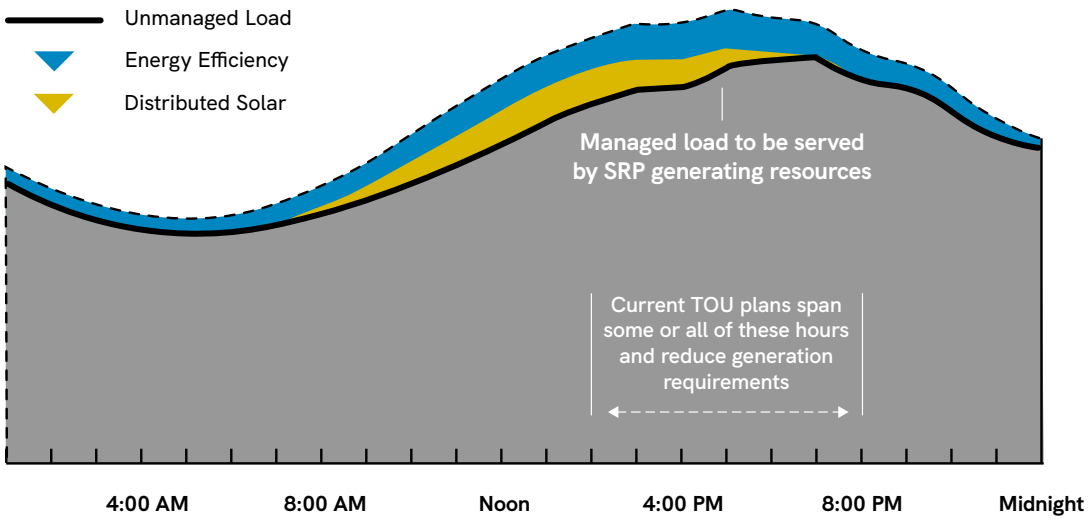
FIGURE 6.27: OPERATIONAL RISK RATING



Considerations for Future Customer Programs and Pricing Plans

Customer programs and pricing plans play an important role in managing SRP's load and peak energy demand. Figure 6.28 includes an illustrative projected peak day in 2035 and depicts how energy efficiency, distributed solar and time-of-use (TOU) programs can reduce SRP's load. Energy efficiency reduces total energy consumption throughout the day; distributed solar offsets generation from other resources during daytime hours; and TOU price plans can incentivize customers to reduce demand during peak hours. After accounting for these programs, the remaining load that SRP must serve is lower and shifted slightly later in the day.

FIGURE 6.28: ILLUSTRATIVE DEPICTION OF HOW CUSTOMER PROGRAMS AND PRICE PLANS HELP SRP MANAGE PEAK ENERGY DEMAND



SRP's existing customer programs work well for demand management in the current system. However, as increasing amounts of solar and wind are added to the system, the net load that is served by dispatchable resources begins to peak after the existing TOU window, as shown in Figure 6.29. This highlights the growing need for evening and overnight load reduction. However, the growth of mid-day renewable generation also presents the opportunity to shift load to these low-cost, low-emissions hours.

FIGURE 6.29: CUSTOMER PROGRAMS AND PRICING PLANS CAN HELP SRP MEET NEW SYSTEM NEEDS

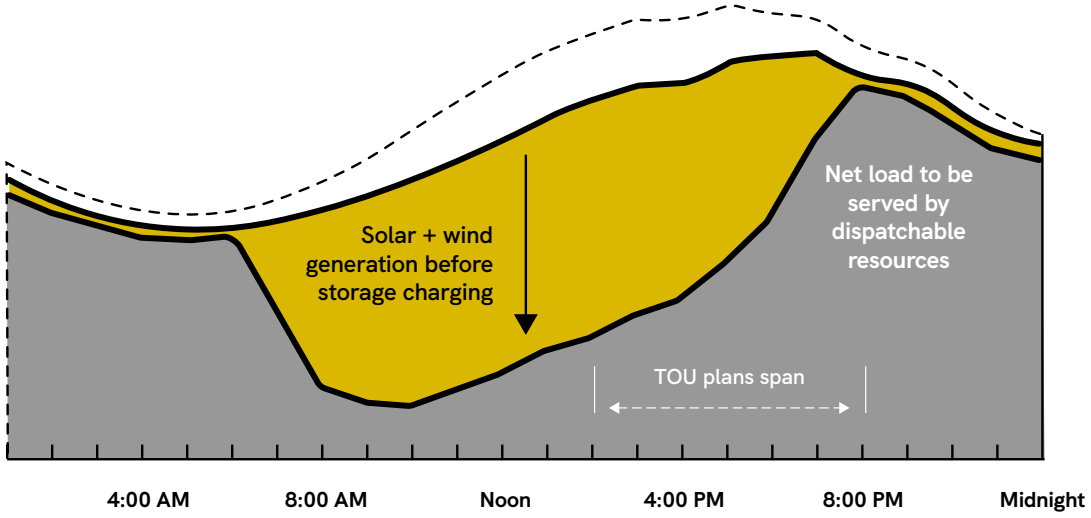


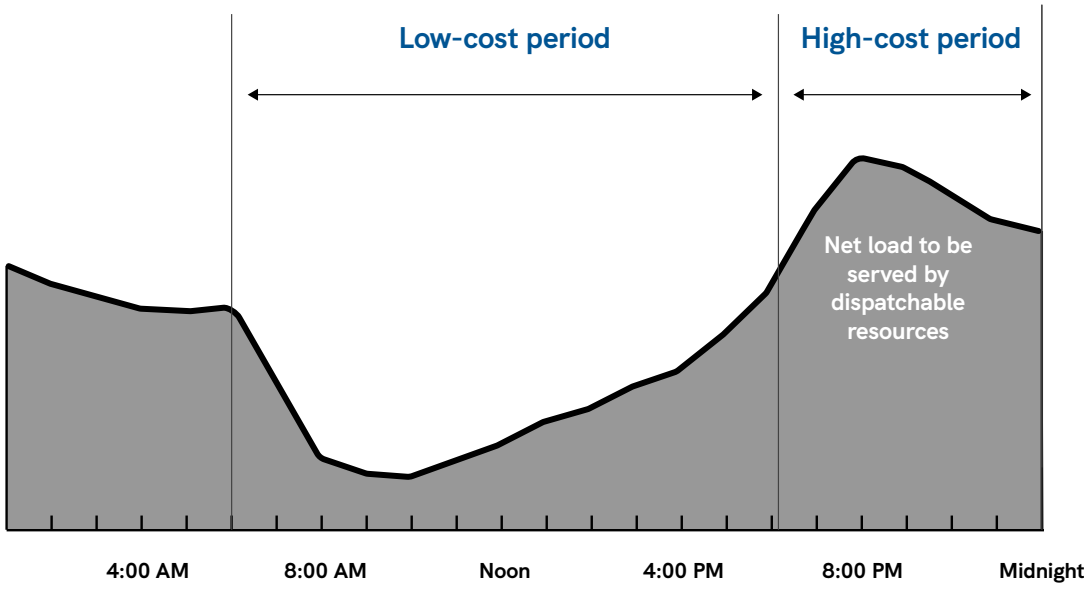
Figure 6.30 illustrates how system costs will change in the future system, with high-cost hours shifting to later in the evening, between 6 p.m. and midnight, and the low-cost period shifting to mid-day.

KEY FINDINGS

SRP will need to evolve programs and price plans to encourage shifts in consumer behavior, and further educate customers on when to consume and when to conserve energy.

Changes in how our customers use energy will require continued innovation and flexibility in planning.

FIGURE 6.30: AS THE SYSTEM TRANSFORMS, NET LOAD IS THE NEW TARGET FOR PRICING AND PROGRAMS.



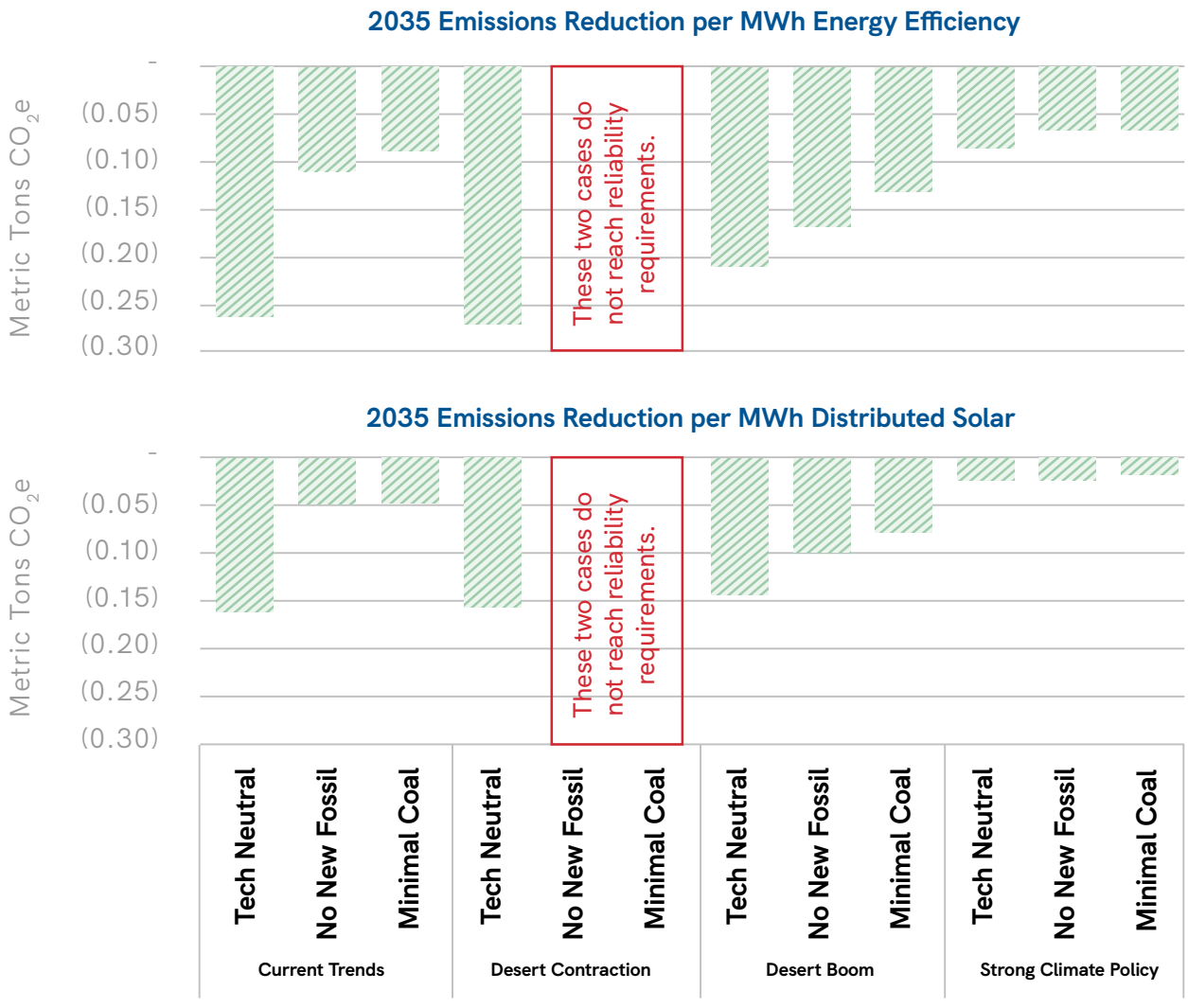
CO_2 Emissions Reductions from Energy Efficiency, Distributed Generation and Electrification

As customer programs reduce energy demand and peak load, they can also enable CO_2 emission reductions. Figure 6.31 first shows the avoided CO_2 per MWh of energy efficiency and distributed generation. Both programs result in avoided emissions without any increased grid emissions. The programs result in greater avoided CO_2 under Technology Neutral (except for under Strong Climate Policy) because the energy mix comprises a greater share of carbon-emitting sources in those cases. As the power sector decarbonizes, marginal carbon emission reductions from energy efficiency and distributed generation will diminish over time because the impacts of these programs tend to align with hours of lower marginal emissions. This finding is particularly prominent under Strong Climate Policy cases due to the more stringent carbon targets. However, continuing to offer programs that reduce load during high-demand hours will lead to greater emissions reductions.

KEY FINDING

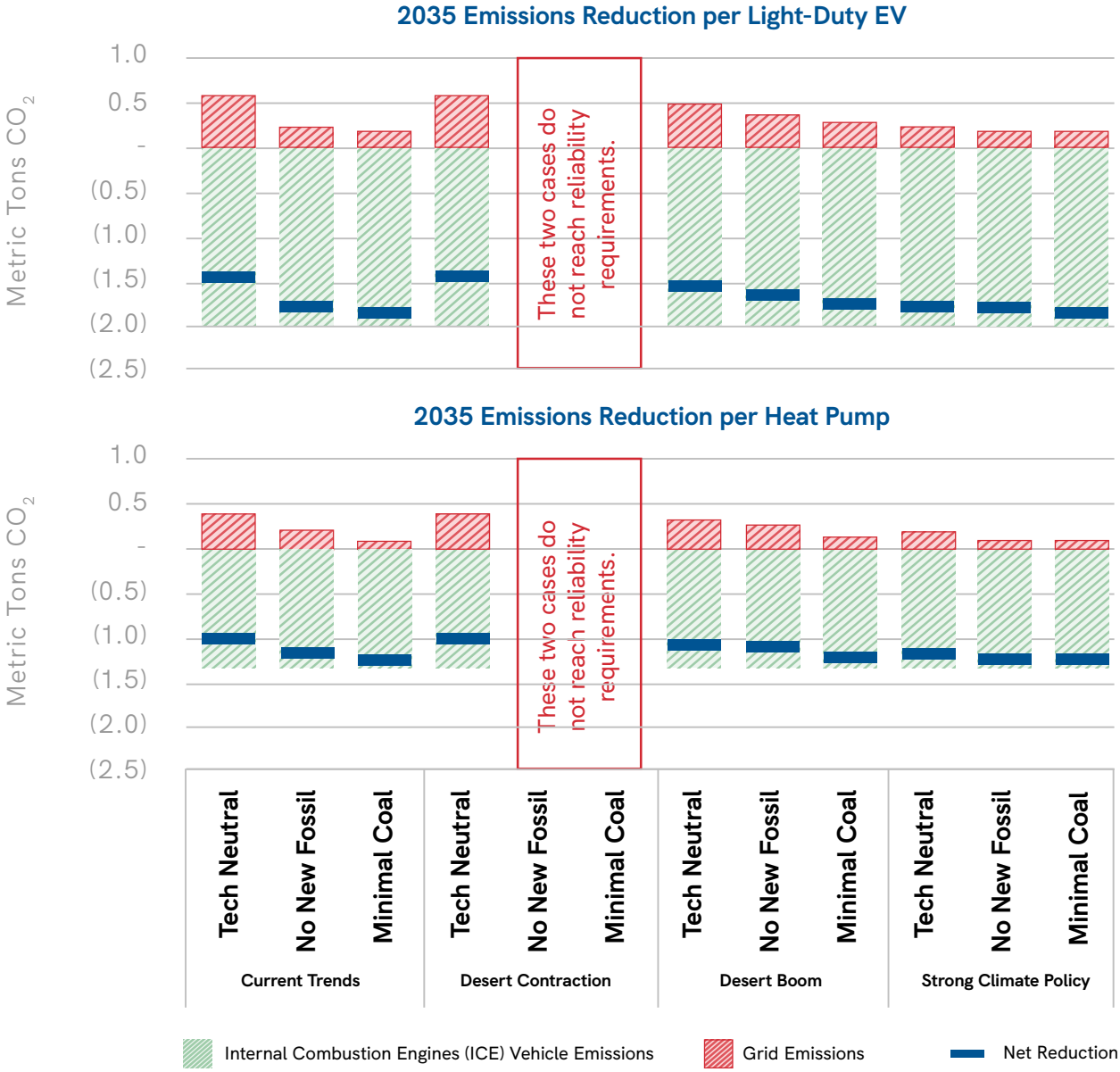
Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

FIGURE 6.31: AVOIDED CO_2 FROM ENERGY EFFICIENCY AND DISTRIBUTED GENERATION



Transportation and building electrification can also result in economywide carbon reduction, such as through greater adoption of electric vehicles and heat pumps. However, as these measures shift energy consumption to the electricity system, potential increases in grid emissions need to be accounted for. Figure 6.32 shows the marginal emission reductions, grid emissions and net reductions from light-duty electric vehicles and heat pumps in each scenario in 2035. The reduction in carbon emissions by replacing internal combustion engine vehicles outweighs the incremental emissions from EV charging loads. Under the current rate structure, light-duty and heavy-duty vehicles primarily charge overnight, when grid emissions are higher. However, shifting EV charging to daytime periods, when emissions are lower, through managed charging programs and/or pricing plans, could lead to further emissions reductions. Similarly, although incremental load from heat pumps increases carbon emissions on the grid, carbon emission reductions from offsetting gas usage is much more significant. In this case, heat pump usage concentrates in the morning when grid emissions are relatively high.

FIGURE 6.32: AVOIDED CO_2 FROM ELECTRIC VEHICLES AND HEAT PUMPS



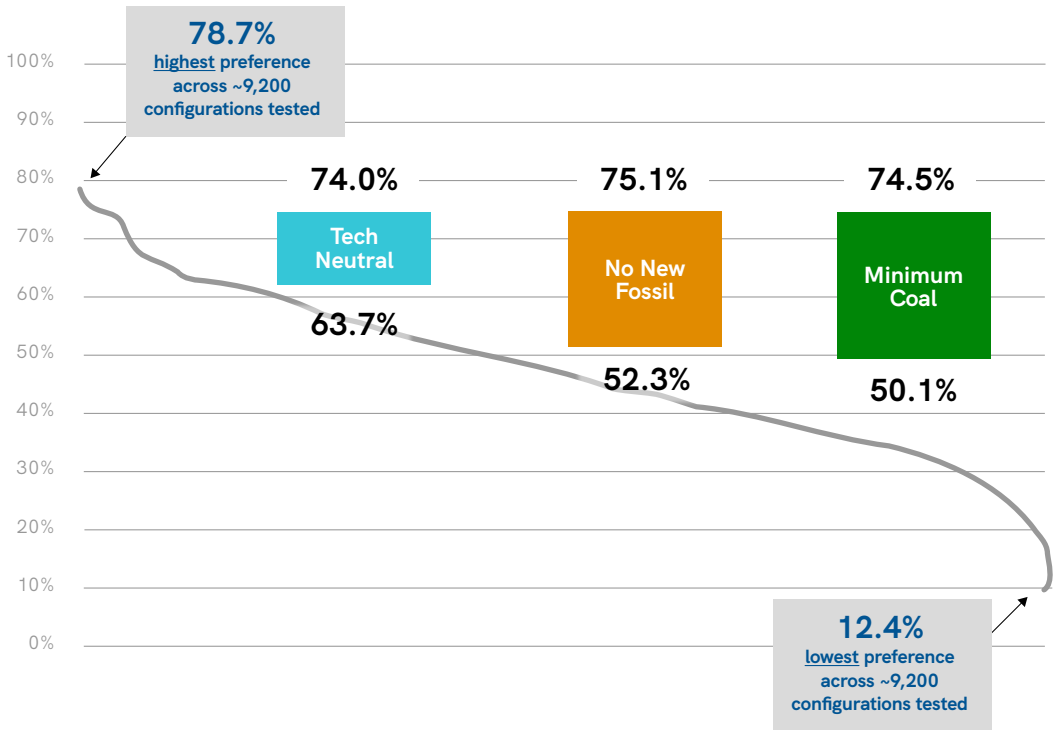
Residential Customer Research

Research consultant Bellomy assisted in the development of a Customer Preference Rating for each of the core system plans in the ISP, as shown in Figure 6.33. This metric was developed using over 1,000 residential customers' responses in a conjoint survey designed to understand how they value different aspects of the power system.

Residential Customer Preference Ratings represent the percentage by which customers expressed preferences of each strategic approach in various future scenarios relative to SRP's current system. Based on the results of the residential customer surveys, the preference ratings ranged between 12% and 79% versus the current system when all potential configurations were considered. System plans analyzed in this research that represented the ISP strategic approaches all achieved preferences over 50% versus SRP's energy system today.

Key findings from the research revealed that Technology Neutral was the most favorable strategic approach by SRP residential customers in futures with higher load growth such as Desert Boom and Current Trends. On the other hand, Minimum Coal and No New Fossil strategic approaches had a greater preference in futures where load growth was low, such as Desert Contraction, and additional federal incentives for carbon-free and hydrogen technologies were assumed, like in the Strong Climate Policy future scenario. Overall, there were more consistent preferences for Technology Neutral across the various futures when compared to the other strategic approaches.

FIGURE 6.33: CUSTOMER PREFERENCE RATINGS - SHARE OF PREFERENCE VERSUS CURRENT ENERGY SYSTEMS



Note: Within the Strong Climate Policy scenario, cases for Tech Neutral and No New Fossil are identical. Only one illustrative mix was shown to customers to represent both cases, thus data shown are identical for these two cases. No New Fossil and Minimum Coal cases were not tested in Desert Boom because they did not reach reliability targets.

Key findings from Residential Customer Research

Top factors – affordability and bill impacts: Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes, who make up approximately a third of SRP's residential customer base, put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change: Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy and overall quality of life. Thus, they understood the need for a lower-carbon future energy system. Across scenarios, however, lower-cost strategic approaches were preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage: Customers reported positive experiences with SRP's current programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts and infrastructure improvements.

Recommendations from residential customers for SRP's ISP

Findings revealed that from the residential customer's perspective, the ideal future energy system should:

- Manage cost, first and foremost.
- Keep monthly bill impacts below a 10% increase (from current electricity bills).
- Include a diverse energy mix to ensure reliability.
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase (from current electricity bills).

For additional details about the ISP customer research effort and key findings, please refer to the full reports for phases 1, 2 and 3 provided as appendices to this report.

Sensitivities

This section presents results for the 10 sensitivities that SRP analyzed for each strategic approach in the ISP.

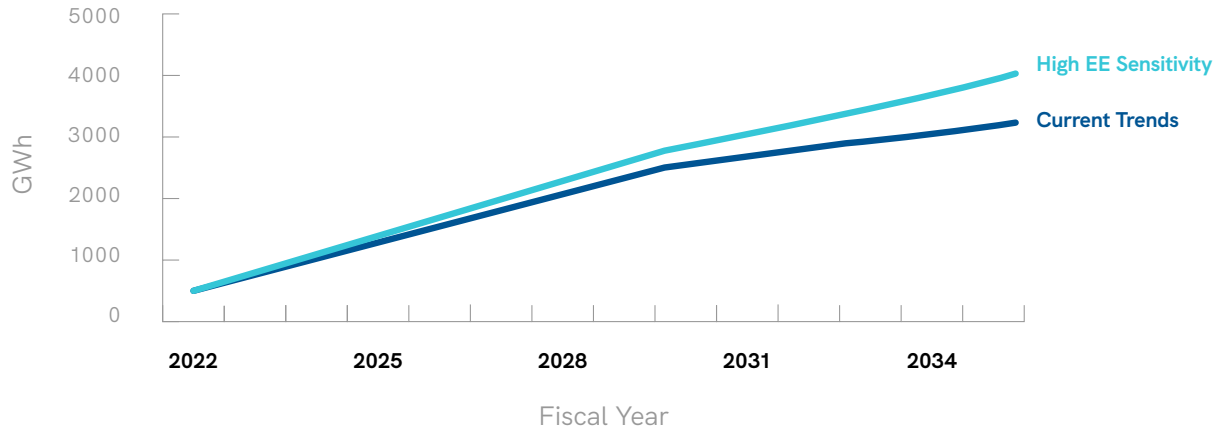
- High Energy Efficiency
- High Distributed Generation Adoption
- High Demand Response
- Increased Load Management
- High Gas Price
- Low Gas Price
- Volatile Gas Price
- High Technology Cost
- Low Technology Cost
- Regional Diversity

Each sensitivity is conducted relative to the Current Trends scenario as that scenario reflected the central planning assumptions. For presentation of the results, the three gas price sensitivities (High, Low and Volatile Gas Prices) are grouped together, as well as the two technology cost sensitivities (High and Low Technology Costs), yielding seven groups of sensitivities.

High Energy Efficiency

In the High Energy Efficiency (High EE) sensitivity, expansion of requirements pursuant to federal codes and standards lead to approximately 700 additional GWh of energy efficiency by 2035 relative to Current Trends. With this higher energy efficiency growth, total energy efficiency savings reach 4,471 GWh by 2035.

FIGURE 6.34: ANNUAL ENERGY EFFICIENCY ASSUMPTIONS



Figures 6.35 and 6.36 show peak load and energy demand forecasts for the High EE sensitivity, compared to Current Trends. In addition to reducing annual energy demand and overall load growth rates through 2035, these expanded energy efficiency customer programs reduce peak load by 395 MW in 2035 relative to Current Trends.

FIGURE 6.35: PEAK LOAD (MW) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

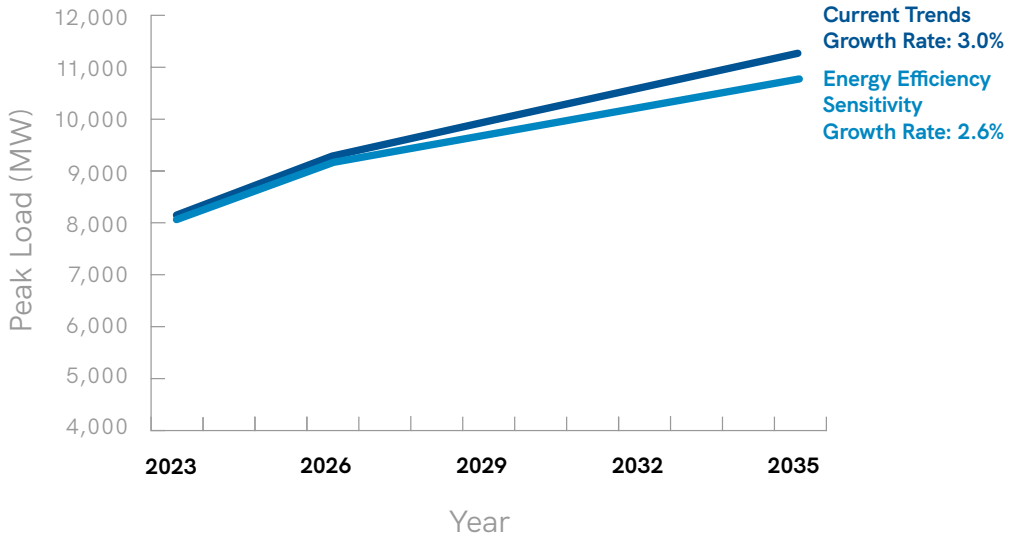


FIGURE 6.36: ENERGY DEMAND (GWH) FORECASTS - HIGH ENERGY EFFICIENCY SENSITIVITY

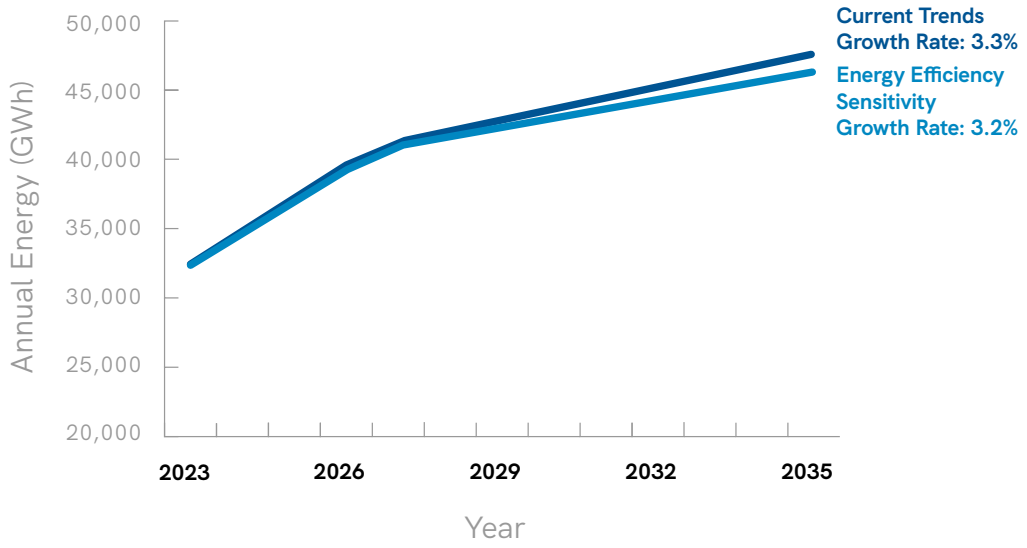
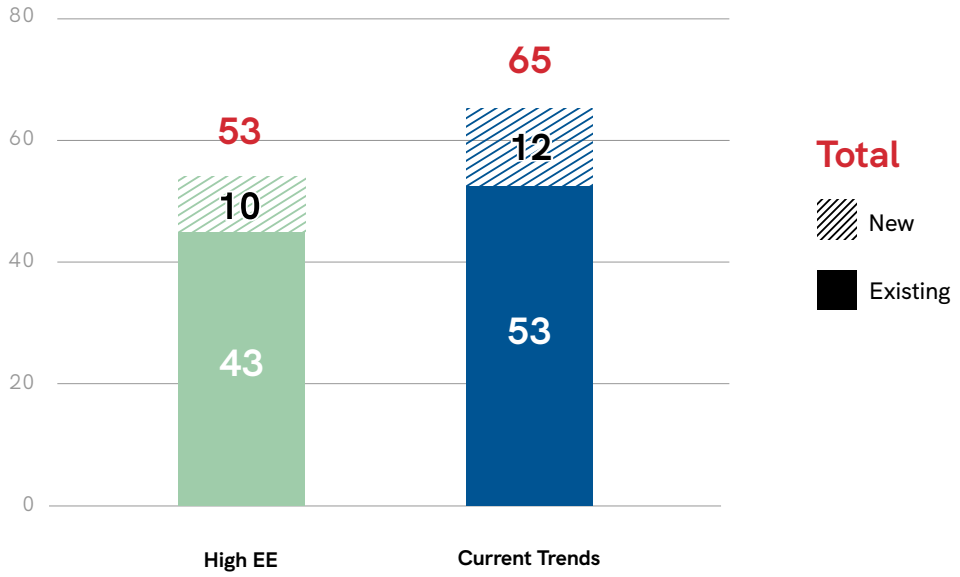


Figure 6.37 shows the distribution substation bay additions under the High EE sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High EE sensitivity results in slightly fewer substation bay additions than in Current Trends. The investment needs are similar to the Strong Climate Policy scenario, however, because the load forecasts are similar. The sensitivity results demonstrate a potential for energy efficiency to help defer distribution investment needs. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.37: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH ENERGY EFFICIENCY SENSITIVITY



As shown in Figure 6.38, the additional energy efficiency in the High EE sensitivity case reduces the need for resources across all strategic approaches. In the Technology Neutral case, there are about 400 MW less new gas peaker builds in the High EE sensitivity than in Current Trends. In the No New Fossil and Minimum Coal cases, there are even fewer resource builds, particularly batteries (which had been the primary resource selected to meet capacity needs) and solar (which is less economic to add with fewer batteries to integrate the solar).

FIGURE 6.38: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH ENERGY EFFICIENCY SENSITIVITY

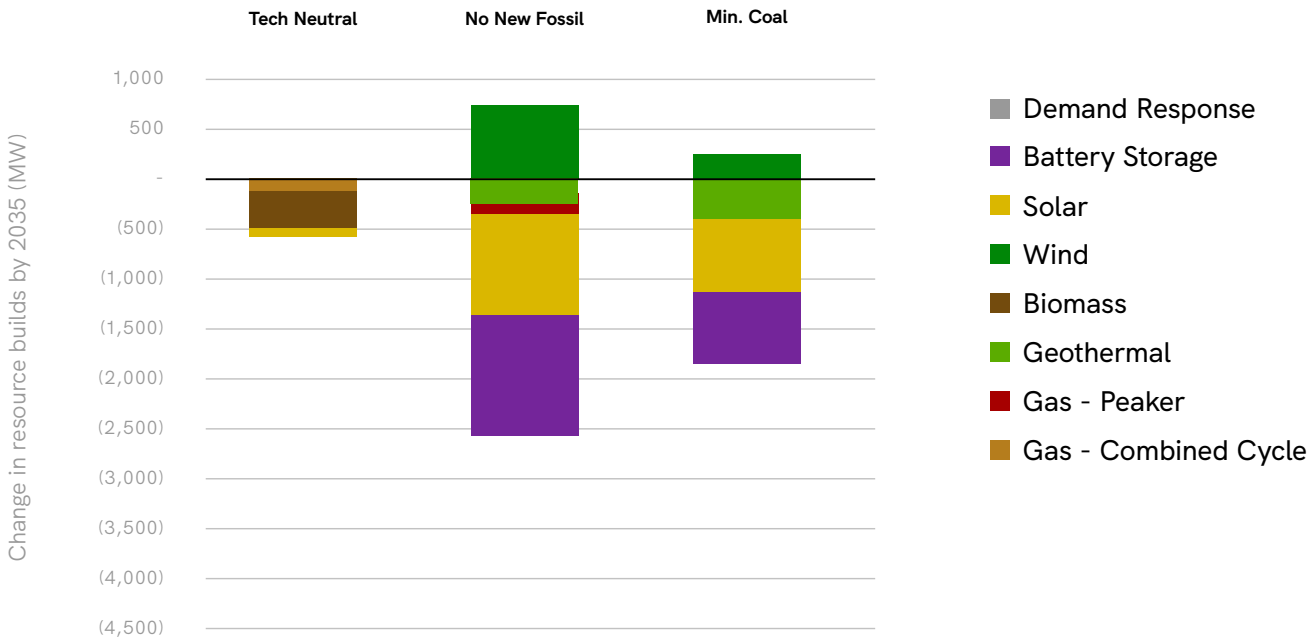
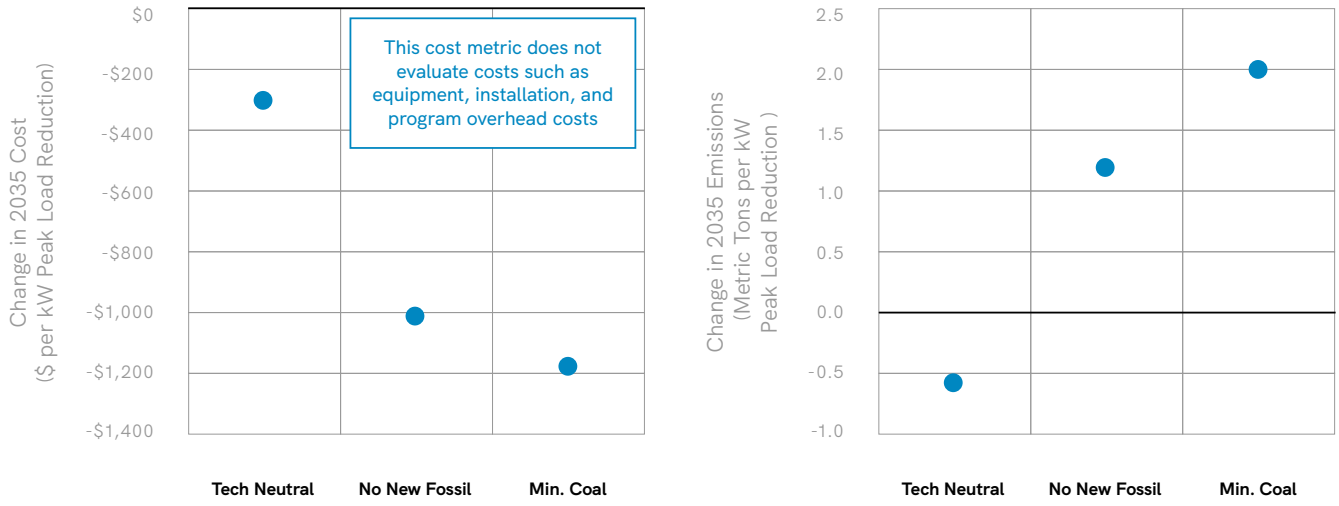


Figure 6.39 shows the resulting changes in total system cost and emissions under the High EE sensitivity, normalized by the kW reduction in PRM from the increased energy efficiency. It is important to note that the results do not include costs such as equipment, installation and program overhead, nor incentive payments or lost revenue that are relevant to ratepayer benefits and costs (such as those captured in the Ratepayer Impact Measure test). Because higher energy efficiency reduces the PRM requirement and the cost of meeting the PRM requirement under No New Fossil and Minimum Coal is higher without new firm resource options, additional energy efficiency results in greater cost savings in the Minimum Coal and No New Fossil cases. Conversely, additional energy efficiency results in relatively lower savings in the Technology Neutral case, where there are new firm capacity options. The Minimum Coal and No New Fossil cases also experienced emissions increases with more energy efficiency due to a net offset in renewable resource capacity and greater natural gas generation and market purchases, while the Technology Neutral case saw a decline in emissions due to a reduction in natural gas generation.

FIGURE 6.39: HIGH ENERGY EFFICIENCY: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, the High EE sensitivity case demonstrates the ability for energy efficiency to not only offset overall energy demand but also demand during peak periods, which in turn can help mitigate the need for incremental investments in the distribution system and firm capacity resources. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

High Distributed Generation Adoption

The High Distributed Generation sensitivity included approximately 960 additional MW of distributed solar and approximately 175 MW of distributed storage by 2035. The expanded distributed generation reduces annual peak load and energy demand growth relative to Current Trends, as shown in Figure 6.41.

FIGURE 6.40: HIGH DISTRIBUTED GENERATION SENSITIVITY CAPACITY (MW)

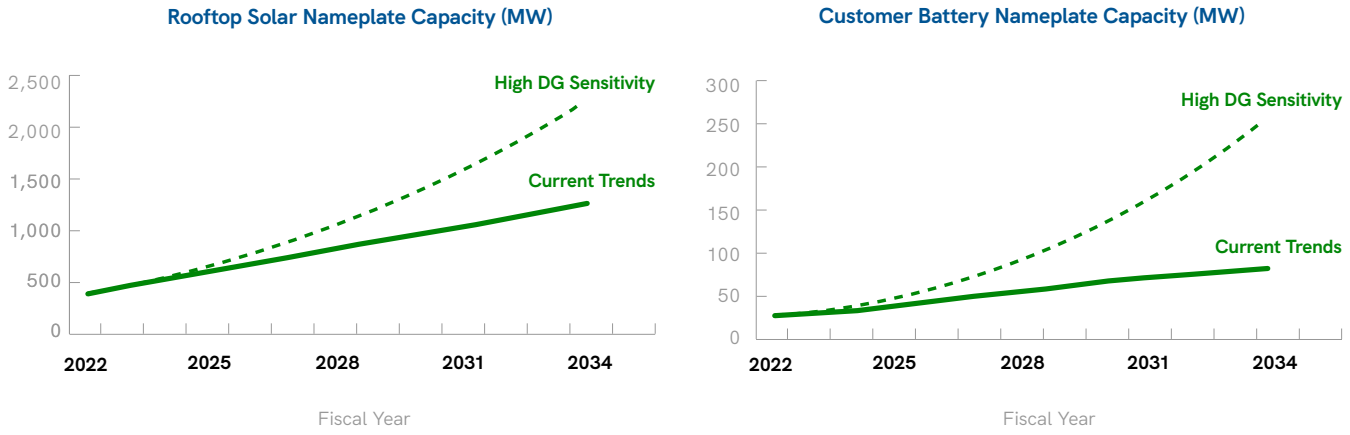


FIGURE 6.41: PEAK LOAD (MW) AND ENERGY DEMAND (GWH) FORECASTS - HIGH DISTRIBUTED GENERATION SENSITIVITY

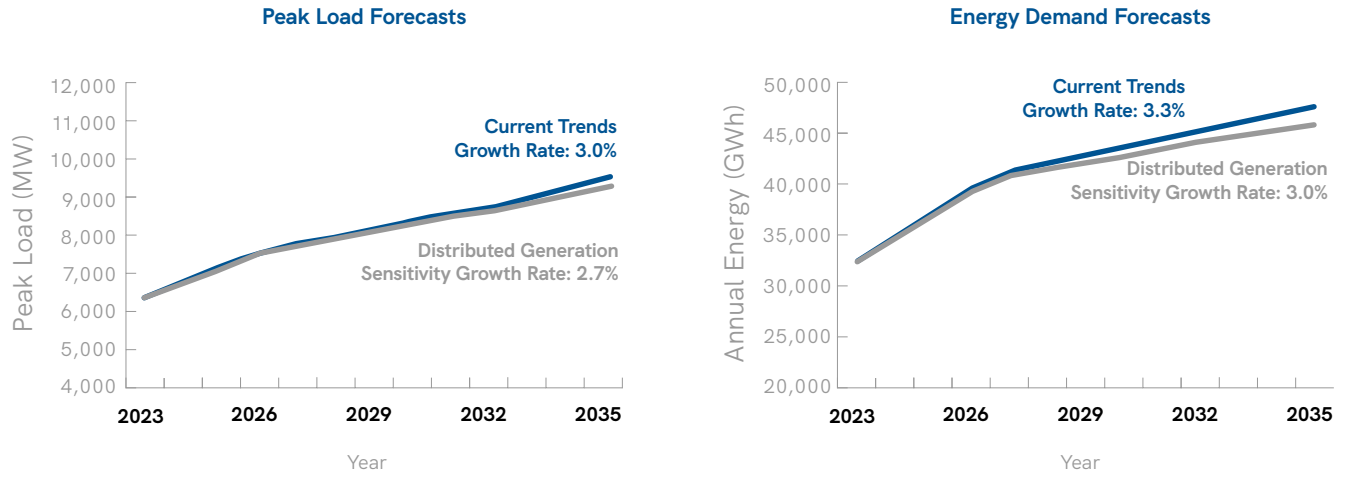
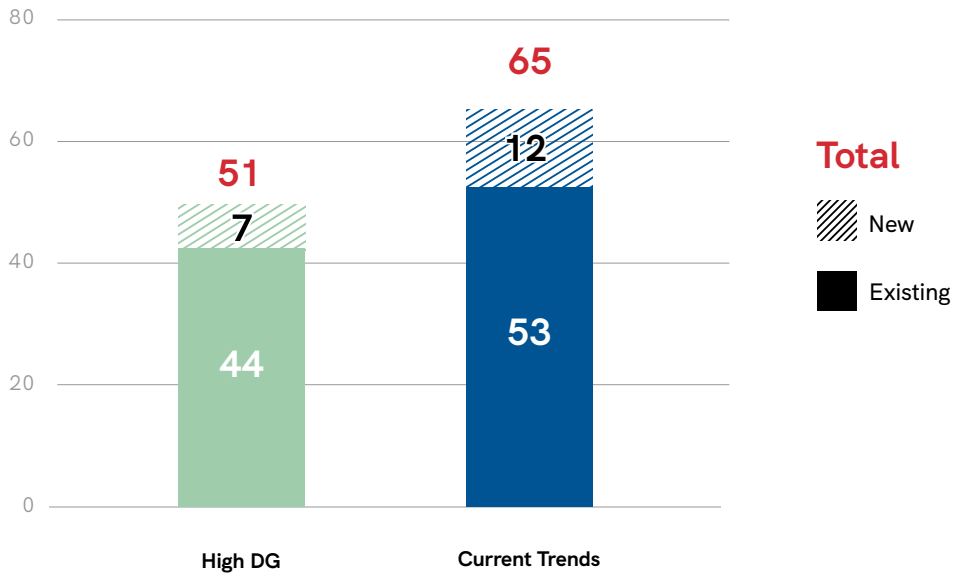


Figure 6.42 shows the distribution substation bay additions under the High Distributed Generation sensitivity relative to the Current Trends scenario (see Figure 6.8 for the remaining scenarios). The High Distributed Generation sensitivity results in slightly fewer substation bay additions than in the Current Trends scenario. The load forecast for this sensitivity is similar to that in the Strong Climate Policy scenario, which is why the investment needs are similar between these two cases. This result reflects the potential for distributed generation to help defer distribution investment needs generally. However, this ability to help defer future investments will vary significantly across the system and must be assessed on a case-by-case basis when evaluating future distribution investments.

FIGURE 6.42: SUBSTATION BAY ADDITIONS AT EXISTING AND NEW SUBSTATIONS (FY23-35) - HIGH DISTRIBUTED GENERATION SENSITIVITY



Additional distributed generation reduces the overall need for new resources, as shown in Figure 6.43. In the Technology Neutral case, increased distributed solar primarily displaces utility-scale solar, while distributed storage displaces some natural gas capacity. In the No New Fossil and Minimum Coal cases, increased distributed generation primarily displaces utility-scale solar and storage.

FIGURE 6.43: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DISTRIBUTED GENERATION SENSITIVITY

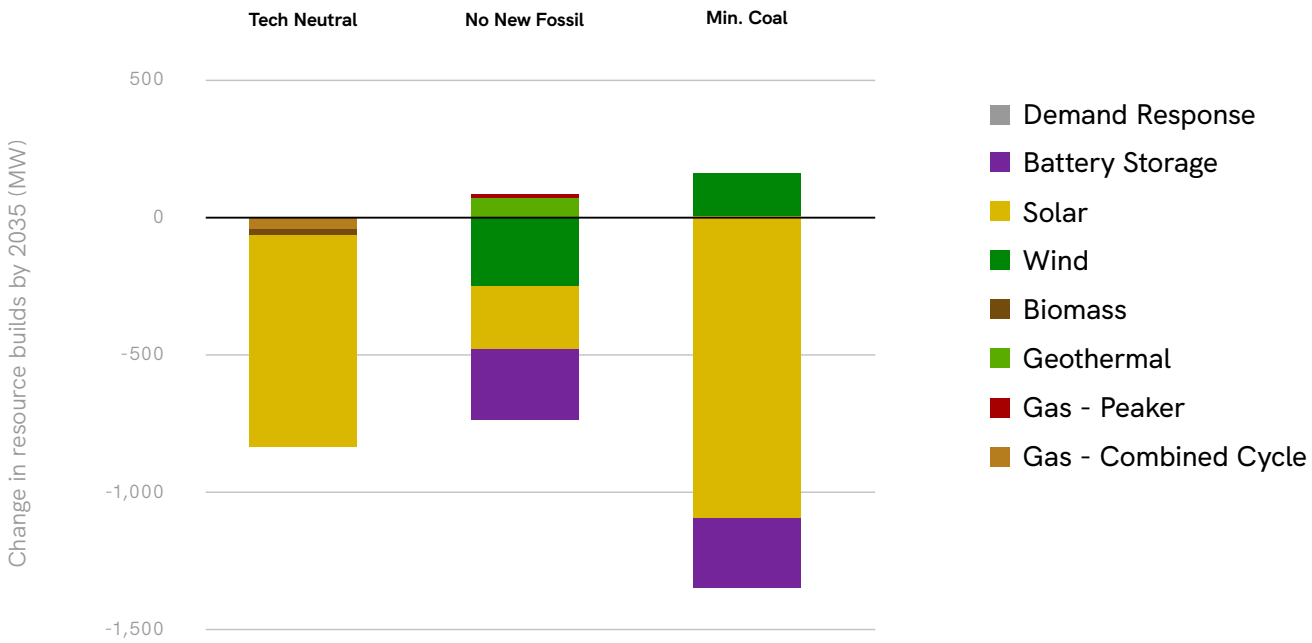
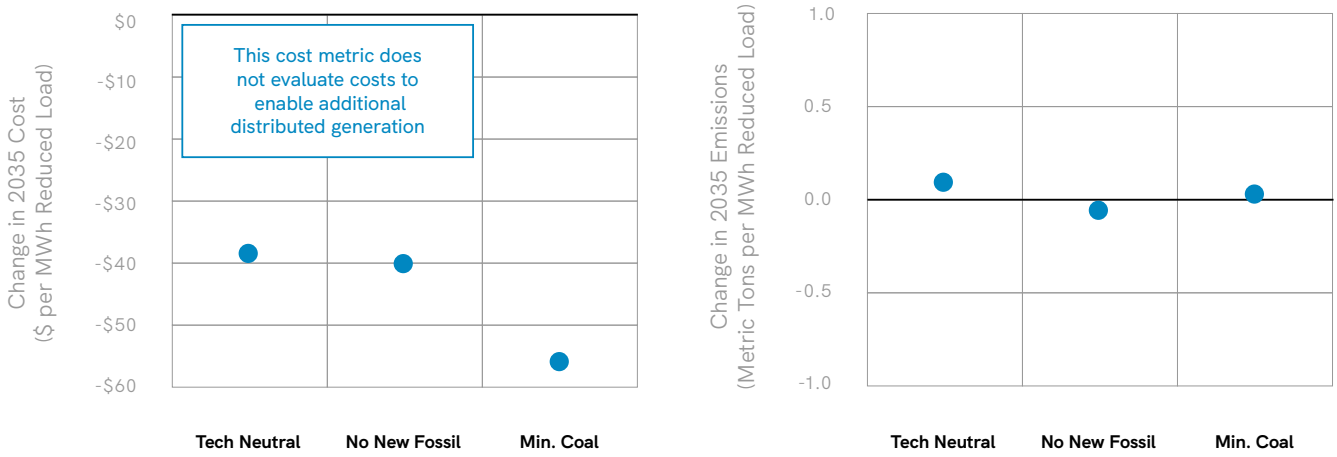


Figure 6.44 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the MWh of reduced load from additional distributed generation. It is important to note for these results that there is uncertainty as to how well distributed storage dispatch would align with grid needs and that these results do not include the costs to SRP or its customers of adding the distributed generation. Adding distributed generation generally leads to total system cost reductions, with the greatest reductions in the Minimum Coal case due to the greatest offset of capacity. However, there was very little impact of distributed generation on emissions across all cases, given it primarily substituted distributed solar generation for utility-scale solar generation.

FIGURE 6.44: HIGH DISTRIBUTED GENERATION: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY MWH REDUCED LOAD

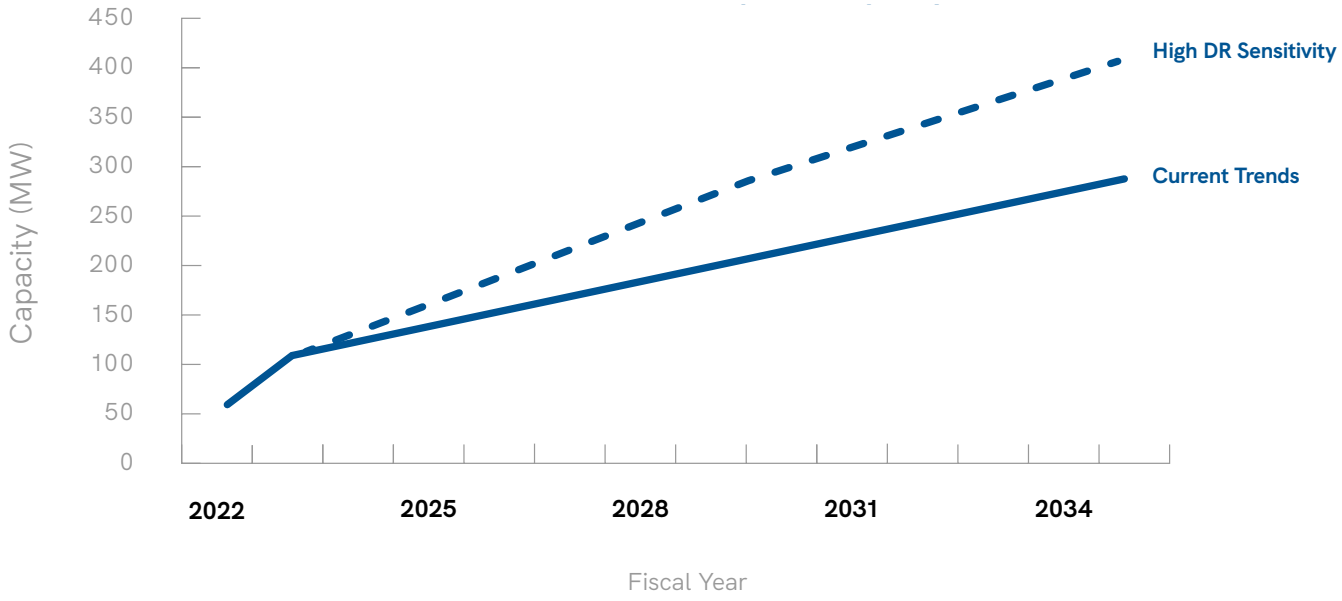


Overall, increased levels of distributed generation resources (solar PV and battery storage) reduce overall energy demand as well as energy demand during peak periods that need to be served by utility-scale resources. As a result, increased adoption of these resources helps mitigate the need for incremental distribution system investments and offsets the need for some utility-scale generation resources: Distributed solar primarily helps offset utility-scale solar, while increased distributed storage is able to offset a portion of capacity resources (gas and/or batteries). The analysis finds that increased adoption of distributed resources leads to the greatest reductions in total system costs in the Minimum Coal strategic approach due to the greatest offset of utility-scale resources and a relatively small impact on emissions across all cases.

High Demand Response

The High Demand Response sensitivity assumes an additional 100 MW of demand response by 2035, reaching a total of 400 MW (compared to 300 MW under the Current Trends scenario).

FIGURE 6.45: ANNUAL DEMAND RESPONSE CAPACITY ASSUMPTIONS



The additional demand response capacity results in a change in resource builds relative to the Current Trends scenario, as shown in Figure 6.46. Increased demand response displaces capacity resources in all strategic approaches. In the Technology Neutral case, adding an additional 100 MW of demand response reduces over 30 MW of natural gas peaker builds.
In the No New Fossil and Minimum Coal cases, the additional demand response substitutes for 50 MW of battery storage builds. The outcome that the reduction of battery capacity is equal to half of the demand response additions reflects the assumption that demand response provides less reliability capacity to the system than batteries; while demand response and battery resources provide similar services to the system, demand response is more limited in number and duration of dispatch events. Because some of the storage resources that are offset are battery storage paired with solar, there is a reduction in solar capacity and a corresponding increase in wind (and biomass in No New Fossil). Less capacity is offset in the Technology Neutral case because natural gas capacity has a greater contribution to reliability needs relative to demand response, battery storage and solar.

FIGURE 6.46: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH DEMAND RESPONSE SENSITIVITY

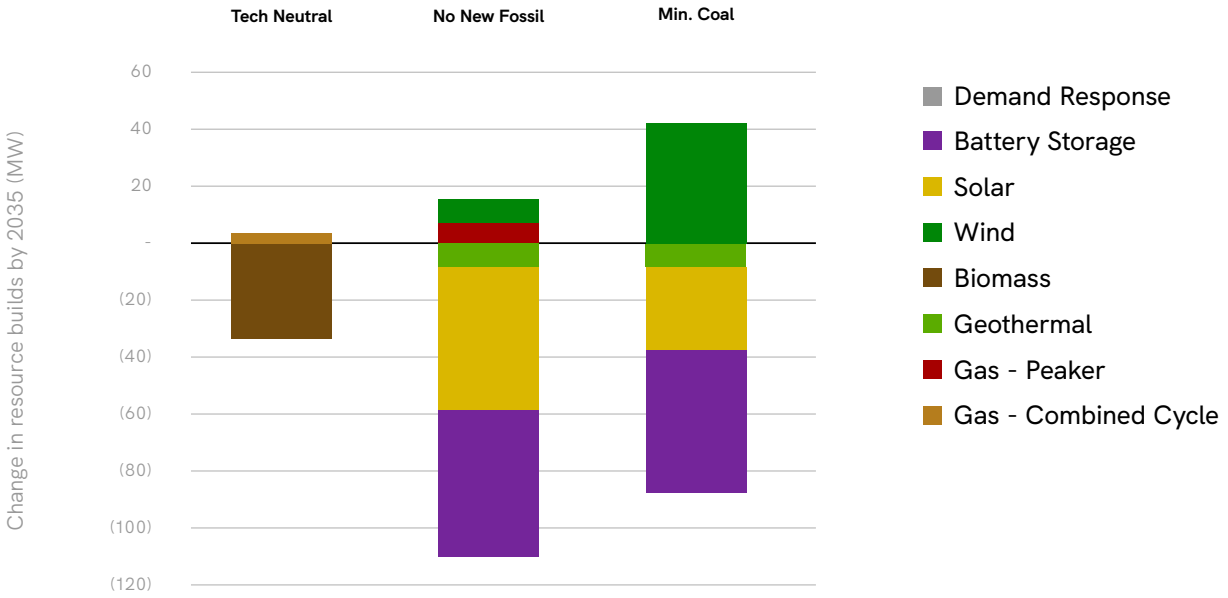
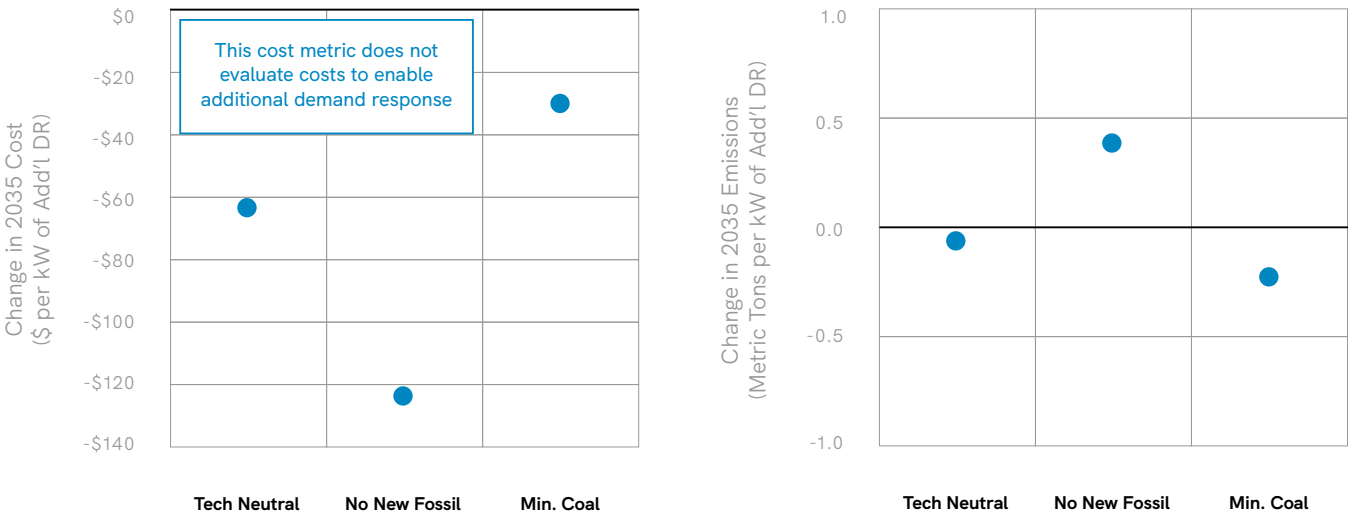


Figure 6.47 shows the resulting change in total system cost and emissions under the sensitivity, normalized by the additional demand response capacity. Note that the total system cost metric does not include the incremental costs needed to enable this additional demand response capacity, so the change in total system cost only reflects gross savings and not net savings. Additional demand response results in the greatest gross savings under the No New Fossil case due to larger offsets in capacity additions. The Technology Neutral case has a smaller reduction in costs because a relatively small amount of natural gas capacity is offset. Emissions increase in the No New Fossil case when demand response is added due to a slight increase in gas emissions to compensate for the net reduction in clean energy capacity. There are small emissions reductions in Technology Neutral due to the reduction in gas capacity and in the Minimum Coal case due to the greater additions of wind capacity offsetting the displaced capacity.

FIGURE 6.47: HIGH DEMAND RESPONSE: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, NORMALIZED BY KW OF ADDITIONAL DEMAND RESPONSE



Overall, increased levels of demand response largely help mitigate the need for capacity resources (gas and/or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees an uptick in emissions.

Increased Load Management

The Increased Load Management sensitivity assumed that there is an additional 200 MW of aggregate flexibility through managed EV charging or other flexible loads, allowing SRP to shift up to 800 MWh of energy demand each day.

SRP found that increased load management displaces a portion of resources needed for reliability. In the Technology Neutral strategic approach, additional load management reduces gas builds and helps integrate more solar capacity by shifting energy demand from evening hours to daytime hours. In the No New Fossil and Minimum Coal cases, load management substitutes one for one for battery storage capacity, offsetting the paired battery storage and solar that is otherwise built and leading to a small increase in wind.

FIGURE 6.48: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - INCREASED LOAD MANAGEMENT SENSITIVITY

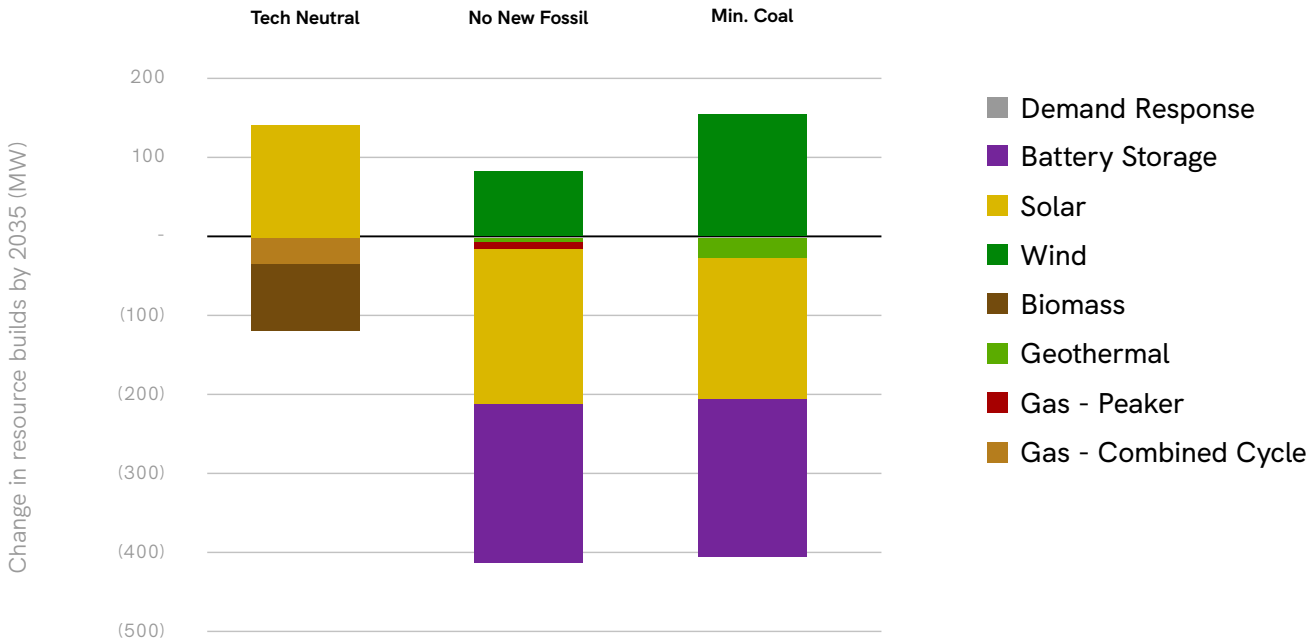
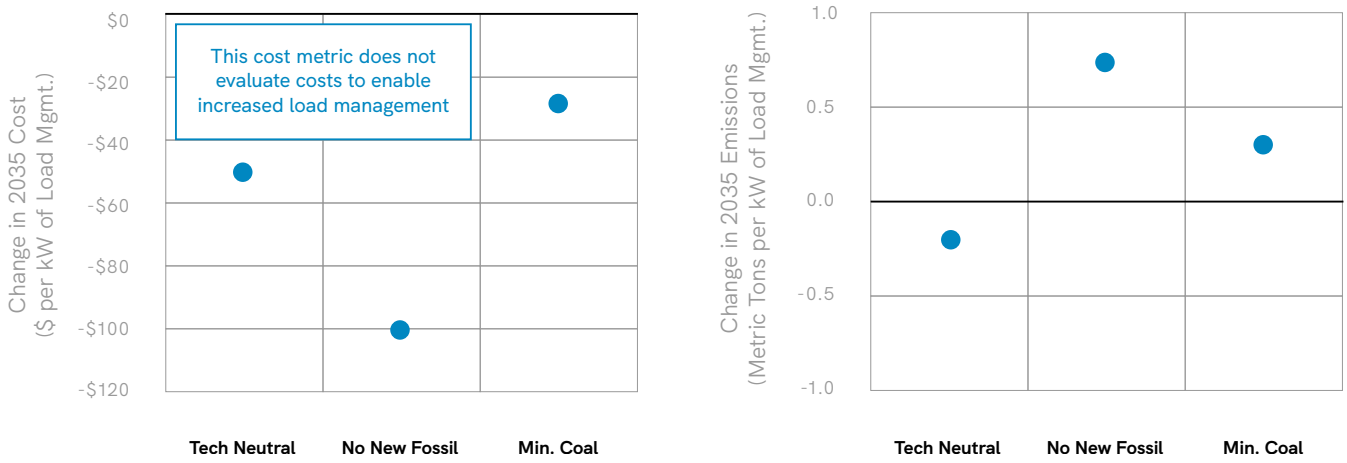


Figure 6.49 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by kW of increased load management. This sensitivity assumes that SRP has sufficient control or can incentivize customers to get desired performance. Additionally, this sensitivity does not evaluate costs to enable increased load management. The dynamics of increased load management are similar to that of demand response, resulting in similar cost and emissions impacts. Relative to the Current Trends scenario, increased load management generally leads to reductions in total system costs, with the greatest impact on the No New Fossil case. The Minimum Coal case has the smallest reduction in costs because greater amounts of wind capacity are added to make up for the reduced solar and battery capacity. While emissions decrease in Technology Neutral due to the reduction in gas generation, emissions increase under No New Fossil and Minimum Coal due to the larger decline in clean energy capacity.

FIGURE 6.49: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW OF INCREASED LOAD MANAGEMENT



Overall, increased levels of load management such as managed EV charging largely help mitigate the need for firm capacity resources (gas or batteries). Mitigating the need for these resources leads to total system cost savings, with the greatest savings in the No New Fossil case, although this case also sees the highest uptick in emissions.

High, Low and Volatile Gas Prices

The high and low gas price sensitivity cases were based on the 2022 EIA AEO Low and High Oil & Gas Supply Cases, respectively. SRP found that additions of natural gas and renewable/storage resources depend on gas prices, but in all cases, both new renewables and firm capacity are part of a least-cost portfolio. For example, higher natural gas prices (HGP) increase total capacity additions, driving increases for solar, wind and storage while offsetting some gas capacity. On the other hand, lower natural gas prices (LGP) reduce total capacity additions, driving higher additions of natural gas while offsetting solar and wind additions.

FIGURE 6.50: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO – HIGH AND LOW GAS PRICES SENSITIVITY

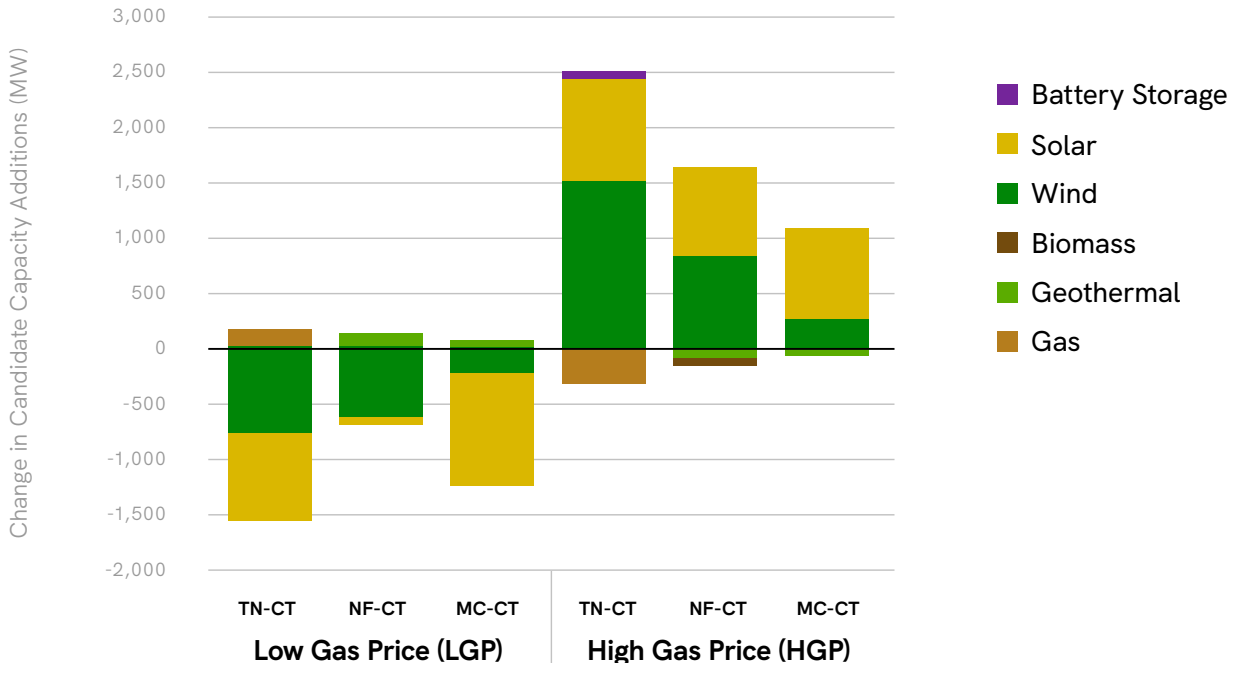


Figure 6.51 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. High Gas Prices had the strongest impact on total system cost for the Technology Neutral approach, while the costs for the No New Fossil and Minimum Coal cases were relatively stable. For Technology Neutral, the High Gas Price sensitivity caused a larger change in cost than the Low Gas Price sensitivity because the high gas prices increased more than the low gas prices decreased. Cost impacts under No New Fossil and Minimum Coal were mild for both the High Gas and Low Gas price sensitivities. Emissions increased in the Low Gas Price sensitivity and decreased in the High Gas Price sensitivity for all strategic approaches, but to a lesser extent for No New Fossil.

KEY FINDING

New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas prices.

FIGURE 6.51: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO

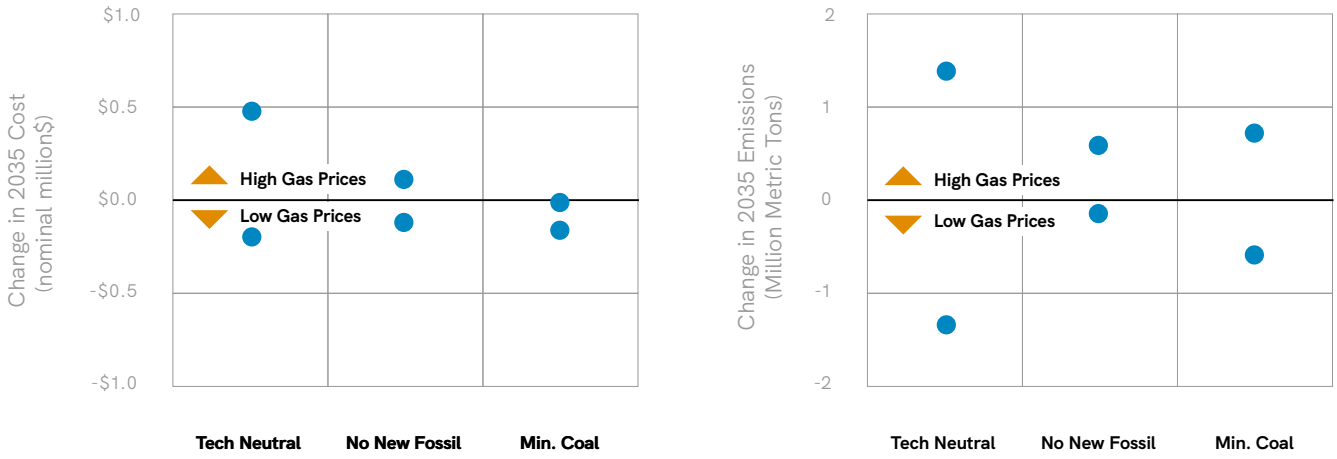
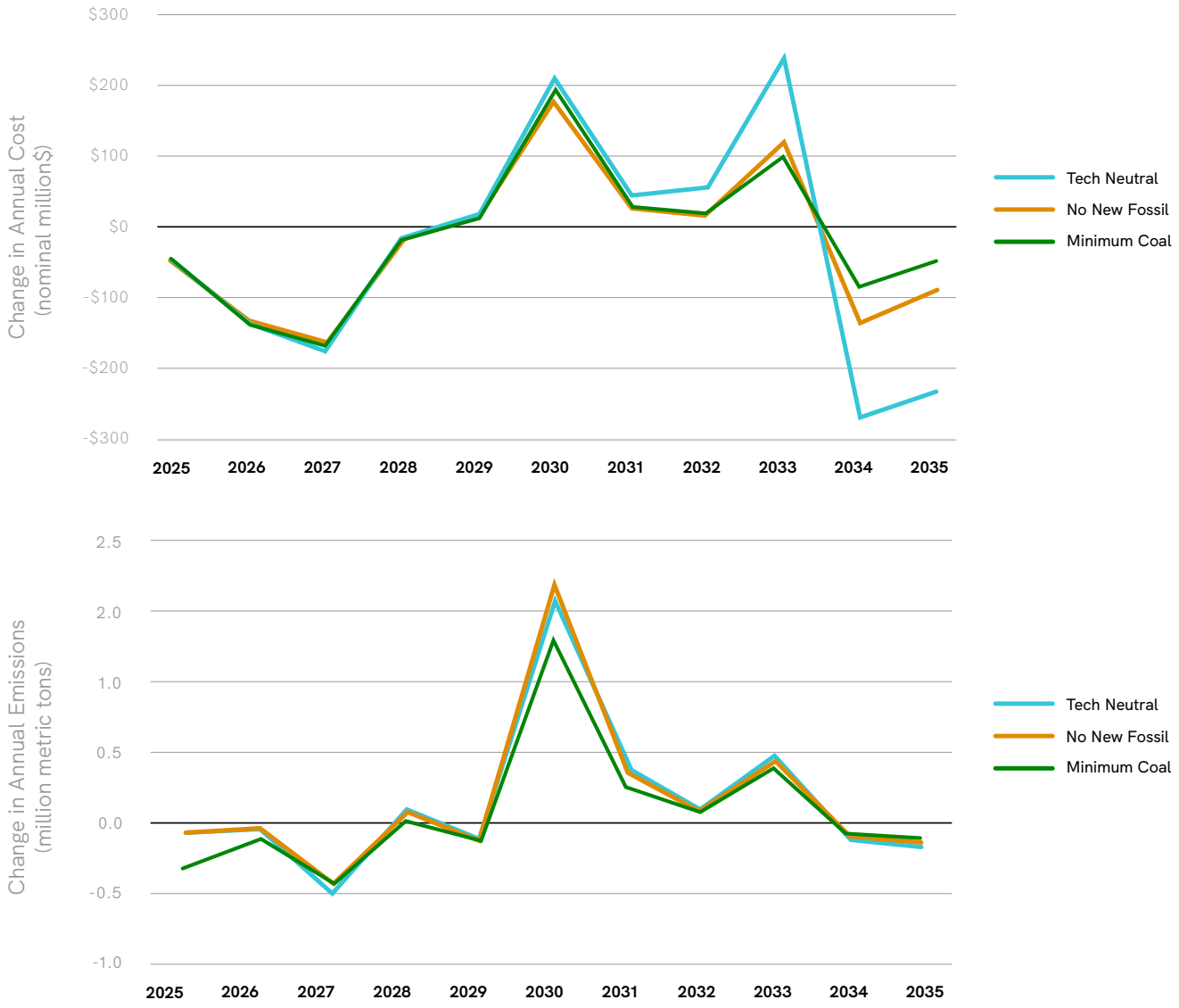


Figure 6.52 shows the impacts of the variable gas price sensitivity on total system cost and emissions between 2025 and 2035, relative to the Current Trends scenario. This sensitivity did not vary resource buildouts, so the changes over time are only a result of changes to gas prices (and associated impacts on market prices). The variability in natural gas prices leads to fluctuations in total system costs, particularly in the 2030s, with total system cost increasing or decreasing by over +/- $200 million in a given year and emissions increasing by over 2 million metric tons in a given year.

FIGURE 6.52: VARIABLE GAS PRICES: ANNUAL CHANGE IN TOTAL SYSTEM COST (TOP) AND EMISSIONS (BOTTOM), RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future natural gas can have important implications for SRP's resource portfolio. Higher natural gas prices result in increased additions of renewables and storage (offsetting a smaller amount of natural gas builds in Technology Neutral), higher total system costs and lower emissions in 2035. Lower natural gas prices result in lower renewable additions (with a slight uptick in natural gas builds under Technology Neutral), lower total system costs and higher emissions. The potential for unexpected gas price volatility in the future could result in higher system costs or emissions.

High and Low Technology Costs

The High and Low Technology Cost sensitivities were based on the 2022 NREL ATB High and Low Cases, respectively. Lower Technology Costs (LTC) increase total capacity additions, driving increases in solar and battery storage while offsetting some natural gas capacity. On the other hand, Higher Technology Costs (HTC) reduce total capacity additions, primarily offsetting solar additions.

FIGURE 6.53: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - HIGH & LOW TECHNOLOGY COSTS

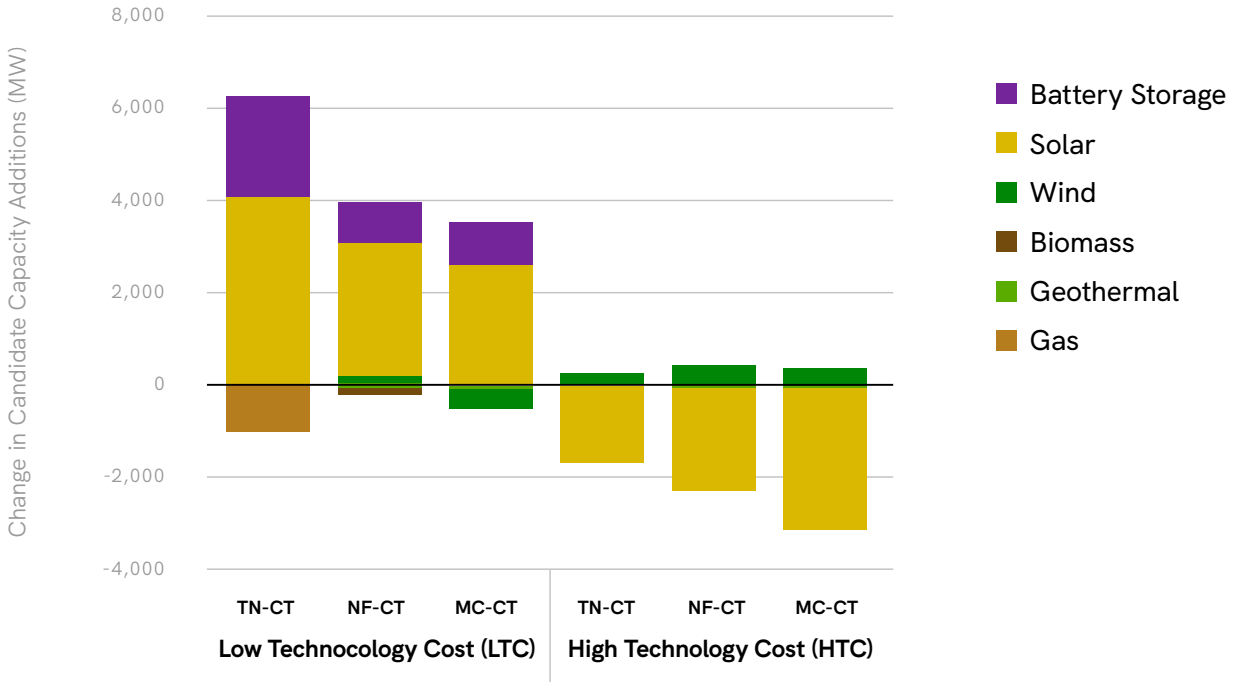
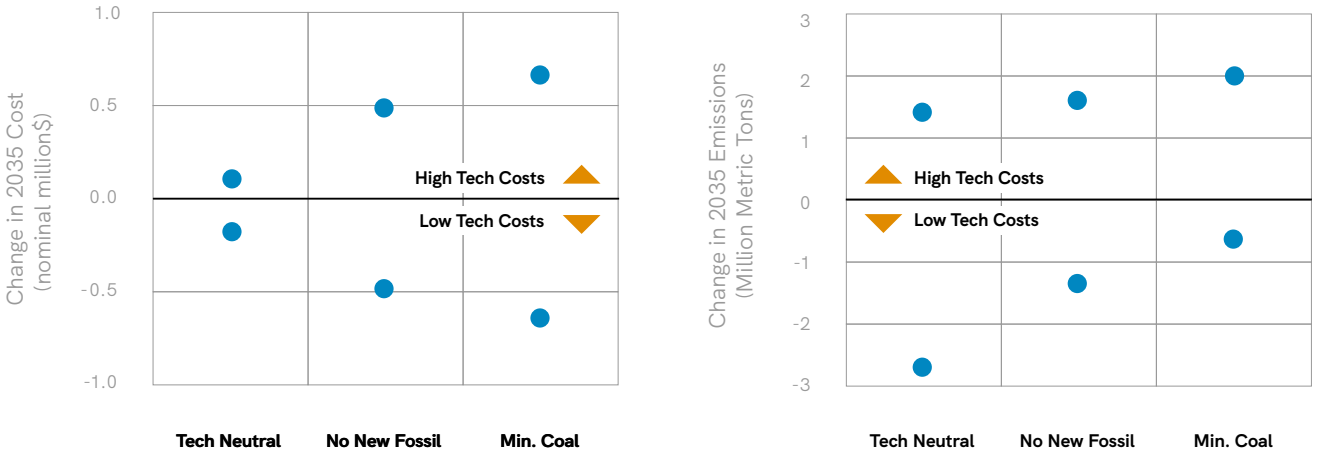


Figure 6.54 shows the change in 2035 total system cost and emissions, relative to the Current Trends scenario. The change in technology costs causes the greatest cost impact on the Minimum Coal case, while the Technology Neutral case experiences relatively low impacts to cost. Across all cases, higher technology costs lead to higher emissions and lower technology costs lead to lower emissions.

FIGURE 6.54: CHANGE IN 2035 TOTAL SYSTEM COST AND CO_2 EMISSIONS, RELATIVE TO THE CURRENT TRENDS SCENARIO



Overall, the trajectory of future technology costs can have important implications for SRP's resource portfolio. Lower renewables and storage technology costs result in increased additions of solar and storage (and higher total capacity additions), lower total system costs and lower emissions in 2035. Higher technology costs result in lower renewable additions, higher total system costs and higher emissions. In all cases, new firm capacity is still needed.

Regional Diversity

In the Regional Diversity sensitivity, SRP reduced the target planning reserve margin (PRM) from 16% to 13% (338 MW reduction by 2035) to serve as a proxy to represent the assumption that expanded transmission and regional coordination allow for increased resource and load diversity. The lower PRM reduces the need for resources on SRP's system. In the Technology Neutral strategic approach, there are fewer gas peaker builds. In the No New Fossil and Minimum Coal cases, larger amounts of resources are offset. The most impacted resources are batteries (due to the lower total PRM requirement) and solar (which is less economic to add with fewer batteries to integrate the solar). These resources are partially replaced by wind in both cases.

FIGURE 6.55: CHANGE IN RESOURCE BUILDS BY 2035 (MW) RELATIVE TO THE CURRENT TRENDS SCENARIO - REGIONAL DIVERSITY

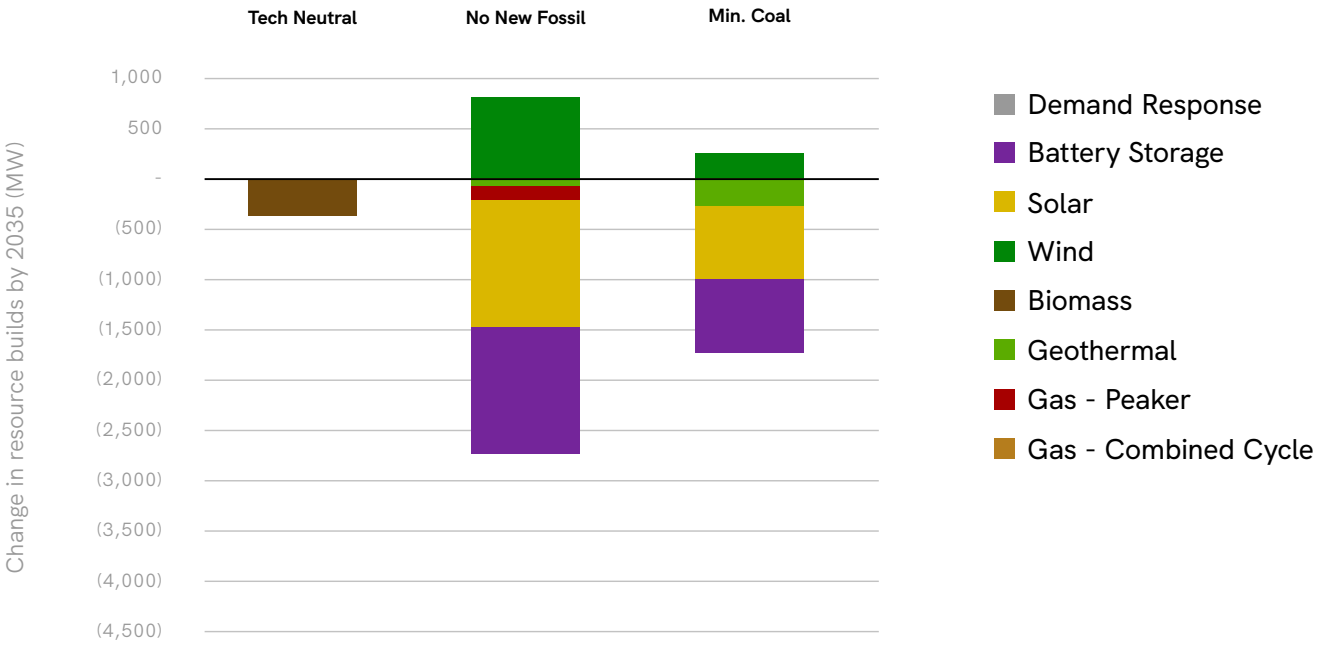


Figure 6.56 shows the resulting reductions in total system cost and changes in emissions under the sensitivity, normalized by the kW PRM reduction. For this sensitivity, the 3% PRM reduction is hypothetical, and the results do not consider any trade-offs or costs to realize greater regional diversity benefits for capacity planning. Because No New Fossil and Minimum Coal have higher costs of meeting the PRM due to the lack of new firm capacity resources, Regional Diversity results in the greatest cost reductions for these cases and the lowest cost reductions for Technology Neutral, in which there are new firm capacity resource options. While the Technology Neutral case experiences a very slight decrease in emissions, No New Fossil and Minimum Coal have increases in emissions due to natural gas generation and market purchases compensating for the reduction in renewable generation.

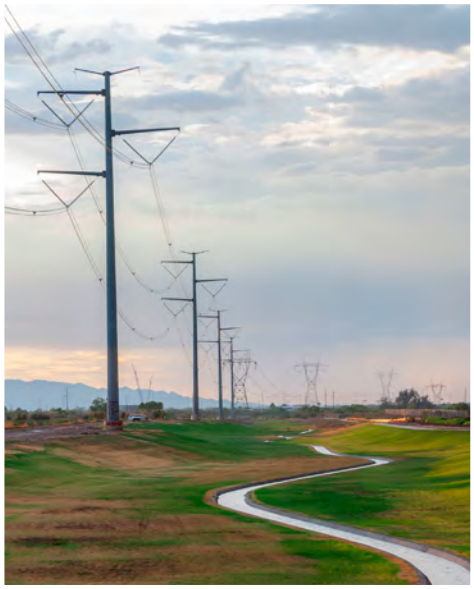
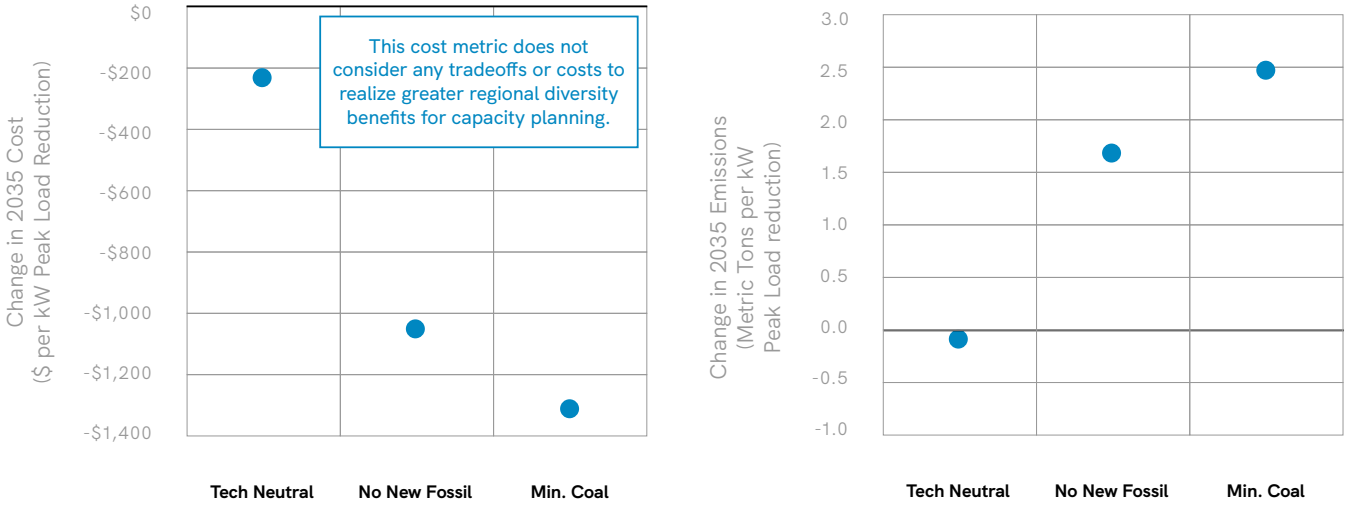


FIGURE 6.56: CHANGE IN 2035 TOTAL SYSTEM COST AND EMISSIONS, NORMALIZED BY KW PEAK LOAD REDUCTION



Overall, increased regional market participation largely helps mitigate the need for firm capacity resources (gas and/or batteries) due to increased resource and load diversity. Cost savings are highest in cases with limited firm capacity resource options (No New Fossil and Minimum Coal) due to the higher cost of meeting the PRM in those cases (relative to Technology Neutral), although emissions increase in those cases due to greater reliance on emitting generation resources to meet energy demand.

Summary of ISP Key Findings

The key findings from the analysis described above are summarized here for reference. These key findings served as the foundation to inform the ISP System Strategies described in Section 8.

Customer Programs and Pricing Plans

- SRP will need to evolve programs and price plans to encourage shifts in consumer behavior and further educate customers on when to consume and when to conserve energy.
- Electrification of end uses, including transportation and heating demand, creates new opportunities to shift energy usage to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.
- Changes in how customers use energy will require continued innovation and flexibility in planning.

Infrastructure

- Customers' energy demand is expected to increase rapidly through 2035 in most scenarios, even with significant expansion of customer programs and customer-sited generation.
- Significant investments in new transmission infrastructure are needed over the next decade to connect new resources and customers while also achieving reliability and sustainability goals. These investments will need to be strategically located and timed.

- Load growth will drive new distribution infrastructure needs while changes in how our customers use energy will require innovation and flexibility.
- SRP will likely need to double or triple resource capacity in the next decade to serve customers while achieving reliability and sustainability goals. This will be at an unprecedented pace.
- New renewables and firm capacity are part of a least-cost portfolio, even under a wide range of gas price and technology cost sensitivities.
- When paired with firm capacity, solar and wind contribute to a least-cost portfolio while helping SRP reduce carbon emissions and water usage. If the U.S. government enacted a mandate for 85% CO_2 reductions by 2035 (Strong Climate Policy), further acceleration of renewable and storage deployment would be required.
- Hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers could be needed relative to today.
- Location of generation matters and plays a significant role in the buildout of the 500 kV and 230 kV transmission system.

Operations

- Without new firm generation capacity, the system cannot satisfy reliability requirements under a high load growth scenario. In other load growth scenarios, the system can satisfy reliability requirements without new firm generation capacity but requires significant additions of renewable and energy storage resources.
- The reduction in coal generation and expansion of carbon-free resources over time allow SRP to meet, and in many cases exceed, SRP's 2035 goals for carbon emission reductions and water resiliency.
- A future system that relies more on variable renewable resources presents new challenges and will require new operating practices to ensure sufficient flexibility, reduce wear and tear on existing assets, and maximize benefits to customers.

Partnerships to Meet the Pace of Transformation

- With the amount of future infrastructure and resources needed, internal and external partnerships are going to be essential to build the future system and maintain high customer value.
- To meet the pace of infrastructure needs, supply chain and development solutions are essential to managing costs and to meet the pace of transformation needed.

SECTION 7

System Strategies

System Strategies

SRP faces an uncertain future that will continue to change at a rapid pace. In this dynamic and evolving environment, we must establish diverse strategies that can stand up to these changes while allowing for flexibility and adaptation. Utilizing our analysis and key findings, we have established seven System Strategies that will allow us to deliver the best value to our customers under future uncertainty and a wide range of potential outcomes.

The **System Strategies** are the Board-approved long-term strategies for planning and operating the power system in an integrated manner. These are strategies for all power system areas, including customer programs, distribution planning, resource planning, transmission planning, pricing and system operations. The strategies will guide us today through 2035, and they consider system developments needed beyond 2035 to meet SRP's 2050 goals. As a whole, these strategies will help to:

- Guide how we plan the system for the future and serve as the focal point for prioritizing our investments.
- Provide direction while maintaining flexibility to allow us to respond to future conditions.
- Guide our decisions on day-to-day planning activities.
- Signal to stakeholders and customers how we plan to evolve the system and meet the changing needs of our customers.

The System Strategies are also the starting point for developing the ISP Balanced System Plan and the ISP Actions, which are covered in detail in sections 8 and 9.

SRP used key insights from the ISP analysis, as discussed in Section 6, to develop the System Strategies that will help us maintain reliability and affordability while driving increased sustainability across a wide range of potential future scenarios. We also gathered and incorporated feedback from the Advisory Group members on these strategies before bringing them to SRP's Board. On Oct. 2, 2023, the Board approved the System Strategies.

Below are the seven interdependent System Strategies. Each strategy is reliant on the other strategies also being in place to ensure success and achievability. These are the strategies we can begin to implement now. Some strategies may take longer to implement than others, but the execution of all strategies together will enable us to meet evolving customer needs, achieve our 2035 Sustainability Goals, manage costs for customers, achieve an adequate and reliable power system, and adapt to a more sustainable future regardless of what the future may be in 2035.

Below is a detailed description of the seven System Strategies and discussion of the key findings from the ISP analysis that support them.

Energy Investments

Invest in renewable resources and storage to manage fuel consumption and drive carbon and water reductions.

The ISP analysis demonstrated that new renewables combined with firm generation are part of a least-cost power generation portfolio. Across the different future scenarios, we saw the least-cost system plans add an average of 4,800 MW of renewables and storage.

Renewables do more than just contribute to a least-cost portfolio. They help reduce fossil fuel consumption and contribute to improved sustainability, helping SRP meet its 2035 carbon reduction and water use goals. Our customers also want more renewables. We found from the residential customer research that customers want us to provide the most sustainable energy portfolio possible without significantly increasing their costs or compromising reliability. This strategy focuses on investing in renewables and storage to deliver exceptional value to our customers and help drive carbon and water reductions.

Capacity Investments

Invest in firm generation, including natural gas, to support reliability and manage affordability while also supporting the advancement of emerging firm technologies.

The ISP analysis shows that firm generation, such as natural gas, is key to maintaining reliability. Firm generation includes resources that can dispatch on demand and generate over long periods of time (e.g., multiple days). Without new firm generation, reliability is compromised by 2028 under a high load growth scenario.

Firm generation resources, when added along with renewable and storage resources, are also key to maintaining affordability. On average, the least-cost system plan adds more than 2,000 MW of natural gas capacity by 2035, helping to offset losses in firm generation from coal plant retirements and the expiration of a natural gas tolling agreement. When new natural gas is not allowed to be added, total system costs are 17%–24% higher under the Current Trends scenario and 7%–11% higher under the Desert Contraction scenario. The addition of firm generation allows SRP to mitigate these cost impacts and maintain affordability.

While adding new firm generation is key to maintaining reliability and affordability, it does not mean that these resources will have high utilization. The Energy Investments system strategy envisions adding renewable and storage resources to reduce fuel consumption from fossil fuel-fired resources, which is reflected in the ISP analysis. As a result, new and existing natural gas generation resources are projected to operate less over time, with the anticipated systemwide capacity factor declining to roughly 25% by 2035.

This strategy recognizes the need for the advancement of other emerging firm technologies (such as hydrogen, new nuclear and long-duration storage) and the role that emerging technologies can play in helping meet a portion of firm resource needs in the future. We expect the new investments in natural gas generation to be hydrogen-ready to allow SRP to transition those resources to hydrogen if and when hydrogen becomes a commercially viable fuel option.

Proactive Transmission

Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth.

The ISP analysis showed that a significant investment in transmission is needed over the next decade, driven by the large amount of generation required to meet our growing loads. By 2035, SRP could need hundreds of miles of new or upgraded transmission lines and nearly double the number of 500/230 kV transformers relative to today. The location of this new generation capacity matters and has a significant impact on the buildout of the 500 kV transmission system. We must strategically locate and build out new grid infrastructure to connect new resources and customers. It is in our best interest to strategically find the best location for new-generation resources and transmission. Siting and permitting transmission can be a decade-long process, necessitating a proactive approach in transmission planning.

Distribution Innovation

Ensure distribution grid readiness to maintain reliability and enable customer innovations to drive carbon reductions.

The distribution innovation strategy is focused on ensuring we are prepared for anticipated growth while maintaining reliability and enabling customer innovation. Load growth will drive additional infrastructure needs, while changes in how our customers use energy will require innovation and flexibility. This strategy allows us to understand and adapt to the complexities of balancing energy load growth with innovation that may reduce customer demand, such as managed EV charging, expanded deployment of distributed solar, and next-generation demand response programs.

This strategy helps enable us to provide a dependable supply of electricity to all SRP customers and provide a reliable grid that can prepare for and recover from unanticipated disruptions to ensure energy availability, while at the same time helping us meet evolving customer needs.

Partnerships & Suppliers

Explore partnerships and supply chain and development solutions that manage cost and availability to meet the pace of transformation.

SRP anticipates the need to double or triple resource capacity in the next decade to be able to best serve our customers while achieving our 2035 Sustainability Goals. This is an unprecedented pace of resource development, with potential additional needs for hundreds of miles of new transmission lines and numerous transformers on the transmission and distribution system. It will also require making decisions on specific investments, procurements, workforce development, information technology systems, etc. With the amount of future infrastructure and resources needed and long lead times for certain assets, external partnerships will be essential to build the future system and maintain high customer value.

Customers and community partnerships will also be critical to achieving the transformation of the power system. To enable construction of the large amount of infrastructure SRP is planning, we must proactively build relationships and partnerships with communities, cities, counties, towns, government agencies and tribes, and engage with advocacy organizations to understand their perspectives. We can then better identify, prepare and preserve options for feasible sites for future system infrastructure. Through these partnerships, SRP can respond to evolving customer needs by providing safe, reliable, affordable and sustainable power while recognizing the different needs, challenges and perspectives of our customers.

In addition to partnering with customers and communities, supply chain disruptions and delays that are still being felt following the pandemic necessitate the need to find supply chain and development solutions. Future supply chain disruptions could further impact our ability to develop new infrastructure. This strategy helps enable supply chain solutions essential to managing costs for our customers and to meeting the pace of transformation needed which could include ordering key supplies as early as possible and developing a wider pool of potential suppliers to diversify supply chain risks.

Evolution of Customer Programs & Pricing

Evolve pricing and customer programs to improve economywide carbon reductions and pace infrastructure development, while recognizing customers' diverse needs.

SRP will need to evolve programs and price plans to deliver the best value to our customers. We saw in our Time-of-Use Exploratory Study, existing customer programs and price plans are effective at managing peak energy demand today, but as our energy mix changes, so must our customer programs and price plans. Adding significant amounts of solar energy will mean abundant, low-cost energy is often available during daytime hours. The more expensive peak period will then shift later into the evening once the sun sets.

This also creates new opportunities to shift energy from increased electrification programs to mid-day hours to help integrate more renewable energy and maximize carbon reduction impacts.

During our transition to a more sustainable future, the timing and availability of low-cost resources will change with the increased adoption of renewable resources. We strive to strike the right balance of reliable, affordable and sustainable power for our customers. Currently, we have targets for Energy Efficiency and Demand Response adoption in our 2035 goals. We will continue studying options to accelerate and adapt to meet changing patterns in our customers' electricity use and help address significant load growth and capacity constraints over the next several years.

This strategy allows us to adapt to the needs of a changing grid and gives us an opportunity to recognize the different needs, challenges and perspectives of our customers and reflect that through new customer offerings that will help us maintain industry-leading customer satisfaction.

Strategic Investment & Reinforcement of Existing Assets

Reinforce and maximize value of existing infrastructure with strategic investments to manage affordability and ensure future performance, grid security and resilience.

SRP's existing assets and generation are the foundation for our future. Our existing and contracted generating assets will make up 50% of our capacity, 70% of our reliability needs and 45% of our carbon-free energy in 2035. Additionally, our existing transmission lines will make up an estimated 90% of the total number of 230-plus kV line miles in 2035, and our distribution substation bays will make up 85% of the substation bays we need in 2035. The existing system is important, and we must strategically reinvest in the system we have today by continuing to perform routine maintenance to extend the life of our assets. Existing resources are needed to meet future customer needs and maintain a reliable grid that can prepare for and recover from both anticipated and unanticipated disruptions to ensure energy availability. This will ensure continued grid security, safety and performance.

We must also explore repurposing existing or retired coal plants with other emerging technologies and making more strategic generation investments to connect and use existing transmission whenever possible.

This strategy allows us to deliver exceptional system and energy value by minimizing the need for additional grid resource investments, which helps keep costs lower for our customers.

The System Strategies discussed in this section will guide SRP's planning activities and investment decisions in a way that balances all important considerations in developing a reliable, affordable and sustainable power system. Through robust analysis in the ISP, SRP developed a detailed understanding of the inherent trade-offs between reliability, affordability and sustainability and sought to establish an Integrated System Plan that fully balances all considerations.

It is important to reiterate that none of the System Strategies above can stand on their own. These strategies are intertwined and need to be executed simultaneously to best serve our customers and ensure that we will continue to provide reliable, affordable and sustainable power regardless of what the future brings.

SECTION 8

Balanced System Plan

Balanced System Plan

The ISP Balanced System Plan is an illustration of what SRP's power system may look like in 2035 by implementing the seven System Strategies. We constructed the **Balanced System Plan** to help customers and stakeholders visualize the future power system based on what is known today. However, as discussed in previous sections, the entire utility industry faces a lot of change and uncertainty. As a result, we will inevitably need to adapt and evolve this plan as new information (e.g., updated economic development forecasts and technology cost projections) becomes available and as circumstances change, such as new laws or regulations being enacted.

Developing the Balanced System Plan

The ISP System Strategies detailed in Section 7 are the foundation for the Balanced System Plan. To identify how the system could evolve in a manner consistent with the System Strategies, SRP leveraged the results and key findings from the ISP analysis.

Of the strategic approaches analyzed, it was clear that no individual strategic approach performed best across all metrics. For example, the Technology Neutral strategic approach resulted in the lowest system cost and lowest residential customer bill impacts, whereas the Minimum Coal strategic approach performed best across multiple sustainability metrics. Separately, results from the ISP residential customer research found that customers want it all. They want SRP to advance sustainability performance while maintaining high levels of reliability and limiting cost increases.

In building out the Balanced System Plan, we considered the results of the various analyses, findings from the different strategic approaches and feedback from our customers to strike a balance between sustainability, affordability and various power system reliability risks.

Specific considerations used in developing the Balanced System Plan included the following goals:

- **Reliability:** Maintain firm generation capacity and expand grid needs while preparing for emerging grid technologies.
- **Affordability:** Utilize an all-of-the-above approach to diversify and moderate the pace of investments.
- **Sustainability:** Significantly expand investments in renewable energy and storage to drive carbon reductions and reduce water consumption.
- **Customer Focus:** Focus on managing costs and advancing sustainability and customer programs without sacrificing reliability.

FIGURE 8.1: GOALS OF THE BALANCED SYSTEM PLAN

Reliability

Maintain firm generation capacity and expand grid needs, while preparing for emerging grid technologies

Affordability

Utilize an all-of the-above approach to diversify and moderate pace of investments

Sustainability

Significantly expand renewable and storage development to drive emissions reductions and reduce water consumption from power generation

Customer Focus

Focus on managing costs, advancing sustainability and customer programs without sacrificing reliability

Resources and Customer Programs

The Balanced System Plan envisions significant resource additions between 2025 and 2035. By implementing the Energy Investment System Strategy, SRP could triple the total installed capacity of renewable and storage resources by 2035. Solar, being a low-cost renewable resource that helps displace fossil fuel generation, makes up the majority of the renewable energy additions in the Balanced System Plan, with 6,000 MW added. Other renewable additions include 800 MW of wind located in eastern Arizona to leverage existing transmission that becomes available when Coronado Generating Station retires in 2032, as well as 50 MW of geothermal and 50 MW of biomass to help provide resource diversity. The Balanced System Plan also includes 2,500 MW of additional energy storage, split between four-hour lithium-ion batteries and pumped hydro storage.

By implementing the Capacity Investment System Strategy, SRP would maintain similar levels of thermal generation as today to provide firm capacity. This includes investing in 2,000 MW of new natural gas generation to replace 1,300 MW of retiring coal generation and a 975 MW gas tolling agreement that expires in 2031. We did not include advanced nuclear or hydrogen in the Balanced System Plan due to development risks with those technologies becoming commercially available by 2035.

In addition to the utility-scale resource additions, the Balanced System Plan includes customer programs and customer-sited resources, which will help displace the need for utility-scale resources. Specifically, the Balanced System Plan envisions 700 MW of combined capacity from energy efficiency and demand response (labeled Customer Programs in figures 8.2 and 8.3) as well as 750 MW of customer-sited solar, demonstrating SRP's implementation of the Evolution of Customer Programs & Pricing System Strategy. While the Balanced System Plan does not reflect changes to customer pricing over time, SRP's evolution of price plans can help further mitigate resource additions by providing price signals to customers to moderate their demand during periods of lower supply.

FIGURE 8.2: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY 2025-2035

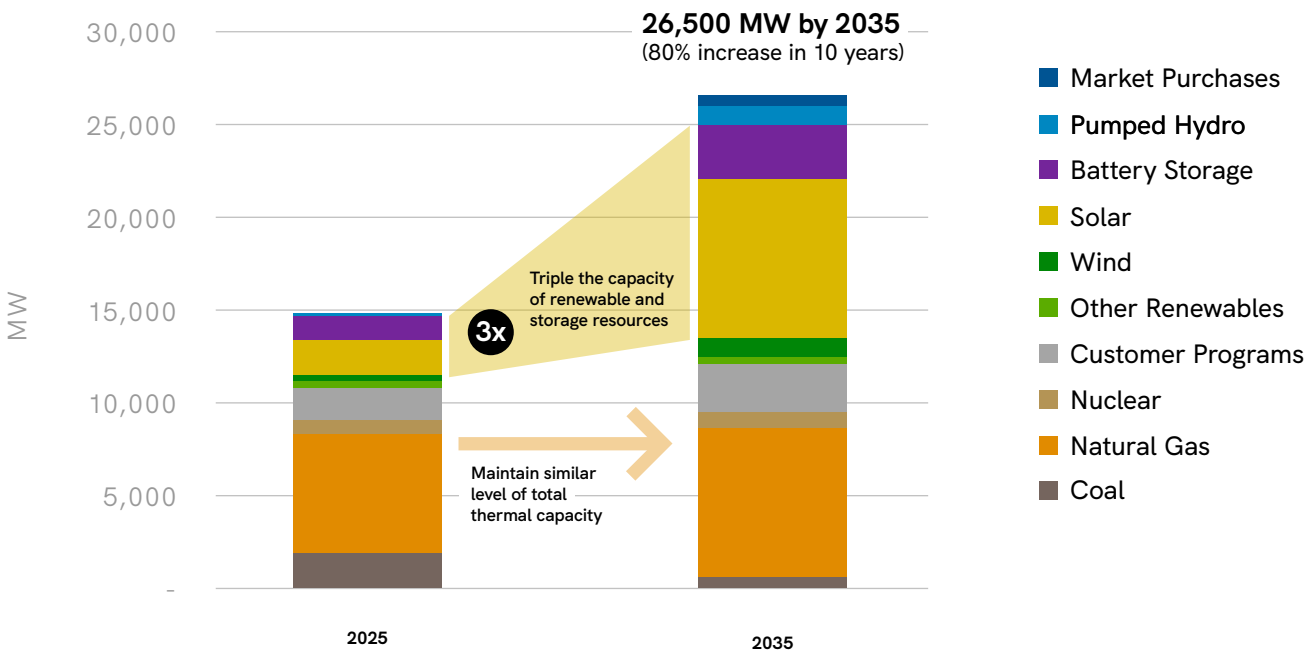


FIGURE 8.3: BALANCED SYSTEM PLAN NAMEPLATE CAPACITY ADDITIONS BY 2035 (MW)

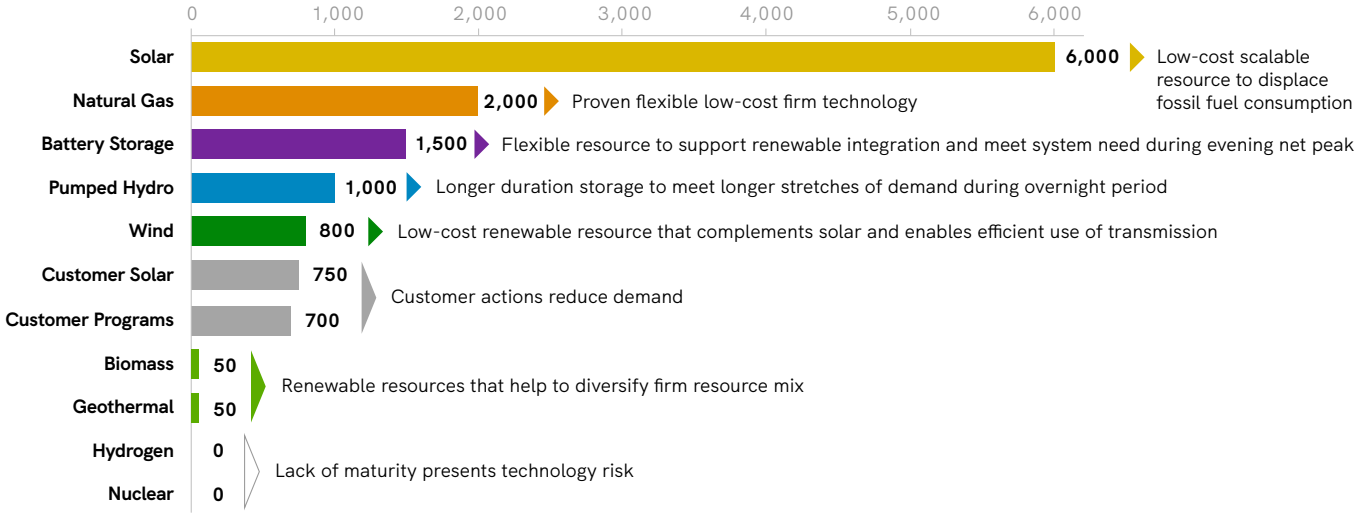
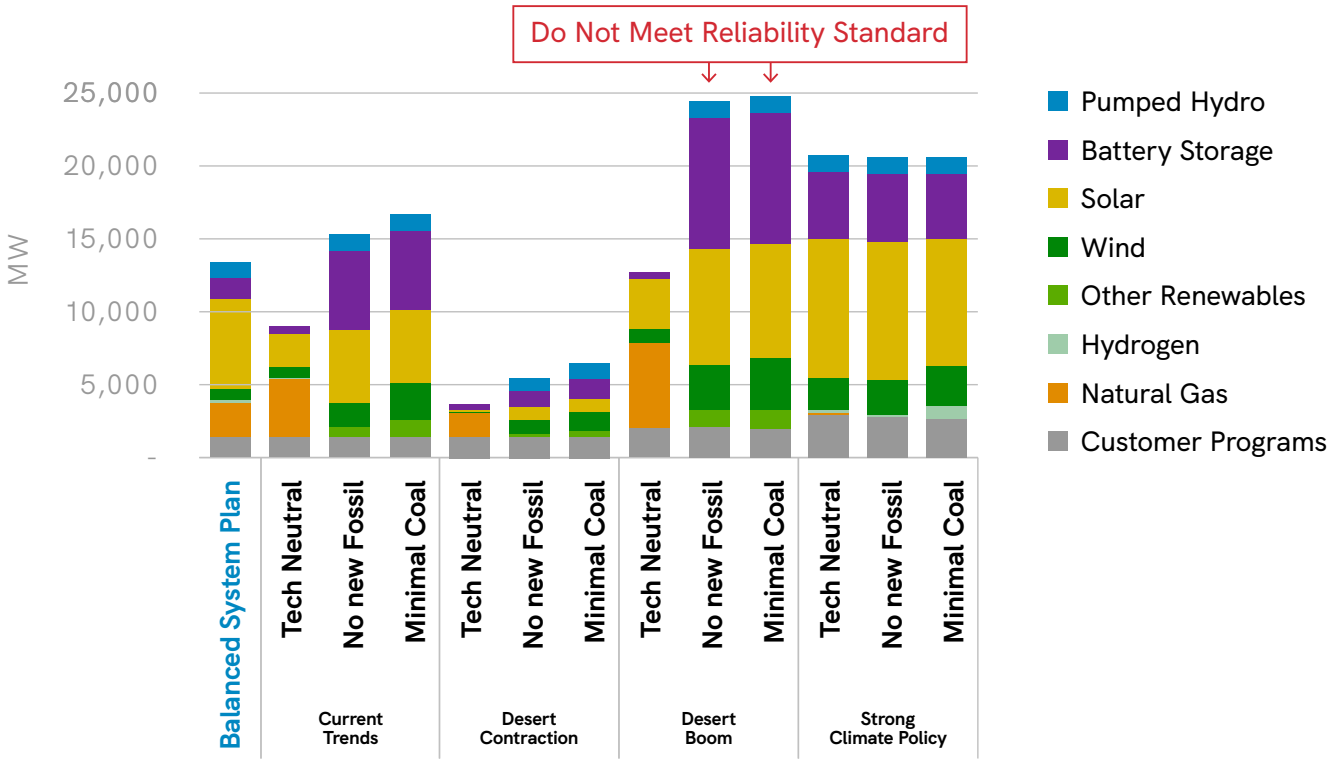


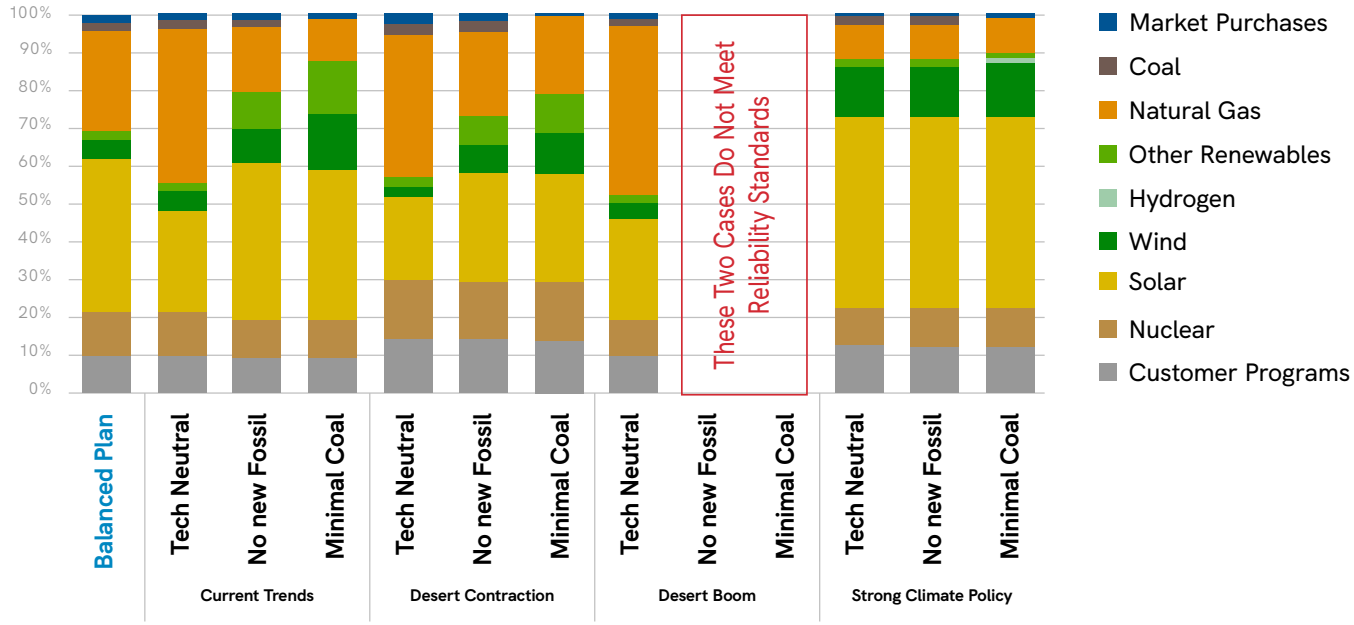
Figure 8.4 shows the nameplate capacity additions for the Balanced System Plan alongside those for the ISP cases for comparison. While we considered the full range of scenario analysis when constructing the Balanced System Plan, we used the Current Trends scenario assumptions to illustrate specific infrastructure requirements. In comparison to the other system plans under the Current Trends scenario, the Balanced System Plan includes approximately 6,000 MW of additional carbon-free resources and over 1,000 MW less gas than the Technology Neutral strategic approach (i.e., least-cost system). Natural gas is still included in the Balanced System Plan to help mitigate costs, unlike the No New Fossil and Minimum Coal strategic approaches, which were found to be considerably more expensive with natural gas not being included in the strategic approach assumptions. The Balanced System Plan thus results in less carbon-free resource additions compared to the No New Fossil and Minimum Coal cases in the Current Trends scenario.

FIGURE 8.4: NAMEPLATE CAPACITY ADDITIONS BY 2035



On an energy basis, for the Balanced System Plan, 70% of SRP's customer energy needs would come from carbon-free sources, which is in the middle of the range when compared to the other Current Trends scenario system plans, as shown in Figure 8.5.

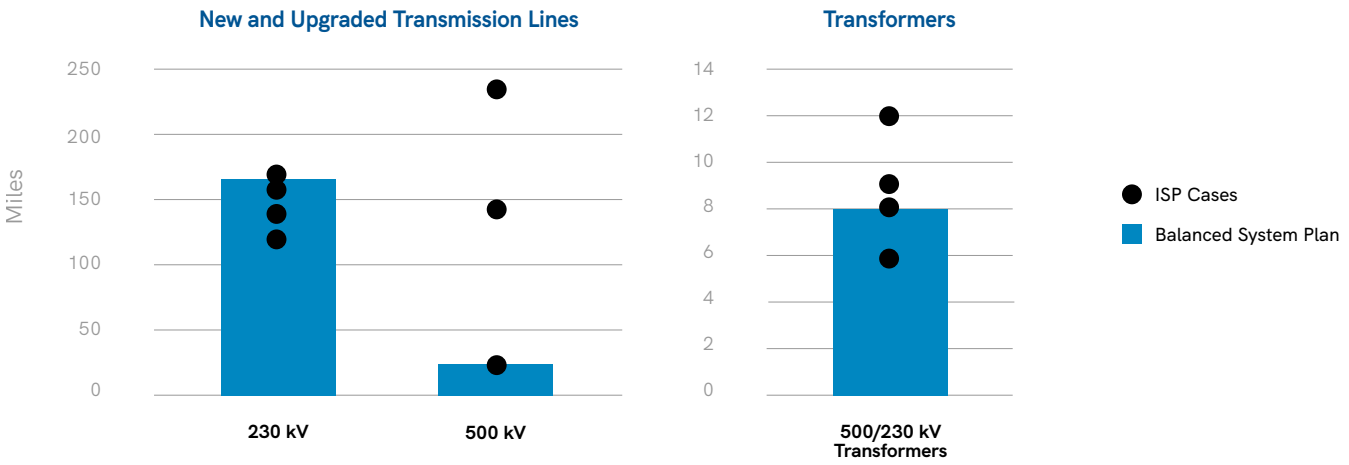
FIGURE 8.5: ENERGY MIX IN 2035



Transmission

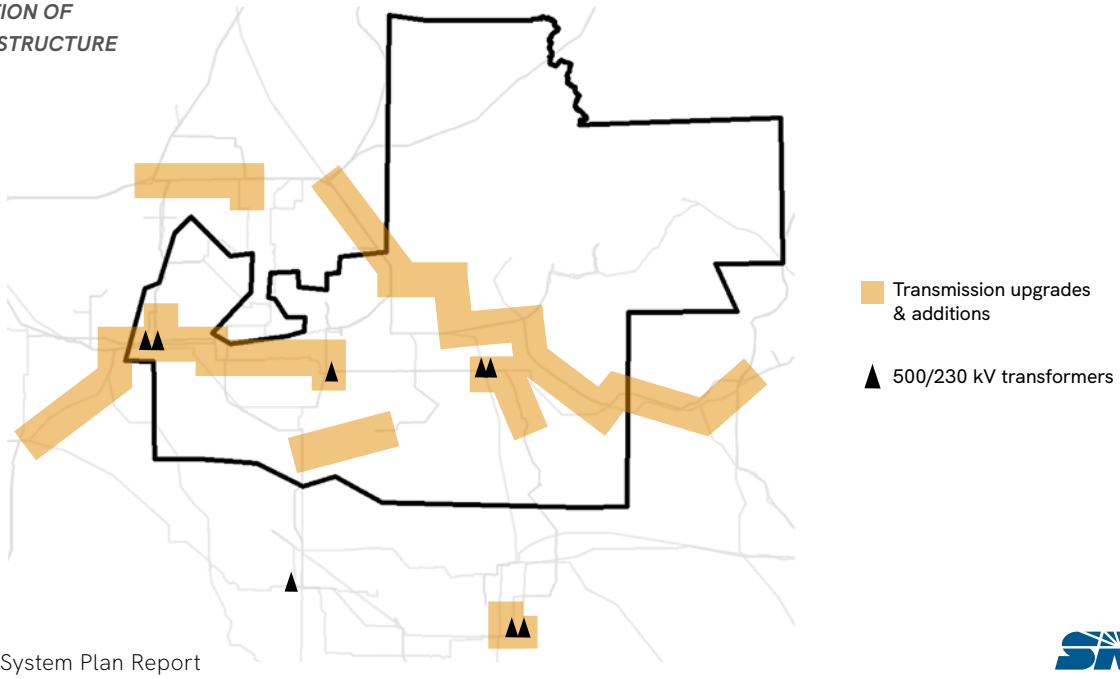
To connect the significant amount of new generation resources included in the Balanced System Plan to our customers, additional high-voltage transmission infrastructure would be needed at both the 500 kV and 230 kV levels. The additional transmission needs for the Balanced System Plan compared to the scenario-based system plans analyzed are shown in Figure 8.6. As detailed in Section 5, we evaluated two different location sensitivities for where the generation resources would be located (Pro-Rata and Hub). For the Balanced System Plan, we utilized a hybrid approach where resources were distributed across the transmission system, but certain areas that required significant upgrades were avoided. This resulted in 165 miles of new or upgraded 230 kV lines, 25 miles of new or upgraded 500 kV lines, and eight new 500/230 kV transformers by 2035. The long lead times for siting, permitting and procuring this transmission infrastructure emphasize the need to implement the Proactive Transmission System Strategy.

FIGURE 8.6: TRANSMISSION SYSTEM ADDITIONS BY 2035



An illustration of where this new transmission infrastructure could be located, overlaid with SRP's electric service area, is included in Figure 8.7.

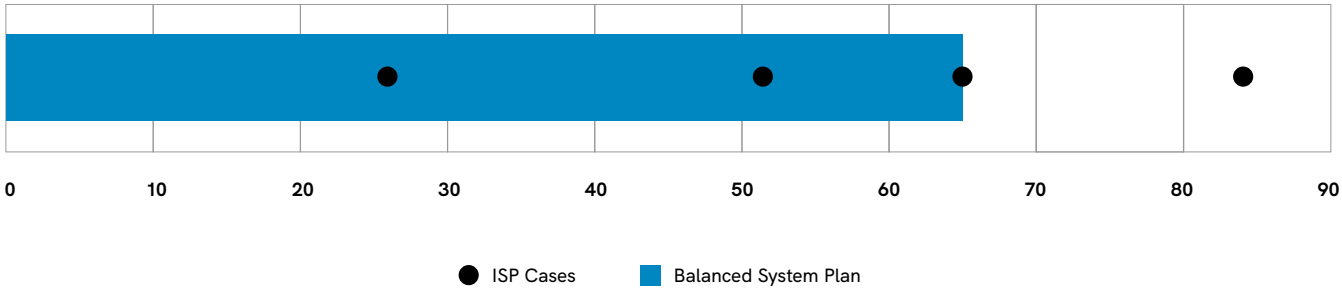
FIGURE 8.7: ILLUSTRATION OF TRANSMISSION INFRASTRUCTURE ADDITIONS



Distribution

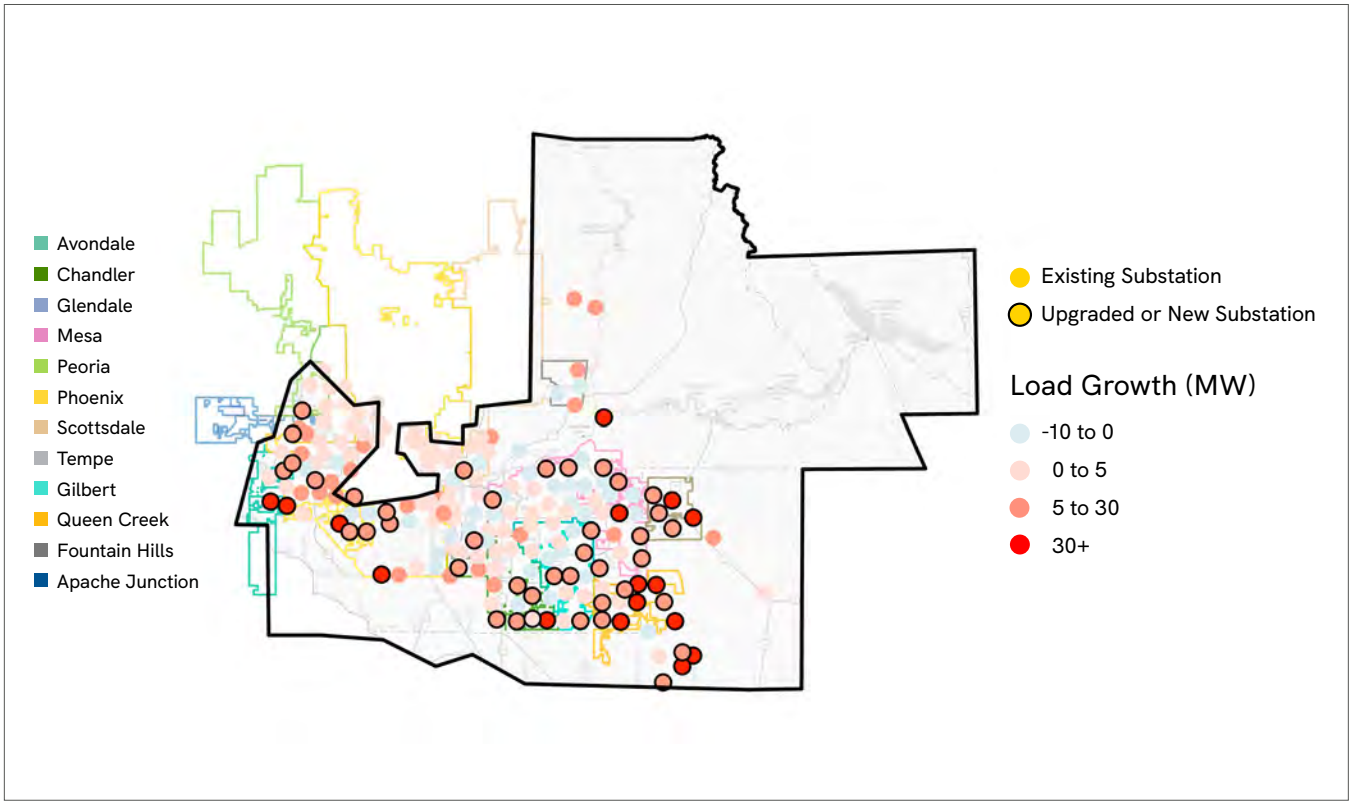
By implementing the Distribution Innovation System Strategy, SRP will need to add a number of additional distribution substation bays to ensure reliability. For the Balanced System Plan, this includes 65 additional substation bays to meet growing customer energy needs.

FIGURE 8.8: DISTRIBUTION SUBSTATION BAY ADDITIONS



We anticipated most of this substation bay addition will be located in the southeastern and western portion of the SRP electric service territory where there is the most potential for growth, as shown in Figure 8.9 below. However, additional substation bays will also be needed in central parts of SRP's electric service territory due to urbanization and growth in electric vehicles.

FIGURE 8.9: ILLUSTRATION OF DISTRIBUTION INFRASTRUCTURE ADDITIONS



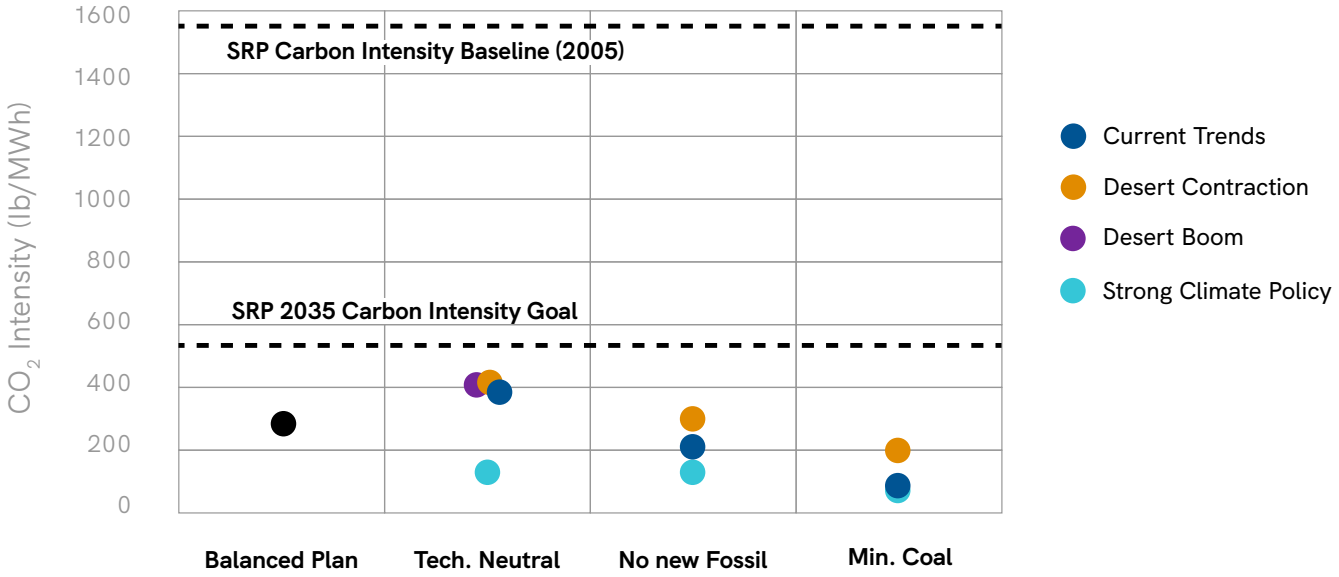
Balanced System Plan Performance

When developing the Balanced System Plan, we evaluated the plan's performance by quantifying the same metrics used to analyze each of the ISP cases. As noted earlier, we used findings from the ISP analysis and residential customer research to develop a system plan that advanced sustainability performance while avoiding significant cost increases to SRP and its customers. The following subsections discuss key metrics for the Balanced System Plan and show how it achieves this objective.

CO_2 Reductions

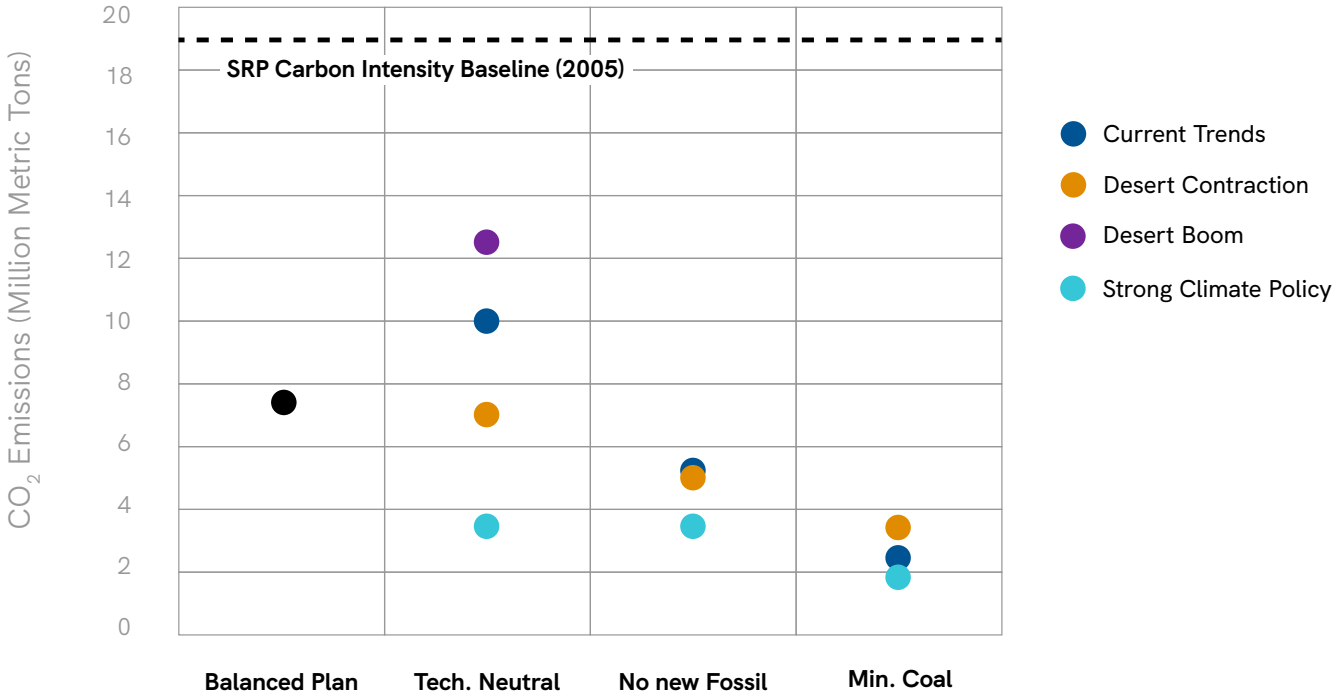
The CO_2 intensity and mass emissions for the Balanced System Plan in 2035 are included in figures 8.10 and 8.11, respectively, and are shown alongside the core system plans for comparison. The Balanced System Plan exceeds SRP's 2035 goal by achieving a CO_2 intensity rate of 284 lbs./MWh, an 82% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends scenario (the scenario used for the Balanced System Plan), the Balanced System Plan carbon intensity is 28% lower than that of the Technology Neutral strategic approach at 396 lbs./MWh but is not as low as that of the No New Fossil and Minimum Coal strategic approaches at 202 lbs./MWh and 94 lbs./MWh, respectively.

FIGURE 8.10: BALANCED SYSTEM PLAN CO_2 INTENSITY IN 2035



Similarly, for CO_2 mass emissions, the Balanced System Plan performs in the middle of the range when compared to the core system plans, with a CO_2 emission rate of 7.39 million metric tons in 2035. This is a 61% reduction from SRP's 2005 baseline. Compared to the system plans developed for the Current Trends cases, the Balanced System Plan achieves 25% lower carbon emissions than the Technology Neutral strategic approach (9.83 million metric tons) but not as low as the No New Fossil and Minimum Coal strategic approaches (5.11 million metric tons and 2.40 million metric tons, respectively), as shown in Figure 8.11 on the next page.

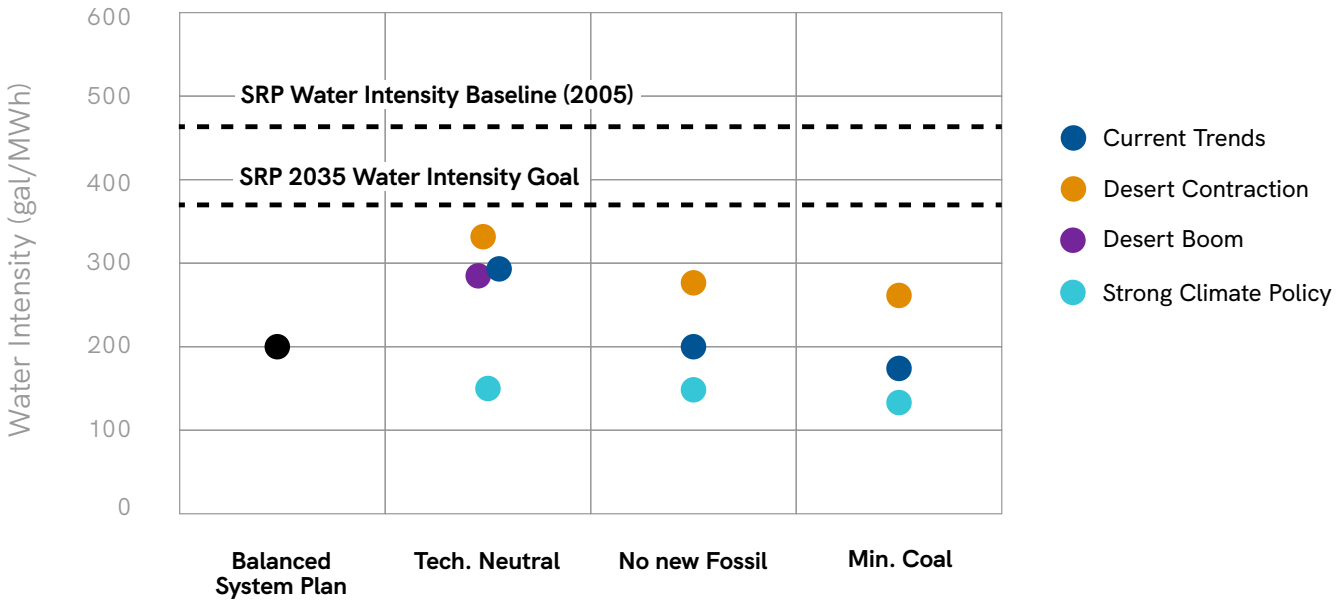
FIGURE 8.11: BALANCED SYSTEM PLAN CO_2 EMISSIONS IN 2035



Water Use

As shown in Figure 8.12, the Balanced System Plan also achieves a significant reduction in water consumption by 2035 with a water consumption rate of 204 gal/MWh (56% reduction from SRP's 2005 baseline levels), exceeding SRP's 2035 Sustainability Goal (20% reduction from 2005 baseline) and falling toward the lower end of the range of the core system plans analyzed in the ISP. Compared to the Current Trends cases, the Balanced System Plan achieves a 30% lower water consumption rate than the Technology Neutral strategic approach (293 gal/MWh), but not as low as the No New Fossil and Minimum Coal strategic approaches (199 gal/MWh and 171 gal/MWh, respectively).

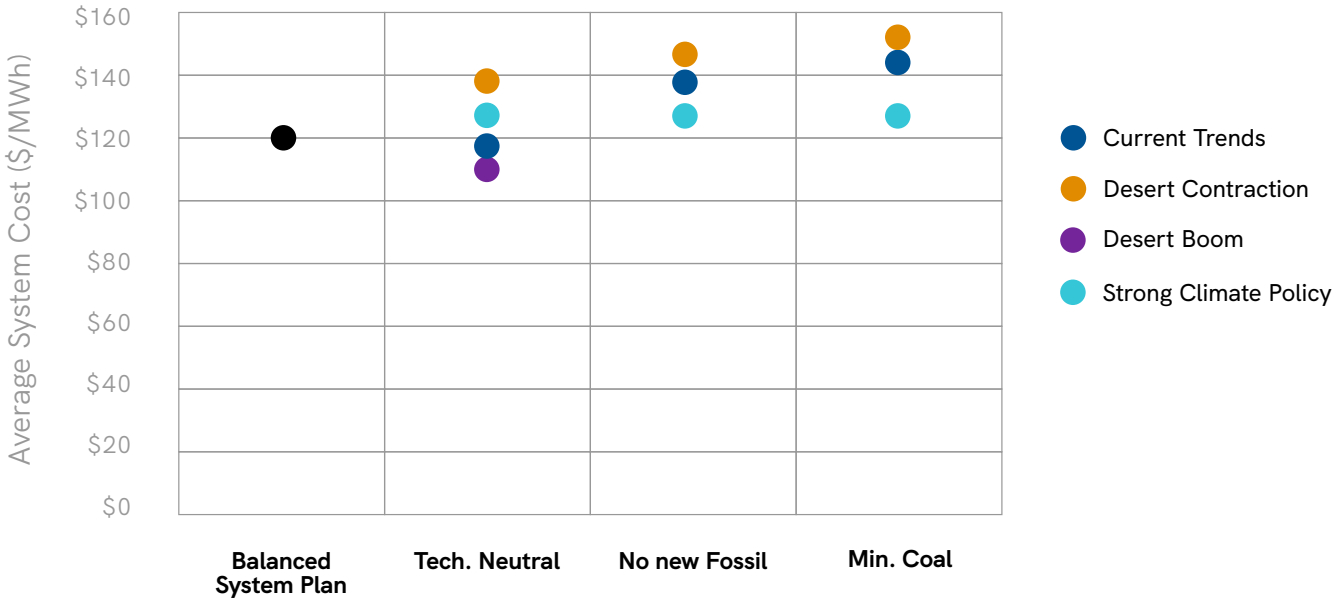
FIGURE 8.12: BALANCED SYSTEM PLAN WATER CONSUMPTION



Average System Cost

The average system cost for the Balanced System Plan, with comparisons to the core system plans from the ISP analysis, is shown in Figure 8.13. The Balanced System Plan results in an average system cost of $121/MWh, which is near the lower end of the range of costs observed from the ISP analysis. Compared to the Current Trends cases, the Balanced System Plan is only 4% higher than the Technology Neutral strategic approach ($116/MWh), despite adding more than double the amount of carbon-free resources and having a 28% lower carbon intensity. Meanwhile, the addition of 2,000 MW of firm natural gas in the Balanced System Plan allows the average system cost to be considerably lower than the No New Fossil and Minimum Coal strategic approaches ($136/MWh and $144/MWh, respectively).

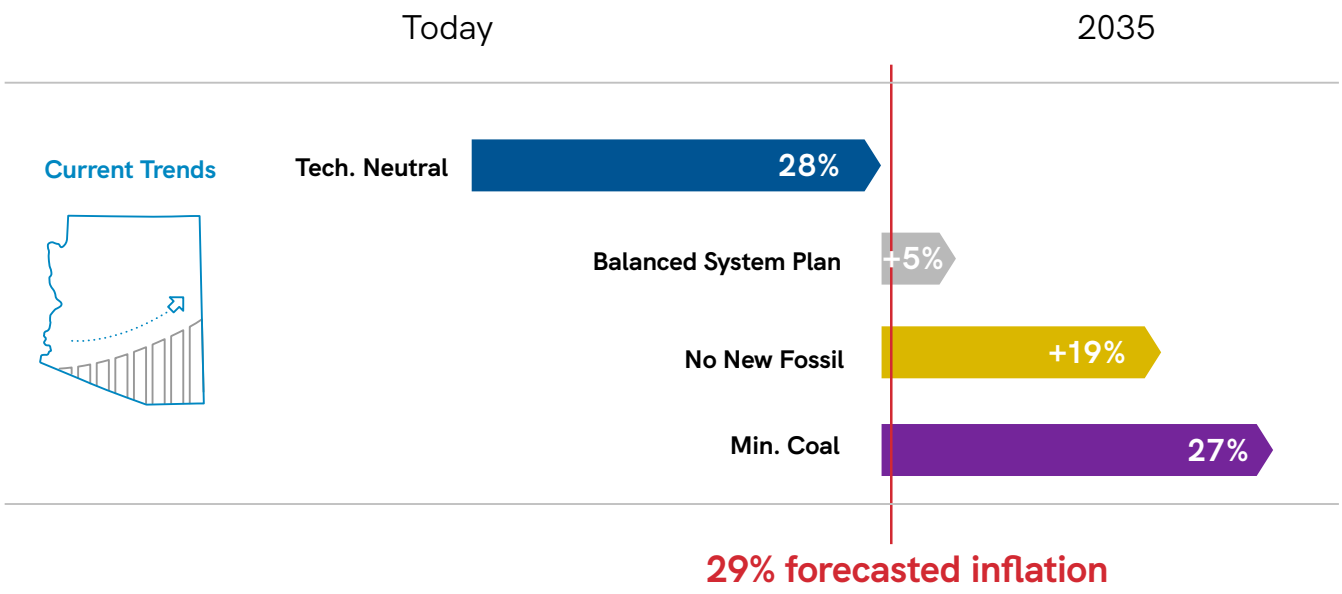
FIGURE 8.13: AVERAGE SYSTEM COSTS IN 2035 ($/MWH)



Residential Bill Impact

There are many factors that will impact costs in the future such as customer growth, inflation, the Inflation Reduction Act (IRA) funding and technology costs. Figure 8.14 shows the residential bill impacts for the Balanced System Plan compared to the other strategic approaches under the Current Trends scenario. This is a simplified look of what a base rate increase could look like in 2035, and we selected the Current Trends scenario because it reflects a central case for how the future might unfold. As shown in Section 6, the least-cost strategic approach, Technology Neutral, results in a price increase of 28% by 2035, just below inflation (estimated at 29% over the same time period). The Balanced System Plan results in a 5% increase in cost over the Technology Neutral strategic approach but is well below the residential price increases for the No New Fossil and Minimum Coal strategic approaches.

FIGURE 8.14: RESIDENTIAL PRICE INCREASE BY 2035



29% forecasted inflation

These are representative results based on ISP analysis modeling, not projections of SRP's future prices, and are not inclusive of factors beyond the scope of ISP analysis.

SECTION 9

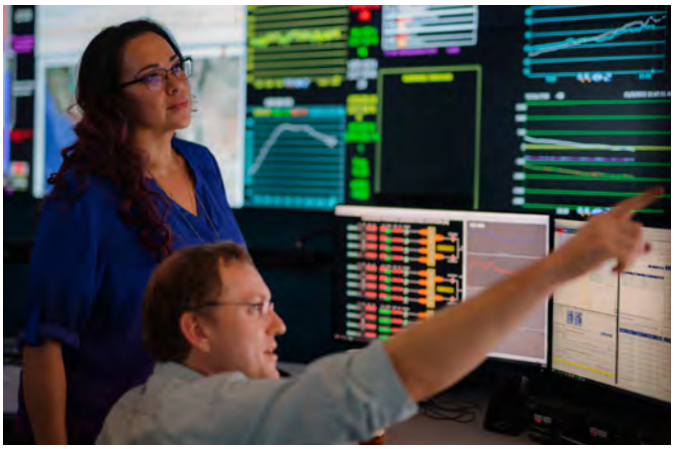
ISP Actions

ISP Actions

SRP's planning processes do not stop with the ISP. In many ways, the conclusion of this ISP represents new beginnings as our planning groups begin to execute the System Strategies. To further progress toward implementing the System Strategies, we have defined 10 ISP Actions that we will take over the next few years.

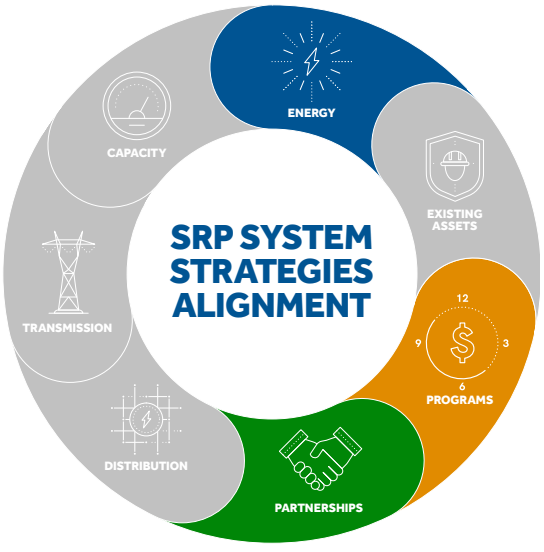
We developed the ISP Actions based on the ISP key findings, the System Strategies and the Balanced System Plan. They include actions for all aspects of system planning, including pricing, customer programs, customer resources, utility-scale resources, distribution and transmission. Just as the seven System Strategies are integrated and interdependent, so are the ISP Actions. Each action furthers multiple System Strategies and requires collaboration across our planning groups. In this section, we will describe each of the 10 **ISP Actions** and show how each one furthers specific System Strategies.

We are committed to pursuing diverse actions, establishing a roadmap for implementing the System Strategies and making progress toward our 2035 Sustainability Goals with the development of the ISP Actions.

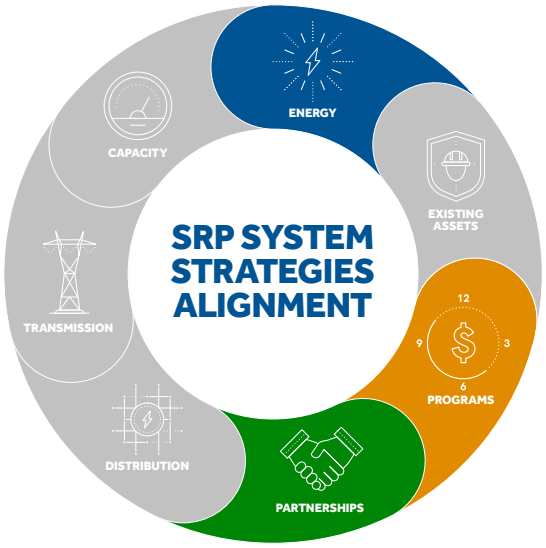


ISP Action #1: Residential Time-of-Use Pilot

We will execute a residential time-of-use price plan pilot and perform customer research to evaluate customers' responses to new time-of-use peak periods and a super off-peak period in the middle of the day, which will inform our load forecast for long-term system planning and our pricing process.



ISP Action #2: Time-of-Use Evolution



We will engage commercial, small business, large industrial, and residential customers and stakeholders to inform them of how the evolving grid will impact time-of-use periods and develop a roadmap for implementing new time-of-use periods.

To accomplish Action #2, we will:

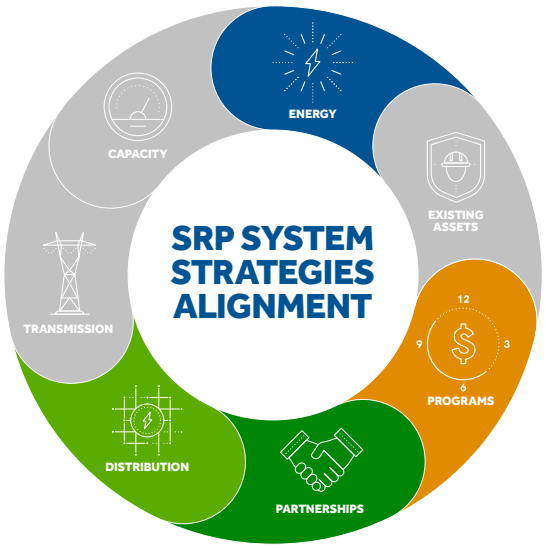
- Undertake a pricing process informed by the ISP to determine how time-of-use plans should evolve.
- Propose new time-of-use hours, including a super off-peak period when the cost to serve customers' needs is lowest and on-peak hours updated for the modern grid.
- Develop communication plans for all customer types and segments to educate about any new time-of-use price plans focusing on promoting affordability and potential sustainability benefits.

ISP Action #3: Customer Programs

We will continuously refresh program plans and take steps to drive participation in customer programs at levels consistent with those planned for in the ISP, representing a meaningful increase from our initial 2035 Sustainability Goal for Energy Efficiency.

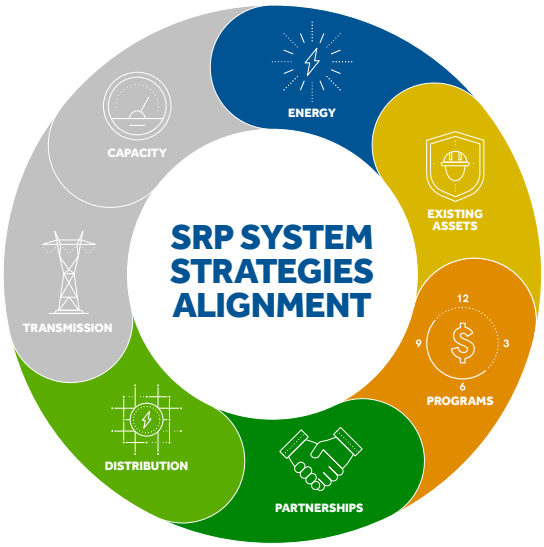
Steps will include:

- Evaluating the cost-effectiveness and emissions impacts of different customer program measures using the avoided costs and emissions impacts results from the ISP.
- Determining whether any changes to the customer programs portfolio are warranted based on this information, considering that these results must be weighed against other important factors such as customer access, equity, cost and satisfaction.



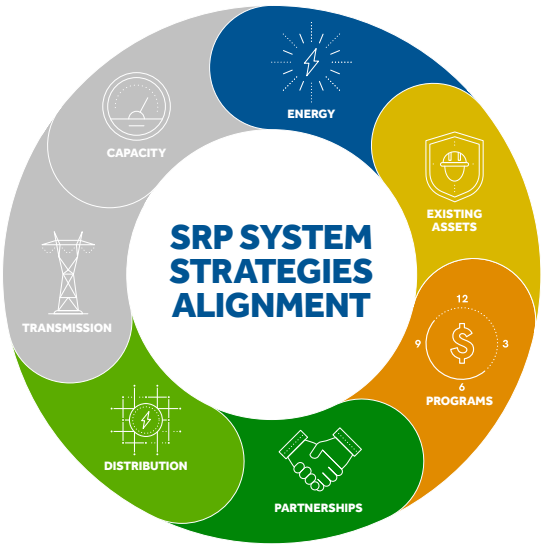
ISP Action #4: Electric Vehicle Management

We will develop an EV roadmap by evaluating customer needs and system impacts and assessing viable pathways for managing electric vehicle charging through price plans, customer programs and educational efforts to align with time periods that are lower-cost and minimize additional infrastructure needs.



ISP Action #5: Electrification

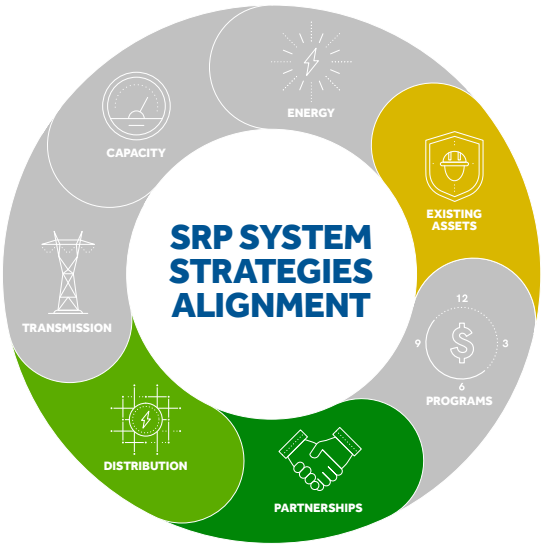
We will analyze the benefits and costs of non-EV electrification within SRP's service area, including effects on our operations and economywide emissions. Assess options for expanding E-Tech program offerings related to residential and commercial electrification.



ISP Action #6: Distribution Enablement Roadmap

We will continue implementing our Distribution Enablement (DE) Roadmap, which includes:

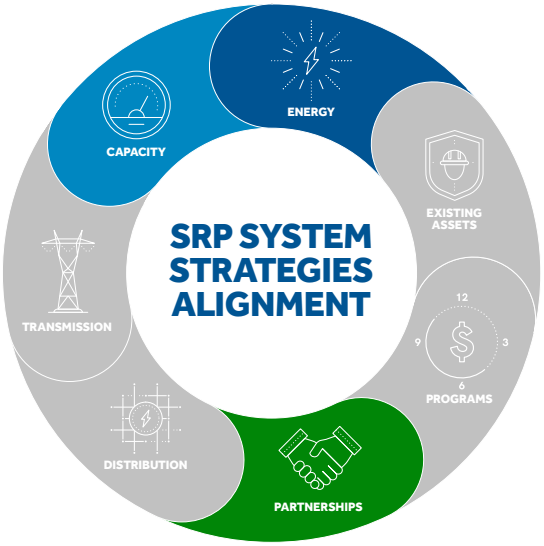
- Deploying the Advanced Distribution Management System (ADMS) and Distributed Energy Resources Management System (DERMS) in 2024. These systems are the foundational platforms needed to integrate distributed energy resources (DERs) with the existing distribution system. We will monitor signposts for the need to deploy more advanced capabilities to support the integration of customer-side resources.
- Implementing advanced planning tools, such as locational value maps and the ability to anticipate and plan solar, storage and electric vehicle adoption at specific customer locations.
- Advancing the interconnection process to enhance the customer experience and technical integration of customer-sited resource interconnections.



- Executing the DE Research and Development plan, which leverages R&D resources, including staff, lab facilities and standardized processes, to execute projects that will ensure readiness to onboard new distribution grid capabilities.
- Sharing the Distribution Enablement Roadmap with external stakeholders to build awareness and support for SRP's approach to transforming the distribution grid.

ISP Action #7: Resource Selection

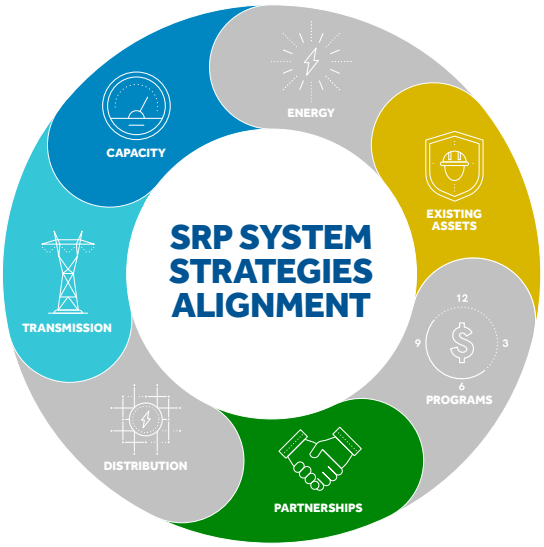
We will issue all-source requests for proposals (RFPs) or requests for information (RFIs) at least once every two years to compare with self-build options and ensure that we can agnostically select resource technologies that minimize total system costs while meeting our reliability and 2035 Sustainability Goals.



ISP Action #8: Coal Transition Action Plan

We will develop a coal repurposing action plan, which will include:

- Coordinating with co-owners to develop a path forward for the Springerville Generating Station, incorporating the need for replacement firm capacity to enable retirement and engagement with the community on a transition plan.
- Preparing plans for repurposing the Coronado Generating Station site, continuing development of system solutions that repurpose transmission following the retirement of coal plants.
- Developing solutions that preserve transmission access following the retirement of coal plants.
- Testing strategies for minimizing emissions from coal power plants, including dispatch strategies and seasonal operations, while leveraging their capacity to maintain reliability prior to retirement dates.

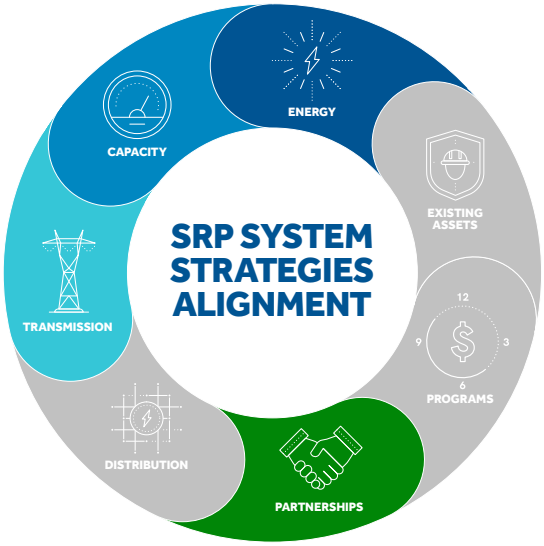


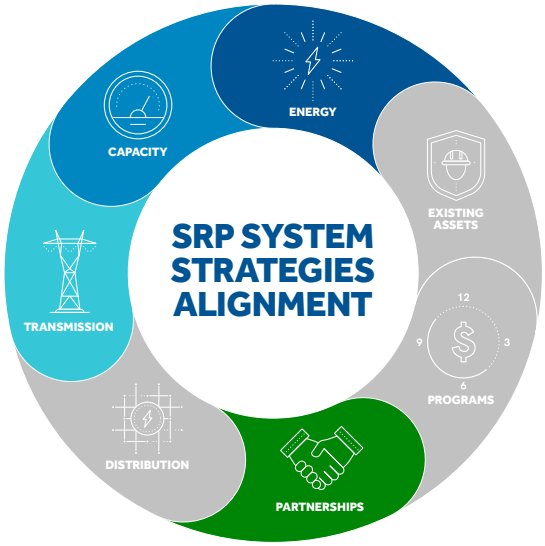
ISP Action #9: Proactive Siting

We will develop and initiate a collaborative community engagement, land, resources and transmission siting research process to proactively identify, prepare and preserve options for feasible sites for future system infrastructure.

ISP Action #10: Regional Transmission

We will pursue transmission projects to enable us to access diverse renewable resource options beyond solar, such as wind and geothermal, and engage with project developers as appropriate.





By implementing these 10 ISP Actions, we are confident that we can meet both the changing power needs of our growing customer base and evolving grid complexity. Many challenges lie ahead, but the actions related to customer programs, time-of-use price plans and EV management will help ensure our customers are provided with options to manage their energy costs while bolstering new clean energy technologies. Other ISP Actions related to phasing out coal resources, proactive siting and regional transmission flexibility will ensure SRP can provide sustained reliable power for the Valley while pursuing the best resource options for the future. These ISP Actions all work together to achieve a balance of reliability, affordability and sustainability for our future energy grid.

Future ISP Cycle and Next Steps

The first ISP was a significant advancement in our planning practices. For the first time, we performed integrated systemwide planning through 2035 and established a process for integrating planning activities across the organization. To continue to improve system planning practices and adapt plans to new information, we plan to complete an ISP on a regular cycle. We will continue to perform comprehensive systemwide modeling and engage SRP elected officials, customers and other stakeholders through a robust public process for future ISP cycles. While we have not yet established a schedule for the next ISP, we are targeting releasing an ISP every three to four years initially, recognizing that future ISP cycles may condense with technological and staff advancements.

SRP management and staff express appreciation for stakeholders and their participation in this first-ever Integrated System Plan process. Maintaining this open communication with customers and stakeholders will continue to produce a sound long-term strategic direction for future resources that balances system reliability, affordability and sustainability measures.

For more information and future updates on the progress of the ISP strategies and actions, refer to our website: srp.net/isp.

APPENDIX A

SRP's Integrated System Plan Assumptions Summary

SRP INTEGRATED SYSTEM PLAN STUDY PLAN APPENDIX – ASSUMPTIONS USED IN SCENARIOS, SENSITIVITIES AND STRATEGIC APPROACHES

This appendix details the assumptions underlying the key drivers outlined in the Integrated System Plan (ISP) Summary Study Plan document for the scenarios, sensitivities and strategic approaches that SRP will analyze. These assumptions were developed in collaboration with the ISP Advisory Group during the *Prepare* Phase of the ISP (November 2021–April 2022). SRP subsequently updated the assumptions in February 2023 to incorporate impacts from the Inflation Reduction Act of 2022. Additional details on these assumptions are included in the meeting materials from the *Advisory Modeling Subgroup Meeting 2: Inputs for the ISP Study Plan, Advisory Modeling Subgroup Meeting 3: Inputs for the ISP Study Plan – Part 2* and *Advisory Group Meeting 9: Continuing Forward*.[1]

Scenarios

Current Trends

Key Drivers	Assumptions
Economic Growth	Economic load grows 1,645 MW by 2035 and residential and commercial load grows by 1,776 MW by 2035, driven by an average population growth of 1.5% per year. The resulting total load growth is 2.9% per year.
Temperature Rise	"RCP[2] 4.5" climate scenario from the Intergovernmental Panel on Climate Change (IPCC)
Carbon Reduction Policy	No federal or state policy beyond SRP's 2035 Sustainability Goals (reduce the emissions intensity [CO2 per MWh] by 65% from 2005 levels by 2035)
Electrification	500,000 electric vehicles by 2035; 83% residential electric heating adoption by 2035
Distributed Generation	1,300 MW distributed solar by 2035
Energy Efficiency	3,800 GWh total energy efficiency by 2035
Renewable and Battery Storage Costs	Midpoint between low cost (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below)
Gas Resource Costs	Energy Information Administration 2022 Annual Energy Outlook (AEO)
Emerging Technology Availability	Carbon capture and sequestration (CCS) available in 2035. 100% hydrogen and nuclear (small modular reactors) are not available by 2035.
Emerging Technology Cost	Gas with CCS costs are midpoint between low costs (Strong Climate Policy Scenario) and high costs (Desert Contraction Scenario) (see below). 100% hydrogen and nuclear are not available by 2035.

[1] https://www.srpnet.com/grid-water-management/grid-management/integrated-system-plan
[2] Representative Concentration Pathway- RPC

Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from solar (blend between Arizona and Utah using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (blend between optimistic and conservative cost declines from California Energy Commission publication CEC-500-2019-055), hydrogen storage (using costs from Department of Energy project ST-001), and hydrogen transport (blend between AZ and UT transport costs, using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 85% monetization.
Gas Prices	Energy Information Administration (EIA) 2021 AEO "Reference" case regionalized based on SRP's gas supply
Hydro Availability	Hydro capacity and energy availability remain relatively constant at current drought conditions.
Market Support	Due to near-term capacity constraints, actions taken to contract maximum market capacity through 2032; afterwards 525 MW of market potential available.

Desert Boom

Key Drivers	Assumptions
Economic Growth	Economic development load grows by 2,900 MW by 2035 and population grows by an average rate of 1.8% per year.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	600,000 electric vehicles by 2035; 86% residential electric heating adoption by 2035
Distributed Generation	1,800 MW distributed solar by 2035
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	*Same as Current Trends*
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	*Same as Current Trends*
Hydrogen Prices	*Same as Current Trends*
Gas Prices	*Same as Current Trends*
Hydro Availability	*Same as Current Trends*
Market Support	*Same as Current Trends*

Desert Contraction

Key Drivers	Assumptions
Economic Growth	Economic development load growth rate peaks in 2026 before declining, resulting in a total of 597 MW added by 2035 compared to 2022. Population growth rate follows a similar trend, peaking in 2027 before declining. This results in an average population growth rate of 0.4% per year between 2023 and 2035.
Temperature Rise	"RCP 8.5" climate scenario from the IPCC
Carbon Reduction Policy	*Same as Current Trends*
Electrification	*Same as Current Trends*
Distributed Generation	*Same as Current Trends*
Energy Efficiency	*Same as Current Trends*
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act Investment Tax Credit (ITC) and Production Tax Credit (PTC) monetized at 80%.[3] Cost increases for solar (15%), wind (30%) and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[4]
Gas Resource Costs	*Same as Current Trends*
Emerging Technology Availability	*Same as Current Trends*
Emerging Technology Cost	Gas with CCS based on Energy Information Administration 2022 AEO +20%. 100% hydrogen and nuclear are not available by 2035.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from UT solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (conservative cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in UT (using costs from Department of Energy project ST-001) and hydrogen transport to AZ (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 80% monetization.
Gas Prices	*Same as Current Trends*
Hydro Availability	Glen Canyon Dam generation production is unavailable at the beginning of the study period (2025). Other hydrogeneration on the Colorado River and Salt River remain consistent with Current Trends assumptions.

[3] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[4] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

Market Support	Loss of Glen Canyon Dam and other hydrogeneration facilities in the West results in 0 MW of market support available. Existing market purchases currently contracted by SRP are honored.

Strong Climate Policy

Key Drivers	Assumptions
Economic Growth	*Same as Current Trends*
Temperature Rise	*Same as Current Trends*
Carbon Reduction Policy	Federal policy that requires a CO2 mass emissions (tons) reduction by 85% from 2005 level by 2035.
Electrification	Electric vehicle adoption consistent with reaching economy-wide net-zero emissions by 2050 (975,000 by 2035); 86% residential electric heating adoption by 2035
Distributed Generation	2,300 MW of distributed solar by 2035
Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
Renewable and Battery Storage Costs	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[5,6]. All near-term supply chain impacts are fully resolved by 2025.
Gas Resource Costs	Energy Information Administration 2022 AEO
Emerging Technology Availability	Gas with CCS available in 2030, 100% green hydrogen available in 2034, and nuclear (small modular reactors) available in 2034
Emerging Technology Cost	Energy Information Administration 2022 AEO. Inflation Reduction Act ITC applied to nuclear and 100% hydrogen, and CCS tax credit applied to gas with CCS all at 90% monetization.[4] 100% hydrogen unit based on frame combustion turbine.
Hydrogen Prices	Green hydrogen forecast developed by E3 using electricity production from AZ solar (using Renewable and Battery Storage Costs above), hydrogen production using alkaline electrolyzers (optimistic cost decline from California Energy Commission publication CEC-500-2019-055), hydrogen storage in AZ (using costs from Department of Energy project ST-001) and hydrogen transport (using Argonne's Hydrogen Delivery Scenario Analysis Model (HDSAM) tool). $3/kg hydrogen production tax credit from Inflation Reduction Act applied at 90% monetization.
Gas Prices	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Hydro Availability	*Same as Current Trends*

[5] ITC and PTC include *the base credit and 5x multiplier for satisfying wage and apprenticeship requirements. 90% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

[6] *Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach).*

Market Support	Favorable regional resource and load diversity allows for the potential for the wider region to carry slightly less total resource capacity while maintaining the same level of reliability. SRP assumes a regional coordination program and a regional diversity benefit and tests this assumption by reducing its Planning Reserve Margin requirement from 16% to 13%. Capacity (MW) market availability assumptions are consistent with Current Trends.

Sensitivities

Sensitivity	Assumptions
High Demand Response	Increased expansion in demand response over time, reaching 400 MW total Demand Response by 2035.
High Energy Efficiency	Federal codes, standards and incentives lead to higher energy efficiency growth, reaching 4,500 GWh total energy efficiency by 2035.
High Distributed Generation	Distributed solar and battery adoption reach 2,300 MW and 249 MW, respectively, by 2035.
Increased Load Management	Increased load flexibility through managed electric vehicle (EV) charging or other flexible loads. Modeled as a virtual battery addition with limitations on when it can charge or discharge.
Regional Diversity	Favorable regional resource and load diversity allows for the potential of a reduced loss of load probability on SRP's system. SRP tests this assumption by reducing the minimum Planning Reserve Margin requirement from 16% to 13%.
High Gas Price	EIA 2021 AEO "Low Oil and Gas Supply" case regionalized based on SRP's gas supply
Low Gas Price	EIA 2021 AEO "High Oil and Gas Supply" case regionalized based on SRP's gas supply
Volatile Gas Price	EIA 2021 AEO "Reference" gas regionalized based on SRP's gas supply, adjusted to reflect gas price volatility observed from 2000-2010
High Technology Cost	NREL 2022 ATB Market + Policy Conservative Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 80%.[7] Cost increases for solar (15%), wind (30%), and batteries (30%) added assuming existing supply chain challenges and trade friction worsen.[8]
Low Technology Cost	NREL 2022 ATB Market + Policy Moderate Scenario forecast. Inflation Reduction Act ITC and PTC monetized at 90%[9]. All near-term supply chain impacts are fully resolved by 2025.

[7] *Includes the base credit and 5x multiplier for satisfying prevailing wage and apprenticeship requirements. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). 80% reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

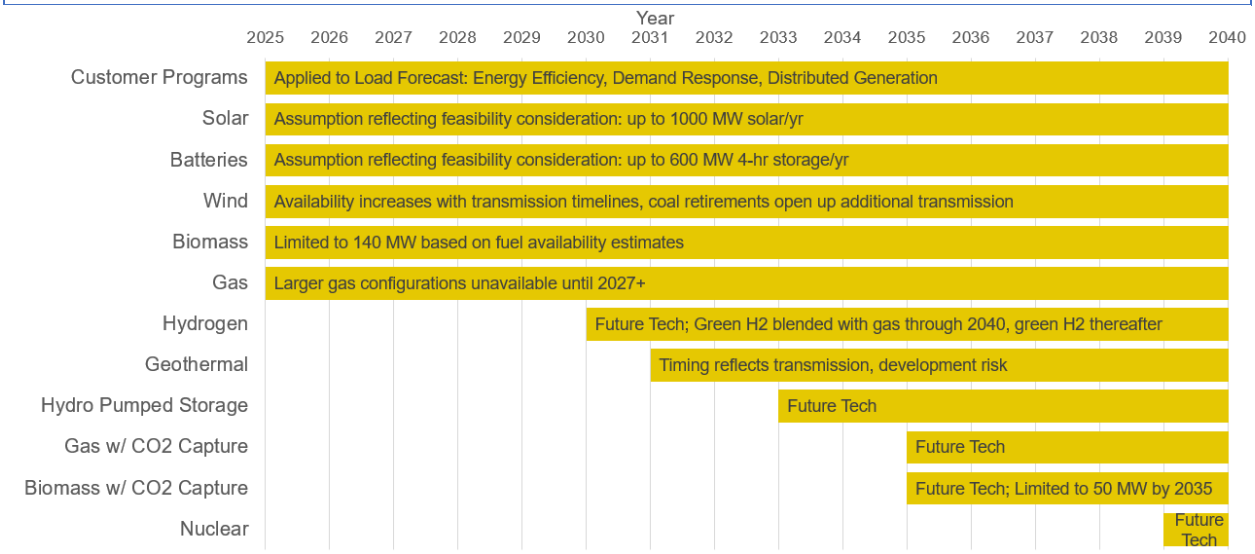
[8] *A smaller increase is made to solar as NREL's conservative scenario forecasts for solar already include adjustment to reflect trade frictions.*

[9] *Includes the base credit and 5x multiplier for satisfying wage and apprenticeship requirements for ITC and PTC. Includes the Energy Community bonus (+10%) for Arizona wind built after the retirement of Coronado (and Springerville in the Minimum Coal strategic approach). Monetization range reflects uncertainty in cost to monetize tax credits (e.g., profit margin for tax equity investor or transfer entity, transaction costs) and to satisfy applicable requirements (e.g., prevailing wage). Assumed phase-out post-2045.*

Strategic Approaches

Tech Neutral

Key Drivers	Assumptions
Technology Availability	All resource technologies available, limits based on technical feasibility availability of new resources (chart below). Strong Climate Policy Scenario includes accelerated availability dates for CO2 capture (2030), 100% green H2 (2034), and nuclear (2034).



No New Fossil

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies

Minimum Coal

Key Drivers	Assumptions
Technology Availability	New gas and gas w/CO2 capture are removed as available resource technologies
Coal Plant Operational Changes	Evaluates impacts from Coronado Generating Station Units 1 and 2 and Springerville Generating Station Unit 4 operating seasonally beginning in 2025 (off-line for three months of the year during non-peak periods) and SRP fully exiting coal by 4/30/2034.

Revision History

Revision	Date	Description
0	August 2022	Original
1	March 2023	Updated to incorporate impacts from the Inflation Reduction Act into technology costs.
2	April 2023	Corrected understated High DG sensitivity assumption and economic growth assumption in the Desert Boom scenario.

APPENDIX B

SRP Customer Research Future of Energy Phases 1 & 2 Report

Future of Energy

Phase I & II Report

June 30, 2022

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

www.bellomy.com

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Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from customers.

Looking into the future, SRP expects there to be many disruptions to the energy industry with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perspectives on this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about sustainability, affordability, and reliability related to power provision and gauge their reactions to a potential energy plan. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement with SRP on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach is being applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and a choice exercise (planned for Fall 2022). This report addresses Phase I and Phase II.

All customers included in the research were SRP residential customers, energy decision makers, who did not work for a competing industry, and were over 18 years old.

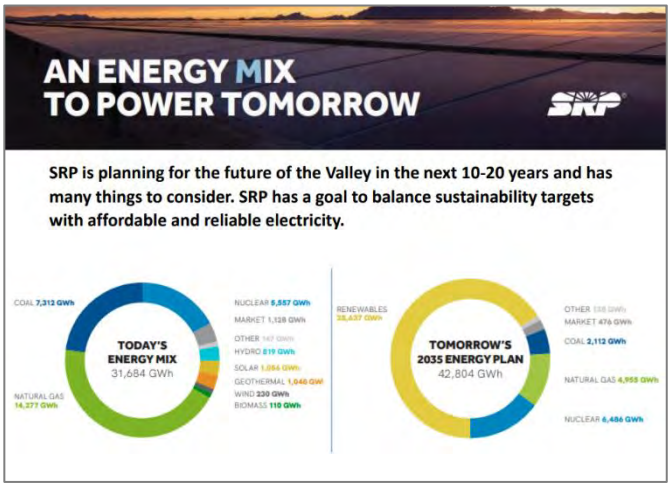
Phase I: Virtual Focus Groups

Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and extract observations.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.



Customers evaluated SRP's proposed energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. Customers were provided background on SRP's priorities.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more)
- **Gender** (Male/ Female)
- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (Preferred/ New Customer/ Satisfactory/Slow/Unsatisfactory)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary

The illustrative plan was rated positively

Most customers reacted positively to the energy plan while a quarter felt it was excellent. Additionally, a majority expressed positive perceptions of SRP and cited outstanding customer service and reliability as reasons for this.

Affordability & reliability were top priorities for the future

Affordability was one of the most-selected future issues facing Arizona and customers felt that affordability should be prioritized.

Both affordability and reliability surpassed sustainability in importance. Customers noted that sustainable electricity was meaningless if not affordable and reliable, especially with rising inflation and increased usage during the Arizona summer heat.

- SRP might increase energy plan acceptance by anticipating and addressing questions on affordability and reliability.

A majority agreed SRP should prioritize the illustrative energy plan

Further, about half felt the plan fit with SRP's brand, was easy to understand, and seemed achievable. Customers reflected that the plan could be improved by providing more details on how it would be achieved and its impacts on affordability.

Respondents also hoped to ensure that SRP selected the best sources of electricity, though opinions on what sources were best varied. Customers were unclear on which sources of electricity SRP would use.

- Emphasizing transparency with customers as SRP solidifies energy sources, including cost impacts, may bolster trust.

Customers wanted to continue to hear about ways to save from SRP

Customers exhibited strong positive feedback on the benefits and effectiveness of SRP's cost saving offerings.

Customers most wanted to hear more about programs that can help them save money, including rebates and energy efficiency programs, which aligned with affordability priorities.

- Continuing to showcase and optimize offerings geared towards energy and cost savings may increase enrollment and contribute to positive overall perceptions of SRP.

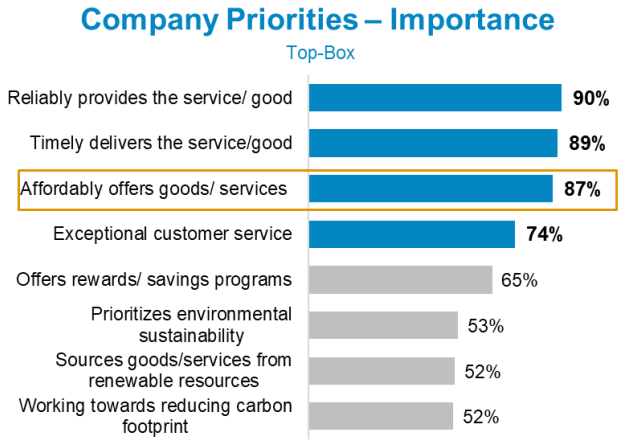
Detailed Findings

Future Issues and Priorities

Customers demonstrated affordability concerns

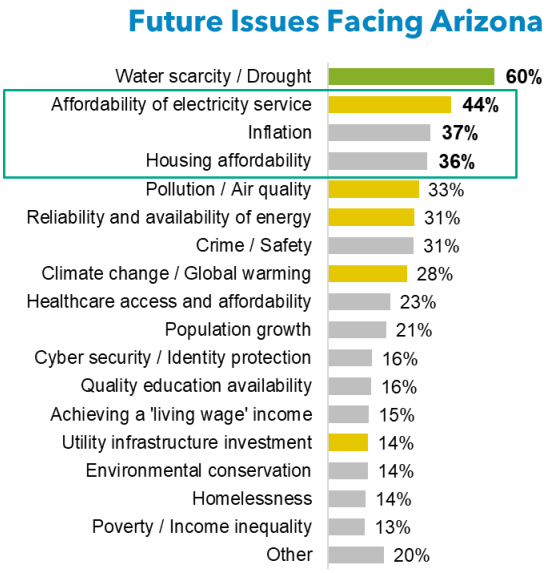
Affordability was rated as a top need for companies to prioritize in the future, with nearly 9 in 10 believing it was important for companies to prioritize the need.

This accompanied reliably providing goods and services, and providing them in a timely manner.



Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

- The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by several items SRP is most able to impact related to pollution, energy reliability, and climate change (highlighted in yellow).
- Lower income customers (earning under $75k/year) reflected greater concern for affordability.



- *Year-round residents are more likely to prioritize housing affordability.*
- *Those with a household income of $75k or more were more likely to prioritize water scarcity but were less likely to prioritize housing affordability.*
- *Non-Hispanic customers were more likely to prioritize water scarcity.*

Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

*Groups **more likely** to be concerned about others' ability to pay their electric bill include:*

- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Similar concerns were seen across top issues

When asked to rank selected issues on importance, rankings mostly mirrored the most-selected future issues facing Arizona. Customers were most likely to rank the following first: Water scarcity (22%), Inflation (13%), Housing affordability (10%), Affordability of electricity (9%)

- *Younger customers (aged 18-44), those with a household income under $75k, females, and Hispanic customers were more likely to rank housing affordability first.*
- *Non-Hispanic customers were more likely to rank water scarcity first.*

Customers mentioned population growth/city sprawl and rising prices added to their concern about top-ranked Issues.

Ranked 1st: Water Scarcity/Drought

*"**Having enough water to sustain the millions of people within the state.** And the temperature increase due to global warming coupled with heat island effects from Phoenix and Tucson sprawl." – Survey Respondent*

Ranked 2nd: Inflation

*"Population growth and cost of living. Being senior citizen on set income inflation has hit hard, **gas prices and growing energy prices concern me**." – Survey Respondent*

Ranked 3rd: Housing Affordability/ Availability

*"**The housing prices are going up but the pay in work is not**, who makes 3x the rent anymore. Nobody and it's ridiculous." – Survey Respondent*

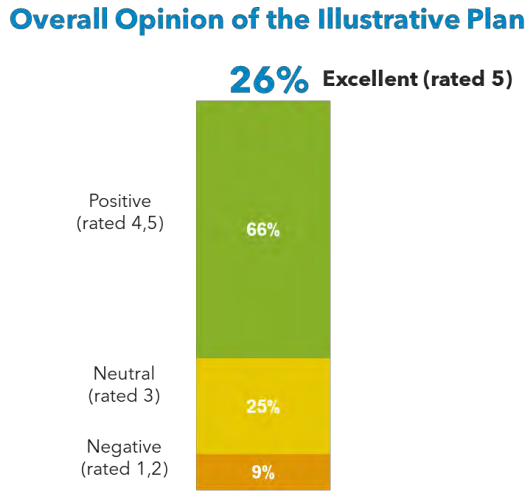
Ranked 4th: Affordability of Electricity Service

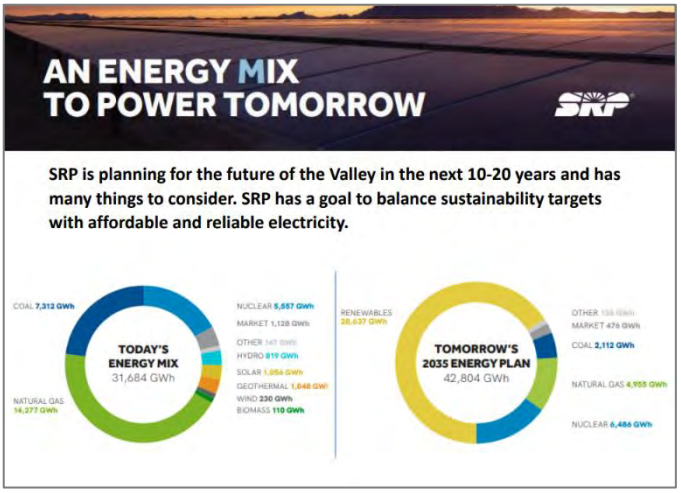
*"**Providing the uninterrupted service at an affordable price** for the growing population, taking inflation into consideration." – Survey Respondent*

SRP Energy Plan

Two thirds rated the energy plan positively

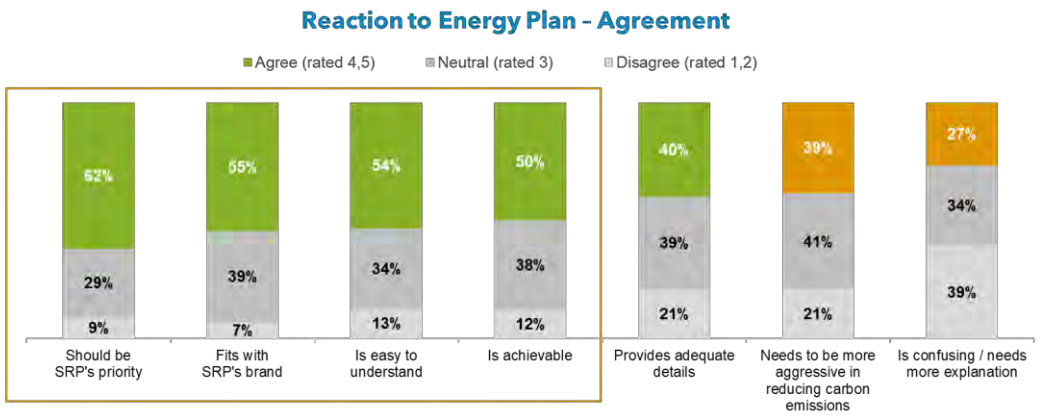
When evaluating SRP's energy plan, one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.





- *Those ranking sustainability first had a more positive impression of the energy plan.*
- *Those with high electricity usage were less likely to rate the plan positively.*

Additionally, at least half agreed the plan should be SRP's priority (62%), fit with the brand (55%), is easy to understand (54%), and is achievable (50%).



- *Year-round residents were more likely to agree that the plan is achievable, fits with the SRP brand, is easy to understand, and provides adequate details.*
- *Customers with a household income under $75k and Hispanic customers were more likely to agree the plan fits with SRP's brand.*

Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
  *"**Renewable energy is fine, but solar and wind require lots of area to house enough energy to power cities.** Still have to maintain natural gas…and some coal. Nuclear power is the way to go, folks." – Survey Respondent*

- Nineteen percent (19%) shared affordability and cost concerns.
  *"I like the direction of the plan **but have my doubts that SRP will follow through on this plan in a way that is still affordable**." – Survey Respondent*

- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.
  *"How long will it take to achieve this? **Needs to be sooner rather than later**." – Survey Respondent*

  *"I don't view it as a plan. Rather strategic long-term objectives. **What is the road map to achieve, timing phases, costs, resources in the land?**" – Survey Respondent*

One-quarter (22%) felt that SRP should prioritize another goal (not already stated in the energy plan) and emphasized thoughts on specific energy sources.

*"**I did not see water conservation listed**, although I know it is on the SRP agenda." – Survey Respondent*

*"**Nuclear power is in my view, the only way forward**, renewable, wind, solar are efforts in futility. Sounds good to a few but a majority know better." – Survey Respondent*

*"**Making solar more affordable to the population**. This would increase the power grid, creating a partnership with the community. Making it more enticing for consumers to provide SRP with power." – Survey Respondent*

*"**Include hydrogen power** for vehicles in use." – Survey Respondent*

*"Since Arizona is a very hot state. **I believe solar panels would be excellent for SRP.** That should be the number one priority for SRP." – Survey Respondent*

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

> *"Accelerate.* ***I want to see the short-term goals.*** *What, specifically, are we doing right now?" – Customer Focus Group Participant*

> *"****I feel like if we can reduce how much coal and other sources that we use at the moment****… So, if this is the company's goal and they want to focus on that, then I would be all for it." – Customer Focus Group Participant*

> *"****Why is it going to take us another 30 years*** *when I've gone to professional developments thrown by SRP about using renewable resources and whatnot?…I like that it's out there and that you have it projected. I also wish that you could be like the Lego corporation and be 100% renewable 20 years before your said date." – Customer Focus Group Participant*

> *"The thing that immediately stuck in my brain is the "Oh, solar isn't available 24 hours." And that's a really old talking point. And it's also not necessarily true anymore…So,* ***I feel like some of the messaging is based on talking points that are out of date and not necessarily forward-thinking****." – Customer Focus Group Participant*

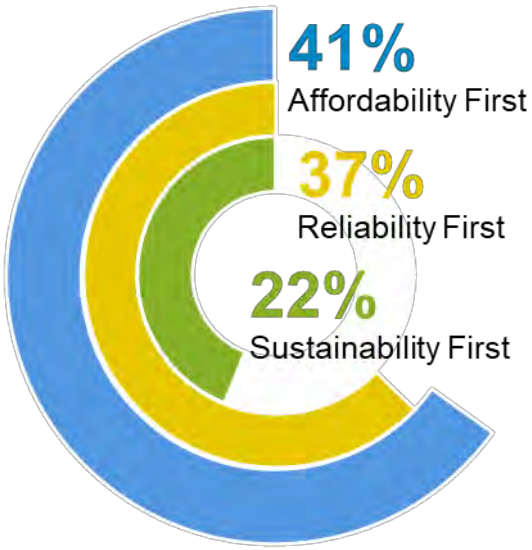
> *"****It's kind of curious why it would take so long to get more solar.*** *I mean, we're in the Valley of the Sun." – Customer Focus Group Participant*

> *"****I wonder how they could include in there something to do with conserving energy, wiser use****. I mean, I know there's been a lot of improvement like in the effectiveness of AC, with LEDs, and stuff like that. It would just be helpful…to consider the conserving side of it. And also, I wonder if the time has come to include in that chart an energy generated from the home, solar panels, whatever, like that. Because most of the people looking at the chart are homeowners like us." – Customer Focus Group Participant*

> *"What does all of this mean? And then, of course,* ***the financial piece of it, just like, okay, how would that even work, honestly, with thinking of all of it?*** *Like what could I do now to make a change? How is that going to develop over the years, just what that would all even look like?" – Customer Focus Group Participant*

Affordability and reliability were most ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, two-fifths (41%) ranked affordability first, with 37% prioritizing reliability, and only 22% prioritizing sustainability.



In the focus groups, while a majority of customers ranked reliability first , they discussed a tough tradeoff between reliability and affordability

> *"If it's not on, it doesn't work, right? It doesn't matter what you spend. Again, we all have budgets, and we all try to stay within them." – Customer Focus Group Participant*

When asked reasons for ranking affordability, reliability, and sustainability as they did, customers responded as follows:

Affordability: Reasons Ranked First

23% Mentioned keeping energy costs down, the rising cost of living, and/or that if electricity isn't affordable, other priorities are meaningless.

*"I only have so much money, and already have seen enough scenarios where **people can't afford to run their air conditioning in summer due to costs**. I have been in valley 23 years and that's an issue every year." – Survey Respondent*

- *Both those with a satisfactory/low/unsatisfactory credit rating and those with a negative experience with SRP were significantly more likely to rank affordability first.*
- *Those with a household income less than $75k and Hispanic customers were more likely to rank affordability as first.*

Reliability: Reasons Ranked First

25% Mentioned that consistent energy is needed to maintain the status quo, and/or that if electricity isn't reliable, other priorities don't matter.

***"Residents and business are dependent upon a steady source of power.** Some uses are essential to life in the case of those who rely on devices to stay alive. Because of the summer heat, a break in power could be fatal to some." – Survey Respondent*

Sustainability: Reasons Ranked First

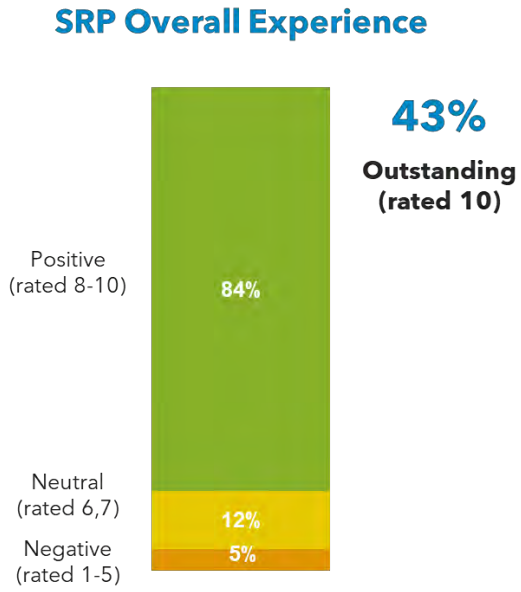
10% Mentioned the need to take care of the earth/ future energy needs.

***"Without sustainability there is no future."** – Survey Respondent*

Those who have lived at their address 2 years or less and those with a positive opinion of the energy plan were more likely to rank sustainability first.

Perceptions of SRP and Topics of Interest

Over four-fifths rated their experience with SRP positively



In qualitative findings, customers noted a highly positive perception of SRP, specifying that reliability of service and helpful customer service were key factors.

"Honestly, I'd give SRP a 10. I haven't had any major issues. Any time I've had anything that's come up, ***I'm able to get someone on the phone, speak with them****, … So, I've had a really good relationship with them." – Customer Focus Group Participant*

"I think the ***consistency of the service****. Being in Arizona, we do have the so hot weather all the time and having air conditioning is definitely a must…* ***And the consistency of them being able to provide that to us without any issues so far is something that I really appreciate****." – Customer Focus Group Participant*

- *Those with a household income under $75k were more likely to rate their experience as outstanding.*
- *Those who had a negative impression of the energy plan and those categorized with high usage were less likely to be satisfied with SRP.*

Over half had interest in ways to save

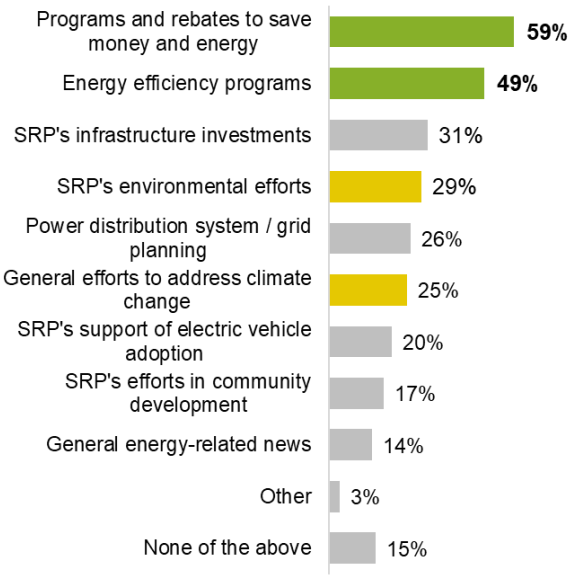
Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their bills.

"I do have the M-Power so I do have prepaid electricity, so I am very acutely aware of my usage. ***I can see what I'm spending per day****." – Survey Respondent*

"I do like the idea that SRP does provide that time of use plan or ***keeps your bills consistent*** *throughout the month or throughout the year." – Survey Respondent*

Topics of Interest

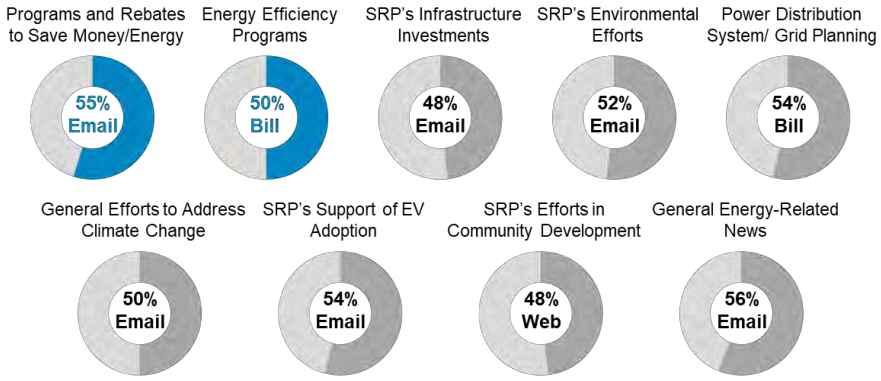


- *Those with a negative overall opinion of the energy plan were significantly more likely to want to hear about SRP's infrastructure investments and the power distribution system; they were less likely to want to hear about SRP's environmental efforts and general efforts to address climate change.*
- *Those with a household income less than $75k were more likely to want to hear about cost saving options.*

Across communication topics, customers most preferred to receive communication via bill insert and email.

Males were more likely to prefer email communications about programs and rebates to save money/energy.

Channel Preference



Appendix

Demographics

	Focus Group (n=24)	Online Survey (n=400)
GENDER		
Female	13	45%
Male	10	51%
Non-binary	1	0%
Prefer not to answer	-	4%
HOUSEHOLD INCOME		
Under $75k	15	41%
$75k or more	9	39%
Prefer not to answer	-	20%
CREDIT RATING		
Preferred	19	67%
Satisfactory/Slow/Unsatisfactory	3	12%
New Customer	2	21%
ETHNICITY (MULTIPLE SELECTIONS)		
White	20	69%
Black or African American	3	4%
Other	3	13%
Prefer not to answer	-	18%
HISPANIC ORIGIN		
Hispanic	2	15%
OWN/RENT HOME		
Own	18	73%
Rent	6	28%

	Focus Group (n=24)	Online Survey (n=400)
AGE		
18-44	13	30%
45-64	6	37%
65+	5	34%
EMPLOYMENT		
Ful-time/Part-time	-	51%
Self-employed	-	6%
Retired	-	33%
Unemployed/seeking employment/student	-	4%
Not working/not seeking	-	2%
N/A / Prefer not to answer	-	5%
YEARS AT ADDRESS		
2 or less	-	7%
3-5	-	10%
6-20	-	30%
21-39	-	30%
40+	-	15%
USAGE		
Low (6,000 kWh or less)	3	19%
Moderate (6,001-12,000 kWh)	8	33%
Medium (12,001-18,000 kWh)	8	29%
High (More than 18,000 kWh)	5	20%

Illustrative Plan Description and Background

In addition to the visual depiction of the illustrative plan, respondents were provided the following additional description and background:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

APPENDIX C

SRP Customer Research Future of Energy Phase 3 Report

Future of Energy: ISP Residential Customer Research

Phase III Report

Revised: December 13, 2023

bellomy

175 Sunnynoll Court
Winston-Salem, NC 27106

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Appendix 18

Background & Objectives

Background

Salt River Project (SRP) is preparing its first Integrated System Plan (ISP), which is focused on a new way of planning the power system through 2035. While multiple inputs are needed to prepare this plan, one crucial contribution is input from residential customers.

Looking into the future, SRP expects there to be many changes and disruptions to the energy industry including evolving customer needs and expectations with a key aspect being the balance between reliability, sustainability, and affordability. Furthermore, the perspectives of different groups of customers, with different values and mindsets and each group's perception of this balance will need to be understood and considered.

Objectives

The goal of this research was to bring the voice of SRP's residential customers into the planning of the future power system.

More specifically, this research was designed to gain an understanding of how customers think about, and value sustainability, affordability, and reliability related to their electricity service from SRP and gauge their reactions to potential energy systems. SRP sought to understand areas of diverse viewpoints and agreement, as well as identify preferred methods of engagement on this topic.

The research aimed to address the following specific objectives:

1. Understand the concerns customers have about the future of Arizona, the economy and the U.S.
2. Understand diverse perspectives and opinions relating to SRP's sustainability plan and evolution.
3. Develop and test system-planning metrics that are understood and resonate with customers.
4. Generate a list of power system and future energy topics that interest customers.
5. Understand customer perspectives on power reliability and potential tradeoffs with sustainability and affordability.
6. Understand preferred methods of learning about and engaging with the power system planning process.

Methodology & Reporting

Approach

A three-phased research approach was applied, starting with virtual focus groups (December 2021), followed by a quantitative confirmation (March 2022) and culminating in a choice exercise (May 2023).

All customers included in the research were SRP residential customers, who were energy decision makers for their household (make decisions about their utility service and pay the bill), did not work for a related industry, and were over 18 years old.

Phase I: Virtual Focus Groups

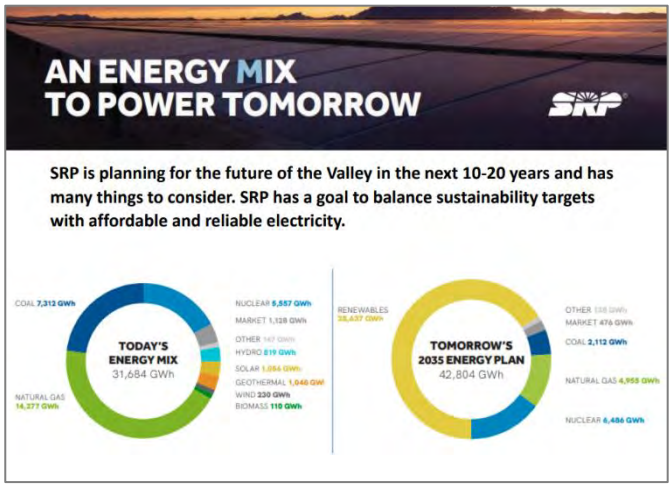
Four 90-minute virtual focus groups were held December 13 & 14, 2021. A total of 24 SRP customers participated virtually (via Zoom) and received a $125 bill credit for participating.

Customers were grouped to encourage engagement and maximize the ability to explore attitudes and have a meaningful conversation.

Phase II: Online Survey

An online survey was fielded between March 7 – March 14, 2022. Respondents evaluated SRP's illustrative energy plan of how the system may develop in relation to attributes of customer interest identified in Phase I. Quotas were set for the survey to ensure the respondent pool best represented SRP's residential customer population.

Customers evaluated a visual example of SRP's future potential energy mix, which describes the transition of the power system over the next 10-20 years. The visual depiction of the illustrative plan shown to respondents is displayed to the right. The illustrative energy plan shown in Phase II did not include details on bill impacts, water reduction, carbon emission reduction, or timing to meet the sustainability goals. Customers were provided background on SRP's priorities prior to evaluating energy mix; this wording is included in the Appendix on page 20.



Pre-Test Research: Optimizing Survey Materials

Prior to the Phase III survey, a multi-staged pre-test study was conducted to test education materials, survey instructions, and choice exercise design among non-SRP customers. The pre-test research included an initial pre-test survey, qualitative ride-along interviews, and a revised pre-test survey.

Throughout the three pre-test phases, respondents identified areas of the instructions and educational materials that were difficult to understand. Based on feedback from this pre-test, instructions for the choice exercise were crafted with clear tasks respondents could understand and accurately complete.

This confirmation helped secure the highest quality of actionable data. Changes made to the choice exercise included:

- Impactful phrase rewording which resulted in less confusion (~40% reduction in confusion)
- Redesign of the choice activity which created an easier survey experience.

This testing ensured SRP's diverse customer base would be able to understand and easily complete the choice exercise in Phase III.

Phase III: Choice Exercise Online Survey

In this 20-minute survey fielded between May 9 and May 29, 2023, offered in English and Spanish, respondents completed a choice exercise to assess their preferences for SRP's potential future energy system. Quotas were set to mirror the true population split for SRP's customer base. A choice-based methodology known as a conjoint exercise was utilized to understand customer preference for potential future energy systems being analyzed in the Integrated System Plan.

Conjoint methodology is used to optimize a product or service of interest by asking respondents to make a series of choices though an exercise simulating real-life situations, determining what tradeoffs they are willing to make.

The following best practices were used in development of the choice exercise for the Phase III survey:

- Exposing respondents to educational information regarding system inputs prior to asking them to make a choice (e.g., explaining energy mixes and defining carbon reduction)
- Ensuring complex inputs are positioned in customer-friendly terms (e.g., showing carbon reduction in terms of the number of gas-powered vehicles)
- Utilizing visuals where possible to "show" rather than "tell" (e.g., including a graphical representation of the energy mix)
- Creating precise levels for each system input (e.g., utilizing data outputs from other ISP research efforts to build levels)
- Ensuring system configurations are realistic to respondents to avoid asking them to make a non-sensical choice

- Including no more than seven inputs per system to ensure ease of comprehension
- Limiting the number of screens in the exercise to no more than twelve to minimize respondent fatigue

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a “none of these” option representing the current energy system and choose the plan they would most prefer SRP to pursue. Through selections made, a customer preference rating was produced for each potential future energy system. An example of the choice exercise is shown on the following page.

The ISP's analytical framework and outputs from the system planning informed the following system inputs for the choice exercise:

- Illustrative energy mix (9 mixes tested)
- When SRP will meet its sustainability goals (2030 or 2035)
- Percent reduction in carbon emissions (4 levels for each energy mix)
- Percent reduction in water usage (4 levels for each energy mix)
- If SRP will build new gas power plants (yes or no)
- Monthly bill impact (4 levels calculated on customers' average bill)
- Number of 2-hour power outages (0, 1, 2, or 3)

Illustrative mixes and variations in options for the inputs shown were representative of the resource builds and implications for each strategic approach under the future scenarios from the ISP system plans. Various levels (or options) were shown for each component resulting in evaluation of over 9,200 possible system configurations. An example of the choice exercise screen respondents completed is located in the Appendix on page 21.

Reporting

Quantitative results are reported in charts at the total level with qualitative results represented throughout. When evaluating survey data, sub-groups were compared to one another to investigate if there were statistically significant differences between two or more groups.

A 95% confidence level is used, which indicates we can conclude with 95% confidence that differences are not due to chance and that survey results should match results from the actual population (plus or minus the margin of error). Only significant differences relevant to the research objectives are reported.

The following subgroups are noted in this report:

- **Age** (18-44 years old/ 45-54 years old/ 55-64 years old/ 65+ years old)
- **Income** (Under $75k/year / $75k/year or more) (Phase II Only)
- **Limited Income** (200% of HHS Poverty Guidelines/ Non-Limited at 200%)
- **Gender** (Male/ Female/Nonbinary)

- **Energy Mix Prioritization** (Affordability first/ Reliability first/ Sustainability first)
- **Hispanic** (Hispanic/ Non-Hispanic)
- **Credit Rating** (5 levels)
- **Usage Category** (Low/ Moderate/ Medium/ High)
- **Overall Opinion of Energy Plan** (Positive/ Negative)
- **Overall Experience as SRP Customer** (Positive/ Neutral/ Negative)
- **Years at Address** (2 or less/ 3-5/ 6-20/ 21-39/ 40+)

Analysis Note: Rating scale questions are reported differently for 10-point and 5-point scales.
10-point scales are reported using Top-Box (TB – ratings of 10), Top-3-Box (T3B – ratings of 8,9, or 10), Middle-2-Box (M2B – ratings of 6 or 7), and Bottom-5-Box (B5B – ratings of 1-5).
5-point scales are reported using Top-Box (TB – ratings of 5), Top-2-Box (T2B – ratings of 4 or 5), Middle-Box (MB – ratings of 3), and Bottom-2-Box (B2B – ratings of 1 or 2).

Executive Summary

In Phase I & II, most customers reacted positively to SRP's initial path forward, and a quarter felt it was excellent. A majority agreed the plan should be prioritized by SRP. Phase III revealed residential customers' preferences for the future energy system.

Top factors: affordability & bill impacts

Affordability concerns were some of the most-selected future issues facing Arizona. In each phase of this research, affordability surpassed reliability slightly in importance when ranked by customers. Those with limited incomes put greater emphasis on affordability, while non-limited income customers reflected greater balance across factors. Additionally, when choosing a future energy system, customer selections revealed monthly bill impact as the top driver of preference.

Understanding and openness to change

Despite prioritizing affordability, customers recognized that the forthcoming challenges facing the region are interrelated and pose risks to sustainability, the economy, and overall quality of life. Thus, they understood the need for a lower-carbon future energy system, however, across scenarios, lower cost strategic approaches were more preferred by customers. While customers recognized the need for and expressed interest in SRP's investment in sustainable energy sources, they do not want to bear the cost of that investment.

Willingness to engage

Customers reported positive experiences with SRP's programs and over half were interested in programs and rebates that will help them save money and energy. Additionally, about a third or more expressed interest in learning about SRP's energy efficiency programs, environmental efforts, and infrastructure improvements.

Recommendations

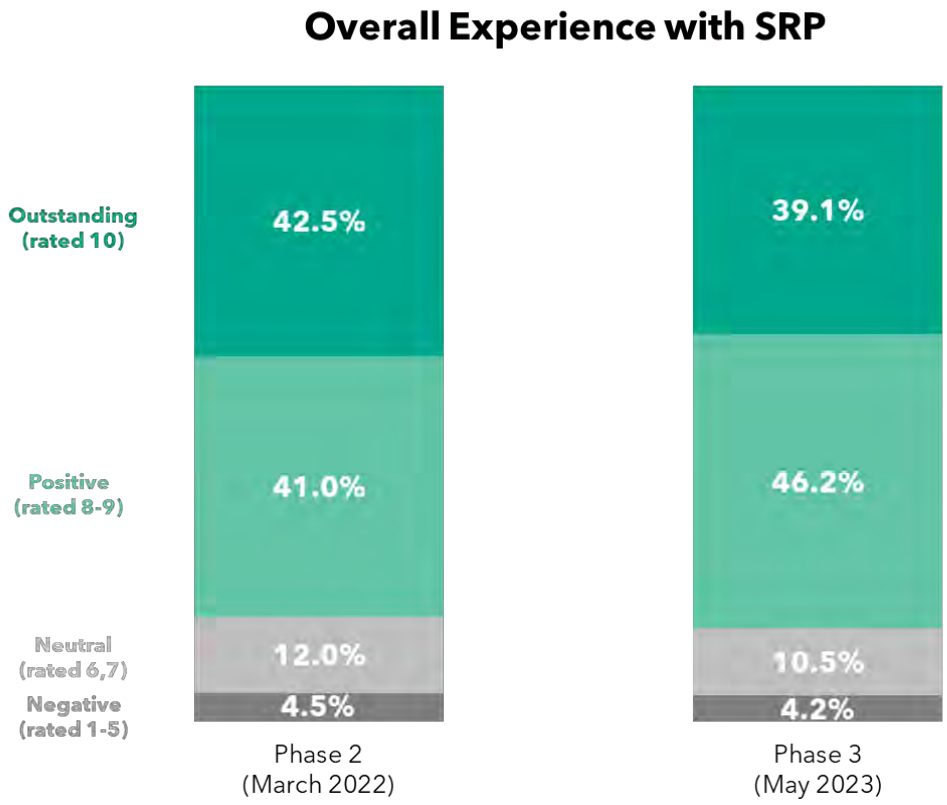
- **For SRP's ISP, focus investment on a least-cost portfolio:** With cost being the top driver of customer preference, it will be critical to ensure system costs are managed and explained to customers proactively and transparently.
- **For SRP's ISP, highlight and maintain grid readiness and resiliency:** Reliability was the second highest ranked priority.
- **In ISP implementation, utilize a targeted approach to customer programs:** Customers expressed a willingness to engage with SRP via customer programs. These programs should be designed to meet the varying needs of customers.

Detailed Findings

Experiences with SRP, Concerns, and Priorities

Most rated their experience with SRP positively

Similar to March 2022, in May 2023 surveying, over 4 in 5 customers rated their experience with SRP positively. While about 2 in 5 provided an "Outstanding" rating.



In qualitative focus groups, customers attributed their highly positive perception of SRP to the reliability of service and helpful customer service. Additionally, participants felt positively about SRP's customer programs, agreeing that programs help them manage
and reduce their electricity bills.

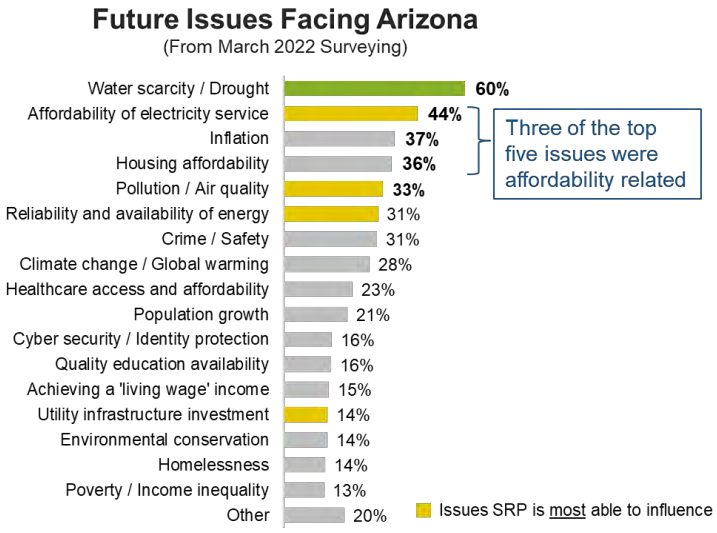
*Groups **more likely** to provide a positive rating of their experience with SRP included:*

- *Customers aged 55 or older*
- *Non-Hispanics*

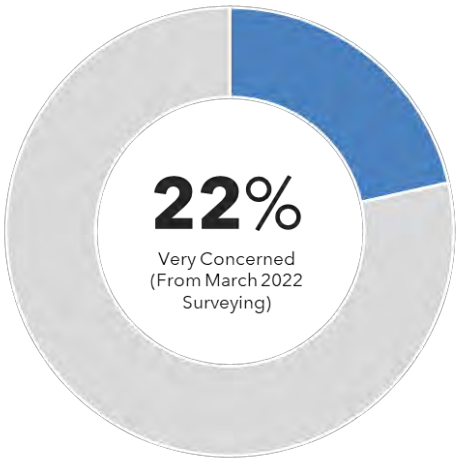
Customers demonstrated affordability concerns

Respondents most selected that they were concerned about water scarcity. After water scarcity, affordability related to electricity, inflation, and housing were most concerning.

The focus on affordability of electricity is of note, as it was the second-most selected future concern. These issues were followed by some items related to energy service, including pollution, energy reliability, and climate change.



- ***Lower income*** *customers (earning under $75k/year) reflected* ***greater concern for affordability****.*
- ***Year-round*** *residents are more likely to* ***prioritize housing affordability****.*
- *Those with a household* ***income of $75k or more*** *were more likely to* ***prioritize water scarcity*** *and were less likely to prioritize housing affordability.*
- ***Non-Hispanic*** *customers were more likely to* ***prioritize water scarcity****.*



Further, 22% of customers were very concerned about other community members being able to pay their electricity bills.

Groups ***more likely*** *to be concerned about others' ability to pay their electric bill include:*

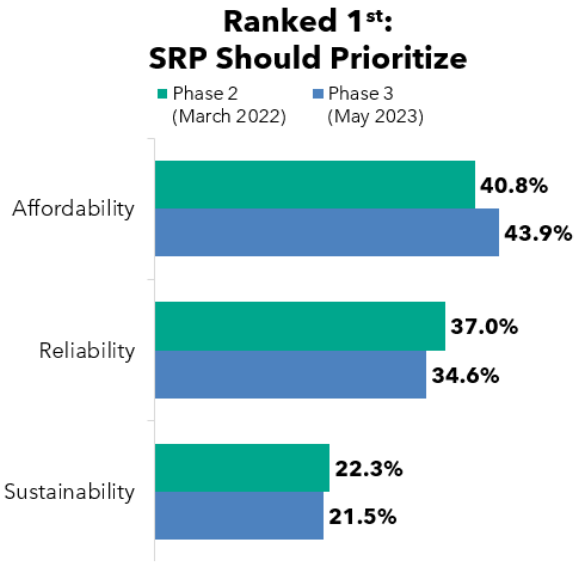
- *Customers with household incomes less than $75k*
- *Females*
- *Hispanic customers*

Affordability and Reliability were most often ranked 1st

When asked how SRP should rank affordability, reliability and sustainability, affordability was the top priority in both Phase II & III for over two-fifths of customers. Over one-third prioritized reliability, and less than one-quarter prioritized sustainability.

In the focus groups, while a majority of customers ranked reliability first, they discussed a tough tradeoff between reliability and affordability.

While the ranking of priorities was similar across Phases, reasons for these rankings in May 2023 highlighted greater emphasis on the rising cost of living and a need for consistent electricity.



Affordability: Reasons Ranked First

Almost half (46%) of those who ranked affordability first in Phase III mentioned keeping energy costs down and the rising cost of living. This was more than in Phase II where only one-third ranked affordability first for the same reason. The increase in concern over rising cost of living and keeping energy costs down may be due to the rise in inflation and increased conversation about rising prices across products and services in 2023.

*In Phase III surveying, groups **more likely** to rank **affordability first** included:*

- ***Limited income** customers (200% of HHS Poverty Guidelines)*
- *Females*
- *Hispanics*
- *Those enrolled in **M-Power for Pre-Pay***

Reliability: Reasons Ranked First

In Phase III, half (51%) of the customers who ranked reliability first noted a need for consistent electricity to maintain the status quo. This increased from about one-quarter (23%) ranking reliability first in Phase II for the same reason.

*In Phase III surveying, groups **more likely** to rank **reliability first** included**:***

- *Non-Limited income customers*
- *Males*
- *Those with Preferred Credit Ratings*

Sustainability: Reasons Ranked First

While the smallest proportion of customers ranked sustainability first, three-fifths (62%) of those who did in Phase III noted the importance of taking care of the Earth and future energy needs. This was higher than the almost half (45%) who ranked sustainability first for the same reason in Phase II.

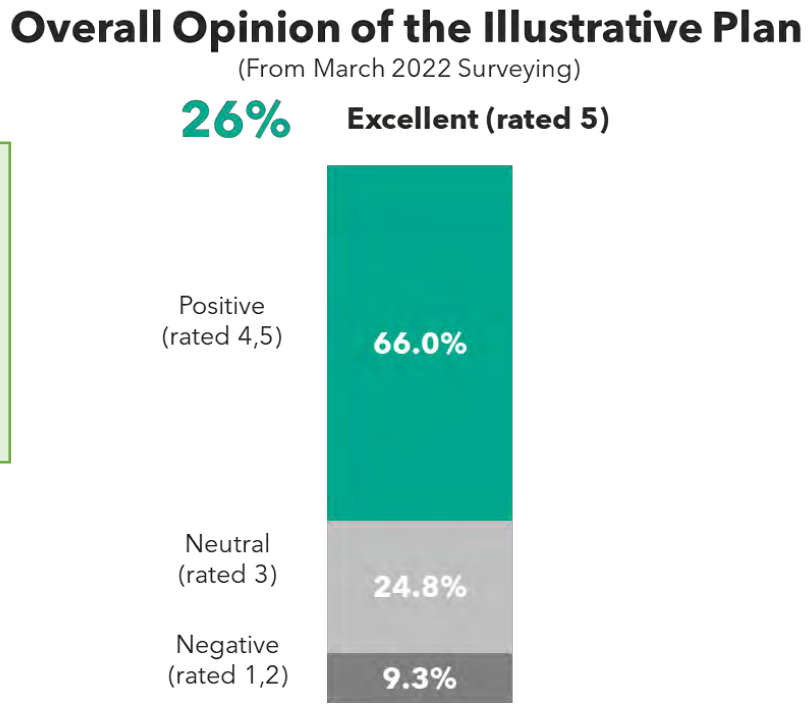
*Customers **aged 55 to 64 were less likely** than all other age groups to rank **sustainability first**. In Phase III surveying.*

SRP Energy Plan: Initial Reactions (Phase I & II)

Two thirds rated the initial energy plan positively

When evaluating an illustrative example of SRP's energy plan during initial phases of research (visual and background evaluated can be found in the Appendix on page 20), one-quarter (26%) rated it as excellent, but 66% rated it positively overall (rated 4 or 5 on a 5-point scale). This demonstrates opportunity for improvement.

- *Those ranking **sustainability first** had a **more positive** impression of the energy plan.*
- *Those with **high electricity usage** were **less likely** to rate the plan positively.*



Customers noted the plan could be improved with more specifics

Initial responses to viewing the plan revealed that customers were interested in more specifics. In addition to questions on plan affordability and achievability, respondents cited varying thoughts on which renewable sources SRP should prioritize.

- Twenty-seven percent (27%) of customers shared concerns around the type of energy sourced.
- Nineteen percent (19%) shared affordability and cost concerns.
- Thirteen percent (13%) shared achievability concerns regarding the timing of the plan being too slow.

Focus group participants were also generally positive about the plan's intent but suggested some opportunities for improvement. These opportunities included the amount of time needed to implement the plan, getting customer buy-in and being transparent, ensuring SRP's accountability for the changes, and clarifying how this would affect rates.

Phase III Customer Preference for Future Energy System

Monthly bill impact of most importance when selecting an energy system

After completing the exercise, over one-third of respondents (37%) reported the monthly bill impact was the most important input when choosing a preferred future energy system.

*Groups **more likely** to rank **monthly bill impact first** included:*

- *Year-round residents*
- *Those **employed part-time***

Among those ranking the **energy mix first (14%)**, top ranked priorities were evenly split:

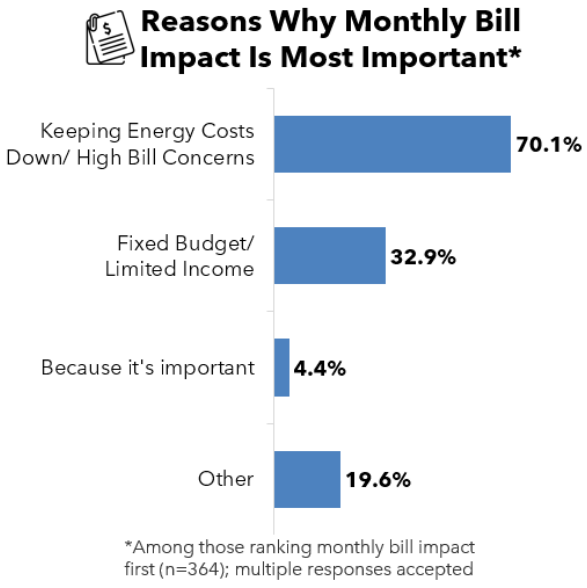
- Affordability – 31% ranked 1st
- Reliability – 36% ranked 1st
- Sustainability – 34% ranked 1st

This suggested the energy mix was seen as a component related to all three priorities.

Attribute	Ranked 1st Most Important
Monthly bill impact	36.8%
Reduction in carbon emissions	15.9%
Number of 2-hour power outages	14.5%
Energy mix	13.9%
Reduction in water usage	11.4%
If SRP will build new gas power plants	5.0%
When SRP will meet its sustainability goals	2.5%

Reasons for ranking inputs first varied

Customer open-ended comments highlighted concerns regarding financial constraints due to changing socio-economic conditions and future uncertainty stemming from inflation and escalating energy expenses. Looking to the future, customers attributed greater costs to the anticipated new infrastructure needed to meet growing demand for electricity and expressed concerns that cost increases could impact quality of life. Additionally, the viability and affordability of future green energy initiatives raised doubts for some given the present economic context.



*The following groups were **more likely** to mention **"fixed budget/ limited income"**:*

- *Customers **aged 55+***
- *Retirees*
- *Those with **limited incomes** (200% of HHS Poverty Guidelines)*

Among those ranking carbon reduction first, about a third mentioned reducing carbon via the use of cleaner energy sources (like solar or nuclear) while nearly half of those ranking energy mix first mentioned these topics as reasons for ranking energy mix as most important.

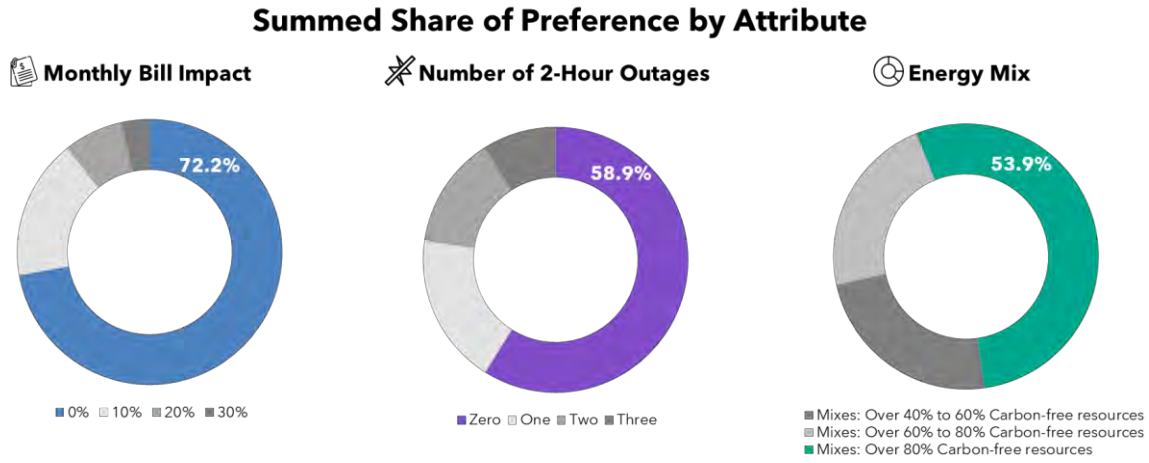
Reasons Why Most Important

Reduction in carbon emissions *(n=169)	Number of 2-hour power outages *(n=139)	Energy mix *(n=147)
37% Reducing carbon has direct impact on climate change	**58%** Dangers associated with outages (hot climate, health concerns, etc.)	**46%** Emphasis on reducing carbon and/or increasing solar or nuclear
32% Emphasis on reducing carbon and/or increasing solar or nuclear	**34%** General reliability concerns	**33%** Some energy sources are limited/ need a mix

Choices indicate a desire to "have it all"

The choice exercise also revealed the preference for each level of key factors in isolation.

- Bill Impact: a majority preferred 0% increase
- Outages: a majority preferred zero 2-hour outages
- Energy Mix: a majority preferred energy mixes with over 80% carbon-free sources



While monthly electricity bills have the largest impact on preference (72%), these preferences indicate that customers want the cleanest, greenest energy at the lowest cost with no implications to reliability.

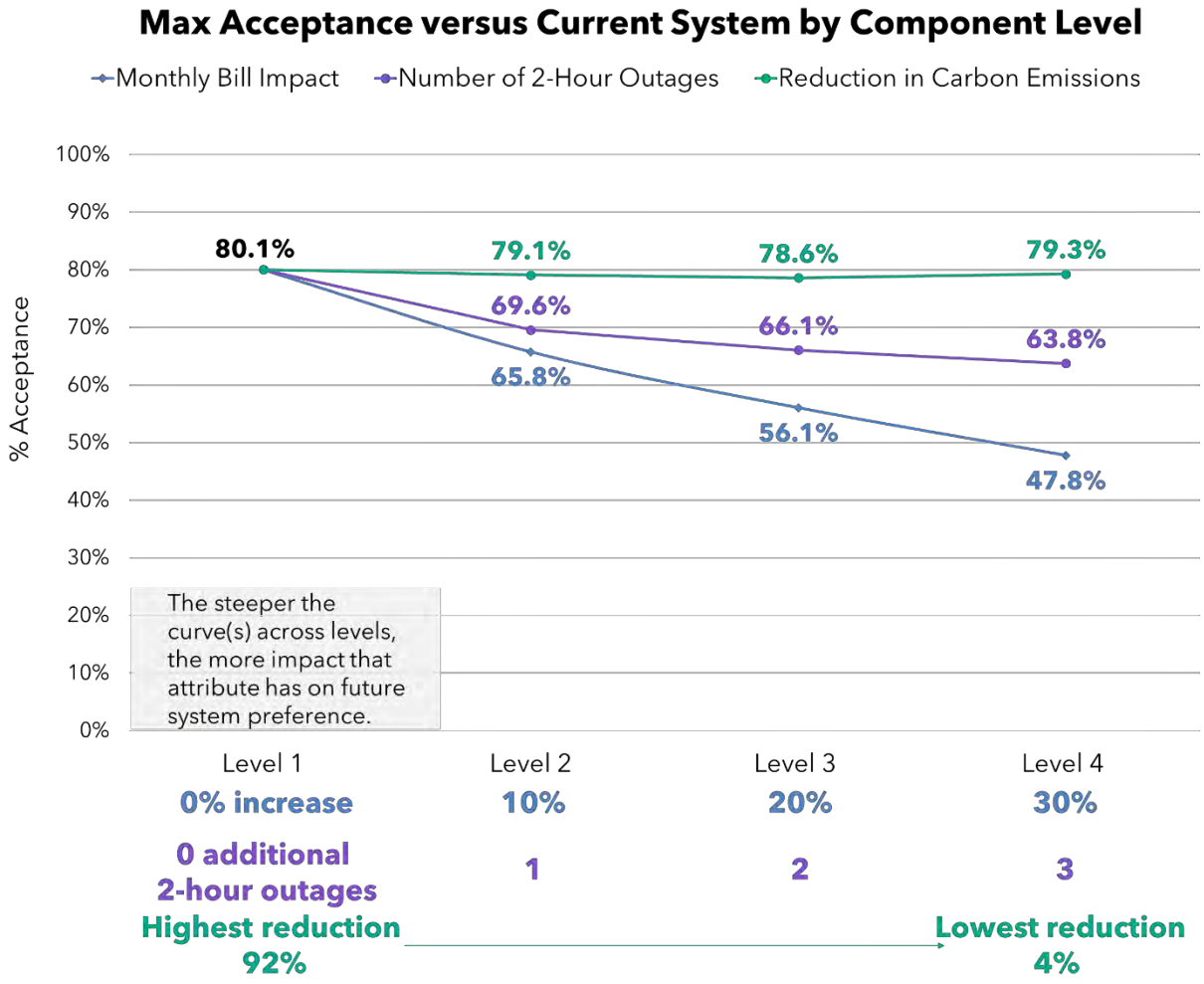
Real-world cost constraints force tradeoffs

While most customers agree that sustainability is important and should be considered by SRP and their customers, there are limitations on how much customers feel they can invest in the “greater good.” Customers expressed that fixed incomes and limited budgets often constrain the degree to which they can support and prioritize sustainability.

Acceptance of future energy systems declines above 0% bill impact

As bill impacts increase, the proportion of customers who accepted an energy system over the current system declined sharply. However, acceptance declines were less steep for the number of 2-hour outages suggesting that customers are less accepting of price increases and more tolerant of minimal additional 2-hour outages.

Furthermore, when tradeoffs are required, carbon reduction has minimal impact with acceptance of energy systems relatively unchanged as the level of reduction in carbon emissions increases.



Customer preferences for a balanced future energy system

While SRP does not know what the future will look like, it will be important to design the future energy system with customer preferences in mind. Findings revealed that from the residential customer's perspective the ideal future energy system should...

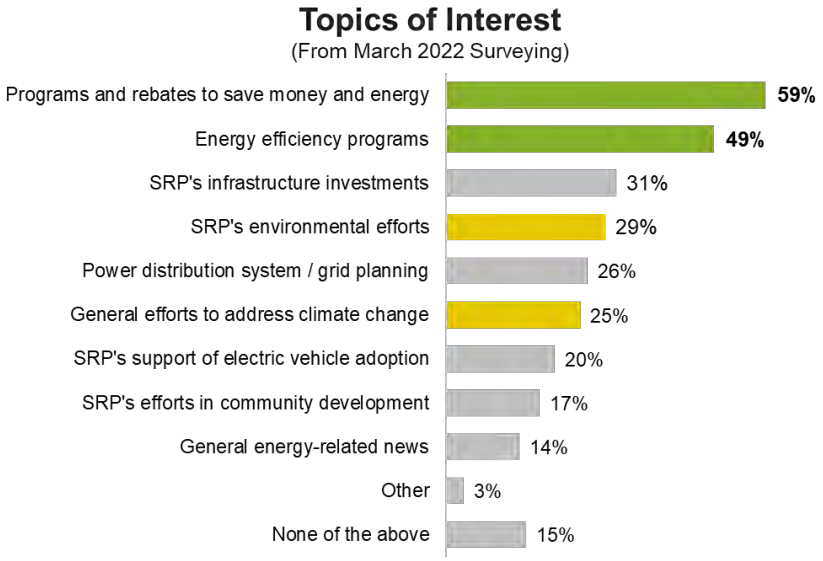
- Manage cost, first and foremost
- Strive to manage monthly bill impacts below a 10% increase
- Include a diverse energy mix to ensure reliability
- Provide the cleanest, most sustainable energy without exceeding a 10% bill increase

Topics of Interest

Over half had interest in ways to save

Customers would most like to continue to hear about ways to save via energy efficiency program and/or rebates. Meanwhile, over one-quarter were interested in topics related to SRP's environmental efforts and/or climate change.

Focus group participants agreed that SRP programs help customers manage and reduce their electricity bills.



*Those with a **household income less than $75k** were **more likely** to want to hear about the following:*

- *Programs and rebates to save money and energy*
- *SRP's support for community development*

*Groups more interested in hearing about **SRP's infrastructure investments** included:*

- *Customers **aged 65+***
- *Non-Hispanics*

***Part-time residents** were **more likely** than those living in Phoenix year-round to want to hear about the following**:** energy efficiency programs, SRP's environmental efforts, and general efforts to address climate change*

Appendix

Focus Group Participant Description*

Total	24
Gender	
Female	13
Male	10
Non-binary	1
Ethnicity	
Black	3
Hispanic	2
White	18
Other	1
Homeownership	
Own	18
Rent	6

Age	
25-34	6
35-44	7
45-54	2
55-64	4
65-74	2
75+	3
Income	
<25k	2
25-49k	5
50-74k	8
75-99k	3
100-149k	3
150+	3

** Focus Groups are exploratory in nature and cannot be projected to a larger population. Attendees are not representative of the full SRP customer base or stakeholders*

Survey Respondent Demographics

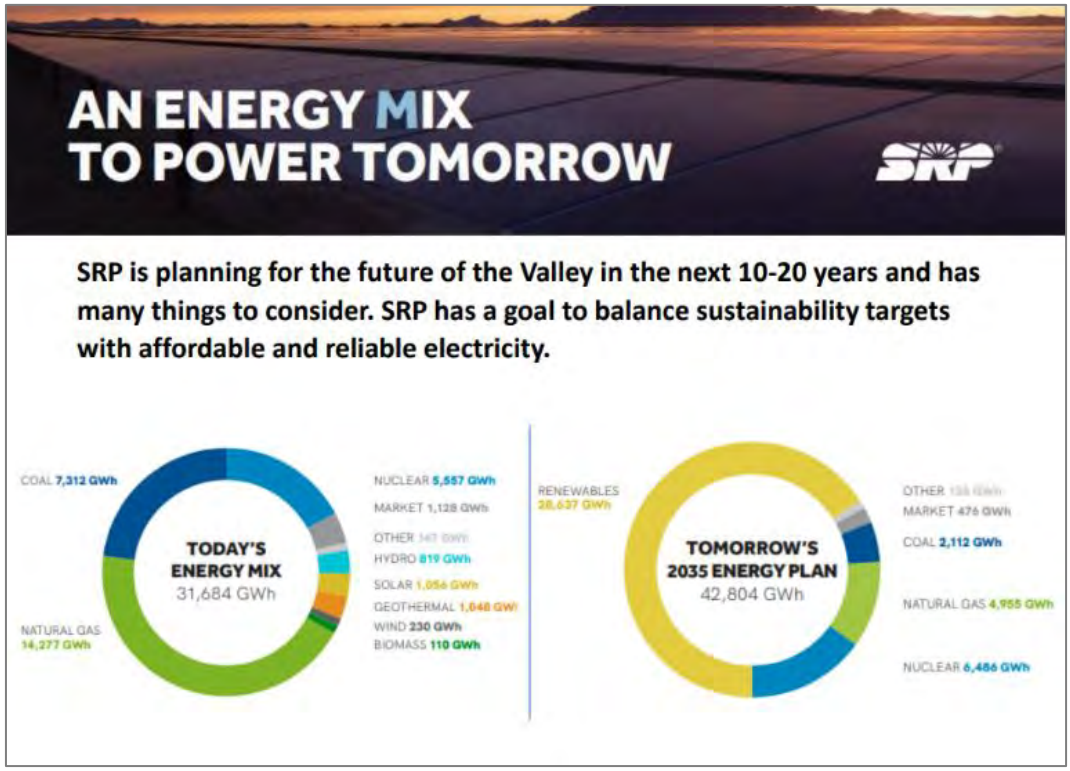
	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
GENDER		
Female	51%	49%
Male	45%	46%
Non-binary	0%	0%
Prefer not to answer	4%	5%
INCOME		
Limited Income 200%	31%	31%
Non-Limited Income 200%	69%	69%
CREDIT RATING		
Preferred	67%	64%
Satisfactory/Slow/ Unsatisfactory	12%	18%
New Customer	21%	18%
Cash Only	-	1%
ETHNICITY (MULTIPLE SELECTIONS)		
White	69%	69%
Black or African American	4%	5%
Other	13%	12%
Prefer not to answer	18%	17%
HISPANIC ORIGIN		
Hispanic	15%	12%
OWN/RENT HOME		
Own	73%	71%
Rent	28%	29%

	Phase 2 Survey March 2022 (n=400)	Phase 3 Survey May 2023 (n=1,011)
AGE		
18-44	30%	38%
45-64	37%	37%
65+	34%	25%
EMPLOYMENT		
Ful-time/Part-time	51%	53%
Self-employed	6%	8%
Retired	33%	27%
Unemployed/seeking employment/student	4%	3%
Not working/not seeking	2%	2%
N/A / Prefer not to answer	5%	7%
YEARS IN PHOENIX		
2 or less	7%	8%
3-5	10%	9%
6-20	30%	34%
21-39	30%	29%
40+	15%	20%
USAGE*		
Low (6,000 kWh or less)	19%	12%
Moderate (6,001-12,000 kWh)	33%	32%
Medium (12,001-18,000 kWh)	29%	31%
High (More than 18,000 kWh)	20%	23%

Illustrative Plan Description and Background (Phase I & II)

In addition to the visual depiction of the illustrative plan shown below, respondents were provided the following additional description and background during Phases I & II of this research:

> "SRP is working at all times to make sure your power stays on, including during Arizona's extreme summers. To ensure power quality continues to improve, SRP needs to plan long term for the future of the Valley. This means:
>
> - Balancing a transition to clean energy
> - Planning for population growth (and an increased demand for energy)
> - Considering the types of power to buy to make up their power mix (including solar, wind, geothermal, biomass, nuclear, natural gas, and coal)
> - Reducing SRP's carbon intensity (the amount of carbon released per unit of energy produced) by 90% by the year 2050"

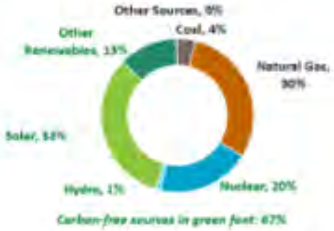


Choice Exercise Example Screen (Phase III)

Customers were asked to evaluate 11 screens, each showing 2 energy plans and a "none of these" option representing the current energy system. An example screen with question wording is shown below.

Which of these hypothetical future energy systems would you prefer SRP implement
Please read through each plan carefully and select the plan you most prefer.

Click here to view a glossary of terms. This will open in a new browser and you can come back to this page to complete the activity.

	2035	2030
Energy Mix:	*Carbon-free sources in green font: 66%*	 *Carbon-free sources in green font: 67%*
SRP will meet its Sustainability Goals by:	**2035**	**2030**
% reduced carbon emissions (equal to number of gas-powered cars on the road each year):	**20% reduction** (about 675,000 gas-powered cars)	**61% reduction** (about 2.0 million gas-powered cars)
% reduced water usage (equal to the amount of water used by the number of 4-person households shown per year):	**16% reduction** (about 9,000 households)	**52% reduction** (about 30,000 households)
Will SRP build new gas power plants to source energy?	**Will** build	**Will not** build
Your monthly bill will:	Increase by **$30**	**Not increase**
Number of 2-hour power outages experienced in one year due to high energy demand (on a hot summer's day):	**Two** 2-hour outages	**Three** 2-hour outages
	Select	Select

None of these, I would stick with the current system at my current monthly bill amount.

Select

Delivering water and power®

982100 03/24

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit HH: SPP, *SPP Reliability Plan* (Jun 2, 2025)

SPP RELIABILITY PLAN

0820EXT00108

Business Owner: Derek Hawkins
Effective: 06/02/2025
Revised: 06/2/2025
Version: 8.0

Approved By:	Brian Strickland	Digitally signed by Brian Strickland Date: 2025.06.11 13:41:29 -05'00'
SME Signature (Brian Strickland)		Date

Approved By:	Derek Hawkins	Digitally signed by Derek Hawkins Date: 2025.06.11 13:42:26 -05'00'
Business Owner Signature		Date

Revision History

Author	Version	Revision Date	Effective Date	Description
ORWG	1.0	6/1/05		Complete re-write to align with revised NERC Policy 9 as approved by NERC 06/15/04.
		6/15/05		Per NERC ORS request, removed Appendix B – Reliability Assessment Process and Procedure.
		1/11/06		Added CLECO to the plan.
		1/26/06		Added Constellation Balancing Authorities BCA, CNWY, DENL, DERS, PUPP, and WMUC to the plan.
		1/27/06		Updated to reflect changes in SPP processes and procedures after the SPP EIS Market is implemented.
		2/9/06		Made necessary changes to conform with NERC functional model terminology present in existing reliability standards.
		9/8/06		Added LAGN to the plan with an effective date of November 1, 2006
		12/5/06		Added Constellation Balancing Authority BUBA
		1/1/09		Changes consistent with Criteria 12.3. Corrected Batesville Generating Station acronym from BCA to BBA. Added Missouri Public Service (MPS) to footprint.
		4/1/09		Added Nebraska entities – LES, NPPD and OPPD
		10/1/09		Added Constellation Balancing Authorities OMLP and PLUM
		4/1/10		DENL Balancing Authority moved from operation by Constellation to operation by NRG and changing DENL to NLR
		1/1/11		CNWY and WMUC Balancing Authority moved from operation by Constellation to operation by NRG and changed from CNWY to CWAY and from WMUC to WMU
		2-15-11		City Utilities of Springfield (SPRM) becoming a stand-alone Balancing Authority Areas instead of a TOP imbedded inside the SPA Balancing Authority Areas.
		4/11/12		Added Brazos Electric to list of Balancing Authorities. Updated map to reflect addition. Changed “OPS1” application in reference to outage scheduling to “CROW” application reference. Clarified the RTCA and monitored elements by voltage in sections C.4. and E1. Noted the primary and BUCC location changes in 2012 in section I.

Author	Version	Revision Date	Effective Date	Description
		6/1/13		Transferred the southern reliability members from SPP to MISO (with exception of the CECD entities) per Entergy move to MISO
		12/19/13		Removal of the CECD entities from the SPP Reliability footprint. Changed cover page date to Dec 19, 2013.
		3/1/14		Replaced "EIS" with "Integrated", removed OPS1 references, replaced PowerWorld with E-terravision, removed member map, and changed list of BA/TOPs to reflect new consolidated BA (SPP BA).
		6/1/15		Added the IS entities of WAPA, Corn Belt to the TOP list within the Introduction and the SPP Reliability Areas. Changed WECC references to PEAK Reliability.
	2.0	4/21/16		Changes made due to overall review, and to correct studies, update tools, Operating Criteria changes, DC tie additions, reduce redundancy of sections and Market constraint management.
Terry Oxandale	3.0	4/30/2019	4/30/2019	Modified for SPP RC for Western Interconnect effective 12/3/2019. Added changes in RE, additional TOPs in Appendix A, and included aspects of the Western Interconnect not included in the current Eastern Interconnect practices. Converted to current template and assigned new Operations document ID 0820PCS00108.
Brian Strickland, Derek Hawkins	3.1	11/20/2019	11/20/2019	Updated with additional information on loss of necessary applications, weather, Cyber Attack, and SPS/RAS. Updated AZPS (under CAISO RC) to AEPC (under SPP RC). Updated for clarifications per RCRT review. Deleted Gila River Power (GRMA) from Appendix A table being they are not a TOP per Bryan Wood.
Brian Strickland, Yasser Bahbaz	3.2	2/10/2021	4/1/2021	Added GRID effective 4/1/2021 to "BAs and TOPs in SPP RC Areas" section in Appendix A. Also updated file name of documents referenced in Appendix B.
Brian Strickland	4.0	1/07/2022		Added language to GMD to address monitor responsibilities and added a section on voltage. Changed business owner and SME per B. Wood.
Julie Gerush, Brian Strickland	5.0	04/12/2023	04/12/2023	Comments addressed from Operations review. Changes to accommodate changes to IDC. Updated cover pages.

Author	Version	Revision Date	Effective Date	Description
Heather Harris, Brian Strickland	6.0	04/01/2024	04/01/2024	Removed Appendix B (RC Related procedures), updated to identify no delegation of task or actions requested for adjacent RCs, minor language changes to mirror requirement language. Removed GRIF under entities due to merger with GRID. Added language for SOL/IROL communication and general cleanup Changed document ID.
Hayden Johnson	7.0	01/31/2025	02/01/2025	Added First Light Energy (BNBA) to the list of BAs/TOPs in the Appendix.
Hayden Johnson	8.0	06/02/2025	06/02/2025	Removed New Harquahala Generation Station (HGMA) from the list of BAs/TOPs in the Appendix.

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Introduction

The North American Electric Reliability Corporation (NERC) delegates its authority to monitor and enforce compliance with NERC Reliability Standards to the Regional Entities (RE). The RE carries out their reliability activities with the Registered Entities for their reliability region. Southwest Power Pool (SPP) is recognized as the Reliability Coordinator (RC) for all Transmission Operators (TOPs) and Balancing Authorities (BAs), listed in **Appendix A**, in both the Eastern and Western Interconnections.

SPP RC is responsible for the bulk transmission reliability and power supply reliability within its RC Areas. Bulk transmission reliability functions include assessment of real-time and next day operating conditions, congestion management, coordination of transmission and generation outages and instructing curtailment of transactions and/or load. SPP RCs use a risk-based approach to communicating actual and potential SOL exceedances with impacted TOPs, as described in SPP's Reliability Coordinator Area System Operating Limit Methodology and Reliability Coordinator Area System Operating Limit Methodology Western Interconnection. Power supply reliability entails monitoring BA Areas performance and coordinating BAs and TOPs actions, including instructions, for load curtailment, generation and transmission actions, and adjustments to voltage schedules in situations where the system is in jeopardy. SPP RC procedures and policies are consistent with those of NERC.

Operating agreements are in place to facilitate communication, notification, exchange of information, and coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability.

SPP RC communication mediums include phone, the SPP Reliability Communications Tool (R-Comm), the Reliability Coordinator Information System (RCIS), email, NERC Hotline, cellular phones, satellite phones, etc.

NOTE: Unless explicitly defined, any reference to "RC" is applicable to both East and West.

A. Responsibility and Authority

1. SPP has a wide-area view, operating tools, processes, procedures, authority and responsibility for the reliable operation of the Bulk Electric System (BES) within the SPP RC Areas in accordance with NERC Reliability Standards including applicable regional variances, the SPP Membership Agreement, SPP Required Data Specification (RDS), and SPP Reliability Customer agreements. These executed agreements are posted on the SPP website under SPP Documents & Filings/Governing.

    1.1. The SPP RC has a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and

real-time conditions. More details are provided in appropriate sections of this document.

1.2. The executed agreements give the SPP RC clear decision-making authority to act and instruct actions to be taken by the SPP RC Members and Reliability Customers to preserve the integrity and reliability of the BES. SPP's responsibilities and authorities, as well as its RC members' and customers' responsibilities are clearly defined in SPP's governing documentation.

2. SPP acts first and foremost in the best interest of the BES before that of any other entity. This expectation is clearly identified in the SPP Membership and Reliability Customer agreements, and in the job description of the SPP personnel acting in the role of the RC.

3. Per the SPP RC Member and Reliability Customer agreements, the BAs, TOPs, and other operating entities in the SPP RC Areas (i.e. West and East RC Areas) shall carry out required emergency actions as instructed by the SPP RC, including the shedding of firm load if required, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. In those cases, SPP RC Members or Reliability Customers must immediately inform the SPP RC of the inability to perform the operating instruction.

4. Weather-related event is to be determined in advance, based on weather evaluations, storm information, next day studies, etc., for action to be taken by SPP RC as necessary. The evaluation and coordination of analysis information may lead to issuing a Weather Advisory or Conservative Operations. In a coordinated effort, SPP has a process to exchange information related to weather events where SPP or a portion of SPP expects temperatures at a level that is of concern, or where tornado, ice storm, or high wind might be forecasted. Weather Advisories may be issued to prepare personnel and facilities for expected extreme weather conditions.

   4.1 For the Western Interconnection, SPP has a process to exchange information related to potential reliability impacted weather events, including utilizing R-Comm, emails, satellite phones, etc.

5. SPP Information Technology (IT) group maintains an awareness and level of protection from Cyber Attacks. SPP IT group has a process to determine if and when notifications should be made to Operations staff to increase awareness of potential cyber activities. In the event that Operations suspects or detects a Cyber Attack first, they will follow the process in accordance with the SPP Sabotage Procedure to notify the necessary parties.

6. In the event of the loss of a necessary application, SPP shall notify neighboring RCs, BAs, and TOPs to monitor the SPP RC Areas footprint when necessary.

B. Responsibilities – Delegation of Tasks

The SPP RC has not delegated any RC tasks. Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

C. Common Tasks for Next Day Operations

1. SPP coordinates operations and ensures reliable operation of the BES by utilizing System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) during the real-time and next day operating horizons for the SPP RC Areas including additional thermal, voltage and stability-related analysis as necessary. SPP will communicate and coordinate the results of its reliability assessments with those performed by the SPP RC Members and Reliability Customers, to ensure that any potential or actual SOL exceedances are properly identified and reported. SPP models a sufficient wide-area view to ensure properly coordinated operations with neighboring RCs. SPP will share its Operational Planning Analysis (OPA) via its secure FTP site.

2. SPP is responsible for determination of IROLs within the SPP RC Areas, and does so via documented methodologies. As part of the daily OPA and/or RTA, SPP highlights additional potential SOLs. That list of potential SOLs and the existing list of SOLs are screened for potential IROL criteria. The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in cascading outages or widespread voltage problems, unless there are studies or system knowledge that the SOL is not an IROL. Additionally, when temporary constraints are defined for various operating circumstances identified through OPA and/or RTA, this process is performed to verify if an IROL exists. SPP disseminates IROL information within its RC Areas and with neighboring RCs.

3. SPP ensures that SPP RC Members and Reliability Customers operate to prevent the likelihood that a disturbance, action or non-action in the SPP RC Areas will result in an SOL or IROL exceedance in another entity of the Interconnection. SPP's RC Members and Reliability Customers are required to adhere to NERC Reliability Standards. SPP is required by its seams agreements with its neighbors to coordinate maintenance outages in such a way that impacts on the other systems' reliability are minimized. SPP performs OPA on a daily basis for the next day. If a potential SOL or IROL exceedance is observed on a neighboring party's system, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan, if one does not already exist. In instances where there are differences in operating limits derived by SPP and its neighbors or between SPP entities, SPP will operate to the most conservative result until the reasons for these differences can be identified and an agreement is reached.

4. SPP ensures that its RC Members and Reliability Customers are always operating under known and studied conditions and ensures that they reassess and re-posture their systems following contingency events within 30 minutes. SPP performs next day OPA pursuant to the Reliability Assessment Process Overview. These analyses are performed for each day. These analysis model peak conditions for the day being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. SPP performs an N-1 contingency analysis monitoring the post-contingency flow of both SPP and neighboring system facilities. If a potential SOL or IROL exceedance is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan if one does not already exist.

   SPP performs a next-day assessment of capacity and adequacy for each hour of the day, as well as a next-hour assessment of capacity and adequacy on an hourly basis. These analyses model peak conditions for the day/hour being studied including scheduled generation and transmission outages and anticipated generation dispatch to support the forecasted load plus net interchange. If a capacity issue is observed, SPP will coordinate with the impacted and impacting parties to develop an appropriate mitigation plan.

   SPP monitors, in real-time, all facilities considered critical. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at the facility ratings, SOL and IROL levels. SPP tracks real-time and applicable post-contingency flows on all constraints and alarms when applicable SOLs and IROLs are approaching the limit or are exceeded. Additionally, when any identified IROL is exceeded in real-time, an email notification of the exceedance is sent to operations management and engineering staff to initiate post-event analysis.

   SPP also uses a State-Estimator solution to run its Real-Time Contingency Analysis (RTCA) application at least every 6 minutes. SPP has defined all branches and transformers with low side voltages of 115 kV and higher (with some 69kV) within the SPP RC Areas and all branches and transformers with low side voltages of 230 kV and higher within the first-tier BA Areas as contingencies in RTCA. SPP monitors the post-contingency flow on all SPP branches and transformers with low side voltages of 115kV and higher. Alarms are triggered if that flow exceeds the emergency rating of the branch or transformer. Additionally, SPP monitors post-contingency flow on all branches and transformers with low side voltages of 230 kV and higher within neighboring systems as well as selected lower voltage facilities within neighboring systems that are known to be impacted by an SPP contingency. The RC receives alarms for any RTCA exceedance.

5. The SPP RTO acts as the Transmission Service Provider (TSP) for all Transmission Owners in the Eastern Interconnection, subject to the SPP Tariff. For these entities,

SPP uses Flowgates as proxies for transmission limitations in the determination of ATC. The same Flowgates monitored in real-time by the SPP RC and their associated SOLs are also incorporated in the models used by SPP to calculate ATC and administer its OATT. SPP limits sales of transmission service to the SOLs of all identified Flowgates. When a need for a new Flowgate is determined by the SPP RC, the new Flowgate is included in the models used by the SPP TSP for calculation of ATC. These Flowgates are posted on the SPP OASIS.

5.1 SPP is not the TSP in the Western Interconnection, with the exception of WAUW.

6. SPP communicates reliability Operating Instructions in a clear, concise, and definitive manner. Per SPP RC procedures, the SPP RC requires the recipient to repeat back any reliability Operating Instructions communicated by the SPP RC. Proper communications protocols are included in Operator training provided by SPP.

D. Next Day Operations

1. SPP performs an OPA to identify potential SOL and IROL exceedances pursuant to the Daily Reliability Assessment Procedure. These analyses are performed daily with the exception of the weekend and holiday analyses being performed on the previous Friday, or day prior to the holiday. SPP's day-ahead reliability assessment consists of off-line PSS/E studies of the modeled system conducted by the Operations Engineering staff. Contingency-based analyses are conducted daily, which include Remedial Action Schemes (RAS). In these contingency analyses, at a minimum, SPP includes BES facilities in SPP and first-tier area above 100 kV as contingencies, and monitors facilities above 100 kV. SPP will include other facilities identified with impact to BES or with significant risk to the BES. SPP also runs a 7-day contingency analysis to review upcoming operating conditions over the next week for the Eastern Interconnection. Planned transmission and generation outages within the SPP RC Areas are coordinated with adjacent RCs. Outages external to the SPP RC Areas are obtained from neighboring RCs. Peak conditions are modeled using anticipated generation dispatch to support the forecasted load plus expected scheduled net interchange.

    1.1 If, in the next day OPA, parallel flows from the SPP RC Areas are observed as causing a potential problem on a neighboring system, SPP will contact the neighboring RC and coordinate to determine if the problem could result in an SOL or IROL exceedance. If it is agreed that an exceedance could occur, SPP will coordinate with the neighboring RC to develop an appropriate mitigation plan, if one does not already exist. The mitigation plan will identify appropriate actions to be taken to prevent the exceedance from materializing which may include creation of appropriate constraints to be monitored, commitment of appropriate generation capacity, reconfiguration of the transmission system, or re-dispatch of generation as well as actions to be taken in the event the

exceedance materializes in real-time, including identifying potential transmission system reconfigurations, generation that can be re-dispatched, schedules that can be curtailed, and, if necessary, load that can be shed.

2. SPP receives operating information, such as transmission and generation facility maintenance schedules, tap settings, and generation resource plans, required for performing an OPA from responsible SPP RC Members and Reliability Customers. The applicable SPP RDS requires SPP RC Members and Reliability Customers to submit the necessary data to SPP. SPP receives similar information from its neighbors. SPP uses load forecast, generation forecast, and/or tag data as its basis for incorporating Interchange Transactions into the OPA.

3. SPP shares the results of its OPA, when conditions warrant, or upon request, with other RCs. SPP also posts the results of its analyses via its secured FTP site for appropriate SPP RC Members, Reliability Customers, and neighboring RCs. If the results of the OPA indicate potential reliability problems and efforts outlined in (4.) below do not resolve the potential condition, the SPP RC issues the appropriate alerts via the RCIS.

4. The SPP RC initiates conference calls, or other appropriate communications, such as R-Comm, as necessary when conditions revealed by the OPA warrant. Conditions that warrant communications with other RCs include potential IROL exceedances determined as described in part 1.1 of this section and capacity deficiencies that could result in shedding of firm load.

E. Current Day Operations

1. SPP monitors facilities within the SPP RC Areas and adjacent RC Areas to ensure determination of potential SOL and IROL exceedances.

   1.1 SPP will make reasonable efforts to provide notice to a neighboring RC if SPP identifies a potential reliability problem in that RC's Areas. If both parties agree that a reliability problem exists, SPP will coordinate with its neighboring RCs any actions required to mitigate the situation. In the event that all parties cannot agree on the reliability issue, SPP will follow the most conservative approach. This coordination may include evaluation of the impact of maintenance and forced outages on the situation, implementation of existing emergency procedures or operating guides, reconfiguration of the transmission system, curtailment of point-to-point transactions, re-dispatch of generation, and load shedding.

2. In the SPP EMS, real-time flows on all critical facilities are monitored and alarmed at both SOL and applicable IROL levels. SPP uses constraint monitoring applications that track post-contingency flows on all constraints and alarms as applicable SOLs

and IROLs are approached and/or exceeded. Post-contingency flows on constraints are calculated using real-time flows and Line Outage Distribution Factors (LODFs) that are updated to reflect current system topography.

3. SPP monitors the necessary RC Area's parameters to ensure it is continuously aware of conditions within the SPP RC Areas.

   3.1. SPP monitors the status of BES elements using an EMS complete with State Estimator, Alarming, Real-Time Contingency Analysis, and Power Flow applications. SPP receives the data necessary to maintain the EMS from its RC Members and Reliability Customers in accordance with applicable SPP RDS.

   3.2. The SPP EMS model represents the SPP RC Areas, neighboring BA Areas and other portions of the Eastern and Western Interconnection. For the Eastern Interconnection, SPP's RC Area represents approximately one-third of the SPP EMS network model of Eastern Interconnection facilities. The EMS uses near real-time measurements received from these same entities via ICCP.

      3.2.1. For the Western Interconnection, SPP maintains a full model referenced from the Western Interconnection-wide Model (WIM) consistent with the Western Interconnection Modeling and Monitoring Methodology.

   3.3. SPP monitors, in real-time, pre-contingent and anticipated post-contingent element conditions. This is achieved through the EMS and constraint monitoring tools which utilize real-time Line Outage Distribution Factors based on the latest system topology.

   3.4. SPP monitors real-time flows and statuses of facilities 100 kV and above and select lower voltage facilities in the Eastern Interconnection. Contingencies of facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are studied. The post-contingent flow on facilities with low side voltages of 115kV and higher within the SPP RC Areas as well as those with low side voltages of 230 kV and higher within neighboring systems are monitored.

      3.4.1. For the Western Interconnection, the monitoring of facilities is consistent with the Western Interconnection Modeling and Monitoring Methodology agreed upon according to applicable NERC standards.

   3.5. SPP monitors real and reactive reserves. SPP receives real-time operating reserves data from its RC Members and Reliability Customers, and compares this data to the operating reserves required. SPP monitors and displays the reactive output of generators within the SPP RC Areas as well as the remaining reactive capability by BA Area. SPP receives real-time voltages on critical buses

which alarm the RC when a voltage limit is exceeded. SPP will contact the appropriate TOP or BA as necessary to develop mitigation plans. SPP RC makes all reasonable efforts to provide notification and coordination of actions that may impact adjacent RC Areas for voltage control, including coordination of reactive resources.

3.6. SPP monitors voltage points based upon a ±5% tolerance around nominal voltage. This tolerance may vary per TOP and for nuclear power stations. When a high or low voltage alarm is received from the EMS system indicating limit violations, SPP will coordinate with the affected TOP to determine if the indicated voltage is correct and verify the TOP's voltage limits for that particular area. SPP will assist the affected TOP in developing a course of action to address undesirable voltage conditions including verifying and changing status of static reactive devices, reconfiguration, coordinating resource commitments, establish power transfer limits and re-dispatch as appropriate, etc.

3.7. The SPP RTO within the Eastern Interconnection monitors capacity and adequacy conditions through the SPP Reserve Sharing System (RSG) and market applications. SPP also receives resource plan information for all resources participating in the SPP Integrated Marketplace (Eastern Interconnection). This information contains data for each resource for each hour of a 7-day horizon beginning with the current day and is updated as necessary throughout the day. SPP will use this and other system information to perform hourly assessments of capacity and adequacy for the next hour.

3.7.1. For the Western Interconnection, SPP West RC will monitor capacity and adequacy conditions utilizing applicable RSG and BA submitted data as documented in the required data specifications.

3.8. SPP monitors current ACE and frequency in real-time for all BA Areas in the SPP RC Areas using the real-time data sent by the BAs through ICCP pursuant to applicable SPP RDS. This information is displayed to the SPP RC constantly.

3.9. SPP monitors current external impacts on its system from external network load, Market flows in the Eastern Interconnection, external generation to load (GTL) and transactions.

3.10. SPP receives and reviews resource plans and generation schedules from its Reliability Customers.

3.11. SPP monitors planned and unplanned transmission and generation outages. SPP's RC Members and Reliability Customers are required to submit all generator and transmission outages. Timing requirements and approval

procedures are documented in the applicable SPP Outage Coordination Methodology and applicable SPP RDS. The generator and transmission outages are sent to the Outage Scheduler database of the EMS system and used by the State Estimator and RTCA if the real-time measurements of the facility do not contradict with the submitted outage. The SPP RC Operators are constantly verifying the submitted outage data using State Estimator displays and its alarming application. They contact the appropriate SPP RC Member or Reliability Customer if a scheduled outage does not materialize in real-time as planned or if a line, transformer or unit trips without having a scheduled outage.

SPP utilizes graphical display systems designed to increase SPP RC situational awareness of the SPP RC Areas. The systems use near real-time and/or EMS data to provide a wide-area view.

4. SPP monitors BES parameters that may have significant impacts upon its RC Areas and neighboring RC Areas as follows:

4.1. SPP maintains awareness of all Interchange Transactions that wheel-through, Source, or Sink in the SPP RC Areas.

4.1.1. SPP acts as a Scheduling Entity on behalf of the Market Operating Entities or PSEs in its Eastern Interconnection RC Area by approving all transactions that wheel-through, Source and Sink in its Eastern Interconnection RC Area. SPP makes available its Eastern Interconnection RC tag information to all RCs in the Eastern Interconnection as necessary.

4.1.2. SPP is not a scheduling entity in the Western Interconnection. The RC maintains awareness of scheduling impacts on constraints through the Enhanced Curtailment Calculator (ECC).

4.2. SPP evaluates and assesses additional Interchange Transactions that could violate SOLs and/or IROLs. SPP utilizes Interchange information, real-time data in the SPP EMS, and SPP's constraint monitoring tools to make an assessment of the impacts of additional transactions on constraint loading. SPP is authorized to utilize all resources, including load shedding, to address a potential or actual IROL exceedances. This authorization is reiterated to each SPP RC Operator in their job description and by a personal memorandum from SPP's Chief Operating Officer (COO).

4.3. SPP monitors operational data submitted by BAs within the SPP RC Areas to ensure that the required amount of Operating Reserves are provided and available as required to meet NERC Control Performance Standards (CPS) and Disturbance Control Standards (DCS). If necessary, SPP will instruct the BAs in the SPP RC Areas to arrange for assistance from neighboring BAs. SPP has the

authority to instruct the acquisition of generation capacity and, if that instruction is not satisfied, instruct the shedding of load in the deficient BA Areas.

4.4. SPP will identify the cause of potential or actual SOL or IROL exceedances. SPP shall initiate control actions or emergency procedures to relieve the potential or actual IROL exceedance without delay, and no longer than 30 minutes. SPP will choose the most effective means of relieving the IROL exceedance within 30 minutes including instructing generation re-dispatch, facility switching, and load shedding. SPP is authorized to instruct utilization of all resources, including load shedding, to address a potential or actual IROL exceedance.

4.5. SPP will communicate start and end times for time error corrections to all BAs within its RC Area in both the Eastern and Western Interconnections.

4.6 SPP will review TOP submitted Geo-Magnetic Disturbance (GMD) plans and acknowledge, via email, of both receipt and review. SPP will ensure that all TOPs and BAs within its RC Areas are aware of GMD forecast information and will assist in the development of any required response plans. For GMD levels K8 or above, SPP RC will initiate a satellite phone call test to ensure satellite phone functionality has not been damaged during the event. SPP will communicate GMD forecast information to its BAs and TOPs via one or more of the following; R-Comm, email communication, ICCP, and/or phone communication.

While performing the role of the GMD monitor, for all K-7 or higher GMD warnings and alerts, SPP will participate in the Space Weather Prediction Center (SWPC) initiated phone communication with other Reliability Coordinators via the NERC Hotline and perform a roll call of RCs expected to participate. As the GMD monitor, SPP RC will contact RCs who did not participate in the SWPC call, provide details concerning the GMD notification and post a message to the Reliability Coordinator Information System and, for the Western Interconnection RCs, to R-COMM utilizing the blast message option outlining the GMD event information.

4.7. SPP will participate in NERC Hotline discussions, assist in the assessment of the reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. SPP will disseminate this information within its RC Areas as necessary.

4.8. SPP monitors system frequency and its BAs' performance, and if necessary, will instruct any rebalancing required for a BA to return to CPS and DCS compliance to ensure reliability. SPP receives at least one real-time frequency point via ICCP for each Balancing Authority Areas in the SPP RC Areas. At the instruction

of SPP, its BAs shall utilize all resources, including firm load shedding, to balance load and generation.

4.9. SPP coordinates with other RCs and neighboring BAs or TOPs, as needed, in the development and implementation of mitigation plans for potential or actual SOL, IROL, CPS or DCS exceedances. SPP coordinates pending generation and transmission maintenance outages with other RCs, as necessary, in both the real-time RTA and next day OPA timeframes. SPP participates in periodic conference calls with neighboring RCs as necessary.

4.10. SPP will assist the BAs in the SPP RC Areas in arranging for assistance from neighboring RCs or BAs by issuing reserve sharing contingency notifications (for the Eastern Interconnection SPP RSG Members) or EEAs as appropriate.

4.11. SPP identifies sources of large ACEs that may be contributing to frequency, time error, or inadvertent interchange and will implement corrective actions with the appropriate BA. SPP receives the real-time ACE for each BA Area in the RC Areas via ICCP. The SPP RC receives an alarm if any ACE values change significantly or exceed a predefined limit. Excessive ACEs would be addressed by a call to the BA to determine the cause of the deviation and the course of action that the BA has planned and/or implemented to address the situation. Assistance would be provided in the Eastern Interconnection RC Areas by accessing operating reserves with the SPP Reserve Sharing Group to address the deviation should that be required. Should the situation be causing overloads on system facilities, instruction would be issued to dispatch/re-dispatch generation to relieve the situation.

4.12. SPP maintains awareness that Special Protection System (SPS) or Remedial Action Scheme (RAS) within the SPP RC Areas are armed. The host BA/TOP is required pursuant to applicable SPP RDS to keep SPP informed of the operational status of the SPS. If there is concern with the state of an SPS/RAS, and if not previously informed, the RC shall contact the responsible TOP, or neighboring entity as applicable, to inquire about the SPS/RAS state change.

5. SPP will alert all affected BAs and TOPs in its RC Areas, and all affected RCs within the Interconnection when it foresees an IROL exceedance or a significant loss of real and/or reactive generation capacity within its RC Areas through OPA and/or RTA. SPP will disseminate this information to its BAs and TOPs, utilizing appropriate communication channels, such as R-Comm, verbal communications, etc.

6. SPP confirms RTA and/or OPA results and determines the effects within its RC Areas and adjacent RC Areas. SPP will derive and discuss options to mitigate potential or actual SOL or IROL exceedances and identify and implement only those actions as necessary as to always act in the best interest of the Interconnection at all times.

Communication and coordination are completed with adjacent RCs, yet no request for delegation of task or action is requested.

F. Emergency Operations

1. In the event the loading of transmission facilities progresses to, or is projected to progress to, an SOL exceedance, SPP will use congestion management processes to reduce the loading to prevent an exceedance as soon as practicable. In the event the loading of transmission facilities progresses or is projected to progress to an IROL exceedance, SPP will take immediate actions, but no longer than 30 minutes, to return loading to the facility rating up to and including load shed.

2. SPP maintains copies of all pertinent operating guides/instructions as supplied by SPP RC Members and Reliability Customers. SPP reviews and coordinates these instructions with the BAs and TOPs in the SPP RC Areas. The SPP RC Operator maintains communication with the Transmission Operator who may be implementing these guides for local area relief to ensure regional reliability is not jeopardized by the implementation of said procedures. SPP RC Operators will instruct the appropriate Transmission Operators to take specific actions on how to mitigate the situation.

3. For the Eastern Interconnection RC Area, SPP will comply with the provisions of the NERC TLR procedure as follows. If the SPP RC is the sink RC and receives notification via the IDC that another RC has issued a TLR that calls for curtailment and/or halts of transactions sinking in SPP, the SPP RC will use the IDC to acknowledge the transaction curtailments and/or halts for the next hour, or current hour, and monitor the transactions to ensure that the transaction curtailments/halts are properly implemented. SPP acts as the sink RC in the IDC for transactions sinking into ERCOT across the East and North DC ties and for transactions sinking into Western Interconnection across the Eddy County, Stegall, Blackwater, Rapid City, Miles City, Lamar and Sidney HVDC ties.

    3.1. If SPP determines, through Source-to-Sink impact evaluation, that curtailment of a transaction as identified by the IDC would actually increase flows on the constraint for which relief has been requested, it will not acknowledge curtailment of such transaction. SPP may also determine that, through Source-to-Sink impact evaluation, transactions having a significant impact on the constraint exist but are not identified for curtailment by the IDC. In those cases, SPP will instruct curtailment of those transactions as necessary.

    3.2. If SPP receives notification from the IDC that SPP has a Generation to Load (GTL) relief obligation in response to a TLR issuance, SPP will utilize its market systems to calculate and send dispatch instructions to its Market Participants (MPs) necessary to achieve the relief.

3.3. SPP will follow procedures included in Market Protocols and its operating procedures to implement relief procedures, up to and including the point that emergency action is necessary. When SPP observes constraint loading that approaches the applicable SOL, it will communicate with the constraint owner to verify actual real-time flows and coordinate necessary actions to be taken. SPP will make a coordinated decision based on current and/or anticipated conditions to pursue relief by using the congestion management process.

4. For the Western Interconnection, SPP will utilize the Western Interconnection Congestion Management Methodology, including Unscheduled Flow Mitigation Procedure (UFMP).

5. SPP will monitor system frequency and its BAs' performance. If SPP determines that one or more of its BA areas are contributing to a frequency excursion, SPP will instruct the BA(s) to use all resources available, including load shedding, to comply with CPS and DCS requirements.

6. SPP will take or instruct whatever action is needed, including load shedding, to mitigate an energy emergency within the SPP RC Areas. SPP will provide assistance to other RCs experiencing an energy emergency as necessary.

7. SPP requires that any BA Area within its RC Areas that is experiencing an energy emergency, first use Operating Reserves available within its applicable Reserve Sharing Group (RSG). If the energy emergency still persists, SPP will issue an EEA on behalf of the deficient BA Area.

G. System Restoration

1. SPP is knowledgeable of the restoration plans of each of the Transmission Operators in its RC Areas and has a written copy of each plan in its possession. SPP verifies that the most current plans are on file on an annual basis. During system restoration, SPP monitors the restoration progress and coordinates any needed assistance.

2. SPP has regional restoration plans for the SPP RC Areas that provides coordination between individual restoration plans of each SPP Transmission Operator and that ensures reliability is maintained during system restoration events. The SPP RC Areas Regional Restoration Plans and NERC Reliability Standards require that the role of the SPP RC during system restoration is to facilitate this coordination. Furthermore, the SPP RC approves, communicates, and coordinates re-synchronization of system islands or synchronizing points such that a burden is not caused on adjacent TOP, BA, or RC Areas. SPP Communications Protocols delineate the processes for Emergency Communications.

3. SPP will disseminate information regarding restoration to neighboring RCs and BAs/ TOPs not immediately involved in restoration by posting pertinent information on the RCIS and/or via phone call. SPP will also use the NERC Hotline for updates to other RCs as needed.

H. Facility

SPP performs the RC function at each of its two Coordination Centers. Each Coordination Center has the necessary facilities for the SPP RCs to perform their responsibilities. Full functionality is provided with full backup of the systems, communications, data, and tools required for SPP to perform as the RC for its RC Members and Reliability Customers. Both primary and alternate sites are staffed and functional 24x7.

1. SPP has redundant data communications between the two SPP sites, which are staffed 24x7 with working communications such as voice and data links between RC Member and Reliability Customer sites and SPP systems. SPP also employs a Voice-over-IP (VOIP) phone system that allows the phones to ring at both Coordination Center sites simultaneously. Cell phones are used as the alternate voice communication capability.

   SPP IT's 24x7 desk and additional on-call staff provide support of the voice and data communications, hardware, and software, working with communication service companies as appropriate.

2. A satellite phone system is installed at both of SPP's Coordination Centers as well as at all SPP RC Areas BA/TOP primary operations centers, for purposes of communicating during emergency conditions per SPP Communications Protocols. This system bypasses the Public Switched Telephone Network (PSTN) and can be used for point-to-point or broadcast (all-call) communications. The satellite service can also route a phone call to a land line, providing access to any operable wire or wireless phone.

3. SPP has detailed real-time monitoring capability of the SPP RC Areas and sufficient monitoring capability of surrounding RC Areas to ensure that potential or actual SOL or IROL exceedances are identified. SPP has monitoring systems that provide information that can be easily understood and interpreted, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure. SPP monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL exceedances within the SPP RC Areas. SPP monitors both real and reactive power system flows,

operating reserves, and the status of system elements that are or could be critical to SOLs and IROLs and system restoration requirements within the SPP RC Areas.

4. SPP utilizes two separate EMS clusters, an Authorized cluster and an Unauthorized cluster. If the Primary Location is lost, the primary EMS systems in the Alternate Location will automatically take over EMS functionality at the Alternate Location. As part of the EMS model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

5. SPP utilizes two separate ICCP clusters, a primary cluster and a back-up cluster (secondary ICCP). If the Primary Location is lost, the primary ICCP systems located in the Alternate Location will automatically take over primary ICCP functionality. As part of the ICCP model upload and patching processes, all nodes of the primary and maintenance clusters are updated within the maintenance window.

6. Per the applicable SPP RDS, SPP RC Members and Reliability Customers are required to send and receive near real-time data to both the primary and secondary systems concurrently as appropriate. Data from both systems are fed to the EMS providing an alternate data source for use when the primary source is failed for any reason.

I. Staffing

1. SPP 24x7 operations consists of four RC Operators and two Shift Engineers. The personnel is split between our primary and our alternate facilities with two RC Operators and one Shift Engineer at each location. These RC Operators and Shift Engineers are required to hold the NERC RC certification as well as being desk qualified at their position. SPP requires its RC Operators to complete yearly training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

2. SPP ensures that its RC Operators have a comprehensive understanding of the SPP RC Areas and required interaction with neighboring RCs. The SPP RC Operators have an extensive understanding of the RC Member and Reliability Customer systems within the SPP RC Areas such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. SPP makes year-round training opportunities available for the RC Operators, which includes the use of a Dispatcher Training Simulator (DTS) to provide realistic simulations of system emergencies described in the previous section.

   SPP creates training and performance support to ensure the SPP RC Operators understand the SPP region and the interface with neighboring regions. This includes opportunities for continuing education hours, including required

emergency operations and simulation hours. This training includes familiarization with Member BAs/TOPs by including RC training on the RC Members' and Reliability Customers' operating guides, system configuration, and transmission facilities. Control Center evacuation training and performance-based exercises are provided annually through instructor-led courses. Operations personnel who have a role in the evacuation plan are required to participate in the evacuation training and performance-based exercise annually. In addition, SPP conducts regional system restoration drills annually.

SPP's training department documents all training for recordkeeping and reporting purposes. All information required by the NERC Continuing Education program is available in a variety of report formats.

3. An Officer of SPP has signed the NERC Reliability Coordinator Standards of Conduct on behalf of the SPP RC. Each SPP RC Operator is required to sign and receive training on the SPP Standard of Conduct annually. The SPP Standard of Conduct requires the signatory to maintain proper confidentiality procedures and processes. SPP is an independent organization with an independent Board of Directors. SPP's independence enables its staff to fully comply with both the NERC and SPP Standards of Conduct.

Appendix A – BAs and TOPs in SPP RC Areas

Balancing Authorities and Transmission Operators in the SPP Reliability Coordination Areas:

Entity	BA	TOP	East	West
Arlington Valley Power Cooperative (AVBA)	X			X
American Electric Power – West (AEP)		X	X	
Arizona Electric Power Cooperative/SW Transmission Coop (AEPC)		X		X
Black Hills Corporation (BHE)		X		X
City Utilities of Springfield (CUS)		X	X	
Colorado Springs Utilities (CSU)		X		X
Corn Belt Power Cooperative (CBPB)		X	X	
El Paso Electric (EPE)	X	X		X
Empire District Electric Company/Liberty Utilities (EDE)		X	X	
Farmington Electric Utility System (FEUS)		X		X
First Light Energy (BNBA)	X			X
Grand River Dam Authority (GRDA)		X	X	
City of Independence Power & Light Department, Missouri (INDP)		X	X	
Gridforce Energy Management (GRID)	X			X
CORE Electric Cooperative (CORE)		X		X

Entity	BA	TOP	East	West
ITC Great Plains (ITC)		X	X	
The Board of Public Utilities, Kansas City, Kansas (BPU)		X	X	
Kansas City Power and Light Company (KCPL)		X	X	
KCP&L Greater Missouri Operations Company (UCU)		X	X	
Lincoln Electric System (LES)		X	X	
Midwest Energy, Inc. (MIDW)		X	X	
Nebraska Public Power District (NPPD)		X	X	
Oklahoma Gas and Electric (OKGE)		X	X	
Omaha Public Power District (OPPD)		X	X	
Platte River Power Authority (PRPA)		X		X
Public Service of Colorado (PSCO)	X	X		X
Sunflower Electric Power Corporation (SEPC)		X	X	
Southwest Power Pool (SPP)	X		X	
Southwestern Power Administration (SPA)	X	X	X	
Southwestern Public Service Company (SPS)		X	X	
Tri-State G & T (TSGT) *		X	X	X
Tucson Electric Power (TEPC)	X	X		X
Western Areas Power Administration (WACM)	X	X		X
Western Areas Power Administration (WALC)	X	X		X
*Western Areas Power Administration (WAUE)		X	X	
Western Areas Power Administration (WAUW)	X	X		X
Western Farmers Electric Cooperative (WFEC)		X	X	
Westar Energy, Inc. (WRGS)		X	X	

**Eastern and Western Interconnections*

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit I: Department, Order No. 202-25-7 (Aug. 20, 2025)

Order No. 202-25-7

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. §7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

Based on my determination of an emergency set forth above, I hereby order:

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit II: NERC, *Emergency Operations*

A. Introduction

1. Title: **Emergency Operations**

2. Number: **EOP-011-4**

3. Purpose: To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. Applicability:

4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.2 Reliability Coordinator

4.1.3 Transmission Operator

4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. Effective Date: See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit J: CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E

Colorado PUC E-Filings System

Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR). The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar	Standalone Battery
Wind	Dispatchable Combustion Turbine
Solar + Battery	Dispatchable Natural Gas with CCS
Wind + Battery	
Geothermal	

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Location in Moffat County or West End of Montrose County • Community Benefits
Counterparty Profile	• Bidder's prior experience with project development

	• Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed • Financial viability of the bidder • Markup of PPA or term sheet terms and conditions
Project Feasibility	• Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives • Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status • Local opposition or community efforts to stop project development • Ability to source materials • Project retirement/decommissioning plan • Legal, engineering and other costs required to implement the proposed project
Project Capability	• Renewal and purchase options at end of PPA (if applicable) • Impact on scheduling project output to Tri-State load • Operational flexibility

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS
Solar	12	2,303	-
Wind	6	1,218	-
Solar+Battery	12	2,049	907
Wind+Battery	1	180	100
Short-Duration Storage	16	-	2,200

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

Long-Duration Storage	1	-	100
Gas Plant	2	495	-
Gas Tolling	1	314	-
Geothermal	1	20	-
TOTAL	**52**	**6,579**	**3,307**

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios					
			1 – NEE	2 – NELG	3 – FLEX	4 – FLEXSR	5 – NNG	6 – NNGSR
PV-0004-4-nm	Solar	100	☒	☒	☒		☒	
PV-0004-5-wco	Solar	140	☒	☒			☒	
PV-0006-8-eco	Solar	200				☒		☒
WI-0013-2-wyo-wne	Wind	200	☒	☒	☒	☒	☒	☒
WI-0013-3-eco	Wind	200	☒	☒		☒	☒	☒
WI-0016-1-eco	Wind	297			☒			
PC-0009-2P-eco	Solar / Battery	150 / 75	☒	☒	☒		☒	
PC-0018-1P-nm	Solar / Battery	100 / 50	☒	☒	☒	☒	☒	☒
ST-0002-5-wco	4hr - Battery	50	☒	☒	☒	☒	☒	☒
ST-0002-6-wco	4hr - Battery	100		☒				
ST-0004-10-eco	4hr - Battery	100		☒		☒	☒	☒
ST-0004-6-eco	4hr - Battery	150				☒		☒
ST-0004-8-wco	4hr - Battery	200					☒	☒
ST-0004-9-eco	4hr - Battery	100					☒	☒
ST-0009-3-wco	4hr - Battery	200	☒	☒	☒	☒	☒	☒
ST-0009-4-nm	4hr - Battery	100	☒	☒	☒	☒	☒	☒
ST-0010-4-eco	4hr - Battery	150			☒		☒	☒
ST-0017-1-eco	4hr - Battery	100	☒	☒	☒		☒	☒
ST-0018-1-eco	4hr - Battery	50			☒		☒	
ST-0019-1-eco	Iron Air Battery	100	☒				☒	

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

GG-0006-1-wco	Combustion Turbine	307		☒				
GG-0006-2-wco	Combustion Turbine[23]	307	☒		☒	☒		

Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

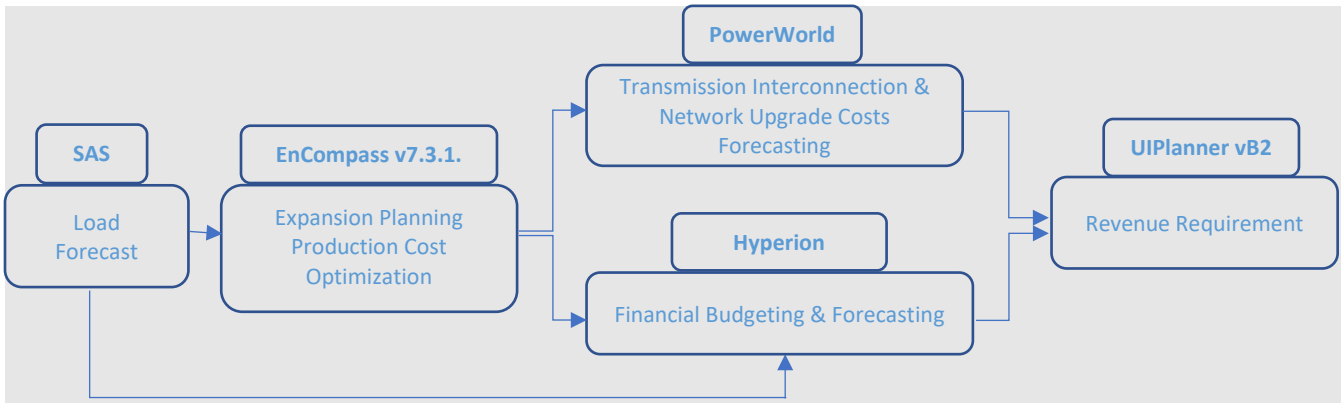
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

Figure 1: Modeling Software Tools



Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

Comparative Analysis

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).
[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=
[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.
[33] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.
[34] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.
[35] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.
[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.
[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each portfolio and affirms that all portfolios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 5: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[38, 39]		New Mexico RPS[40]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 6: Expansion Plan (Portfolio 1 – NEE)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[41]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	1	100
	-	10hr - Battery	East Colorado	100	1	100
2037	-	Wind / Battery	Wyoming / W.Neb	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	1	100
	-	Wind	East Colorado	100	3	300
2043	-	10hr - Battery	East Colorado	100	1	100
	-	Wind	East Colorado	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

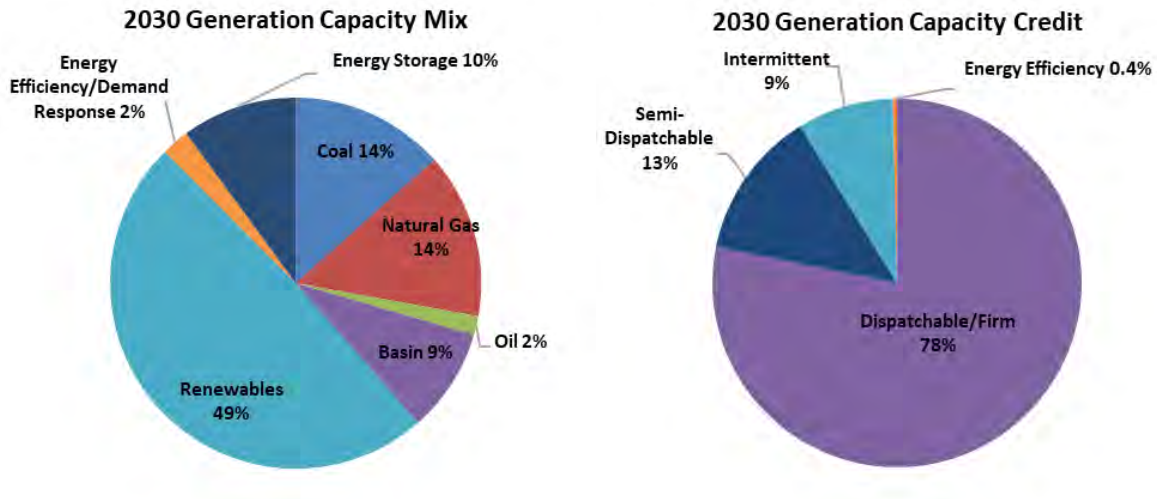
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

Table 7: Modeled Retirements (Portfolio 1 - NEE)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[43]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]



[42] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

[44] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits (RECs) received via the Basin contract, and hydropower purchases.

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)[46]

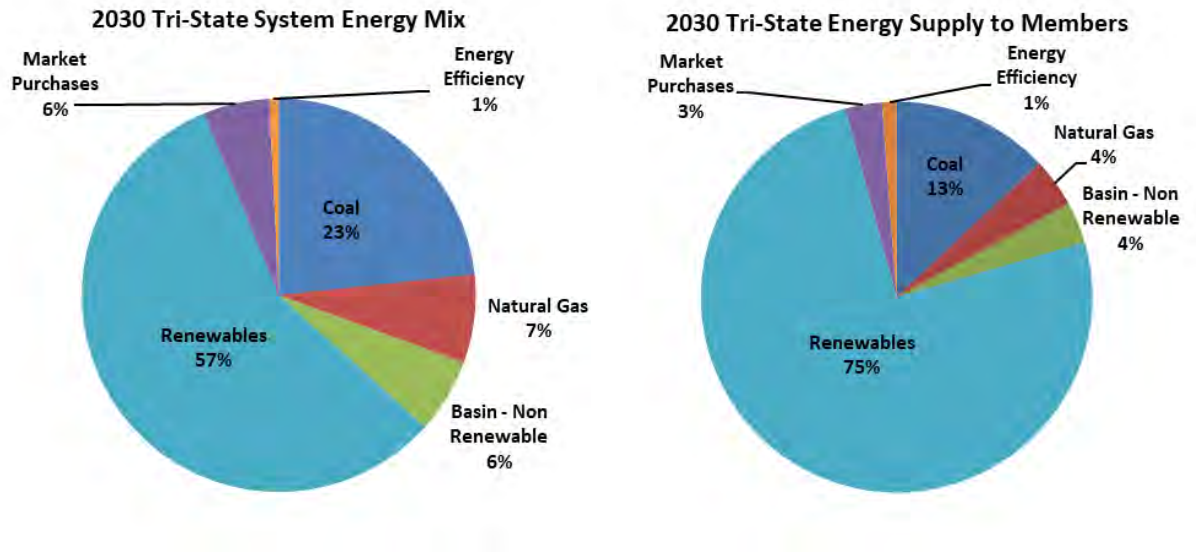


Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	68%	84%	65%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	5%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	0%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	26%	19%	24%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 1 (New ERA Expanded) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE) [47]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,962,306	6,093	7,512	0.0335	975	4,183,354,305	24,235
2027	11,750,117	5,940	7,360	0.0327	961	4,161,589,886	23,953
2028	9,874,804	5,208	6,125	0.0290	841	3,480,893,766	20,201
2029	9,043,741	7,796	6,571	0.0268	729	3,080,720,212	17,940
2030	7,345,275	10,258	6,986	0.0238	607	2,691,211,959	16,047
2031	6,399,384	9,943	6,815	0.0207	370	2,139,654,056	13,265
2032	5,656,566	9,627	6,510	0.0177	259	1,784,885,467	11,492
2033	5,818,338	9,697	6,570	0.0187	278	1,863,239,379	11,783
2034	5,682,522	9,640	6,485	0.0181	274	1,803,058,523	11,491
2035	5,813,155	9,712	6,584	0.0187	273	1,845,867,435	11,847
2036	5,570,335	9,577	6,460	0.0173	252	1,750,921,710	11,305
2037	5,706,630	9,672	6,538	0.0181	266	1,785,001,792	11,627
2038	5,448,317	8,616	6,119	0.0176	252	1,666,538,080	11,330
2039	5,553,097	8,731	6,199	0.0181	254	1,712,426,151	11,584
2040	5,180,884	7,717	5,792	0.0167	221	1,547,476,901	10,991
2041	5,164,345	7,364	5,705	0.0167	222	1,513,398,513	11,008
2042	5,000,692	6,947	5,545	0.0159	210	1,426,738,301	10,699
2043	4,973,141	6,509	5,436	0.0159	202	1,395,662,722	10,776
Total	**134,188,571**	**154,604**	**122,581**	**0.406**	**8,306**	**43,732,557,038**	**273,981**
Pounds/Gallons per MWh[48]	**902**	**1.04**	**0.82**	**0.000003**	**0.06**	**147**	**2.030**

[47] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[48] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Carbon
2025	$1,139,132,187
2026	$1,151,025,894
2027	$1,182,993,732
2028	$1,027,875,370
2029	$972,185,689
2030	$815,346,559
2031	$741,565,451
2032	$676,606,840
2033	$726,019,364
2034	$731,664,351
2035	$772,246,675
2036	$771,269,337
2037	$814,965,697
2038	$802,439,822
2039	$851,748,425
2040	$819,299,456
2041	$841,929,891
2042	$848,377,440
2043	$869,547,745

Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,950,104
2027	$72,370,913
2028	$63,854,206
2029	$59,238,749
2030	$55,323,918
2031	$47,881,107
2032	$43,405,678
2033	$46,538,873
2034	$47,435,734
2035	$51,090,347
2036	$50,898,647
2037	$54,631,126
2038	$55,527,948
2039	$59,194,959
2040	$58,529,071
2041	$60,870,777
2042	$62,289,850
2043	$64,055,746

Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)

Year	Target[49]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 13: Total Financial (Portfolio 1 – NEE)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,836	$12,911	$837	$29,746	$30,584
Difference to preferred plan (Nominal $)	$393	($18)	($1)	$375	$374

Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,508	$971
Transmission (Nominal $)	$1,506	$389

Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,206
2028	$1,539
2029	$1,401
2030	$1,424
2031	$1,501

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,518
2033	$1,552
2034	$1,531
2035	$1,529
2036	$1,597
2037	$1,634
2038	$1,679
2039	$1,717
2040	$1,711
2041	$1,785
2042	$1,835
2043	$1,921

[redacted]

[redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	185	0	0	185
2026	0	896	0	0	896
2027	0	1,429	0	0	1,429
2028	0	1,811	0	0	1,811
2029	0	52	0	124	176
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**4,373**	**0**	**124**	**4,497**

Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)

	Winter	Spring	Summer	Fall
2025	0	118	0	67
2026	13	713	39	131
2027	18	1,189	1	221
2028	61	954	69	727
2029	0	0	12	164
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**92**	**2,974**	**121**	**1,310**

The following table reflects PPA pricing, penalties, and taxes.

Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)

	Wind ($)	Solar ($)
2025	$0	$23,999
2026	$0	$145,247
2027	$0	$224,019

2028	$0	$214,350
2029	$0	$18,138
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$625,753**

Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2038	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Battery	$1.50	$5.85	
2043	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2037	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2041	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	52%	58%	35%

Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 27: Expansion Plan (Portfolio 2 – NELG)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[55]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-1-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	1	100
2036	-	10hr - Battery	East Colorado	100	1	100
	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Wind	East Colorado	100	4	400
	-	Solar	New Mexico	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

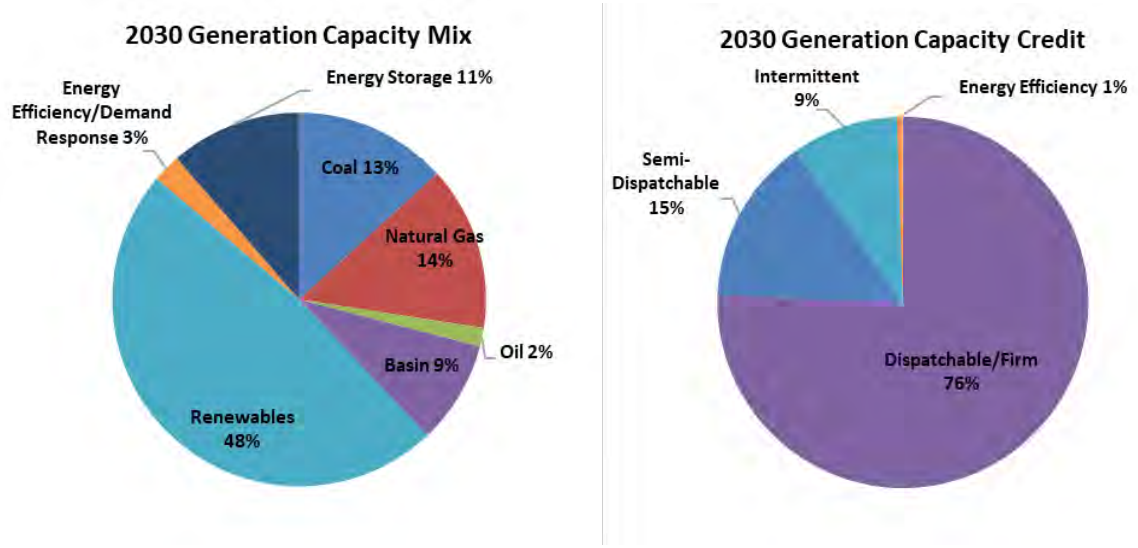
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

Table 28: Modeled Retirements (Portfolio 2 – NELG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[57]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]



[56] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]

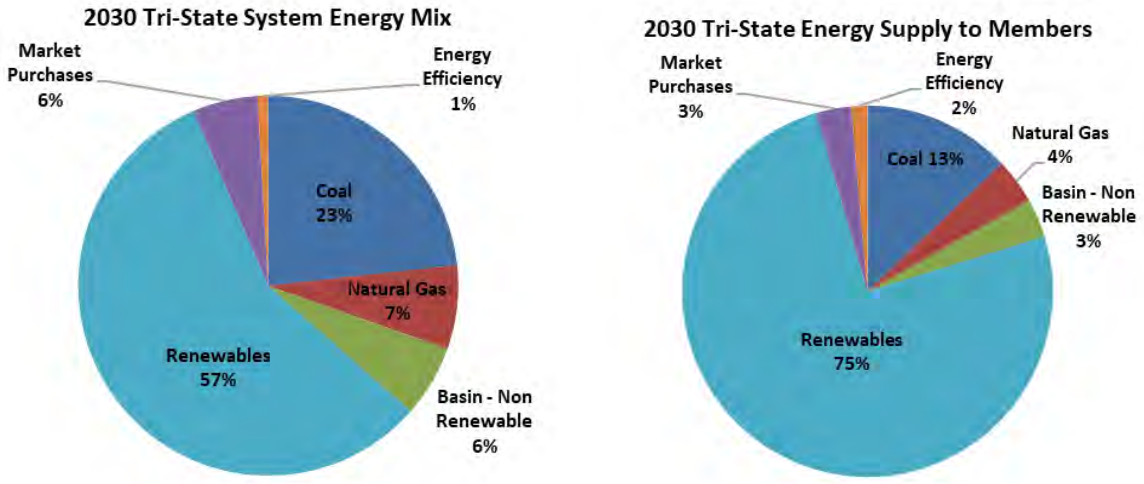


Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	64%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	18%	24%
GG-0006-1-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG) [61]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,684	6,082	7,499	0.0335	974	4,177,652,419	24,195
2027	11,727,659	5,926	7,347	0.0325	958	4,150,755,120	23,895
2028	9,879,304	5,209	6,129	0.0290	839	3,477,044,578	20,198
2029	9,036,223	7,796	6,566	0.0268	726	3,057,173,748	17,831
2030	7,334,742	10,249	6,979	0.0238	606	2,670,517,035	15,863
2031	6,390,985	9,941	6,811	0.0207	369	2,119,971,139	13,074
2032	5,643,142	9,626	6,504	0.0177	258	1,756,894,095	11,314
2033	5,846,331	9,721	6,629	0.0185	276	1,840,356,862	11,660
2034	5,721,745	9,570	6,526	0.0180	272	1,784,592,739	11,401
2035	5,816,518	9,313	6,528	0.0185	267	1,808,182,520	11,756
2036	5,617,103	9,352	6,437	0.0175	253	1,746,259,917	11,294
2037	5,668,595	8,918	6,321	0.0183	262	1,762,046,825	11,511
2038	5,370,590	7,698	5,885	0.0174	240	1,607,675,000	11,165
2039	5,444,002	7,486	5,871	0.0179	237	1,637,977,953	11,421
2040	5,033,242	6,320	5,407	0.0162	202	1,458,912,630	10,787
2041	5,081,355	6,125	5,424	0.0162	205	1,437,999,469	10,924
2042	4,923,968	5,904	5,263	0.0158	200	1,383,150,176	10,618
2043	4,899,783	5,453	5,150	0.0159	192	1,362,250,327	10,712
Total	**133,622,891**	**146,245**	**120,547**	**0.404**	**8,194**	**43,139,330,433**	**272,022**
Pounds/Gallons per MWh[62]	**946**	**1.04**	**0.85**	**0.000003**	**0.06**	**153**	**2.123**

[61] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[62] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,653,707
2027	$1,174,732,910
2028	$1,026,795,307
2029	$973,309,290
2030	$818,577,657
2031	$739,322,590
2032	$676,519,826
2033	$726,175,264
2034	$736,202,715
2035	$775,083,935
2036	$775,046,549
2037	$809,721,903
2038	$794,053,163
2039	$832,968,427
2040	$796,824,782
2041	$828,400,211
2042	$835,361,013
2043	$856,721,090

Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,834,755
2027	$72,194,298
2028	$63,843,496
2029	$58,876,581
2030	$54,688,462
2031	$47,192,177
2032	$42,731,594
2033	$46,052,949
2034	$47,065,889
2035	$50,698,390
2036	$50,851,295
2037	$54,083,272
2038	$54,721,101
2039	$58,358,076
2040	$57,442,190
2041	$60,401,484
2042	$61,819,253
2043	$63,671,990

Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)

Year	Target[63]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 34: Total Financial (Portfolio 2 – NELG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$16,841	$12,852	$831	$29,693	$30,524
Difference to preferred plan (Nominal $)	$399	($77)	($7)	$322	$314

Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$370	($167)
Transmission (Nominal $)	$1,494	$378

Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,046
2027	$1,231
2028	$1,312
2029	$1,326

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2030	$1,432
2031	$1,510
2032	$1,571
2033	$1,572
2034	$1,556
2035	$1,552
2036	$1,623
2037	$1,670
2038	$1,709
2039	$1,746
2040	$1,781
2041	$1,821
2042	$1,907
2043	$1,962

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64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	962	0	0	962
2027	0	853	0	0	853
2028	0	1,132	0	11	1,143
2029	0	242	0	337	579
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,262**	**0**	**348**	**3,610**

Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	35	669	80	178
2027	33	703	32	85
2028	132	288	26	697
2029	0	0	288	291
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**200**	**1,710**	**426**	**1,274**

The following table reflects PPA pricing, penalties, and taxes.

Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$156,979
2027	$0	$114,621
2028	$0	$143,388
2029	$0	$56,325
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$480,683**

Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-10-ECO			
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2027	100	ST-0002-6-WCO	$1.30	$3.25	
2029	307	GG-0006-1-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	36%	54%	59%	36%

Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	31%	31%	32%	32%	33%	31%	34%	36%	34%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 48: Expansion Plan (Portfolio 3 – FLEX)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[69]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
2033	-	Wind / Battery	New Mexico	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	2	200
	-	10hr - Battery	West Colorado	100	1	100
	-	Solar	West Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Wind	East Colorado	100	3	300
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

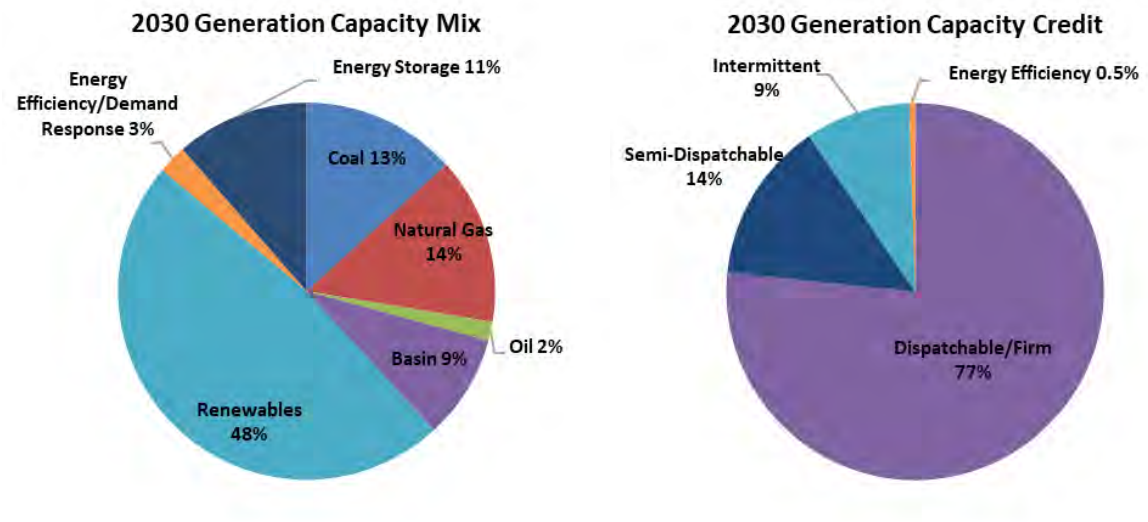
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

Table 49: Modeled Retirements (Portfolio 3 – FLEX)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[71]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]



[70] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)[74]

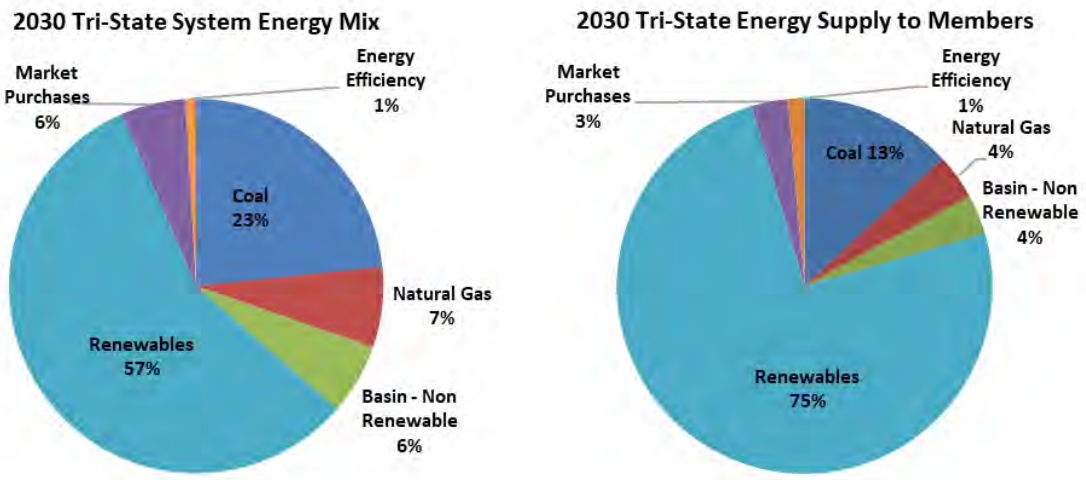


Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	52%	70%	83%	82%	80%
SPV 3	87%	87%	89%	75%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	22%	16%	21%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX) [75]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,943,290	6,082	7,500	0.0335	974	4,177,494,353	24,196
2027	11,568,153	5,770	7,226	0.0311	936	4,045,072,240	23,327
2028	9,779,075	5,148	6,077	0.0284	818	3,407,958,468	19,883
2029	8,967,361	7,781	6,521	0.0267	724	3,038,458,535	17,867
2030	7,315,232	10,260	6,967	0.0237	605	2,657,827,563	16,039
2031	6,350,647	9,935	6,786	0.0206	367	2,096,814,877	13,210
2032	5,635,838	9,629	6,501	0.0176	257	1,753,123,139	11,482
2033	5,820,676	9,711	6,616	0.0184	274	1,827,280,223	11,797
2034	5,720,467	9,667	6,551	0.0179	272	1,784,031,850	11,563
2035	5,832,550	9,741	6,639	0.0185	270	1,814,000,679	11,908
2036	5,602,277	9,601	6,471	0.0175	255	1,753,655,478	11,394
2037	5,653,752	9,638	6,515	0.0177	261	1,752,980,829	11,500
2038	5,458,897	8,694	6,154	0.0176	252	1,654,130,594	11,329
2039	5,548,435	8,783	6,219	0.0180	252	1,690,762,833	11,575
2040	5,178,596	7,783	5,816	0.0165	220	1,530,568,107	10,959
2041	5,191,519	7,349	5,728	0.0167	223	1,503,734,603	11,078
2042	5,095,815	6,784	5,539	0.0165	218	1,460,467,941	10,943
2043	5,039,030	6,269	5,391	0.0164	208	1,427,643,128	10,961
Total	**133,946,532**	**154,182**	**122,485**	**0.404**	**8,246**	**43,275,923,319**	**273,416**
Pounds/Gallons per MWh[76]	**949**	**1.09**	**0.87**	**0.000003**	**0.06**	**153**	**2.134**

[75] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[76] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,712,185
2027	$1,158,755,608
2028	$1,016,378,097
2029	$965,892,008
2030	$816,400,243
2031	$734,656,192
2032	$675,644,270
2033	$722,988,638
2034	$736,038,329
2035	$777,220,279
2036	$773,000,815
2037	$807,601,751
2038	$807,109,612
2039	$848,947,387
2040	$819,836,199
2041	$846,359,980
2042	$864,515,211
2043	$881,068,315

Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,836,579
2027	$70,477,977
2028	$62,847,444
2029	$58,997,890
2030	$55,296,246
2031	$47,683,283
2032	$43,367,675
2033	$46,595,924
2034	$47,733,888
2035	$51,349,932
2036	$51,298,669
2037	$54,036,042
2038	$55,522,239
2039	$59,145,438
2040	$58,361,648
2041	$61,255,841
2042	$63,710,822
2043	$65,154,538

Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)

Year	Target[77]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 55: Total Financial (Portfolio 3 – FLEX)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,761	$12,891	$836	$29,652	$30,488
Difference to preferred plan (Nominal $)	$318	($38)	($2)	$281	$278

Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,129	$592
Transmission (Nominal $)	$1,457	$340

Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,220
2028	$1,371
2029	$1,399
2030	$1,427
2031	$1,503

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,525
2033	$1,557
2034	$1,537
2035	$ 1,531
2036	$1,607
2037	$1,639
2038	$1,697
2039	$1,726
2040	$1,751
2041	$1,785
2042	$1,833
2043	$1,906

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78 [redacted]

79 [redacted]

80 [redacted]

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82 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	770	0	0	770
2027	0	1,019	0	0	1,019
2028	0	847	0	7	854
2029	0	9	0	207	216
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,746**	**0**	**214**	**2,960**

Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	13	601	79	77
2027	18	725	52	224
2028	49	412	1	392
2029	0	0	70	146
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**80**	**1,798**	**202**	**880**

The following table reflects PPA pricing, penalties, and taxes.

Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$125,261
2027	$0	$151,371
2028	$0	$107,958

2029	$0	$18,876
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$416,632**

Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	297	WI-0016-1-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2038	100	Wind + Battery		$5.85	$81.56
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
2036	100	Solar		$5.85	
2036	100	Battery	$1.50	$5.85	
2041	100	Solar		$3.25	
2042	100	Solar		$6.56	
2042	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	54%	58%	36%

Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 69: Expansion Plan (Portfolio 4 – FLEXSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[83]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Wind / Battery	New Mexico	100	2	200
	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
	-	Solar	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	2	200
	-	Wind	Wyoming/ W. Neb.	100	1	100
	-	Wind	East Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

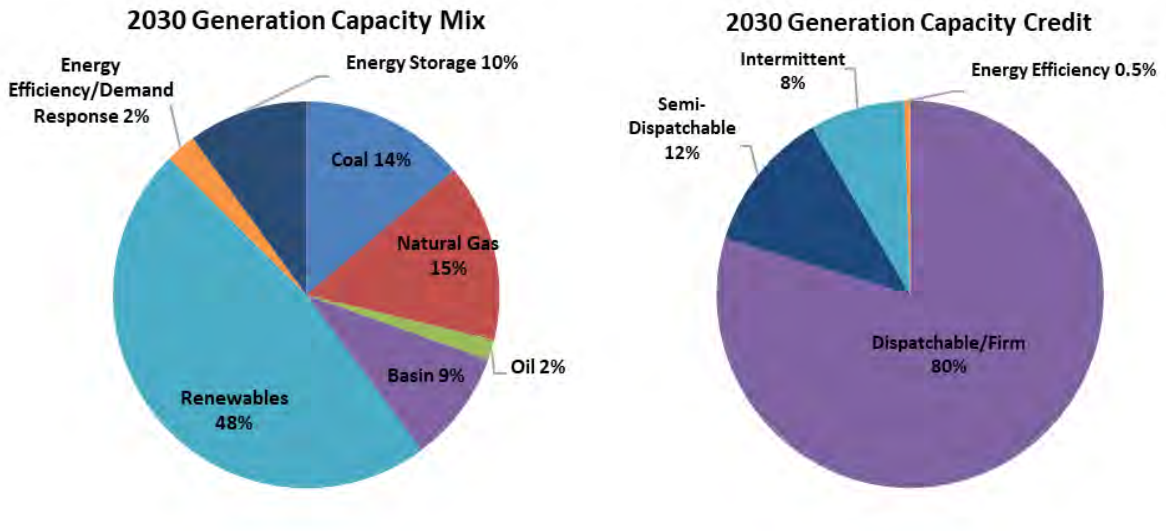
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[85]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]



[84] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]

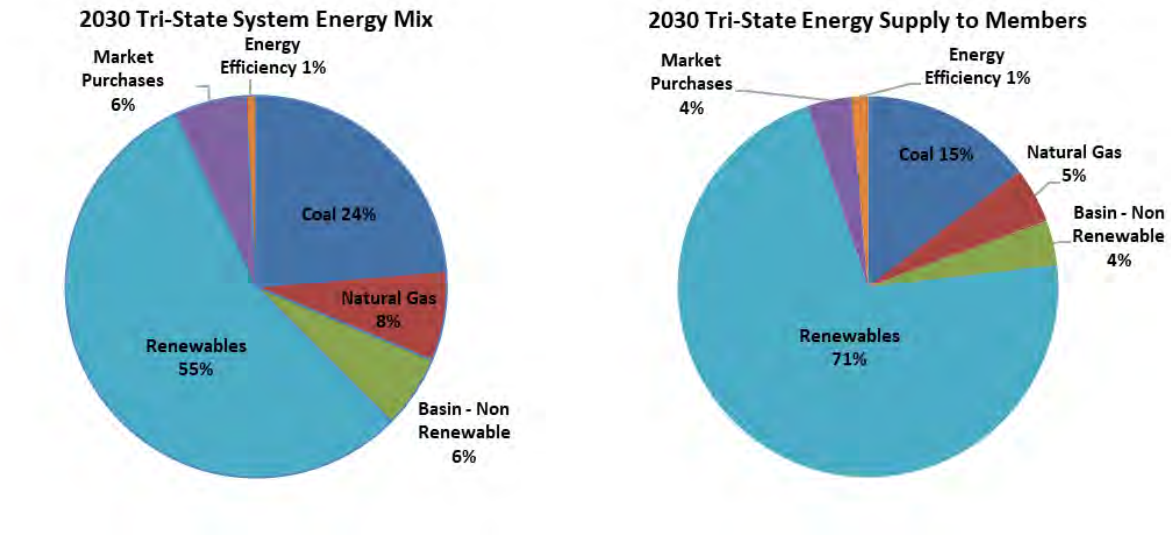


Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	82%	82%	80%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	22%	23%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR) [89]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,421	6,082	7,499	0.0335	974	4,177,610,423	24,195
2027	11,568,735	5,770	7,227	0.0311	937	4,046,667,348	23,331
2028	9,819,361	5,161	6,103	0.0283	814	3,399,083,138	19,893
2029	9,204,229	7,855	6,616	0.0273	767	3,162,829,891	18,345
2030	7,412,404	10,284	7,047	0.0238	610	2,702,448,101	16,151
2031	6,458,059	9,980	6,884	0.0207	371	2,133,619,472	13,382
2032	5,712,026	9,667	6,578	0.0177	259	1,771,382,260	11,617
2033	5,853,864	9,745	6,652	0.0185	275	1,823,859,347	11,905
2034	5,797,935	9,690	6,616	0.0180	276	1,814,833,359	11,665
2035	5,898,663	9,785	6,694	0.0187	274	1,828,879,124	12,058
2036	5,625,841	9,611	6,460	0.0178	260	1,775,162,952	11,446
2037	5,698,331	9,682	6,499	0.0184	270	1,777,568,735	11,664
2038	5,351,664	8,533	6,016	0.0175	249	1,631,722,206	11,143
2039	5,433,584	8,599	6,069	0.0180	250	1,664,645,441	11,377
2040	5,111,931	7,566	5,683	0.0167	220	1,515,089,860	10,911
2041	5,218,379	7,217	5,684	0.0171	227	1,526,405,089	11,155
2042	5,033,011	6,829	5,500	0.0163	216	1,447,560,576	10,793
2043	4,988,533	6,377	5,382	0.0162	206	1,414,798,721	10,834
Total	**134,373,893**	**153,989**	**122,479**	**0.406**	**8,315**	**43,514,083,924**	**274,271**
Pounds/Gallons per MWh[90]	**952**	**1.09**	**0.87**	**0.000003**	**0.06**	**154**	**2.141**

[89] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[90] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,628,339
2027	$1,158,813,840
2028	$1,020,565,222
2029	$991,405,565
2030	$827,244,896
2031	$747,081,881
2032	$684,777,928
2033	$727,110,962
2034	$746,005,989
2035	$786,030,277
2036	$776,252,143
2037	$813,969,586
2038	$791,254,956
2039	$831,374,435
2040	$809,282,328
2041	$850,738,875
2042	$853,860,285
2043	$872,238,852

Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,899
2027	$70,489,792
2028	$62,881,612
2029	$60,575,560
2030	$55,682,337
2031	$48,304,507
2032	$43,879,284
2033	$47,023,762
2034	$48,155,833
2035	$51,996,947
2036	$51,534,377
2037	$54,805,537
2038	$54,614,207
2039	$58,132,606
2040	$58,102,968
2041	$61,679,010
2042	$62,837,645
2043	$64,400,027

Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)

Year	Target[91]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 76: Total Financial (Portfolio 4 – FLEXSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,443	$12,928	$838	$29,371	$30,210

Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)

$, Millions	Expansion Plan CapEx + AFUDC:
Generation (Nominal $)	$537
Transmission (Nominal $)	$1,116

Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,227
2028	$1,306
2029	$1,362
2030	$1,383
2031	$1,435
2032	$1,489
2033	$1,509
2034	$1,511
2035	$1,509

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2036	$1,599
2037	$1,606
2038	$1,669
2039	$1,695
2040	$1,702
2041	$1,745
2042	$1,779
2043	$1,855

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95

96 [redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	945	0	0	945
2027	0	1,432	0	0	1,432
2028	0	707	0	10	717
2029	0	453	0	20	473
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,610**	**0**	**30**	**3,640**

Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	13	672	77	183
2027	19	1,127	58	228
2028	44	527	0	146
2029	0	0	1	472
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**76**	**2,376**	**136**	**1,052**

The following table reflects PPA pricing, penalties, and taxes.

Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$152,487
2027	$0	$193,537
2028	$0	$90,037
2029	$0	$51,807
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$497,237**

Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2027	150	ST-0004-6-ECO	$0.00		
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2029	200	WI-0013-3-ECO		$14.62	$30.00
2033	100	Wind + Battery		$5.85	$81.56
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Wind + Battery		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2042	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Solar		$5.85	$56.46
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Solar		$3.25	
2042	100	Solar		$3.25	

Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	38%	52%	54%	34%

Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	32%	32%	33%	32%	32%	32%	35%	37%	35%	32%	32%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 90: Expansion Plan (Portfolio 5 – NNG)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[97]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal[98]	West Colorado	12	1	12
2038	-	Wind / Battery	East Colorado	100	2	200
2042	-	Wind / Battery	East Colorado	100	1	100
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	Wyoming / W.Neb	100	1	100

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

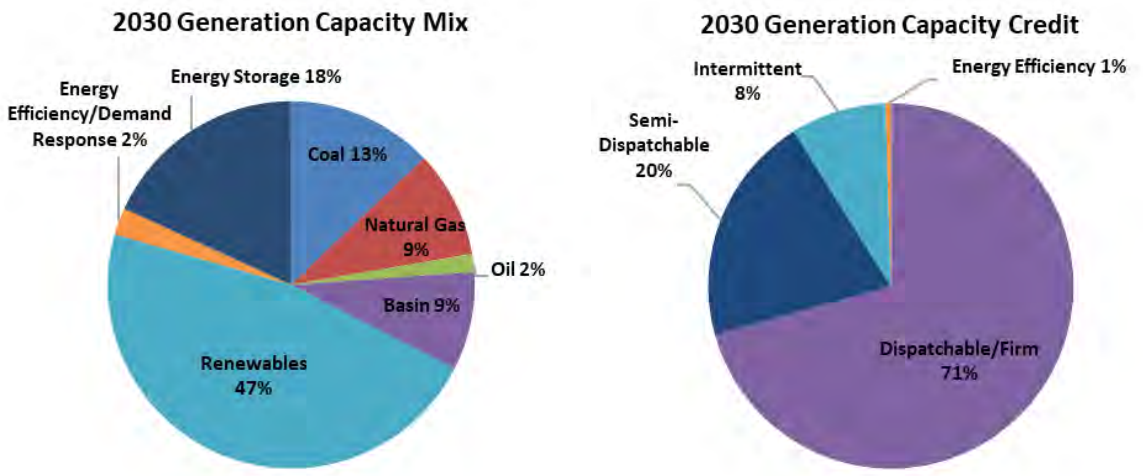
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

Table 91: Modeled Retirements (Portfolio 5 – NNG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[100]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG) [101]



[99] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG) [102]

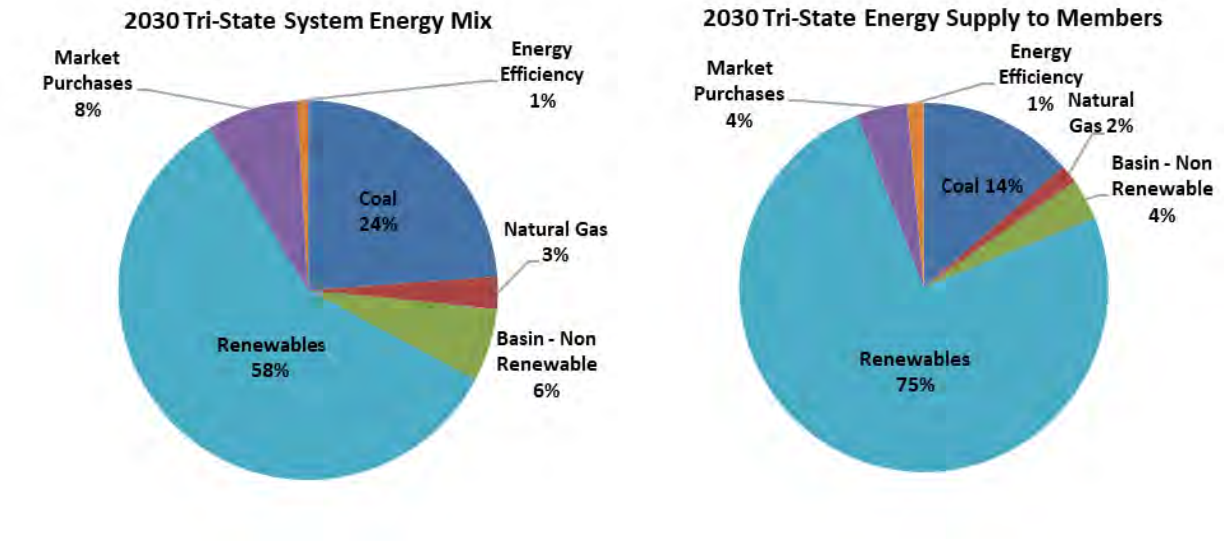


Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	64%	73%	82%	81%	79%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	30%	27%	27%

Portfolio 5 (No New Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)[103]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,265	6,082	7,499	0.0335	974	4,177,589,447	24,195
2027	11,726,163	5,927	7,347	0.0326	958	4,152,095,618	23,899
2028	9,883,456	5,211	6,132	0.0290	839	3,476,173,634	20,198
2029	8,959,962	4,974	5,831	0.0267	701	2,986,775,243	17,946
2030	7,013,425	4,657	5,500	0.0237	557	2,526,716,133	16,088
2031	5,999,591	4,341	5,298	0.0205	314	1,924,297,995	13,251
2032	5,264,320	4,036	5,000	0.0176	203	1,558,763,516	11,552
2033	5,390,667	4,091	5,043	0.0184	219	1,627,608,477	11,744
2034	5,289,574	4,044	4,975	0.0179	218	1,586,884,489	11,497
2035	5,408,588	4,109	5,066	0.0184	216	1,627,443,211	11,822
2036	5,196,722	3,983	4,903	0.0177	203	1,565,648,310	11,396
2037	5,297,401	4,068	4,958	0.0183	216	1,599,262,492	11,628
2038	5,013,729	3,964	4,754	0.0175	205	1,473,591,656	11,134
2039	5,111,419	4,012	4,817	0.0179	206	1,513,672,212	11,383
2040	4,871,635	3,892	4,696	0.0167	185	1,405,407,473	10,925
2041	4,990,642	3,996	4,805	0.0171	195	1,416,107,699	11,183
2042	4,890,992	3,945	4,778	0.0163	188	1,362,105,080	10,925
2043	4,853,274	3,938	4,726	0.0165	186	1,351,564,503	10,934
Total	**129,348,747**	**84,826**	**103,400**	**0.407**	**7,640**	**41,231,625,068**	**274,106**
Pounds/Gallons per MWh[104]	**916**	**0.60**	**0.73**	**0.000003**	**0.05**	**146**	**2.139**

[103] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[104] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,613,302
2027	$1,174,583,082
2028	$1,027,226,838
2029	$965,095,102
2030	$782,717,739
2031	$694,045,278
2032	$631,105,309
2033	$669,577,102
2034	$680,596,397
2035	$720,724,943
2036	$717,042,375
2037	$756,699,323
2038	$741,290,549
2039	$782,081,140
2040	$771,240,407
2041	$813,611,550
2042	$829,766,536
2043	$848,588,980

Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,909
2027	$72,206,255
2028	$63,846,020
2029	$59,255,701
2030	$55,464,509
2031	$47,830,289
2032	$43,632,908
2033	$46,386,308
2034	$47,461,289
2035	$50,983,048
2036	$51,311,539
2037	$54,636,281
2038	$54,569,169
2039	$58,162,802
2040	$58,177,007
2041	$61,837,927
2042	$63,603,366
2043	$64,997,048

Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)

Year	Target[105]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 97: Total Financial (Portfolio 5 – NNG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,067	$12,429	$838	$29,496	$30,334
Difference to preferred plan (Nominal $)	$624	($499)	($1)	$125	$124

Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$652	$115
Transmission (Nominal $)	$3,008	$1,891

Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,049
2027	$1,212
2028	$1,415
2029	$1,423
2030	$1,441

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,523
2032	$1,544
2033	$1,580
2034	$1,555
2035	$1,610
2036	$1,706
2037	$1,739
2038	$1,722
2039	$1,766
2040	$1,789
2041	$1,818
2042	$1,868
2043	$1,954

106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	860	0	0	860
2027	0	759	0	0	759
2028	0	1,707	0	0	1,707
2029	0	62	0	255	317
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,461**	**0**	**255**	**3,716**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	47	579	57	177
2027	33	672	16	38
2028	117	709	0	881
2029	0	0	176	141
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**197**	**2,010**	**249**	**1,260**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$138,416
2027	$0	$105,188
2028	$0	$198,901

2029	$0	$31,189
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$483,064**

Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-9-ECO	$1.50	$5.85	$30.00
2028	100	ST-0004-10-ECO			
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$81.56
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Wind + Battery		$14.62	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$6.56	$1,098.06
2038	100	Wind + Battery		$6.56	
2038	100	Wind + Battery		$6.56	
2042	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
2037	12	Geothermal	$1.30	$3.25	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	39%	53%	58%	35%

Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	31%	31%	31%	33%	36%	33%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 111: Expansion Plan (Portfolio 6 – NNGSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[111]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0013-3-eco	Wind	East Colorado	200	1	200
2030	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	3	300
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Solar	West Colorado	100	1	100
	-	Wind	East Colorado	100	2	200
	-	Solar	New Mexico	100	2	200
2043	-	Solar	West Colorado	100	1	100
	-	Wind	Wyoming/ W. Neb.	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

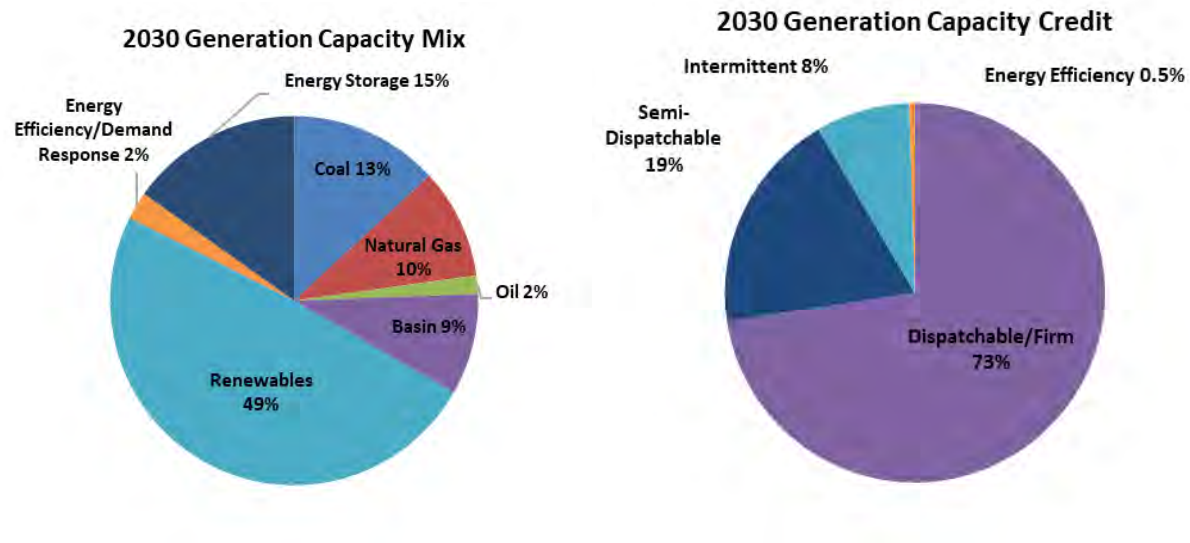
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

Table 112: Modeled Retirements (Portfolio 6 – NNGSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[113]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR) [114, 115]



[112] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]

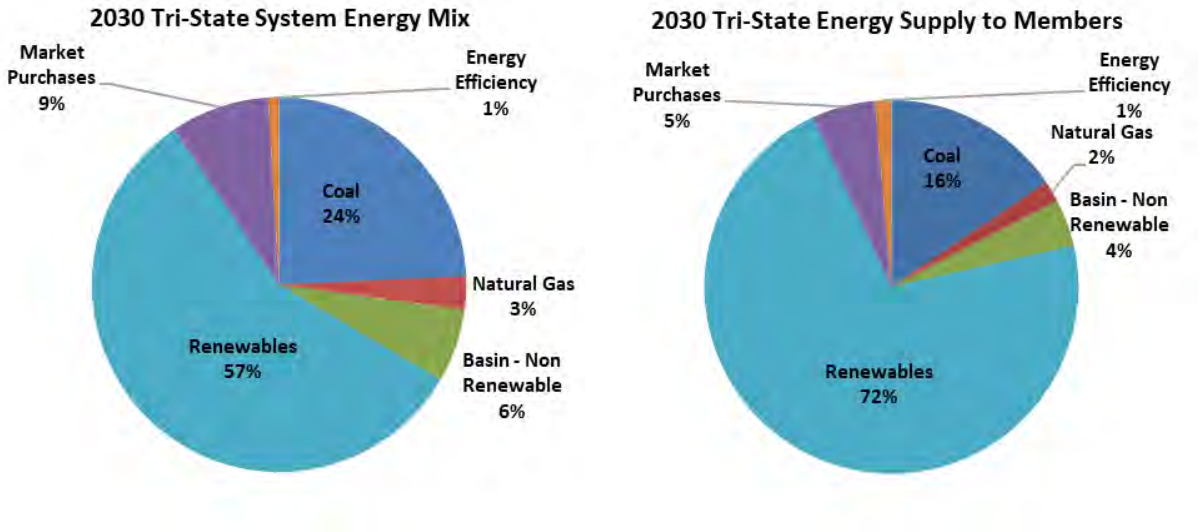


Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	81%	81%	78%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	29%	27%	23%

Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)[117]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,946,206	6,083	7,503	0.0335	974	4,178,260,972	24,199
2027	11,570,025	5,771	7,228	0.0311	936	4,046,421,059	23,332
2028	9,814,861	5,160	6,100	0.0283	815	3,401,715,998	19,898
2029	9,111,475	5,027	5,871	0.0272	737	3,073,163,383	18,316
2030	7,050,577	4,679	5,541	0.0238	558	2,532,813,977	16,162
2031	6,019,427	4,364	5,342	0.0204	312	1,913,037,441	13,312
2032	5,363,900	4,052	5,095	0.0176	206	1,604,501,764	11,641
2033	5,520,168	4,151	5,180	0.0184	223	1,661,803,495	11,946
2034	5,414,719	4,107	5,110	0.0180	221	1,615,591,795	11,712
2035	5,560,472	4,185	5,220	0.0186	221	1,665,887,399	12,084
2036	5,239,029	3,999	4,961	0.0176	203	1,573,524,559	11,453
2037	5,344,620	4,099	5,025	0.0182	215	1,590,771,662	11,726
2038	5,084,182	4,014	4,837	0.0175	205	1,470,546,688	11,293
2039	5,164,519	4,055	4,885	0.0180	205	1,504,603,982	11,518
2040	4,894,020	3,929	4,744	0.0167	183	1,379,333,329	11,025
2041	5,034,909	4,021	4,859	0.0171	196	1,413,662,279	11,266
2042	4,876,519	3,942	4,765	0.0163	188	1,347,184,439	10,913
2043	4,887,594	3,957	4,771	0.0165	186	1,347,404,577	10,997
Total	**130,142,142**	**85,151**	**104,306**	**0.405**	**7,642**	**41,220,146,679**	**275,198**
Pounds/Gallons per MWh[118]	**922**	**0.60**	**0.74**	**0.000003**	**0.05**	**146**	**2.148**

[117] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,993,624
2027	$1,158,943,111
2028	$1,020,097,553
2029	$981,414,787
2030	$786,863,978
2031	$696,339,955
2032	$643,043,287
2033	$685,662,450
2034	$696,698,482
2035	$740,964,313
2036	$722,879,934
2037	$763,444,178
2038	$751,707,224
2039	$790,205,684
2040	$774,784,316
2041	$820,828,229
2042	$827,311,151
2043	$854,589,790

Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,847,236
2027	$70,492,985
2028	$62,895,824
2029	$60,478,517
2030	$55,718,807
2031	$48,051,268
2032	$43,969,826
2033	$47,182,943
2034	$48,348,612
2035	$52,112,380
2036	$51,565,121
2037	$55,096,401
2038	$55,345,788
2039	$58,855,626
2040	$58,711,741
2041	$62,293,992
2042	$63,533,142
2043	$65,368,924

Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)

Year	Target[119]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 118: Total Financial (Portfolio 6 – NNGSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,531	$12,509	$842	$29,039	$29,881
Difference to preferred plan (Nominal $)	$88	($420)	$3	($332)	($329)

Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$265	($272)
Transmission (Nominal $)	$1,100	($16)

Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,051
2027	$1,236
2028	$1,317
2029	$1,335
2030	$1,358

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,447
2032	$1,480
2033	$1,507
2034	$ 1,526
2035	$1,523
2036	$1,610
2037	$1,618
2038	$1,685
2039	$1,711
2040	$1,741
2041	$1,786
2042	$1,839
2043	$1,899

120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	1,205	0	0	1,205
2027	0	1,233	0	0	1,233
2028	0	285	0	13	298
2029	0	5	0	0	5
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,829**	**0**	**13**	**2,842**

Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	72	825	98	210
2027	36	938	54	205
2028	182	57	0	59
2029	0	0	0	5
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**290**	**1,880**	**152**	**520**

The following table reflects PPA pricing, penalties, and taxes.

Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$166,014
2027	$0	$171,286
2028	$0	$42,920
2029	$0	$798
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$394,184**

Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	150	ST-0004-6-ECO			
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2028	100	ST-0004-9-ECO			$30.00
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	
2033	100	Wind		$5.85	$81.56
2033	100	Wind		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
2041	100	Solar		$5.85	
2042	100	Solar		$6.56	
2043	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	

Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	42%	51%	53%	33%

Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	31%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

Table 132: Renewable Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[125]	Total MW
2027	PC-0004-1P-nm	Solar / Battery	New Mexico	90	1	90
	PV-0004-5-wco	Solar	West Colorado	140	1	140
2029	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PC-0021-1P-wco	Solar / Battery	West Colorado	125	1	125
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	WI-0005-3-eco	Wind	East Colorado	150	1	150

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

Table 133: Standalone Storage Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[126]	Total MW
2027	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0006-3-nm	4hr - Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

Table 134: Gas Plant Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[127]	Total MW
2030	GG-0005-1-wco	Combustion Turbine	West Colorado	45.325	4	181.3

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolios is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2026 and 2031.

Figure 14: Comparison of Forecasted System CO_2 Emissions in 2026 and 2031, by Portfolio

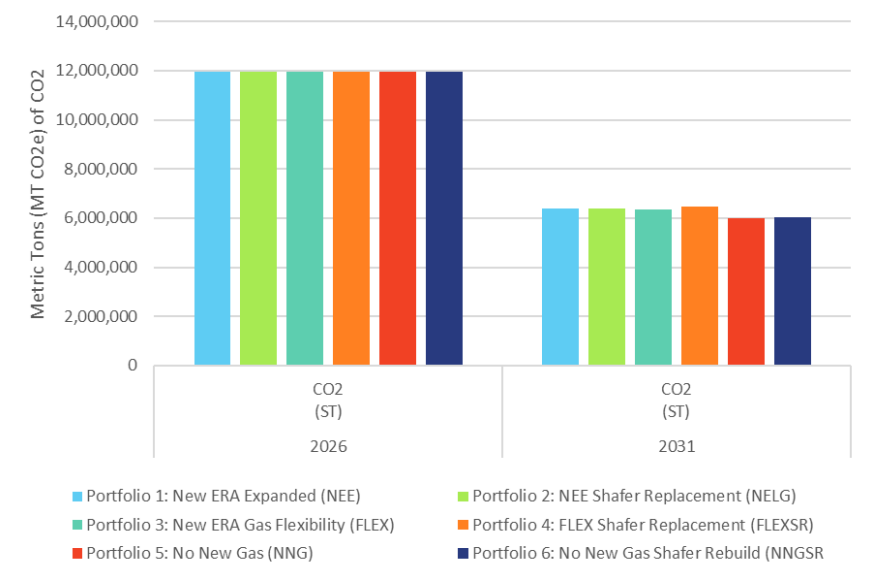
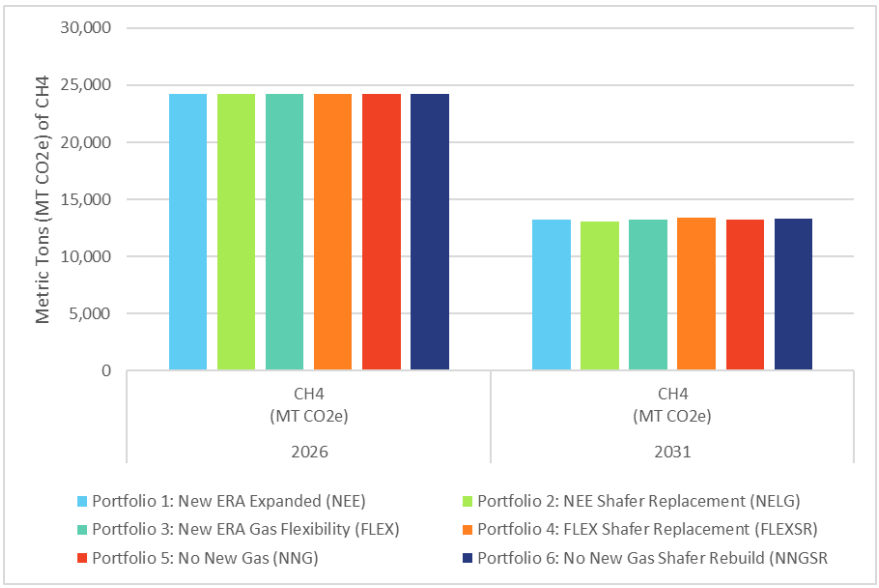


Figure 15: Comparison of Forecasted System CH_4 Emissions in 2026 and 2031, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction

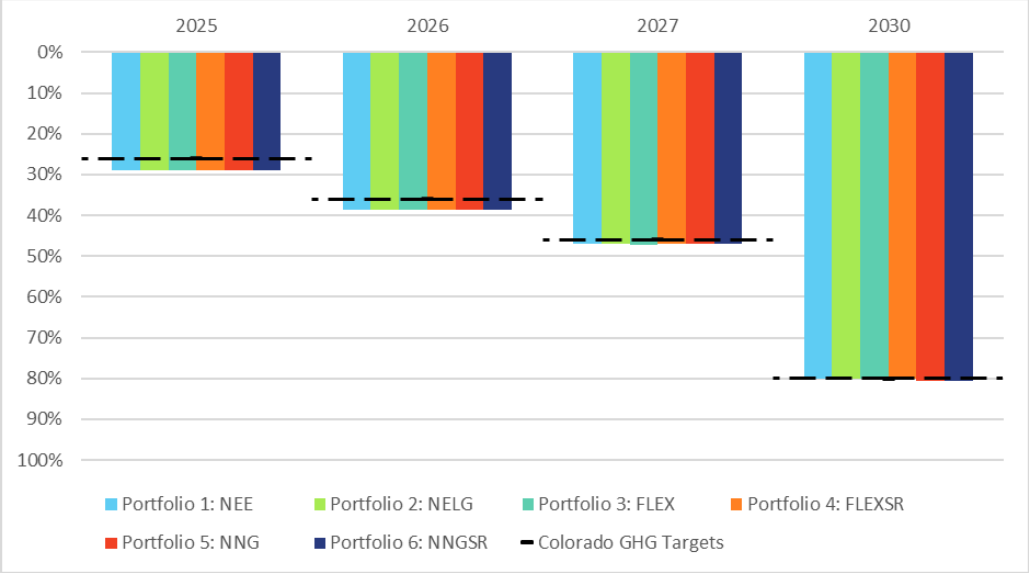
targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years

	2025	2026	2027	2030
Portfolio 1: New ERA Expanded	29%	39%	47%	80%
Portfolio 2: New ERA Limited Gas	29%	39%	47%	80%
Portfolio 3: New ERA Gas Flexibility (FLEX)	29%	39%	47%	80%
Portfolio 4: FLEX Shafer Replacement	29%	39%	47%	80%
Portfolio 5: No New Gas (NNG)	29%	39%	47%	80%
Portfolio 6: NNG Shafer Replacement	29%	39%	47%	80%

Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets



[128] Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

Figure 17: Comparison of Colorado CO2e

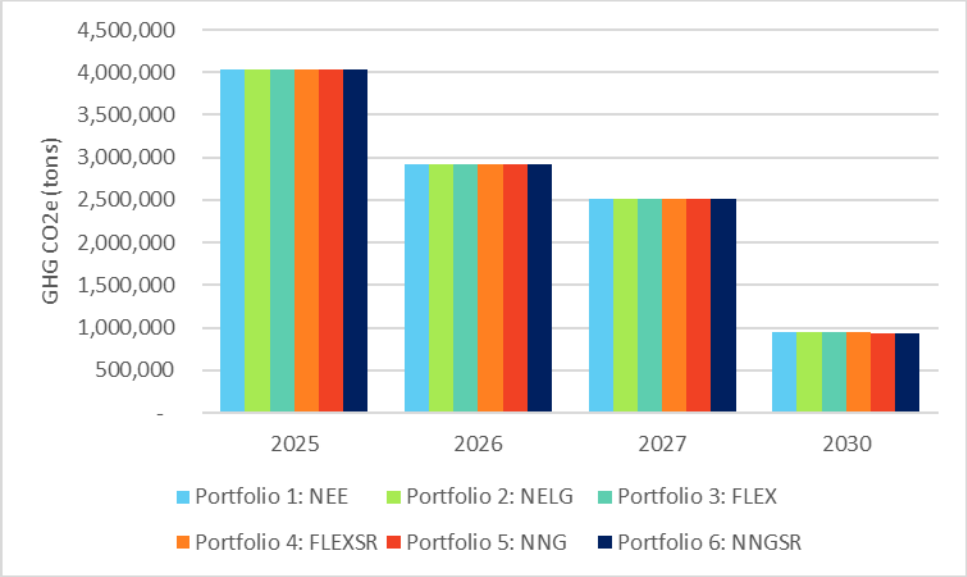


Figure 18: Comparison of SCoC During the RAP

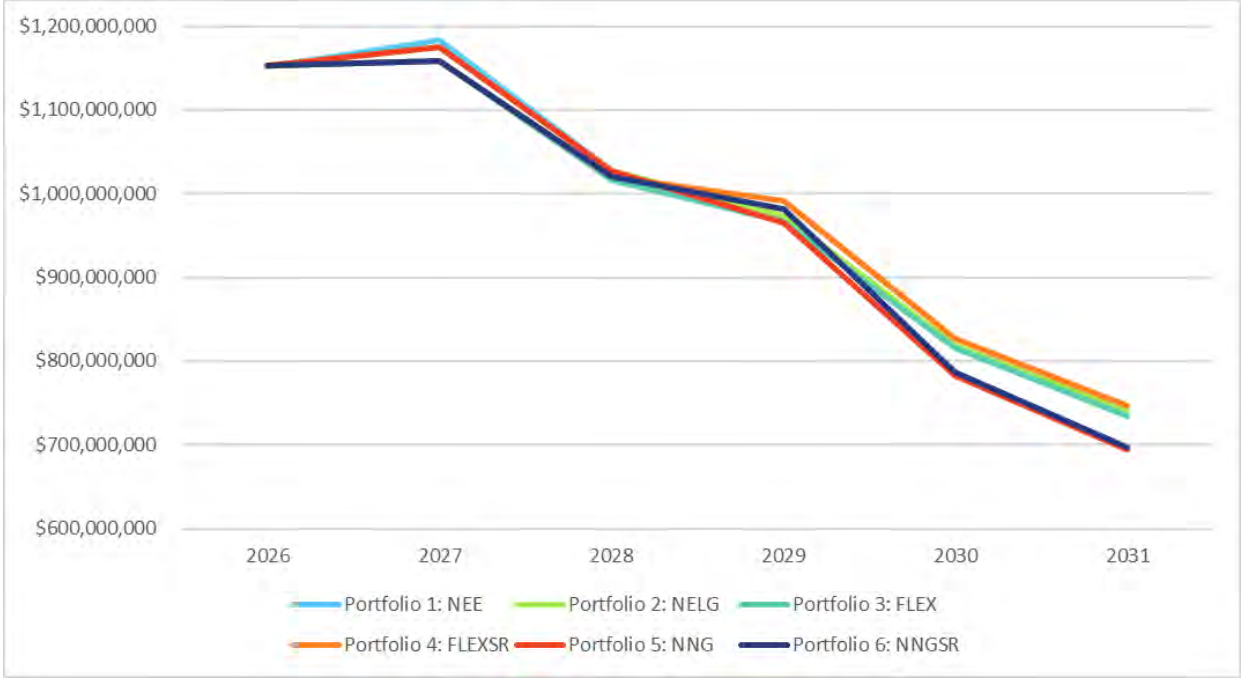
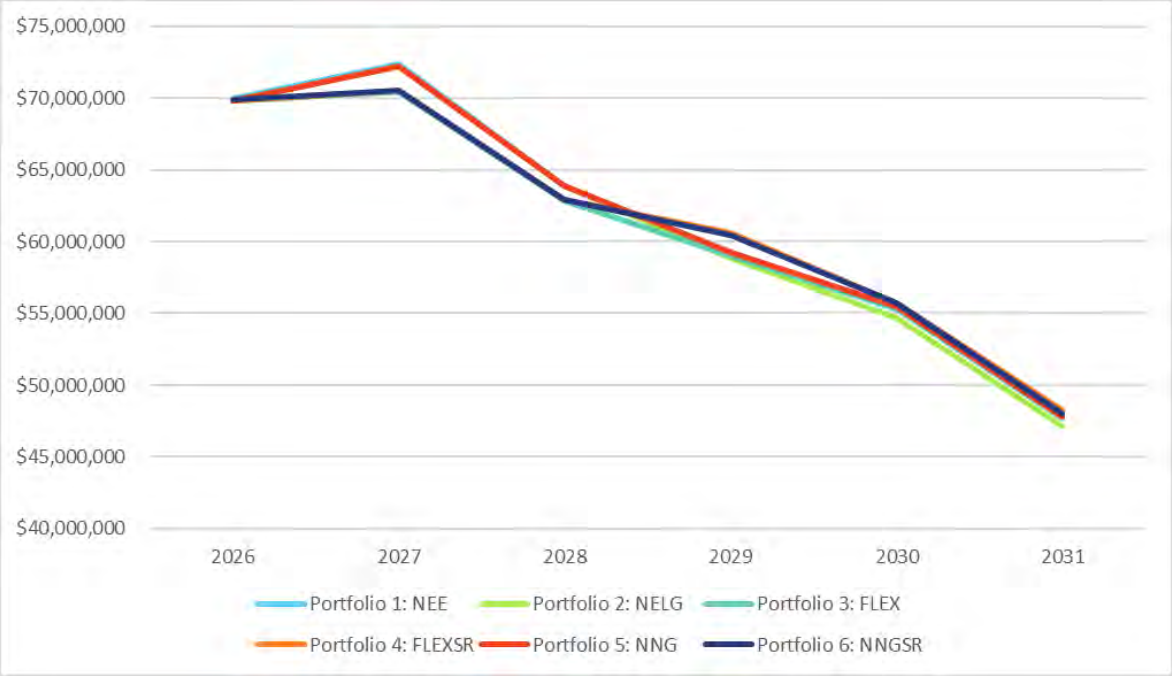


Figure 19: Comparison of SCoM During the RAP



Financial Analysis

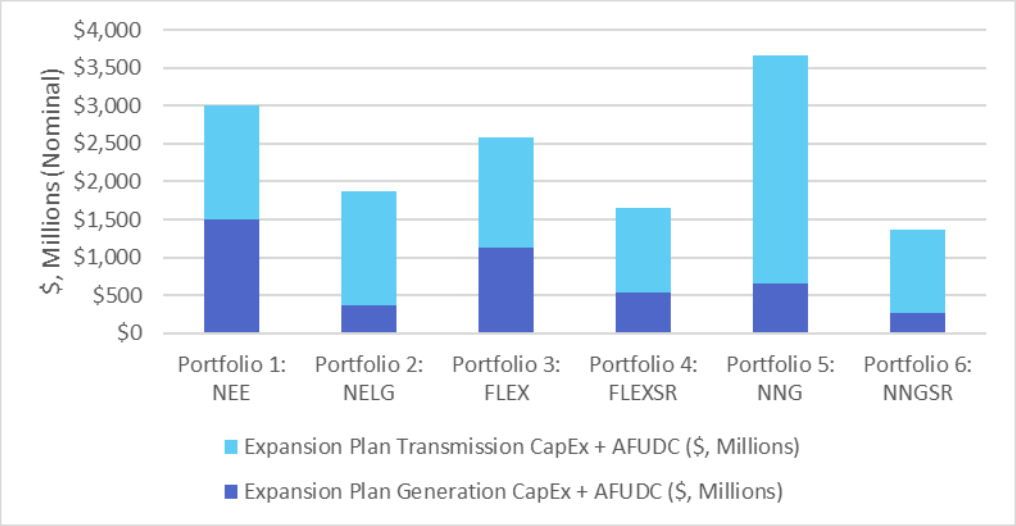
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

Table 136: Comparison of PVRR

	PVRR ($, Millions)	**PVRR w/SCoC and SCoM ($, Millions)**
Portfolio 1: New ERA Expanded	$16,836	$30,584
Portfolio 2: New ERA Limited Gas	$16,841	$30,524
Portfolio 3: New ERA Gas Flexibility	$16,761	$30,488
Portfolio 4: FLEX Shafer Replacement	$16,443	$30,210
Portfolio 5: No New Gas	$17,067	$30,334
Portfolio 6: No New Gas Shafer Replacement	$16,531	$29,881

The following figure compares capital expenditures and MW additions by portfolio.

Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP



As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP

MW	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	400	400	497	400	400	400
Solar	240	240	100	200	240	200
Standalone Storage -Short Duration	450	650	650	600	1,050	1,150
Standalone Storage - Long Duration	100	0	0	0	100	0
Gas	307	307	307	307	0	0
Solar Hybrid	250	250	250	100	250	100
RAP Total	**1,747**	**1,847**	**1,804**	**1,607**	**2,040**	**1,850**
Solar Hybrid – Battery Storage Component	125	125	125	50	125	50
RAP Total w/Hybrid Storage	**1,872**	**1,972**	**1,929**	**1,657**	**2,165**	**1,900**

Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	2	2	2	2	2	2
Solar	2	2	1	1	2	1
Standalone Storage -Short Duration	4	6	6	5	9	9
Standalone Storage - Long Duration	1	0	0	0	1	0
Gas	1	1	1	1	0	0
Solar Hybrid	2	2	2	1	2	1
RAP Total	**12**	**13**	**12**	**10**	**16**	**13**

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio

	2030 System Energy Mix	2030 Tri-State Energy Supply to Members
	% Renewables	
Portfolio 1: NEE	57%	75%
Portfolio 2: NELG	57%	75%
Portfolio 3: FLEX	57%	75%
Portfolio 4: FLEXSR	55%	71%
Portfolio 5: NNG	58%	75%
Portfolio 6: NNGSR	57%	72%

Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio

	2030 Generation Capacity Mix
	% Renewables
Portfolio 1: NEE	49%
Portfolio 2: NELG	48%
Portfolio 3: FLEX	48%
Portfolio 4: FLEXSR	48%
Portfolio 5: NNG	47%
Portfolio 6: NNGSR	49%

Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio

	2030 Generation Capacity Credit
	% Dispatchable/Firm
Portfolio 1: NEE	78%
Portfolio 2: NELG	76%
Portfolio 3: FLEX	77%
Portfolio 4: FLEXSR	80%
Portfolio 5: NNG	71%
Portfolio 6: NNGSR	73%

Curtailments

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

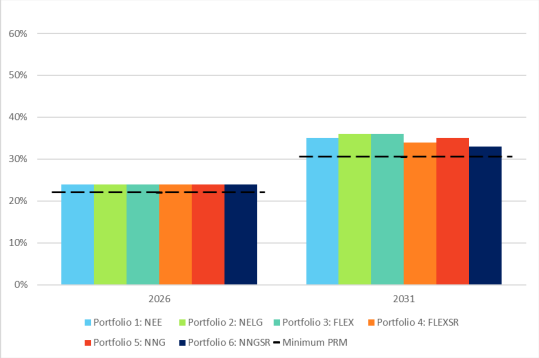
Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
2026	$145,247	$156,979	$125,261	$152,487	$138,416	$166,014
2027	$224,019	$114,621	$151,371	$193,537	$105,188	$171,286
2028	$214,350	$143,388	$107,958	$90,037	$198,901	$42,920
2029	$18,138	$56,325	$18,876	$51,807	$31,189	$798
2030	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0
RAP Total	**$601,754**	**$471,313**	**$403,466**	**$487,868**	**$473,694**	**$381,018**

Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

Figure 21: Comparison of PRMs During the RAP



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit JJ: CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

DIRECT TESTIMONY AND ATTACHMENTS OF BRAD NEBERGALL ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

December 1, 2020

Colorado PUC E-Filings System

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ATTACHMENTS

Attachment BN-1	Responsible Energy Plan
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GLOSSARY

Term	Meaning
AQCC	Colorado Air Quality Control Commission
Basin	Basin Electric Power Cooperative
BoR	Bureau of Reclamation
CAISO	California Independent System Operator
CDPHE	Colorado Department of Public Health and Environment
CEP	Clean Energy Plan
CO_2	Carbon Dioxide
DSM	Demand-Side Management
EE	Energy Efficiency
ERP	Electric Resource Plan
EV	Electric Vehicle
GHG	Greenhouse Gas
GW	Gigawatt
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
MW	Megawatt
PSCo	Public Service Company of Colorado
RAP	Resource Acquisition Period
RE Act	Rural Electrification Act
REP	Responsible Energy Plan
RES	Renewable Energy Standard
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
Tri-State	Tri-State Generation and Transmission Association, Inc.
WAPA	Western Area Power Administration
WESC	Wholesale Electric Service Contract

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Brad Nebergall. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Senior Vice President, Energy Management.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of Tri-State.

Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY PRIOR TO BECOMING AN EMPLOYEE OF TRI-STATE.

I graduated from Iowa State University with a B.S. in Business Administration and a focus in finance. I also have an MBA from the University of Houston. After several years working in commercial banking, I joined an affiliate of InterNorth in 1986, which eventually merged with another company to become Enron Corp. I spent the next 20 years serving in various roles within Enron affiliates, including founding Enron's natural gas trading business in England, co-founding an initiative to capture opportunities within NOx and SO_2 emissions credits trading, and managing Enron's Midwest Region with responsibility for all power, natural gas and diesel sales to large regional energy consumers. After Enron declared bankruptcy in 2001, I was recruited post-bankruptcy to restructure the wind power

operations of Enron Renewable Energy Corporation. I was responsible for all commercial and operational activities for 28 producing wind farms. I held that position through 2006.

Q: WHEN DID YOU BEGIN YOUR EMPLOYMENT WITH TRI-STATE?

A: I became a Tri-State employee in 2007. In 2008, I was promoted to my current position of Senior Vice President, Energy Management.

Q: WHAT ARE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT, ENERGY MANAGEMENT FOR TRI-STATE?

A: I am responsible for Tri-State's activities related to marketing, energy trading, origination, risk management, resource dispatch, corporate development and resource planning. My responsibilities require that I have knowledge of Tri-State's operations, strategic initiatives, costs/expenses, and long-term commitments to Members, lenders and other third parties. In addition, my job requires that I study and track market and industry conditions, including market prices for Tri-State's purchased fuel, its capital expenses and the price at which wholesale electricity can be bought and sold on the spot market.

Q: DO YOUR RESPONSIBILITIES INVOLVE PLANNING TRI-STATE'S FUTURE GENERATION NEEDS AND THE RESOURCES TRI-STATE WILL BUILD OR PURCHASE TO MEET THOSE NEEDS?

A: Yes. Tri-State's resource planning function is a significant part of my responsibility.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: Given that this is the first Electric Resource Plan ("ERP") that Tri-State is filing under new Commission Rule 3605, it may be helpful to provide some background on Tri-State and context for the Commission's and parties' consideration of Tri-State's 2020 ERP. In that regard, my testimony begins with an overview of Tri-State, including its organization, membership, and generation and transmission systems, and discusses how Tri-State is different from investor-owned utilities and how those differences are relevant to the Commission's evaluation of Tri-State's ERP.

The next section of my testimony discusses the evolution of the Commission's regulation of Tri-State's resource planning and some of the unique challenges associated with the current ERP cycle. Next, I discuss Tri-State's Responsible Energy Plan ("REP"), which describes Tri-State's vision for transitioning to a clean energy portfolio and grid, and the relationship between the REP and Tri-State's 2020 ERP. The next section of my testimony provides an overview of Tri-State's resource planning process and discusses some of the key considerations that factored into the development of Tri-State's 2020 ERP.

Finally, I will provide an overview of Tri-State's 2020 ERP, including the objectives of the ERP, the various scenarios and alternatives that were considered, and Tri-State's preferred plan for purposes of moving forward into Phase II of this ERP proceeding.

Q: PLEASE IDENTIFY THE OTHER WITNESSES WHO WILL BE TESTIFYING ON BEHALF OF TRI-STATE.

A: Tri-State's witnesses are:

Ms. Lisa Tiffin, Senior Manager, Analytics & Forecasting. Ms. Tiffin will address various topics associated with the Phase I of the ERP, including Tri-State's load forecast, the assessment of existing resources, planning reserve margins, and the forecasted assessment of need for additional resources.

Mr. Brian Thompson, Resource Planning Manager. Mr. Thompson's testimony will address technical aspects of Tri-State's Phase I filing, including costs and benefits of the integration of intermittent renewable energy resources; studies commissioned and prepared by Tri-State to support the development of this filing; modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems; emissions and water usage and the social cost of carbon.

Mr. Andy Berger, Senior Manager, Environmental Policy. Mr. Berger will provide an overview of the environmental laws and policies influencing Tri-State's resource planning and will explain how compliance with state and federal environmental laws affects Tri-State's Electric Resource Plan ("ERP").

Mr. Christopher Pink, Vice President, Transmission Engineering. Mr. Pink will discuss transmission system capabilities, including injection capabilities, of Tri-State's transmission system, Tri-State's transmission planning process, and, finally, he will provide a discussion of Tri-State's transmission needs and planned projects. He will provide information as required by Commission Rule 3605(d) or identify where such information can be found in the ERP.

Ms. Susan Hunter, Senior Manager, Origination. Ms. Hunter's testimony will address Tri-State's plan for meeting the resource need, including the Phase II evaluation process and Tri-State's proposed RFP.

III. OVERVIEW OF TRI-STATE

Q: SINCE THIS IS THE FIRST TIME THE COMMISSION WILL EVALUATE AND ISSUE A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN, IT MAY BE HELPFUL TO PROVIDE SOME BACKGROUND ON TRI-STATE, ITS MEMBERSHIP, AND ITS MISSION. WHEN WAS TRI-STATE ESTABLISHED?

A: Tri-State was established in 1952.

Q: WHY WAS TRI-STATE ESTABLISHED?

A: A full answer to that question requires a short history review. Congress passed the Rural Electrification Act ("RE Act") in 1936. At that time, 90 percent of rural America lacked electric power. Congress was concerned with the failure of then-existing electric utilities to extend service to rural communities and determined that the national interest would be served by subsidizing rural electrification. The RE Act allowed rural electric distribution cooperatives such as Tri-State's original Members to receive government-subsidized loans to facilitate the delivery of electricity to rural customers.

In late 1951, discussion began among rural electric cooperatives in Colorado, Nebraska, and Wyoming concerning the adequacy of power being supplied to them by the United States Bureau of Reclamation ("BoR"). These cooperatives

ultimately determined that the supply of federal power on which they had historically relied would not be sufficient to meet their growing needs. The cooperatives decided they should develop electric generating facilities that they would own to ensure adequate power supplies for the future. The cooperatives formed Tri-State in 1952 to fulfill that purpose – to ensure a sufficient and reliable power supply for its Utility Members – and Tri-State's Members continue to own and govern Tri-State to meet their collective needs. This is important because this original purpose and the underlying collective benefit for its Members has continued to guide Tri-State and its resource planning decisions for the last nearly 70 years.

Q: WHAT IS TRI-STATE'S MISSION ON BEHALF OF ITS MEMBERSHIP?

A: Tri-State's primary corporate mission is to provide its Utility Members a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles.

Q: PLEASE DESCRIBE TRI-STATE'S MEMBERSHIP.

A: Tri-State has 42 Class A Utility Members and three Non-Utility Members. Tri-State's Utility Members consist of rural electric distribution cooperatives and public power districts which, like Tri-State, operate on a not-for-profit basis. Tri-State's Utility Members include 11 distribution cooperatives located in New Mexico, 17 distribution cooperatives located in Colorado, eight distribution cooperatives located in Wyoming, and two distribution cooperatives and four public power districts located in Nebraska. In addition to providing retail electric service in the

four states in which they are located, certain of Tri-State's Utility Members also provide retail electric service that extends into multiple other states. Tri-State's three Non-Utility Members are all located in Colorado. Figure 1 below generally depicts Tri-State's Utility Members and their service territories.

Figure 1. Tri-State's Utility Members and Their Service Territories

Tri-State operates in interstate commerce and facilitates the generation and transmission of wholesale electricity across a four state, 200,000 square mile area. Tri-State's Utility Members, in turn, serve customers in 56 Colorado counties, 20 Nebraska counties, 28 New Mexico counties, and 14 counties in Wyoming.

All of Tri-State's Colorado Utility Members have voted to exempt themselves from regulation by the Commission, as permitted by the Colorado Public Utilities Law.

Q: HOW IS TRI-STATE GOVERNED?

A: As I have described, Tri-State is a multistate, regional, generation and transmission cooperative corporation that operates on a not-for-profit basis in interstate commerce providing wholesale electric power and transmission services to its Utility Members. To best serve the varying and unique needs of its Members, Tri-State is directly owned and governed by its Members through a Board of Directors.

Tri-State's Board of Directors is comprised of representatives from each of its Utility Members who are elected by the local boards of their respective cooperative or public power district. Tri-State's Board meets on a monthly basis to make decisions regarding the strategic and business affairs of the cooperative. All matters requiring a decision by the Board are decided by a majority vote of the Board members present and voting. Each Utility Member is entitled to one vote. The Members, acting through their representatives on the Board, are responsible for approving rates, major capital investments, long-term contractual commitments and, as relevant here, Tri-State's resource planning decisions.

Recognizing that Board decisions have a significant impact on all Members, the Board acts for the collective benefit of all Members and seeks to treat all Members equitably. This means that Tri-State's assets and system are planned and operated on the basis of mutual benefits and the sharing of costs and risks among all Members. Through its democratic control, Tri-State's Board works to ensure that corporate decisions balance the interests of all Members in all states.

Q: HOW IS TRI-STATE DIFFERENT FROM COLORADO'S INVESTOR-OWNED ELECTRIC UTILITIES?

A: I believe the primary differences are that Tri-State is owned by its Members rather than shareholders, does not seek to generate a profit for outside investors, and is a multistate wholesale electricity supplier that does not provide retail electric service.

Q: WHY ARE THESE DIFFERENCES IMPORTANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN?

A: In several ways. First, Tri-State is a wholesale electricity supplier – an aggregator of its Utility Members' loads. It is not a retail electric utility like Colorado's two investor-owned electric utilities. This is important because Tri-State does not have a direct relationship with end-use retail consumers; that relationship is the exclusive province of Tri-State's Utility Members. As a result, Tri-State is not in the same position as Colorado's retail electric IOUs when it comes to certain resource planning issues such as energy efficiency and demand side management.

Second, unlike Colorado's two retail electric IOUs, which are essentially single-state utilities serving only Colorado customers, Tri-State is a multistate utility serving Members in four states which, in turn, serve customers in multiple states. This difference is important for two reasons. Rather than having a system that is designed to serve the needs of only one state, Tri-State's system has for decades been designed, constructed and operated to serve its Members in multiple states and without regard to state boundaries. As a result, Tri-State's resource planning decisions in Colorado, as well as the Commission's decisions within the scope of its resource planning authority, will have an impact on system operations outside of Colorado and vice versa. Likewise, Tri-State's integrated system must take into consideration the legislative and regulatory requirements and public policy goals of all states in which it operates, not just in Colorado.[1] These state requirements and goals differ among the states yet, under the cooperative business model, the associated costs of compliance are shared by all Members in all states.

Finally, while Tri-State's Board and Members share the Commission's interest in ensuring a reliable and affordable power supply, Tri-State's not-for-profit business model means many of the issues related to utility profits and ownership of resources, which frequently arise in IOU ERP proceedings and lead into subsequent rate cases, are not present in Tri-State's ERP. And, like the wholesale power rates of Colorado's two electric IOUs, Tri-State's wholesale power rates are

[1] Tri-State also has resource planning obligations and submits an Integrated Resource Plan to the Western Area Power Administration.

regulated by the Federal Energy Regulatory Commission ("FERC").

These and other differences between Tri-State and the two Colorado electric IOUs require different considerations as the Commission evaluates Tri-State's 2020 ERP. These considerations are discussed throughout Tri-State's Electric Resource Plan and the testimony of Tri-State's witnesses.

Q: YOU HAVE MENTIONED TRI-STATE'S INTERSTATE GENERATION AND TRANSMISSION SYSTEM SEVERAL TIMES. PLEASE PROVIDE A BRIEF OVERVIEW OF TRI-STATE'S SYSTEM.

A: Tri-State's generating fleet includes: Craig Generating Station, Laramie River Station, Springerville Generating Station Unit 3, J.M. Shafer Generating Station, Rifle Generating Station, Limon Generating Station, Frank R. Knutson Generating Station, Pyramid Generating Station, and Burlington Generating Station.[2] Tri-State's resource mix also includes power provided by Basin Electric Power Cooperative ("Basin") and the Western Area Power Administration ("WAPA") under long-term power purchase agreements. Finally, Tri-State's resource mix includes power purchase agreements associated with the following existing renewable resources: Cimarron Solar, Kit Carson Windpower, Colorado Highlands Wind, Carousel Wind, San Isabel Solar, Alta Luna Solar, and Twin Buttes II Wind, as well as contracts with six small hydropower producers.

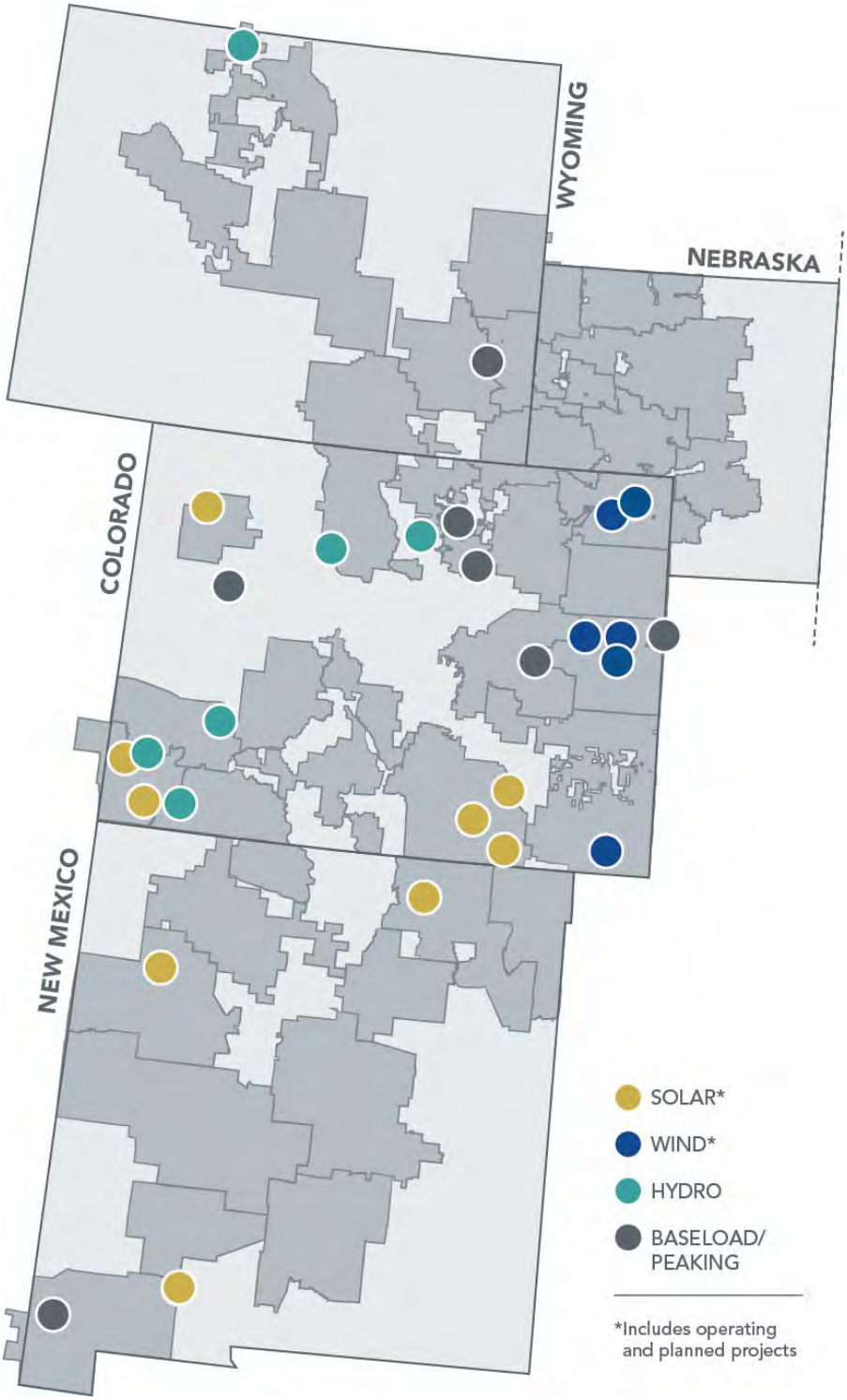
Tri-State's total system resource mix includes 2,432 MW of thermal generation

[2] Tri-State's Escalante Station, located in New Mexico, was retired on November 19, 2020, and is not included in this list.

resources, 452 MW of renewable wind and solar resources, 27 MW of small hydropower resources, and 580 MW of WAPA hydropower resources. Additionally, Tri-State Members own or contract for 131 MW of additional generation resources, consisting of renewable resources such as small solar, hydro, wind, landfill-gas and waste heat.

As a result of competitive bidding processes that Tri-State initiated in 2018 and 2019, Tri-State has executed contracts for additional wind and solar resources that are in various stages of development. Figure 2 below provides a general depiction of Tri-State's operating and planned generation resources. These resources are discussed in greater detail in Volume II of Tri-State's 2020 ERP.

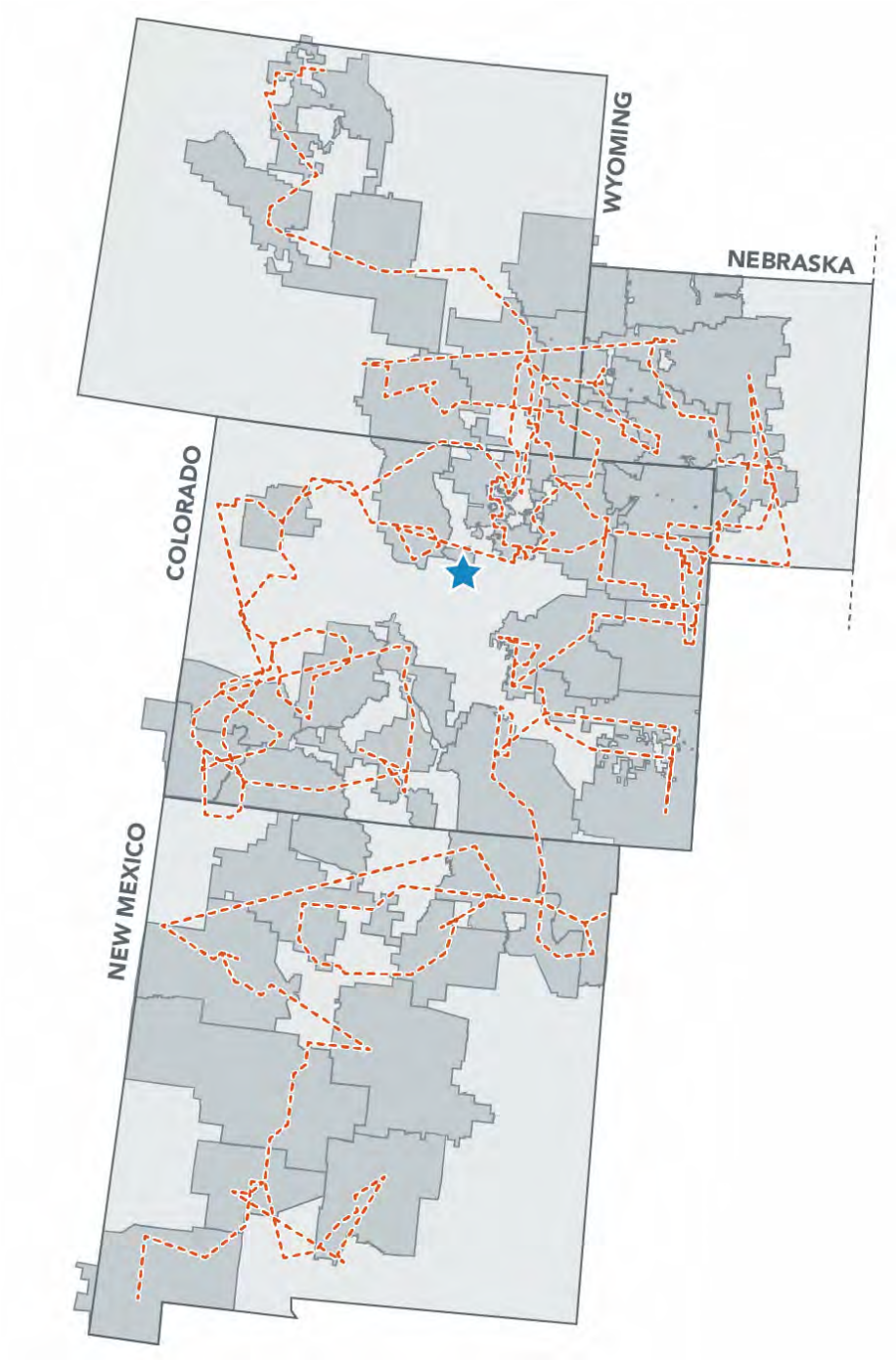
Figure 2. Tri-State's Operating and Planned Generation Resources



In 2019, Tri-State's Utility Member system peak demand was 3,009 MW and Utility Members purchased 16,413 GWh of energy from Tri-State. Tri-State's existing resources, resources under development, plans to retire certain of these resources, and Tri-State's projected resource mix in 2030 are discussed in greater detail in Ms. Tiffin's direct testimony.

Tri-State presently owns, operates, and maintains an extensive interstate transmission system with facilities located in four states: Colorado, New Mexico, Wyoming, and Nebraska. This transmission system includes over 5,665 miles of transmission lines with operating voltages up to 345 kV, 409 substations and switchyards, and over 475 communications sites used for system operations. In addition, Tri-State owns and operates the David A. Hamil DC Tie located in Stegall, Nebraska, which provides a means to transfer electric power between the Eastern and Western Interconnections. As of 2020, Tri-State's total transmission system investment is approximately $559,000,000. Tri-State also relies upon wheeling agreements with PSCo, WAPA, Public Service Company of New Mexico ("PNM"), PacifiCorp, and other transmission service providers for delivery of resources to its Utility Members. Figure 3 provides a general depiction of the location and extent of Tri-State's interstate transmission system.

Figure 3. Overview of Tri-State's Transmission System



Mr. Pink discusses Tri-State's transmission system and the information required by Commission Rule 3605(d) in greater detail in his testimony.

IV. REGULATION OF TRI-STATE'S RESOURCE PLANNING

Q: AT THE BEGINNING OF YOUR TESTIMONY, YOU NOTED THAT THIS IS THE FIRST TIME THE COMMISSION WILL BE EVALUATING AND ISSUING A DECISION IN CONNECTION WITH TRI-STATE'S ELECTRIC RESOURCE PLAN. HOW HAS THE COMMISSION'S REGULATION OF TRI-STATE'S ELECTRIC RESOURCE PLAN CHANGED OVER THE YEARS?

A: During the nearly 70 years since Tri-State was established, the Commission has regulated Tri-State's resource planning to varying degrees. For the last 10 years, Commission Rule 3605 has required Tri-State to file its ERP as an informational report; however, during that period, the Commission did not conduct related adjudicatory proceedings and the Commission did not issue decisions approving Tri-State's ERP. This approach was the result of a proposal advanced by Tri-State and Western Resource Advocates in Docket No. 09I-041E and approved by the Commission in Decision No. C10-0101. Pursuant to that Decision, Tri-State filed its first ERP report on November 30, 2010, a subsequent full ERP report on October 30, 2015, and Annual Progress Reports in the intervening and subsequent years.

Q: DID THAT INFORMATIONAL FILING REQUIREMENT SUBSEQUENTLY CHANGE?

A: Yes. Pursuant to previous Commission Rule 3603, Tri-State's next full ERP would have been due on October 31, 2019. However, in 2019, the Colorado General Assembly passed Senate Bill 19-236, which became Colorado Revised Statute §

40-2-134. That statute required the Commission to promulgate rules requiring wholesale electric cooperatives to submit electric resource plans to the Commission for approval, and rules for the Commission's evaluation and approval of such ERPs. Given these new requirements and the timing of the associated rulemaking proceedings, Tri-State requested in Proceeding No. 19V-0311E a variance of the October 31, 2019, ERP filing deadline. The Commission granted that variance in Decision No. C19-0629 and held that the timing of Tri-State's next ERP filing would be established in the rulemaking proceeding required by § 40-2-134, C.R.S.

On July 31, 2019, the Commission issued its Notice of Proposed Rulemaking in Proceeding No. 19R-0408E regarding electric resource planning rules for wholesale electric cooperatives. The resulting new Rule 3605 went into effect nearly one year later on July 15, 2020, and established a December 1, 2020, filing deadline for Tri-State's full ERP. Commission Rule 3605 requires that Tri-State submit an electric resource plan that, in many respects, is substantially similar to those required of PSCo and Black Hills Energy. Rule 3605 also provides for Phase I and Phase II ERP processes for Tri-State.

Unique to this first ERP filing, Rule 3605 also required Tri-State to file the Assessment of Existing Resources section of its ERP into an adjudicated proceeding on June 1, 2020, for review by the Commission and interested parties. Finally, I would note that certain of the Commission's ERP rules that are at issue in Proceeding No. 19R-0096E apply to Tri-State; however, those rules have not

been finalized and, therefore, are not incorporated into Tri-State's 2020 ERP.

Q: HOW IS THE CHANGE IN THE RESOURCE PLANNING RULES RELEVANT TO THE COMMISSION'S CONSIDERATION OF TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN?

A: The change in resource planning rules applicable to Tri-State presents primarily practical challenges that Tri-State believes the Commission should consider as it evaluates this first ERP under the new rules.

First, the new rules presented timing challenges for Tri-State. While Tri-State was preparing to file its ERP in October 2019 under the prior resource planning rules applicable to Tri-State, those efforts were largely suspended when SB19-236 became law and Tri-State awaited the Commission's development of new resource planning rules for wholesale electric cooperatives. As noted previously, those new rules did not take effect until July 15, 2020 – only four-and-a-half months before Tri-State's first ERP under the rules was due to be filed. Tri-State had a general understanding of what those rules would be as a result of participation in the rulemaking proceeding; however, it could not proceed with certainty until the rules were finalized.

At the same time, Tri-State was required to prepare, file, and respond to numerous and extensive discovery requests related to its June 1, 2020, Assessment of Existing Resources (Proceeding No. 20M-0218E). The Rule 3605(c) information required in this advance filing ordinarily would not be filed separately and would be included in the full ERP itself, as is the case for similar information contained in the

ERPs filed by Public Service and Black Hills. However, in its Decision Adopting Rules, the Commission explained that such advance filing would "allow for Staff and other parties to Tri-State's initial 2020 ERP proceeding to conduct discovery and learn about Tri-State's generation fleet and the underlying financial requirements in the months leading to the later assessment of Tri-State's complete ERP filing." Given the limited nature of the Commission's historical involvement in Tri-State's resource planning, Tri-State recognizes the potential benefits of providing this information in advance of its initial ERP filing. Nevertheless, preparing that filing and responding to over 750 discovery requests presented a substantial challenge at the same time that the same Tri-State personnel were working on the scenario development, modeling, and analyses for the full ERP.

During the course of the Assessment of Existing Resources proceeding, several parties provided recommendations concerning the process for developing, or the contents of, Tri-State's ERP. As Tri-State explained in its response to initial comments filed in that proceeding, not all of those recommendations were appropriate, and it was impossible to accommodate certain of these recommendations in time for the 2020 ERP filing. Depending on the particular recommendation, further changes could be addressed in a subsequent rulemaking or incorporated into Tri-State's next ERP, which is scheduled to be filed on June 1, 2023.

When the Commission deliberated on whether to close the Assessment of Existing Resources proceeding, it discussed further expectations of what Tri-State should

include in its full ERP filing. The Commission's written decision, however, did not issue until the afternoon of November 25, 2020 – two business days before the ERP was due on December 1, 2020. Accordingly, Tri-State did not have the Commission's written decision so as to specifically inform it of these additional requirements or in time to address all of these requirements in the ERP filing. Tri-State will review these new requirements and will supplement its ERP filing, as appropriate, as soon as possible.

Tri-State encourages the Commission to use this first ERP under the new rules to determine what does and does not make sense for purposes of the Commission's review of Tri-State's 2020 ERP, and consider any potential additional or changed requirements in the context of the 2023 ERP.

V. TRI-STATE'S RESPONSIBLE ENERGY PLAN

Q: IN JANUARY 2020, TRI-STATE ANNOUNCED ITS RESPONSIBLE ENERGY PLAN. PLEASE PROVIDE AN OVERVIEW OF THAT PLAN.

A: Earlier this year, Tri-State's Board of Directors described its vision for the future of the cooperative in the Responsible Energy Plan ("REP"). The Responsible Energy Plan is included as **Attachment BN-1** to my testimony and outlines Tri-State's commitments and goals to help make that vision a reality. The REP focuses on reducing Tri-State's greenhouse gas ("GHG") and carbon dioxide ("CO_2") emissions, increasing Tri-State's use of renewable and clean energy resources, increasing Utility Member flexibility with respect to their power supply options, extending the benefits of a clean grid to our Utility Members and their customers

through various beneficial electrification initiatives, supporting our employees and communities as Tri-State implements these transitions, and striving to meet Colorado's clean energy goals while maintaining or reducing Tri-State's wholesale rates to its Utility Members.

Q: SINCE JANUARY, SOME QUESTIONS HAVE BEEN RAISED CONCERNING THE DECISIONS INCLUDED IN TRI-STATE'S REP AND THE COMMISSION'S RESOURCE PLANNING AUTHORITY OVER TRI-STATE. WHAT IS TRI-STATE'S POSITION RELATIVE TO THIS ISSUE?

A: Following SB19-236 being signed into law last year, Tri-State recognizes that its electric resource plans are subject to review and approval by the Commission. The announcement of the REP does not intrude upon or interfere with the Commission's resource planning jurisdiction. Some actions related to the REP - such as the retirement of existing generation resources, the assessment of need for additional resources, and Tri-State's plans for acquiring those resources - will require Commission approval in this or subsequent proceedings, and Tri-State will apply for those approvals. Other REP actions, however, do not necessarily require Commission approval; these include changes to the wholesale contract structure between Tri-State and its Utility Members, support for Utility Members' electric vehicle programs and other beneficial electrification initiatives, and Tri-State's support for employees and communities impacted by the transition from fossil fueled generation.

Q: LET'S DISCUSS THE REP COMPONENTS IN MORE DETAIL. PLEASE DESCRIBE HOW THE RESPONSIBLE ENERGY PLAN IS INTENDED TO REDUCE TRI-STATE'S GREENHOUSE GAS AND CARBON DIOXIDE EMISSIONS.

A: The REP, as originally announced, called for actions that would result by 2030 in a reduction of 90%, relative to 2005 levels, in the CO_2 emissions from generation resources owned or operated by Tri-State in Colorado. These actions were part of an overall effort that would also result in in a reduction of 70% by 2030, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales, compared to the base year of 2005. The REP contemplated a combination of plant retirements, the addition of new clean energy resources, and other actions needed to achieve these reductions including the retirement of the three Craig Station units by 2030. Additionally, the REP committed Tri-State to cancel its participation in the Holcomb Station project. These REP actions in Colorado are paired with Tri-State's decision to retire the Escalante Station in New Mexico by the end of 2020, and Tri-State separately announced the early retirement of the Nucla Station in 2019.

Q: DURING THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING, SOME COMMENTERS CLAIMED THAT TRI-STATE'S RESPONSIBLE ENERGY PLAN WOULD NOT ACHIEVE THE 70% REDUCTION IN CO2 EMISSIONS IN COLORADO BY 2030 THAT YOU JUST MENTIONED. WERE THOSE CLAIMS ACCURATE?

A: No. I believe those commenters confused the base case projections in the Assessment of Existing Resources with the REP initiatives. The 34% CO_2 emissions reduction shown in the base case projections reflected a "business as usual" base case and did not include GHG and CO_2 emission restrictions. It was not intended to illustrate all of Tri-State's Responsible Energy Plan commitments or the emission reductions associated with it, nor did it include additional actions required to reach Colorado GHG emission targets. Tri-State has modeled many scenarios for its full ERP, including scenarios related to CO_2 emission reduction and costs as required by Rule 3605 and to meet the commitments of the Responsible Energy Plan. These scenarios and the associated emission reductions are discussed in the testimony of Ms. Tiffin.

Q: HAS TRI-STATE SUBSEQUENTLY REVISED ITS EMISSION REDUCTION PLANS AS COMPARED TO WHAT WAS ORIGINALLY DESCRIBED IN THE RESPONSIBLE ENERGY PLAN?

A: Yes. Tri-State's plans for emission reductions continue to evolve. The REP, as originally presented, called for a reduction of 70%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. The preferred plan included in Tri-State's 2020 ERP now calls for a reduction of 80%, relative to 2005 levels, in the CO_2 emissions associated with Tri-State's Colorado wholesale power sales by 2030. This is consistent with Colorado's overall GHG and CO_2 emission reduction goals and is consistent with what would be required if Tri-State had voluntarily submitted a Clean Energy Plan.

Tri-State's preferred plan is discussed in greater detail in Ms. Tiffin's direct testimony.

Q: PLEASE DESCRIBE THE RESPONSIBLE ENERGY PLAN'S PROVISIONS RELATED TO INCREASING TRI-STATE'S USE OF RENEWABLE AND CLEAN ENERGY RESOURCES.

A: The REP calls for Tri-State to add to its system one Gigawatt (1 GW) of new utility scale renewable energy projects by 2024. These new resources consist of six utility scale solar projects and two utility scale wind projects: Axial Basin Solar (145 MW; 2023), Coyote Gulch Solar (120 MW; 2023), Dolores Canyon Solar (110 MW; 2023), Escalante Solar (200 MW; 2023), Spanish Peaks Solar (100 MW; 2022), Spanish Peaks II Solar (40 MW; 2023), Crossing Trails Wind (104 MW; 2020), and Niyol Wind (200 MW; 2021).[3] (See Figure 2) These additions will bring Tri-State's total renewable resources to over 2 GW, and we forecast that by 2024 50% of the power consumed by Tri-State's Utility Members' customers will come from renewable resources.

Q: IN THE ASSESSMENT OF EXISTING RESOURCES PROCEEDING THAT PRECEDED THIS ERP, SOME PARTIES EXPRESSED CONCERNS REGARDING THE POWER PURCHASE AGREEMENTS ("PPAs") TRI-STATE ENTERED INTO IN CONNECTION WITH THESE NEW RESOURCES. PLEASE EXPLAIN TRI-STATE'S POSITION WITH REGARD TO THOSE PPAs.

[3] Figures and dates represent each project's nameplate capacity and anticipated commercial operation date.

A: First, I would note that Tri-State provided detailed data on these PPAs as part of its Assessment of Existing Resources and throughout the discovery process in Proceeding No. 20M-0218E. Information on these resources also is included in the revised Assessment of Existing Resources in the 2020 ERP.

These eight resources were contracted through a competitive request for proposals ("RFP") process in 2018 and 2019 prior to the Commission's new ERP rules for Tri-State. Tri-State's competitive acquisition process assured that these new resources provide the best value for its Utility Members. Furthermore, the timing of this competitive acquisition process was intended to ensure that the projects, and by extension Tri-State and its Utility Members, could secure the maximum benefits under the Investment Tax Credit and Production Tax Credit.

These resources will play a significant role in Tri-State's transition to a cleaner portfolio and its ability to timely achieve its emission reduction objectives. These resources also contribute to achieving Colorado's overall legislative and policy goals related to clean energy and emission reductions. Revisiting, let alone reopening, these past renewable RFPs would be counterproductive to Colorado's policy goals and to the interests of Tri-State's Utility Members and their customers in Colorado and in other States. Tri-State believes that the present ERP process should focus on future resource acquisitions and the retirement of existing resources.

Q: WHAT STEPS HAS TRI-STATE TAKEN UNDER THE RESPONSIBLE ENERGY PLAN TO INCREASE ITS UTILITY MEMBERS' FLEXIBILITY WITH REGARD TO POWER SUPPLY OPTIONS?

A: For nearly 20 years, Tri-State's Utility Members have had the option to self-generate up to 5% of the energy they need to serve their member-customers. This option has been very popular and successful, with approximately half of Tri-State's Utility Members taking advantage of it, resulting in 130 MW of renewable energy projects in service or under development. Over the years, Tri-State has provided substantial financial subsidies in connection with such projects. Furthermore, some of Tri-State's Utility Members also have developed local renewable energy projects that exceed the 5% self-generation option pursuant to a Tri-State Board policy addressing such projects.

Given the growing interest in local clean energy, many of Tri-State's Utility Members have expressed a desire for more flexibility in their power supply options. In response, the Tri-State Board, as part of the REP and otherwise, has taken a number of steps to provide that flexibility.

In December 2019, the Tri-State Board approved a new community solar program developed and recommended by the Members' Contract Committee. Under that program, Utility Members have the option to build or contract for community solar projects up to established energy thresholds. Solar generation under the program would not be included in the 5% self-supply option in the Utility Members' Wholesale Electric Service Contract ("WESC") with Tri-State. If all Tri-State Utility

Members took advantage of this new program, it would yield 63 MW of new local community solar projects. This program is being considered by the Federal Energy Regulatory Commission ("FERC") in a pending proceeding.

In 2019, the same Contract Committee began considering possible changes to the WESC that would provide Utility Members even greater power supply flexibility in the form of a partial requirements contract. In October 2020, the Tri-State Board approved a flexible partial requirements contract option and its associated board policies. Under that option, Utility Members may express their intent to transition from their current full requirements contract to a partial requirements contract by participating in an "open season" that will begin in early 2021. This initial "open season" will allocate up to 300 MW to the Utility Members. This self-supply option is in addition to the 5% self-supply option already included in the WESC and the community solar option. The partial requirements contract option also is being considered by FERC in a pending proceeding.

Q: HOW ARE THESE VARIOUS SELF-SUPPLY OPTIONS FACTORED INTO TRI-STATE'S 2020 ERP?

A: While we know which of Tri-State's Utility Members already are taking advantage of the 5% self-supply option under the WESC, we don't yet know how many Utility Members will implement community solar projects or transition to partial requirements contracts and, if so, in what capacity amounts. This challenge and how it was considered in the 2020 ERP is discussed in the testimony of Ms. Tiffin.

Q: YOU MENTIONED ONE OF THE RESPONSIBLE ENERGY PLAN'S OBJECTIVES IS TO EXTEND THE BENEFITS OF A CLEAN GRID TO TRI-STATE'S UTILITY MEMBERS AND THEIR CUSTOMERS. PLEASE EXPLAIN THAT AND THE STEPS TRI-STATE HAS TAKEN SO FAR.

A: Tri-State recognizes that the transition to a cleaner grid and power supply brings opportunities to power homes and businesses with reduced emissions electricity and to more efficiently use that electricity. Tri-State is committed to making sure that its Utility Members, and the retail end-use customers they serve, are able to take advantage of these opportunities.

So far, Tri-State has committed $2 million to extend the electric vehicle ("EV") charging network across our Utility Members' service territories by allocating each Utility Member $45,000 to install EV charging stations. Access to these charging facilities will make EV charging more available in rural communities and will give rural consumers the option to choose an EV the next time they buy a vehicle. It also will substantially expand the regional and state EV charging networks for everyone to use thereby advancing one of the Governor's Roadmap goals. Tri-State also is working with its Utility Members to explore additional opportunities for energy efficiency and demand-side management programs that can lower energy bills and energy use. Tri-State's beneficial electrification, EE and DSM initiatives, and the role they play in Tri-State's 2020 ERP are discussed further in the testimony of Ms. Tiffin.

Q: HOW IS TRI-STATE SUPPORTING ITS EMPLOYEES AND THE VARIOUS COLORADO COMMUNITIES THAT WILL BE AFFECTED BY THE REP AND THE SHIFT TOWARD CLEAN GENERATION RESOURCES?

A: Tri-State recognizes that its transition to a cleaner energy portfolio will affect the many employees who have worked hard for decades to "keep the lights on" by ensuring the safe and reliable operation of Tri-State's coal-fired power plants, and also will affect the Tri-State and subsidiary employees who have ensured the fuel supply for those plants. Similarly, this transition will affect the communities in which those plants are located.

Tri-State is providing support to the communities impacted by plant closures. For Craig Station and the Colowyo Mine, Tri-State is providing retraining and transition support for employees. Tri-State is working with its employees and community members to identify economic development opportunities, retraining programs, and other strategies to ease the transition over time. For example, one of the new solar projects I mentioned will be located on Colowyo Mine property. Tri-State also is working with local, state, federal, and industry leaders to develop, provide financial support for, and implement retraining, educational, and economic development solutions in addition to those that Tri-State is implementing on its own. While this issue is not addressed in the Commission's ERP rules for Tri-State, it is an important issue to Tri-State, its employees, and the impacted communities.]

VI. TRI-STATE'S 2020 ELECTRIC RESOURCE PLAN

Q: WHAT ARE THE OBJECTIVES OF TRI-STATE'S 2020 ERP?

A: Consistent with the Commission's ERP Rules, Tri-State's 2020 ERP is intended to describe Tri-State's need for additional electric resources, and ultimately identify a cost-effective resource portfolio to reliably meet such need. Tri-State's 2020 ERP also is intended to accomplish these regulatory objectives while complying with the legislative and public policy requirements and goals that I discussed previously, and advancing progress toward Tri-State's own goals set forth in the Responsible Energy Plan.

I also would note that the 2020 ERP, together with the complementary initiatives in the REP, is intended to respond to what Tri-State's Utility Members and their member-customers have been asking for – a transition to a cleaner power supply, reduced GHG emissions, and an opportunity to realize the potential benefits of lower cost electricity. Tri-State believes that the preferred plan submitted as a part of the 2020 ERP meets these objectives.

Q: PLEASE PROVIDE AN OVERVIEW OF THE ERP FILING.

A: Tri-State's 2020 ERP consists of two volumes containing the ERP itself and 18 appendices. Tri-State's 2020 ERP is included as **Attachment BN-2** to my testimony.

The ERP begins with an Executive Summary and an Introduction and Background section that discusses the development and organization of the 2020 ERP, and provides an update on progress made since Tri-State's 2015 ERP informational

filing.

The next section of the ERP addresses the current resource planning "landscape" in terms of Tri-State's system energy mix, market dynamics, and other external factors, and presents much of the information required by Rule 3605(a)(IV). As discussed in this section, Tri-State's 2020 ERP uses a 20-year resource planning period from 2021 through 2040 and, as required by Rule 3605(a)(IV)(A), a 10-year resource acquisition period ("RAP") beginning in 2021 and extending to the end of 2030. Tri-State believes that the next 12 to 24 months will provide greater clarity with respect to the variables, challenges, and opportunities that I discussed previously, and Tri-State recommends a measured approach to acquiring new resources during the RAP. Furthermore, Tri-State believes that additional time may allow for the development of new non-emitting dispatchable resources that could be cost-competitive for future acquisition, and Tri-State's 2023 ERP will provide an opportunity in the relatively near future to further consider these options.

The next section of the ERP provides Tri-State's assessment of resource needs, including current load and resource balance, RES/RPS requirements, GHG/CO2 reductions and demand-side management and energy efficiency.

The next section of the ERP presents Tri-State's Alternative Resource Analysis. This section discusses the Base Case as well as the multiple alternative plans that Tri-State considered, including the social cost of carbon and other plans required by Commission rules. This section compares the various plans and presents Tri-State's preferred plan. The next section outlines Tri-State's action plan for the

RAP, including the competitive bidding process and the ERP Implementation Report Plan.

The last section of Volume I of the ERP identifies the relevant confidential and highly confidential information, as required by Rule 3605(a)(IV)(K).

The first section of Volume II of the ERP provides load forecasting as required by Rule 3605(b) followed by details on commodity pricing.

The next section of the ERP presents Tri-State's Assessment of Existing Resources, including some of the information identified in the Commission's November 25, 2020 written decision closing Proceeding No. 20M-0218E.

The next section of the ERP addresses Tri-State's transmission system and transmission planning, and presents the information required by Rule 3605(d).

The next section of the ERP discusses in detail the Phase I modeling including constraints, assumptions, and methodology.

The last section of the report includes detailed environmental data for all scenarios.

Q: WHAT IS THE RESOURCE NEED IDENTIFIED IN THE ERP?

A: Tri-State's analysis shows a need for new capacity to provide replacement capacity support for the retirement of the Craig 3 unit in 2029. Tri-State also identifies the preferred addition of renewable and energy storage resources prior to that time, which will serve to achieve GHG reductions in the relatively near-term.

Q: PLEASE DESCRIBE THE ALTERNATIVES TRI-STATE CONSIDERED IN DEVELOPING THE 2020 ERP.

A: In addition to the Base Case, Tri-State considered seven alternative plans: four different base load scenarios yielding an 80% Colorado CO_2 emissions reduction, relative to a 2005 baseline, by 2030; two different low load scenarios yielding 80% Colorado CO_2 emissions reductions, relative to a 2005 baseline, by 2030; and a scenario that applies the social cost of carbon to all thermal generation units. Table 1 below provides a summary of the alternatives Tri-State considered.

Table 1. Summary of Electric Resource Plan Scenarios

Scenario	**Description**
Base Case	Business as usual case to be used as a reference to measure other scenarios against.
80% CR V1	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes forced (i.e. not a cost-driven model selection) expansion plan low level demand-response and aggressive level energy efficiency resources in Colorado.
80% CR V2	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that includes only existing demand-side management and energy efficiency.
80% CR V3	An 80% carbon-reduction by 2030 from a 2005 baseline for Colorado wholesale electricity sales scenario that is similar to 80% CR V2, but includes an additional wind

	resource to improve carbon dioxide reduction and enhance reliability.
80% CR V4	An 80% carbon-reduction by 2030 scenario that is similar to 80% CR V2, but includes an additional solar resource to improve carbon dioxide reduction and enhance reliability.
Low Load 80% CR V1	An 80% carbon-reduction by 2030 scenario that allows for low-level demand-response and/or low- or aggressive-level energy efficiency resources and uses the low load forecast.
Low Load 80% CR V2	An 80% carbon-reduction by 2030 scenario that includes only existing demand-side management and energy efficiency resources and uses the low load forecast.
Social Cost of Carbon	A Social Cost of Carbon scenario that uses the technical support document under Executive Order 12866—Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, to determine the social cost of carbon and it applies the appropriate cost to carbon-emitting resources.

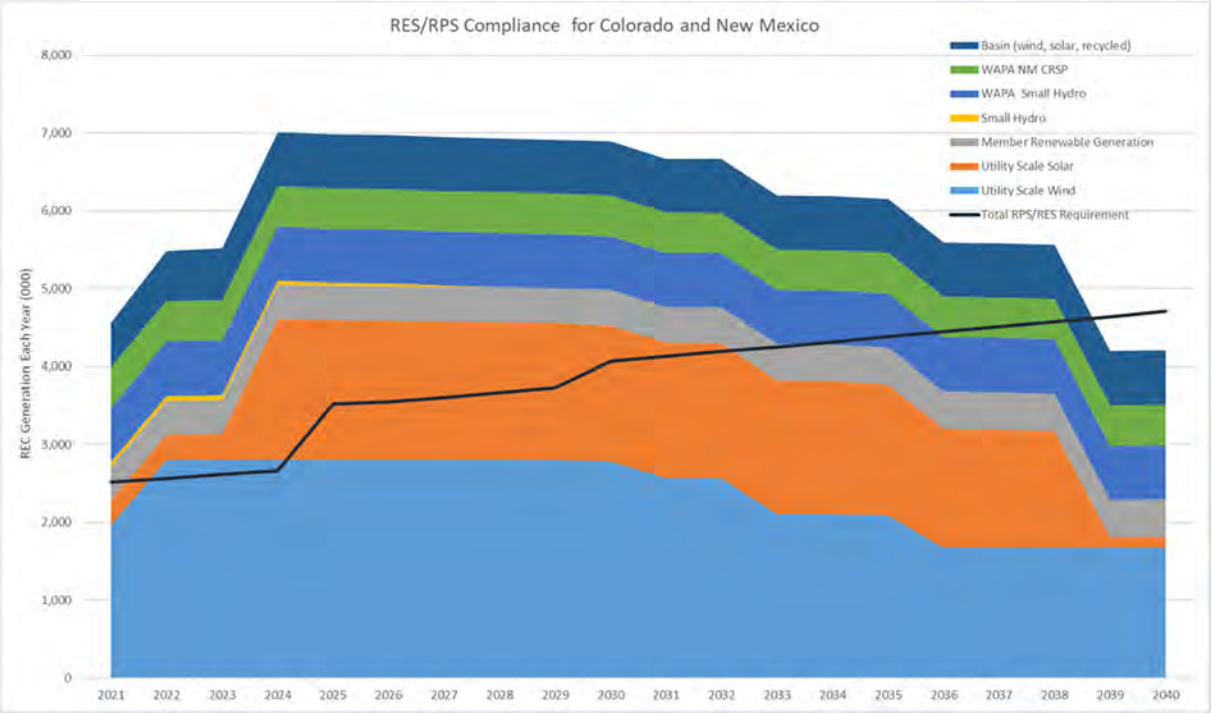
Q: IS TRI-STATE PRESENTING A PREFERRED PLAN IN ITS 2020 ERP?

A: Yes. Tri-State's preferred plan, which is forecast to result in an 80% CO_2 reduction as previously described, is detailed in Ms. Tiffin's testimony.

Q: DOES THE PREFERRED PLAN ENABLE TRI-STATE TO COMPLY WITH ITS COLORADO RENEWABLE ENERGY STANDARD OBLIGATIONS AND SUPPORT ITS COLORADO UTILITY MEMBERS' OWN RENEWABLE ENERGY STANDARD AND RENEWABLE PORTFOLIO STANDARD OBLIGATIONS?

A: Yes. Given that Tri-State operates an integrated generation and transmission system, the preferred plan will provide for compliance with Tri-State's and the Utility Members' RES and RPS obligations in Colorado and New Mexico. Figure 4 graphically depicts Tri-State's compliance with Colorado's RES and New Mexico's RPS.

Figure 4. RES/RPS Compliance for Colorado and New Mexico



RES and RPS compliance issues are discussed in greater detail in Ms. Tiffin's testimony.

Q: ARE YOU FAMILIAR WITH THE RECENT HEARING AND DECISION BY THE COLORADO AIR QUALITY CONTROL COMMISSION IN CONNECTION WITH THE STATE IMPLEMENTATION PLAN FOR REGIONAL HAZE?

A: I did not participate in that hearing and am not directly responsible for issues related to Tri-State's compliance with the Regional Haze State Implementation Plan. I am, however, generally familiar with the Colorado Air Quality Control Commission's ("AQCC") actions at its recent hearing. Mr. Berger discusses the AQCC's actions in more detail in his testimony.

Q: PLEASE DESCRIBE HOW THE RECENT ACTIONS BY THE AQCC MIGHT INFLUENCE TRI-STATE'S 2020 ERP.

A: On Friday, November 20, 2020, the AQCC took action in a Regional Haze proceeding that would call for the retirement of Craig Unit 3 and several other coal-fired generating units in Colorado by December 31, 2028. The AQCC characterized its action as a "preliminary final action"; as such, the AQCC's decision is not final as of the date of Tri-State's ERP filing, and it is unclear at this time whether the AQCC's final decision will be the same as what was discussed at the recent hearing and, if so, when the final decision will be issued.

While Tri-State will continue to evaluate options related to the AQCC's action, if this action does, in fact, require the retirement of Craig Unit 3 by December 31, 2028, that retirement date would be inconsistent with certain analyses contained in this ERP filing. Specifically, the scenarios in this ERP (except for those requiring consideration of the social cost of carbon) provide for the retirement of Craig Unit

3 one year later, by December 31, 2029. Tri-State will address the AQCC's final decision, as appropriate, during Phase 1 of this ERP proceeding.

Q: DOES TRI-STATE'S 2020 ERP FILING COMPLY WITH THE COMMISSION'S ERP RULES?

A: Yes. Tri-State's 2020 ERP complies with all of the requirements of new Commission Rule 3605. A Compliance Table is included at page 4 in the ERP report.

Q: WHAT APPROVAL IS TRI-STATE REQUESTING IN THIS PROCEEDING?

A: Tri-State requests approval of its 2020 ERP, including Tri-State's assessment of need for additional resources during the current resource acquisition period, Tri-State's plans for acquiring such additional resources, and the proposed RFP to be used in conjunction with such resource acquisitions.

Q: DOES THAT CONCLUDE YOUR TESTIMONY?

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN

VERIFICATION

STATE OF Colorado)
) ss:
COUNTY OF Adams)

I, Brad Nebergall, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Signed this 24th day of November, 2020, at Westminster, Colorado.

Subscribed and sworn to before me this 24th day of November, 2020.

Witness my hand and official seal.

Notary Public Faith Warner

My Commission expires: September 7, 2022

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES SEPTEMBER 7, 2022

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit K: NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Corrected July 11, 2025

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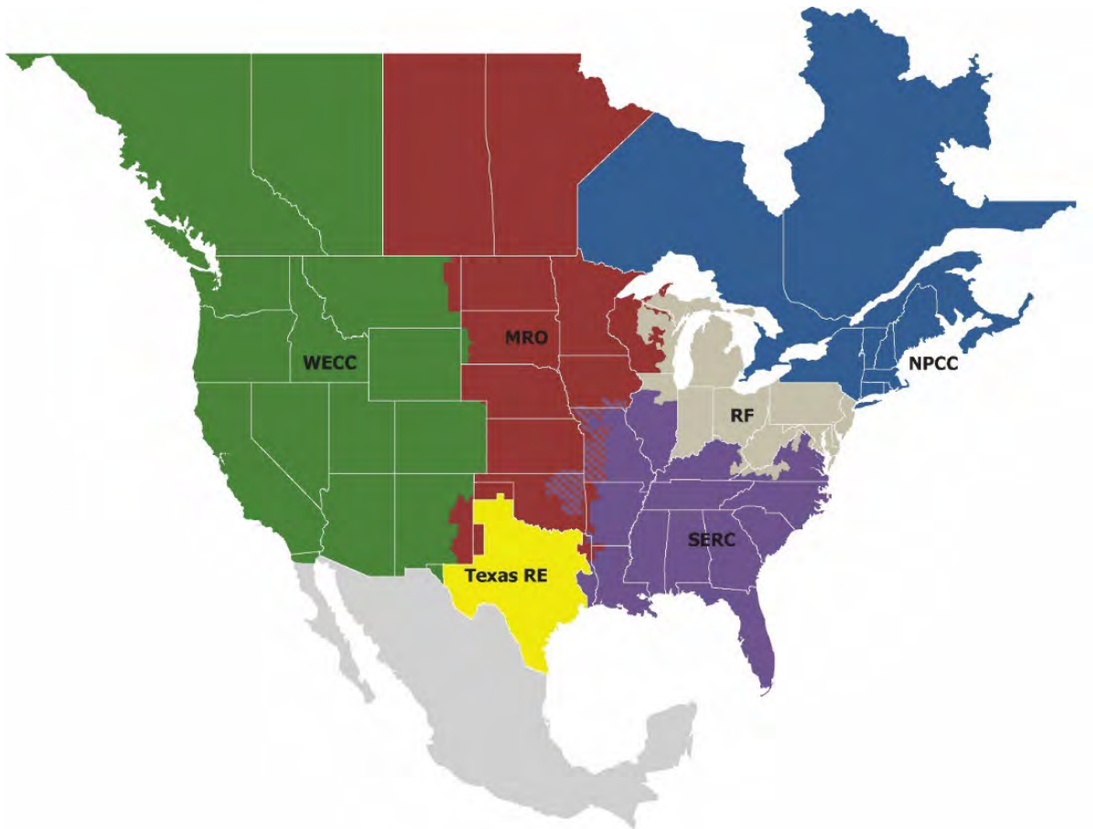
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

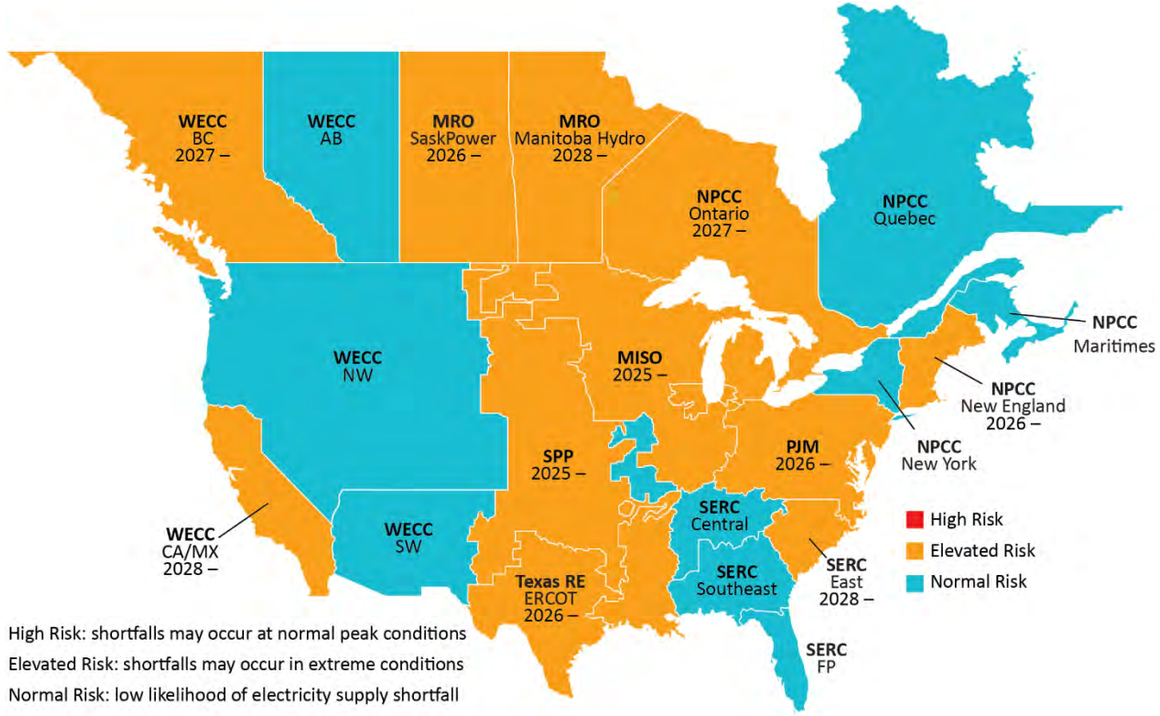


Figure 1: Risk Area Summary 2025–2029 (Corrected July 2025)

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary (Corrected June 2025)			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	Elevated	2025 -	Uncertainty around new resource additions and existing generator retirements results in resource adequacy risks. Above-normal generator outages during extreme weather can result in unserved energy or load loss.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

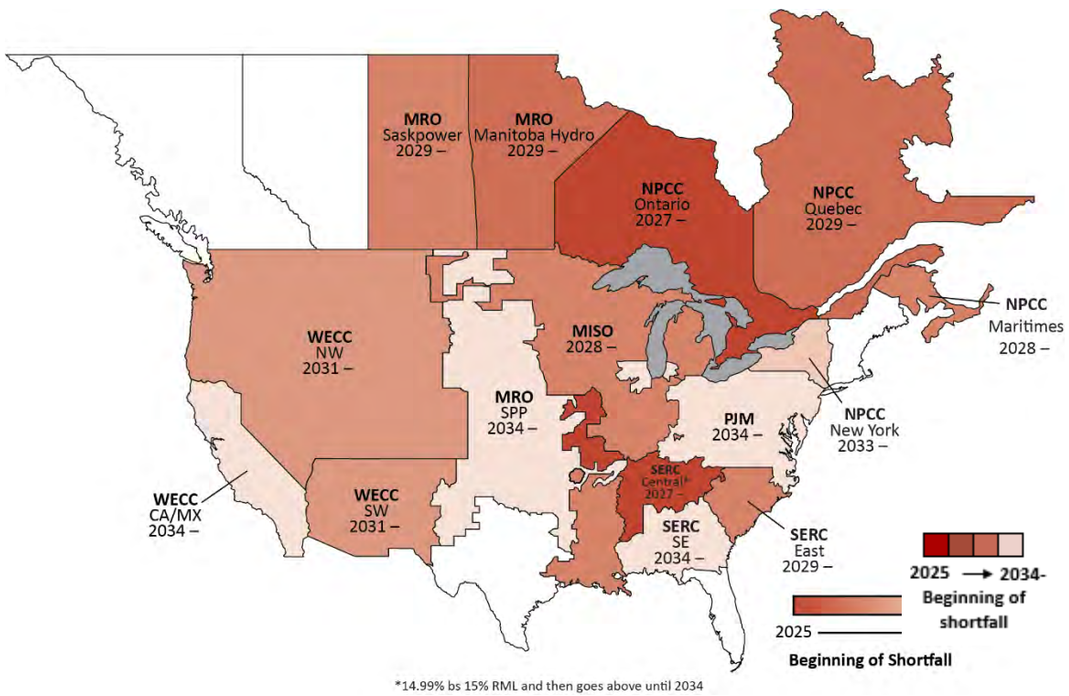


Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (Corrected July 2025)

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.

2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.

3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.

5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary** section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Assessment

The resource mix transformation is making traditional capacity-based adequacy criteria obsolete. Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure sufficient resources are available to meet demand. In their application, current capacity-based adequacy criteria were not designed to differentiate between the scenarios, size, frequency, duration, and timing of energy shortfalls. This has become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. Therefore, supplemental criteria must be adapted to properly assess system adequacy and help determine appropriate solutions. This year's LTRA includes probabilistic indices to measure these additional dimensions of risk and provide a more robust approach to understanding risk of inadequacy in future plans.

Assessment Approach

NERC is using two approaches in this LTRA to assess future resource capacity and energy risk; both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high-risk periods and potential energy constraints resulting in load-loss events. The 2024 ProbA is performed for each assessment area and examines the system as planned for the years 2026 and 2028. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as RML) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

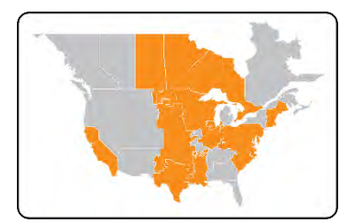
See the **Demand Assumptions and Resource Categories** for further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

An assessment area is **high risk** when established resource adequacy targets or requirements are not met during this assessment period. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See the **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[8] High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Unusual heat waves or deep-freeze events pose an even greater threat to reliability.

For the *2024 LTRA*, assessment areas are classified as high risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA.
- Annual normalized EUE exceeds 0.002% (20 ppm) for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are not met.

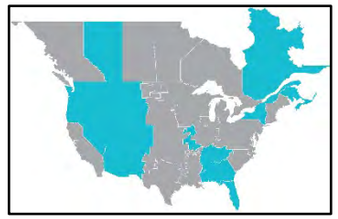


An assessment area is considered an **elevated risk** when it meets the established resource adequacy target or requirement, but probabilistic or deterministic analysis of conditions that are plausible but more extreme than normal seasonal peaks are likely to cause shortfall in area reserves. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. Simply put, elevated-risk areas meet resource adequacy requirements but may face challenges meeting load under extreme conditions. For the *2024 LTRA*, assessment areas are classified as elevated risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA.

[8] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

- Annual normalized EUE is less than 0.002% (20 ppm) but non-zero for one or more years in the ProbA.
- Resource adequacy target(s) established by regulatory authority or market operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.



NERC assesses areas as **normal risk** when resource adequacy criteria are met and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme[9] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2024 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2025–2029):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is negligible or zero.
- Resource adequacy target(s) established by regulatory authority or market operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from probabilistic assessments performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In this year's LTRA, NERC incorporated new probabilistic assessment criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid* alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

Elevated-Risk Area Details

The below areas are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO

MISO has experienced slower resource additions due to market pressures and constraints faced by projects with signed interconnection agreements. MISO has highlighted uncertainties with a large number of new resources that have signed interconnection agreements (Tier 1 additions) and are expected to come on-line in the next several years.[10] Resource adequacy risks could grow over time absent the new capacity reflected in the Tier 1 additions and the deferral of announced retirements (see **Risk from Additional Generator Retirements**).

PRMs in MISO with resource additions are shown in **Figure 3** and **Figure 4**. MISO reports 56 GW of nameplate generating capacity, predominantly solar and batteries, with signed generation interconnection agreements (qualifying as Tier 1 and reflected in the ARM in **Figure 3** and **Figure 4**) as of July 2024 that can help meet resource adequacy needs if connection is completed. If resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

[9] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide Area Heat Dome.
[10] See results from the 2024 Organization of MISO States (OMS)-MISO Survey.

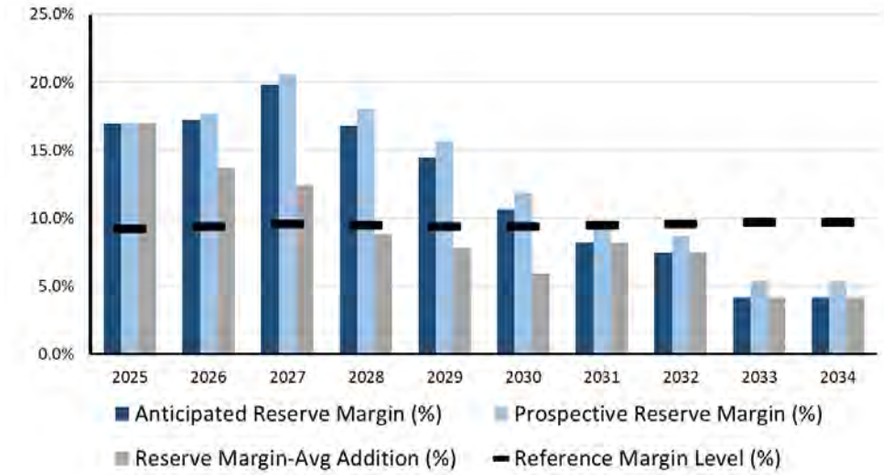


Figure 3: MISO Planning Reserve Margin–Summer

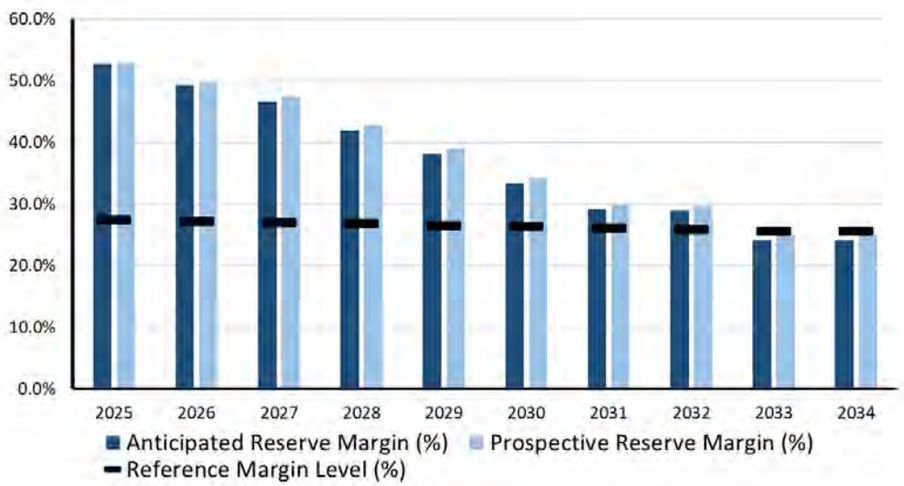


Figure 4: MISO Planning Reserve Margin–Winter

To establish the RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet an LOLE of 1 day in 10 years. See the **MISO** assessment area pages.

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below RMLs within the next five years.

MRO-Manitoba Hydro

The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of electric vehicles. Resource projections have not changed significantly.

As in prior probabilistic assessments, Manitoba Hydro's 2024 ProbA indicates that there is some risk of load loss and unserved energy associated with very low hydro conditions (see **Table 2**). Electricity demand peaks in winter, making this the higher-risk season. However, electricity supplies could fall short during either peak summer or winter conditions should an extreme and prolonged drought affect hydro production.

Table 2: MRO-Manitoba Hydro ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	7.23	**4.71**	**68.87**
EUE (PPM)	0.29	**0.18**	**2.50**
LOLH (hours per year)	0.01	**0.06**	**0.91**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SaskPower

Resource projections for Saskatchewan over the 10-year period have increased since the *2023 LTRA*, rising to just over 1 GW and include two new 377 MW gas-fired generation facilities, expansion of existing gas-fired generation facilities, and new geothermal resources. The peak demand forecast growth rate (1.35% annually) has changed little since the *2023 LTRA*.

The ProbA for SaskPower indicates there is some risk of load loss and unserved energy that diminishes with the new resource additions that are planned for 2027 (**Table 3**). Saskatchewan is a winter-peaking system; however, the unserved energy risks are more closely associated with the planned outages of large generators that typically occur in the fall and spring shoulder periods. The months of September and October are the highest risk periods because of the potential for high temperatures to unexpectedly extend beyond summer and into the maintenance period.

Table 3: MRO-SaskPower ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	117.0	**75.64**	**8.55**
EUE (PPM)	4.4	**2.81**	**0.30**
LOLH (hours per year)	0.9	**0.54**	**0.08**
Operable On-Peak Margin	24.6%	**24.8%**	**30.8%**

** Year 2026 Results from the 2022 ProbA provided for trending*

MRO-SPP

New resource capacity in the interconnection queue—primarily solar, battery, and wind—is currently projected to keep up with rising peak demand forecasts. DR programs are also increasing over the next 10 years. Resource adequacy issues can arise, however, if generators retire earlier than anticipated or new resource additions connect more slowly. Currently, there are over 8 GW of coal and gas-fired generators that have indicated that they may retire within the next 10 years, making the resource outlook unclear. SPP's summer reserve margins, based on installed generator capacity, remain above RMLs through 2029 (see **Figure 5**).

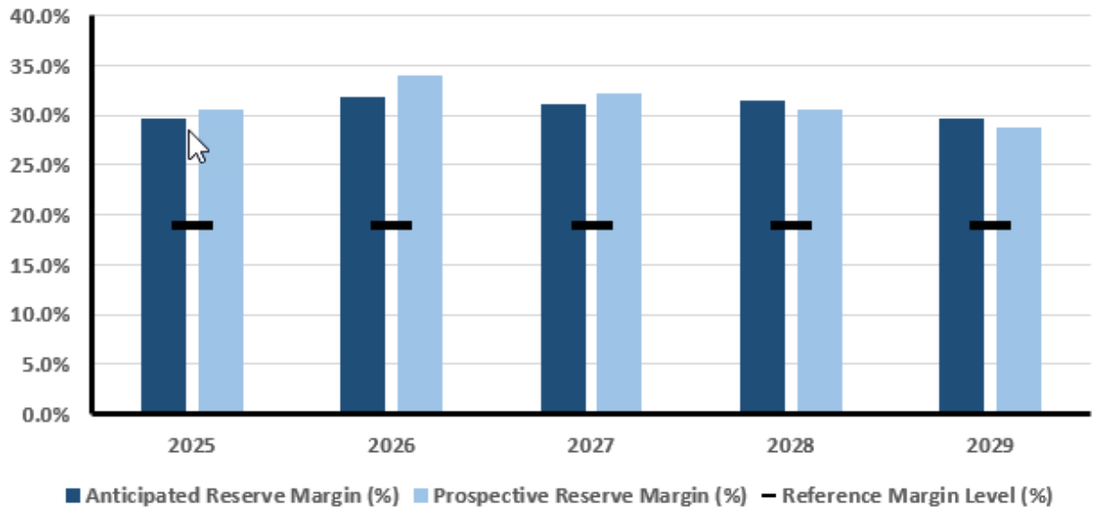


Figure 5: MRO-SPP Five-Year Planning Reserve Margin–Summer

All-hours probabilistic analysis performed by SPP shows that resource adequacy challenges are shifting from summer (when area demand is at its highest) to winter months (when the new resource mix is less capable of performing reliably). Annual results of the ProbA are in **Table 4** below. SPP's 2023 loss-of-load expectation (LOLE) study results indicate that a separate RML and seasonal resource capacity contributions are needed for the summer and winter seasons to effectively provide for resource adequacy.

Table 4: MRO-SPP ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.84	**0.00**	**6.61**
EUE (PPM)	0.00	**0.00**	**0.02**
LOLH (hours per year)	0.00	**0.00**	**0.01**
Operable On-Peak Margin	19.6%	**19.5%**	**16.0%**

** Year 2026 Results from the 2022 ProbA provided for trending*

NPCC-New England

New England is forecasting unprecedented demand growth driven by electrification of heating and transportation. Wind, solar, and batteries make up the projected resource additions, along with growth in distributed energy resources. Since the *2023 LTRA*, the peak demand forecast is relatively unchanged. New England has among the strongest winter demand forecast growth rates of any assessment area, rising over 7 GW in the 10-year period, or 35% from its current peak demand forecast.

The 2024 ProbA for NPCC-New England reveals increasing risk of load loss and unserved energy compared to the 2022 ProbA (see **Table 5**). Higher-demand forecast and replacement of dispatchable resources with more VERs contribute to this trend. In the ProbA modeling, supply shortfall risk is limited to the summer months and is associated with periods of above-normal demand and low resource output (e.g., low wind, solar, or high thermal outages).

Table 5: NPCC-New England ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.55	**10.69**	**67.40**
EUE (PPM)	0.00	**0.09**	**0.06**
LOLH (hours per year)	0.00	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

While NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months, a persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk but were not within the scope of the 2024 ProbA.

NPCC-Ontario

Near- and long-term resource adequacy challenges continue in the NPCC-Ontario assessment area as the Independent Electricity System Operator (IESO) manages lengthy refurbishment outages at nuclear generators and demand growth driven by agriculture and electrification. The beginning of projected shortfalls occurs in 2027 when some contracts for firm capacity are set to expire (see **Figure 6**). However, a number of resources with expiring contracts between 2026 and 2029 are anticipated to be re-committed for five-year terms through the IESO's second medium-term procurement, which is underway. As such, Ontario's Anticipated Reserve Margins (ARM) and Prospective Reserve Margins shown in **Figure 6** (which do not include this set of expiring resources) are conservative. Recommitment of these resources is expected to raise margins above the reference level in 2029 and help maintain reliability through the end of the decade. In May 2024, the IESO finalized long-term commitments for new-build battery storage facilities (1,784 MW) and new-build natural gas and biogas facilities (411 MW). Early operation incentives anticipated to bring a portion of these resources online as early as 2027 could help alleviate the reserve margin gap. The IESO also launched procurements for new capacity and energy-producing resources to be online as early as 2029. In addition, the IESO finalized an agreement with Hydro-Québec for capacity sharing in November 2024, providing 600 MW of firm imports to Ontario starting in Summer 2025 through Summer 2031. This capacity is also expected to help alleviate shortfalls indicated in 2027.

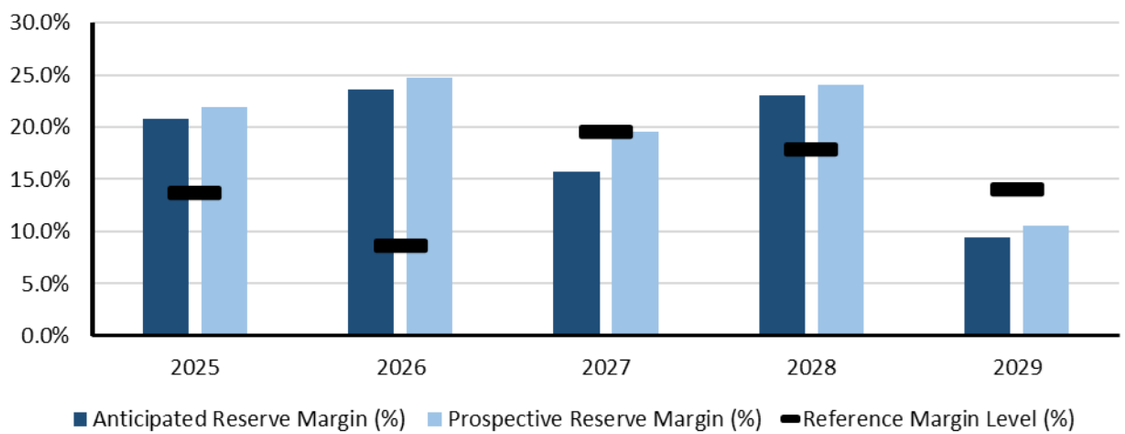


Figure 6: NPCC-Ontario Five-Year Planning Reserve Margin–Summer

The probabilistic assessment for Ontario performed by NPCC provides further insights into the potential for load loss and unserved energy. There is negligible risk of unserved energy and load loss in 2026 and earlier years; however, a small risk of load loss (< 0.01 hours) emerges after 2026 (Table 6). The 2024 ProbA study included only years 2026 and 2028, both of which have projected capacity surpluses above RMLs (see Figure 6). If 2027 and 2029 had been included in the ProbA, it can be expected that there would have been higher amounts of LOLH and unserved energy. ProbA results are also helped by the inclusion of electricity transfers from neighboring areas and modeling for some operating procedures used to manage supply shortfalls.

Table 6: NPCC-Ontario ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

** Year 2026 Results from the 2022 ProbA provided for trending*

PJM

PJM's projections for generator additions in 2025 and 2026 are scaled back dramatically from the *2023 LTRA* while demand forecasts continue to rise. As a result, ARMs for future years have fallen by as much as nine percentage points from last year. The trends in demand growth and resource additions create resource adequacy and system planning challenges for PJM as it carefully manages generator deactivation requests from the aging fossil and nuclear fleet.

PJM's ProbA results provide indication of the increasing resource adequacy risk to the system (see Table 7). EUE and LOLH are found in both ProbA assessment years (2026 and 2028) with risk concentrated in the winter months (especially January). The risk occurs on days where temperatures are very low across the entire PJM area, which results in high loads. While normal resource performance can meet these demand forecasts, resource performance from thermal resources on very cold days has historically been below normal due to freezing and fuel supply issues. Furthermore, solar resources are not likely to contribute during some of the coldest hours, resulting in very low total electricity supply and thus projections of load loss. ProbA analysis shows some summer load-loss and unserved energy risk but at much lower levels. Summer shortfall events are most likely to occur during wide-area heat events that coincide with low wind and low solar output, or very high outage and derates in the thermal generation.

Table 7: PJM ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1,043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.12**	**0.22**
Operable On-Peak Margin	29%	**17.8%**	**17.7%**

** Year 2026 Results from the 2022 ProbA provided for trending*

SERC-East

The addition of solar resources is helping to raise summer on-peak reserve margins in the assessment area, despite rising demand forecasts and additional coal-fired generator retirements. Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024. An additional 2 GW of solar PV resources are in the process of connecting. The summer peak demand forecast has also risen since the *2023 LTRA*, increasing by 2.8 GW (6.3%) over last year's projection. The area reserve margins have increased in the near term as a result of the solar resource additions then drop off after 2028 due to higher demand forecasts and planned generator retirements.

Despite these resource additions and higher summer reserve margins, the 2024 ProbA reveals growing resource adequacy risk in SERC-East (see Table 8). Measures of unserved energy and load-loss have increased since the 2022 ProbA as demand has risen and the resource mix has changed. SERC-East has changed from a summer-peaking area to one with peak electricity demand occurring in both the summer and winter seasons. This change is the result of added solar PV generation that shaves off summer peak demand and trends toward electrification in heating that drives up winter peak demand. The ProbA shows that the risk of unserved energy and load loss is concentrated in winter (January–February) months when wide-area extreme cold weather can affect electricity demand, generator performance, generator fuel supplies, and the availability of electricity imports. Based on current forecasts, resource adequacy risk will increase in SERC-East after 2028 due to the planned retirement of over 1,800 MW in coal-fired generation and continued load growth.

Table 8: SERC-East ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.40	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

** Year 2026 Results from the 2022 ProbA provided for trending*

Texas RE-ERCOT

ERCOT is forecasting explosive demand growth, driven by data center projects, Bitcoin operations, development in oil- and natural-gas-producing areas, and industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. Substantial amounts of solar PV and battery resources are being added to help meet rising demand, but there are significant reliability challenges to address during this period of rapid growth. Resource adequacy risks are mounting as fewer dispatchable resources comprise the resource mix. One of the strategies to address this risk is state implementation of a dispatchable resource generation loan program called the Texas Energy Fund. Furthermore, the forecasted growth in loads and resources poses significant challenges for transmission system planners.

Load growth and the characteristics of the resource mix are contributing to higher levels of unserved energy and load loss in probabilistic analysis (see **Table 9**). In the 2024 ProbA, EUE for the analyzed 2026 ERCOT system has risen to 19 ppm (0.0019 %) of the total annual supplied energy compared to the same analysis in the 2022 ProbA. The 2024 ProbA shows an improving trend in the analyzed 2028 ERCOT system, enabled by additional generation capacity from ERCOT scenarios developed to support rapid growth in large loads.[11]

A deeper analysis of the probabilistic assessment results reveals the unique characteristics of winter and summer risk. While peak winter loads can persist for 48 hours or longer, peak summer periods generally only last for a few hours. This is manifested in the duration and depth of the winter firm load-shed events that appear in the ProbA and has significant implications for the reliability contribution of energy-limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and up to 29 GW in load loss. In contrast, most summer unserved energy events were 1–2 hours in duration.

Table 9: Texas RE-ERCOT ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

** Year 2026 Results from the 2022 ProbA provided for trending*

A key conclusion from the Texas RE-ERCOT 2024 ProbA is that matching the area's demand growth with a resource mix that is more variable and less fully dispatchable is increasing the risk of supply shortfalls that can result in load loss and unserved energy. When the seasonal characteristics of demand and resources are considered, Resource Planners can appropriately focus efforts to reduce the risk of potentially severe, long-duration winter shortfall events. The Public Utility Commission of Texas established a Reliability Standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude.

WECC-CA/MX

Resource additions continue to improve the overall resource adequacy outlook for the WECC California-Mexico assessment area. Since the 2022 ProbA, the planned extension of the Diablo Canyon nuclear plant (2.2 GW) and resource additions (over 5 GW nameplate in batteries, 3.3 GW nameplate in solar PV, and 0.2 GW in natural-gas-fired and geothermal generation) have alleviated supply shortfalls that were driving unserved energy and load-loss metrics in year 2026, as shown in the results of the 2024 ProbA performed by WECC (see **Table 10**).

Table 10: WECC-CA/MX ProbA Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.72	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

** Year 2026 Results from the 2022 ProbA provided for trending*

Demand growth and planned generator retirements cause energy adequacy risks to re-emerge in future years. With a resource portfolio that includes a substantial amount of solar PV, the risk of supply shortfall is associated with summer evening periods when demand is high and solar output is diminished. WECC's analysis for the 2024 ProbA found only a small occurrence (<1 hour) of resources falling below margin levels for reliability in the 2028 study year. WECC further observed that load-loss and unserved energy risk was localized in the Mexico portion of the assessment area, reflecting localized resource and transmission system constraints.

[11] Due to the inclusion of an additional 20 GW of large loads based on newly signed interconnection agreements, study-year 2028 included additional generation capacity from the "High Large Load Adoption" scenario of the ERCOT 2024 Long-Term System Assessment (LTSA), which included 22 GW of combustions turbines (CT) and 4 GW of combined cycles (CC).

The CA/MX 2028 system analyzed by WECC for the 2024 ProbA reflects the continued rapid transformation of the power grid. The analysis assumes forecasted demand growth of 3.5 GW, substantial resource additions (4.6 GW of solar PV, 7.6 GW in batteries, and 0.8 GW of natural-gas-fired generation imported from repowered coal units in Utah), and the retirement of over 3 GW of gas-fired generation. As demand grows and the resource mix becomes increasingly variable, periods of supply shortfalls can emerge. Battery additions and transfers help make up for energy shortfalls that can arise during evening solar down ramps.

WECC-BC

BC has a predominantly hydroelectric generation system with vast amounts of energy storage provided by its reservoirs. Winter peak demand in the province is forecast to grow modestly over the next 10 years, from 11,966 MW this winter to 12,305 MW at the end of the 10-year period. Since the *2023 LTRA*, the winter peak demand compound annual growth rate (CAGR) has fallen from 1.0% to 0.3%. Growth rate and reserve margins are higher. While the overall resource adequacy outlook has improved, the 2024 ProbA indicates the area continues to be at an elevated risk of supply shortfall during extreme conditions. Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Western Interconnection-wide probabilistic analysis performed by WECC for the 2024 ProbA reveals that risk of reserve shortages emerges after 2026, potentially resulting in unserved energy and load-loss events during extreme weather. WECC's analysis identified over five hours in 2028 when high demand and low supply from WECC-BC's internal resources were not able to be remedied with imports from neighboring areas experiencing similar conditions (see **Table 11**). In contrast, 2026 had no unserved energy or load-loss periods. An examination of hourly results showed that imports from neighbors were more available in 2026 to cover periods of potential shortfalls in BC Hydro's internal resources.

Table 11: WECC-BC ProbA Summary of Results

	2026*	2026	2028
EUE (MWh)	24	**0**	**103,132**
EUE (PPM)	0.71	**0**	**1,456**
LOLH (hours per year)	0.00	**0**	**5.52**
Operable On-Peak Margin	12.7%	**16.9%**	**9.4%**

** Year 2026 Results from the 2022 ProbA provided for trending*

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

BC's supply margins relative to demand are lowest during winter peak demand periods. Imports from neighbors in the U.S. Northwest are common during these periods, and often during the overnight hours of 23:00 to 4:00 local. WECC's analysis shows the need for imports growing year to year throughout most of the LTRA forecast horizon. A widespread, extreme cold weather event in the Northwest that limits transfer capability is thus a risk to BC. Even though WECC-BC is expecting only moderate demand growth and relatively few retirements, diminished surplus capacity in neighboring areas is negatively affecting the resource adequacy outlook.

Normal-Risk Area Details

All other assessment areas (see **Figure 1**) are assessed as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Assessment** section in this LTRA is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2024 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that, in the future, the risk assessment map will expand with more elevated and high-risk areas.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, and nuclear generators can have a profound and negative effect on the resource adequacy and reliability of the BPS in the next 10 years. In this preceding **Capacity and Energy Assessment** NERC accounted for nearly 79 GW of fossil-fired and nuclear generator retirements that are anticipated through 2034. Environmental regulations and energy policies have the potential to influence generators to seek deactivation during the 10-year assessment period.[12] An additional 43 GW of fossil-fired generators have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. These retirements, along with the confirmed retirements, contribute to declining reserve margins in the assessment areas over the next 10 years (see **Table 12**). As a result of demand growth and generator retirements, ARM is projected to fall below RML in 18 of the 20 assessment areas by 2034. While forecasts such as this factor into resource planning and market mechanisms to obtain resources needed for resource adequacy, it underscores the significant resource growth needed across North America. The lack of dispatchable resources and diverse generator fuel types in the interconnection processes makes the future resource mix look alarmingly unreliable. The potential for capacity and energy shortfalls and a higher-risk resource mix is heightened by economic and policy factors that place pressure on existing thermal generators.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from** Additional Generator Retirements section.

[12] The Environmental Protection Agency (EPA) issued a final rule on May 9, 2024, establishing Greenhouse Gas Standards and Guidelines for Power Plants (the "GHG Rule"). This rule was released concurrently with three other EPA regulations that impact fossil-fueled power generation: Coal Combustion Residuals, Effluent Limitations Guidelines, and Mercury and Air Toxics Standards. Collectively, these four new regulations impose considerable financial and operational challenges on coal-fired generators.

Table 12: Anticipated Reserve Margins with Announced Retirements											
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
MISO[13]	17.7%	10.3%	10.3%	13.2%	8.6%	7.1%	10.6%	8.2%	7.5%	4.2%	-2.5%
MRO-Manitoba	12.5%	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
MRO-SaskPower	28.9%	27.8%	26.6%	31.1%	29.4%	7.0%	28.8%	28.0%	26.7%	26.8%	1.2%
MRO-SPP	28.3%	26.7%	26.0%	25.0%	20.8%	19.1%	26.7%	24.9%	23.5%	22.4%	8.1%
NPCC-Maritimes	18.9%	20.6+%	25.5%	25.1%	18.6%	3.9%	23.4%	20.7%	19.1%	17.7%	-1.5%
NPCC-New England	20.4%	25.0%	25.0%	26.3%	24.9%	23.5%	22.0%	20.1%	19.7%	17.1%	14.6%
NPCC-New York	18.4%	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
NPCC-Ontario	22.5%	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
NPCC-Quebec	12.5%	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
PJM	29.8%	34.9%	35.7%	28.1%	21.4%	18.2%	23.1%	21.6%	20.1%	18.5%	10.3%
SERC-C	28.2%	18.9%	18.9%	15.0%	16.0%	15.2%	17.3%	17.1%	18.4%	21.1%	11.8%
SERC-E	30.4%	27.3%	25.8%	24.6%	20.6%	14.4%	14.3%	10.2%	6.3%	4.6%	-2.2%
SERC-FP	27.0%	25.4%	26.0%	23.2%	22.1%	20.9%	18.4%	22.0%	20.4%	18.2%	16.0%
SERC-SE	44.9%	39.9%	35.9%	31.5%	24.5%	21.4%	27.7%	25.8%	24.7%	23.7%	13.0%
TRE-ERCOT	24.3%	30.2%	32.5%	29.7%	25.6%	25.4%	27.8%	28.0%	28.4%	28.9%	24.9%
WECC-AB	36.3%	35.8%	35.7%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
WECC-BC	20.9%	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
WECC-CA/MX	38.6%	45.5%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
WECC-NW	34.5%	40.3%	38.9%	35.6%	30.7%	24.5%	18.3%	12.2%	10.2%	8.1%	5.9%
WECC-SW	28.6%	37.0%	35.6%	31.6%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-9.6%

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the Executive Summary.

[13] MISO reserve margins in this table reflect MISO Seasonal Accredited Capacity for summer. Adjustments and derates are applied to account for factors affecting expected resource output, resulting in unforced capacity (UCAP) reserve margins that are lower compared to installed capacity (ICAP) values. For more information see the **MISO assessment area** page.

Resource Mix Changes

Capacity Versus Energy: Changes in the Way to Plan for Resource Adequacy

Industry's methods of planning for resource adequacy need to change. The modern power system requires the enhancement of assumptions and supplementation of risk information for a better characterization of the risk. Historically, the resource adequacy criterion has been based on the LOLE metric, which should be no more than 1 event-day in 10 years when the generating resources are less than load (commonly known as "1-day-in-10"). This has been a design basis for the U.S. electric grid for at least 70 years (with its first formal mention in a 1951 American Institute of Electrical Engineers paper by C. W. Watchorn) and has historically served the industry well. Two important related but separate discussion topics include considerations for assumptions in the calculation of LOLE and other metrics and the establishment of the resource adequacy criteria (i.e., traditionally in terms of LOLE-1-day-in-10). The 1-day-in-10 LOLE criterion is commonly converted into a minimum capacity requirement resulting in a target or RML. In doing this, planners determine the minimum PRM required to maintain a 1-day-in-10 LOLE level. Historically, systems with an actual PRM above the minimum generally have sufficient resources and provide adequate energy and ERSs that operators need to reliably operate the BPS. Issues can arise in resource adequacy planning processes when planners solely rely on the RML comparison as the system transforms from an era of certain to more uncertain fuel sources and load behavior. In recent years, NERC has documented warnings of potential energy shortages in its reliability assessments, while in many cases the RML comparison indicates no shortfall. Substantial uncertainty has been introduced into planning the system with the addition of energy-constrained resources (variable energy resources such as wind and solar, and, at times, just-in-time fuels such as natural gas) that are highly dependent on weather and environmental conditions. Uncertainty in energy sufficiency is increasing as the types of resources change, leaving fewer resources that can be dispatched (dispatchable resources) in response to the variable resource availability and greater exposure to constraints in fuel supplies, reservoir levels, or battery discharge capabilities. Historical generator reliability assumptions based on the idea of well-maintained, well-invested units with an anticipated long life are no longer adequate. This increases uncertainty as a greater proportion of fossil-fueled resources continue to be retired, often with little notice to system planners. Nameplate values of variable energy resources are not as meaningful as projected energy availability, and environmental conditions can adversely impact the simultaneous availability of thousands of megawatts.

Probabilistic analysis enhances deterministic transmission planning from an energy adequacy standpoint given the following factors:

- Considers likelihood of events: It uses historical data to estimate how often different outages and weather conditions might occur.
- Provides more information: It calculates the average impact of these events, including how often and how long power outages might last.
- Helps compare options: It enables the selection of the upgrade(s) that provide the best balance between cost and reliability over time to be chosen.

Detailed recommendations are included in a recently published NERC report:
Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report, June 2024

Changes in Existing BPS Resource Capacity

Thermal generator retirements and new resource additions continue at a rapid pace. Since the *2023 LTRA*, over 8 GW of coal-fired generation has been retired, while substantial solar and battery resources have connected to the grid (see **Table 13**). From a strictly on-peak capacity perspective, there has been little change (8,348 MW is 0.8% of the total BPS summer on-peak resource capacity.)

Table 13: Existing BPS Resource On-Peak Capacity

	2023 Capacity (MW)	2024 Capacity (MW)	Difference (MW)
Coal	188,856	180,402	-8,454
Petroleum	32,107	30,987	-1,120
Natural Gas	483,391	484,148	757
Biomass	7,273	7,381	108
Solar[14]	52,998	66,293	13,295
Wind[15]	32,320	31,370	-950
Geothermal	4,319	3,881	-438
Conventional Hydro	103,368	105,792	2,424
Run of River Hydro	1,565	2,047	482
Pumped Storage	19,463	19,422	-41
Nuclear	106,173	105,385	-788
Hybrid & Battery	5,593	9,909	4,316
Other	2,217	774	-1,443
Total	1,039,643	1,047,791	8,348

This year-on-year change in on-peak capacity continues the general trend of declining baseload and dispatchable generation—which includes coal-fired, natural gas, and nuclear generators—and rising VERs. **Figure 7** shows the trend continuing through 2034, where 20% of the generating capacity will be provided by VERs. Focusing on the relatively small change in total on-peak capacity since 2023 can mask risks to reliability that result when important attributes of the retiring generation resources are not inherent in the replacement resource mix. Thermal generation resources, such as coal-fired generators, have the capability to be dispatched when needed and provide system inertia, dynamic reactive support, and frequency response for stable grid operation. Most types of replacement resources have limited or none of these attributes. Further, retirements in the thermal generator fleet are making the resource mix less effective in meeting winter energy needs.

Figure 7: North America Total Generation Capacity in 2024 and 2034

Capacity Additions

New generation is added to the BPS through the area interconnection planning processes. Solar PV is the overwhelmingly predominant generation type being added to the BPS, followed by battery and natural-gas-fired generators, wind turbines, and hybrid resources. Batteries are now the second most predominant resource in the North America BPS interconnection queues. A summary of generation resources in the interconnection planning queues is shown in **Figure 8**.

Capacity in planning has grown since the *2023 LTRA* by over 44 GW (12%). In general, **Tier 1** resources are in the final stages for connection, while **Tier 2** resources are further from completion (see text box). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. While interconnection queues continue to swell, considerable uncertainty

[14] The capacity values in this table represent the on-peak contribution of solar resources. The total installed (nameplate) capacity of BPS solar in 2024 is 111,102 MW. See Table 11.
[15] The capacity values in this table represent the on-peak contribution of wind resources. The total installed (nameplate) capacity of BPS wind in 2024 is 176,636 MW. See Table 11.

surrounds the timing and amount of resource additions. (See an analysis of projected and actual additions on the next page).

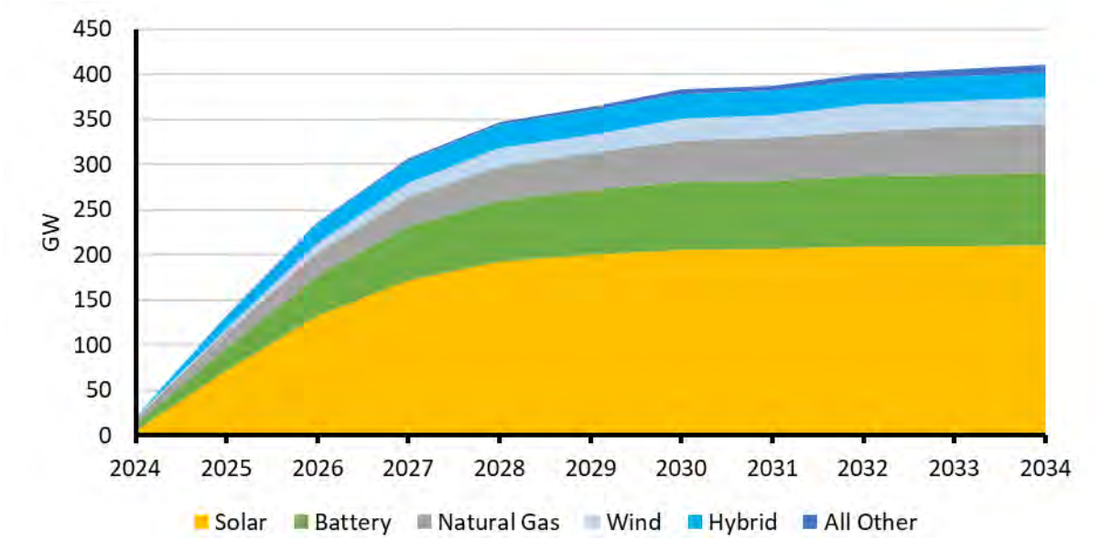


Figure 8: Tier 1 and 2 Planned Resources Projected Through 2034

Solar PV and wind nameplate capacity, both existing and planned, vary widely by area. Figure 9 and Figure 10 show current solar PV and wind installed capacities and the capacity in the planning process through 2034 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (i.e., a wind or solar farm), are connecting to the grid in parts of North America, and many more projects are in BPS planning processes.

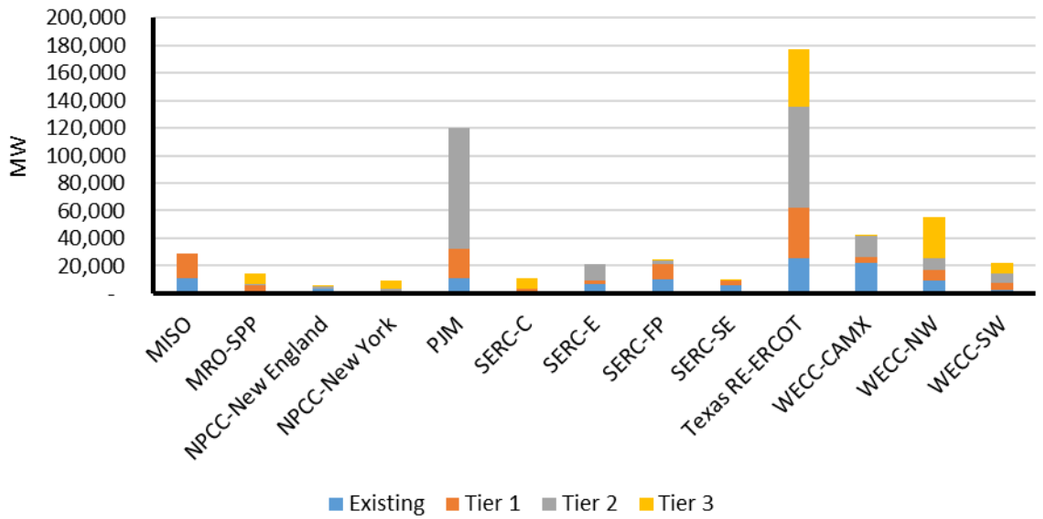


Figure 9: Solar Nameplate Capacity Existing and Planned through 2034

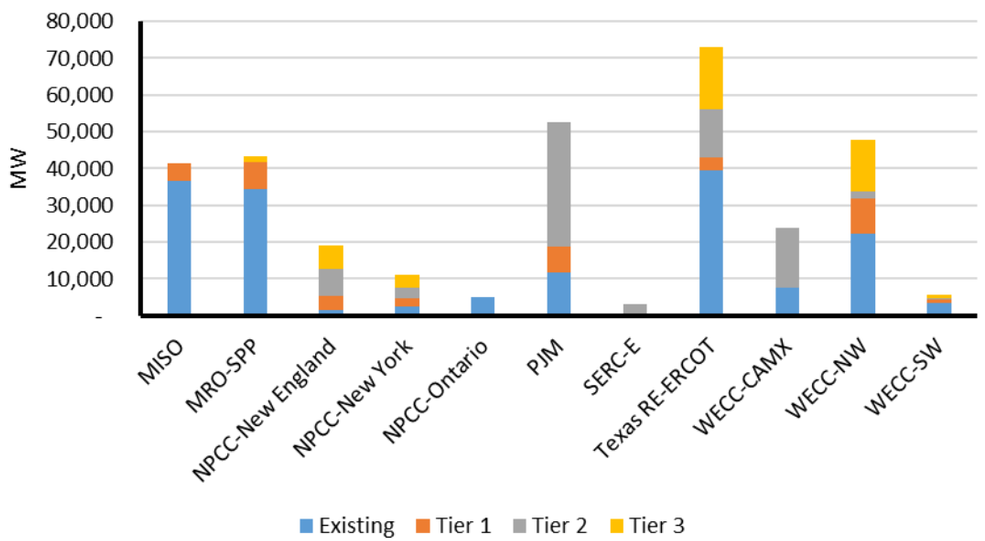
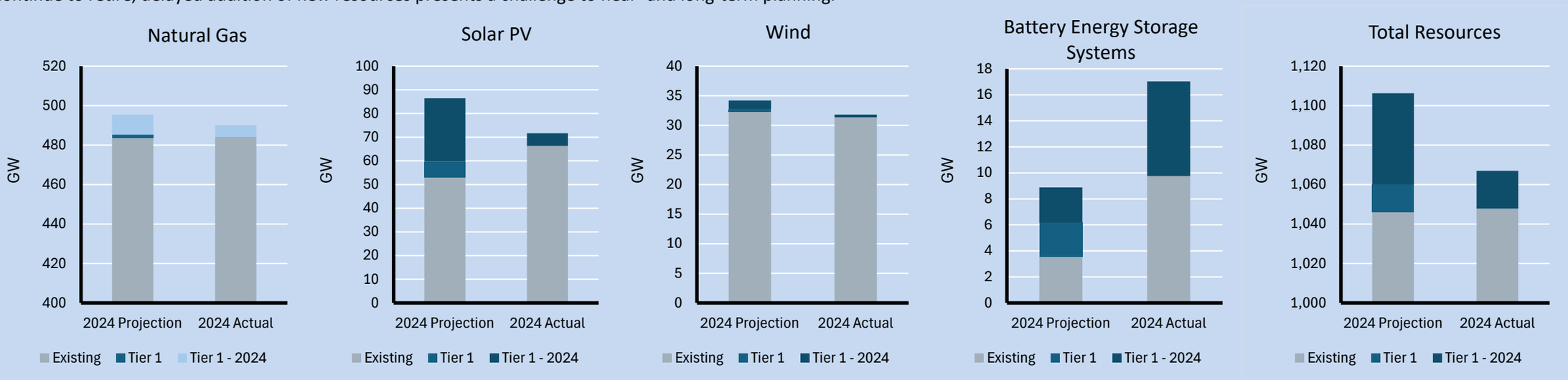


Figure 10: Wind Nameplate Capacity Existing and Planned through 2034

Resource Additions – How Much and When?

The added resource capacity on the BPS over the past year fell short of industry's projections, raising concerns that demand growth has the potential to outpace supply resources. The figures below compare the *2023 LTRA* projection of this year's installed capacity against the actual current installed capacity derived from data collected for this LTRA. Natural gas, solar PV, and wind resources were all over-projected last year. This gives evidence to industry reports of construction delays that prevented the expected interconnection of new resources. To a lesser extent, project withdrawals prior to commercial operation also contributed to lower-than-expected resource additions. One key exception—battery energy storage systems (BESS)—came in higher than last year's projections. As baseload and dispatchable generation continue to retire, delayed addition of new resources presents a challenge to near- and long-term planning.



Comparison of Projected Capacity from the 2023 LTRA to the Actual Capacity in the *2024 LTRA*

The sluggish rate at which new generation moves through the interconnection queue and begins service has been a cause for concern for long-term reliability planning. The Lawrence Berkeley National Laboratory published the results of an interconnection queue study in April 2024 assessing that less than one-fifth of generation capacity projects seeking interconnection between 2000 and 2018 actually came to fruition by the end of 2023.[16] Wait times have also been on the rise: According to the same study, the time from initiating a request for interconnection to the start of commercial operations has increased from less than two years, as was the case from 2000–2007, to more than four years from 2018–2023. The delay in bringing new generation capacity online in assessment areas that are anticipating steady or accelerated thermal capacity retirements, as well as increased demand, presents a significant reliability risk.

In recognition of the interconnection backlog risk, some regional transmission organizations have taken steps to address the lagging completion rates. MISO has assigned multiplication factors to generator requests based on the study phase and the likelihood of that resource coming on-line to more accurately gauge the likely incremental capacity in its footprint.[17] MISO also continues to advance the Joint Targeted Interconnection Queue (JTIQ) with SPP to resolve binding constraints that have delayed the interconnection process. PJM analyzed the completion rate of its interconnection queue and reported that less than 16% of resources submitted into the queue between 1999 and 2023 went into operation. The ISO has also applied a reduction to the nameplate capacity of value of Tier 1 resources to reflect the historical addition rate of new generation. PJM's interconnection process subcommittee is working on enhancements for new generation to interconnect as a capacity resource. These measures and others are examples of the broader effort to streamline generator additions and thus offset retiring capacity.

Offshore wind plants are increasingly entering interconnection queues, located around the Northeastern United States. **Figure 11** shows the current planned capacity in the planning process through 2034 by assessment area. Currently, the existing offshore wind nameplate capacities are small in comparison: a single 29 MW plant in NPCC-New England and a 12 MW plant in PJM.

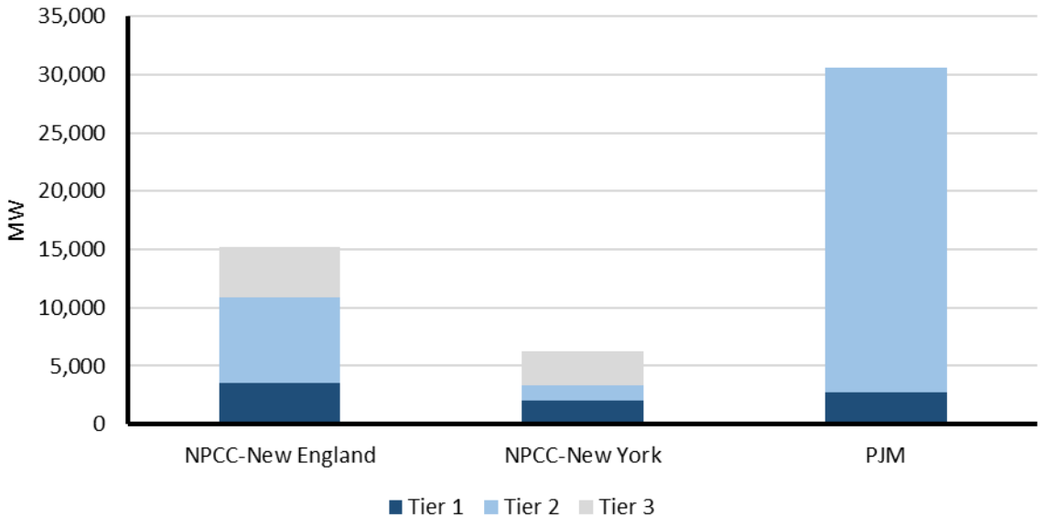


Figure 11: Offshore Wind Capacity Planned through 2034

Battery Resources

As the BPS increases the share of energy provided by VERs, the ability to provide energy by BESS or hybrid-solar PV and wind plants is increasingly important. While currently installed capacity totals just over 17 GW, an additional 306.5 GW of BESS are in planning. **Figure 12** shows the nameplate capacity of BESS resources currently in operation and in planning for connection to the BPS through 2034.

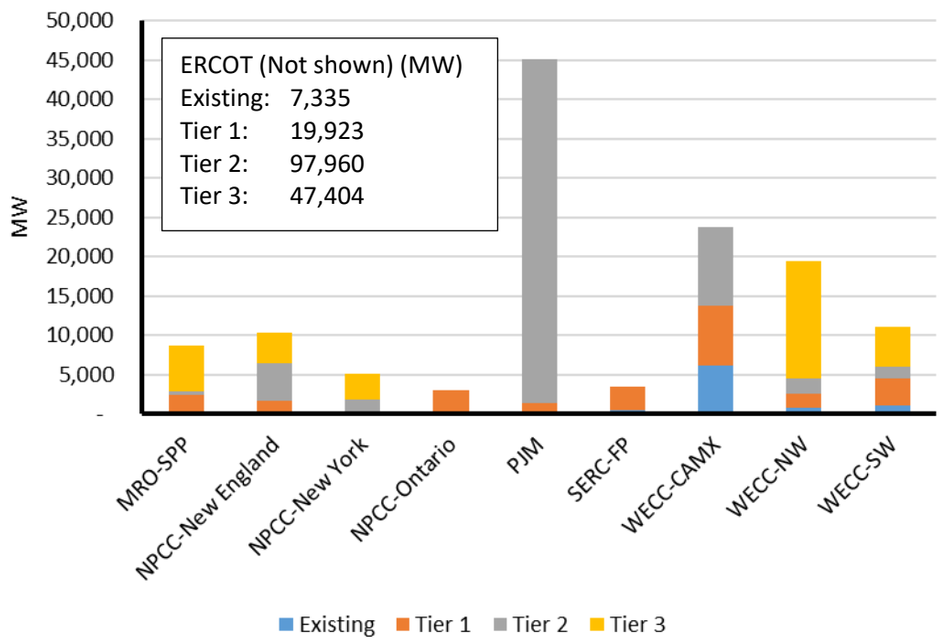


Figure 12: Battery Resource Capacity Existing and Planned through 2034

BESS are improving reliability by helping to offset the variability and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint *NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances*[18] highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 14** shows the nameplate value and the capacity contribution of existing wind, solar PV, hydro, and energy storage systems resources at the peak demand hour for each assessment area. During risk periods after peak demand (e.g., U.S. assessment areas in WECC), contributions of solar PV resources output is diminished during evening periods and additional resources are needed.

[18] NERC–WECC *2022 California Battery Energy Storage System Disturbances*

Table 14: BPS Wind, Solar, Hydro, and Battery Generation Resources by Assessment Area Year 2024												
Assessment Area	Wind			Solar			Hydro			Energy Storage Systems		
	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)	Nameplate (MW)	Expected On-Peak Demand Hour	Expected Share of Nameplate (%)
MISO	41,349	5,715	13.8%	30,502	5,305	17.4%	2,450	1,576	64.3%	401	84	21.0%
MRO-Manitoba Hydro		52	-	-	-	-	6,434	5,704	88.7%	-	-	-
MRO-SaskPower	815	164	20.1%	30	-	-	864	862	99.8%	-	-	-
MRO-SPP	34,475	5,134	14.9%	703	275	39.1%	5,633	4,079	72.4%	2	2	100%
NPCC-Maritimes	-	261	-	-	5.1	-	1,361	1,312	96.4%	-	-	-
NPCC-New England	2,548	127	5.0%	3,361	308	9.2%	1,917	1,469	76.6%	26	9	34.9%
NPCC-New York	2,706	461	17.1%	1,039	240	23.1%	4,915	3,736	76.0%	60	30	50.2%
NPCC-Ontario	4,943	1,364	28%	478	-	0.0%	8,748	6,215	71.0%	18	-	0.0%
NPCC-Québec	3,820	1,375	36.0%	10	-	0.0%	40,907	39,354	96.2%	-	-	-
PJM	11,701	1,760	15.0%	10,735	4,808	44.8%	3,071	2,367	77.1%	222	100	44.8%
SERC-C	982	172	17.5%	2,308	771	33.4%	4,995	3,364	67.4%	100	50	50.0%
SERC-E	-	-	-	6,777	4,753	70.1%	3,170	3,016	95.1%	15	6	38.4%
SERC-FP	-	-	-	10,121	5,618	55.5%	-	-	-	538	523	97.2%
SERC-SE	-	-	-	7,267	5,414	74.5%	3,293	3,260	99.0%	115	40	34.9%
Texas RE-ERCOT	39,532	11,062	28.0%	31,058	19,098	61.5%	583	458	78.6%	10,720	-	0.0%
WECC-AB	5,559	1,867	33.6%	3,042	-	0.0%	894	285	31.9%	270	264	97.8%
WECC-BC	776	279	36.0%	2	-	0.0%	16,902	12,623	74.7%	-	-	-
WECC-CA/MX	7,694	1,158	15.0%	24,905	14,641	58.8%	10,211	3,582	35.1%	11,883	11,155	93.9%
WECC-NW	23,518	3,489	14.8%	12,787	6,877	53.8%	41,257	21,168	51.3%	1,909	1,231	64.5%
WECC-SW	3,784	628	16.6%	5,944	2,527	42.5%	1,025	721	70.3%	2,997	2,592	86.5%

Solar PV Distributed Energy Resource Growth

Behind-the-meter (BTM) solar PV generators are solar PV resources connected on the distribution system, such as residential rooftop solar systems. The rapid growth of BTM solar PV continues with cumulative levels expected to reach over 123 GW by the end of this 10-year assessment period (up from 89 GW reported in the *2023 LTRA*, an increase of 38%). There are currently 58.7 GW of installed BTM solar PV across the North American BPS.

BTM solar PV generators, like grid-connected solar PV, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours; it may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. **Figure 13** shows the current and projected BTM solar PV by area through 2034.

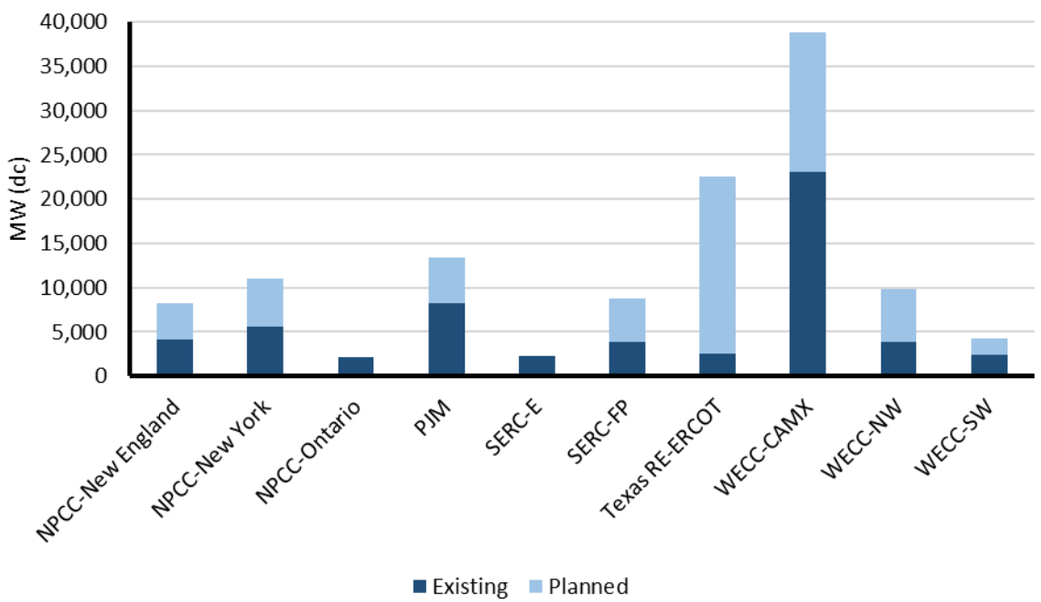


Figure 13: Solar PV DER Capacity Existing and Planned through 2034

Generation Retirements

The total capacity of traditional baseload generation fuel types will continue to decline as older generators retire. Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or the integrated resource planning process in vertically integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Currently, over 79 GW of fossil-fired and nuclear generating capacity is being retired over this assessment period (see **Figure 14**), a small decrease from the 83 GW in retirements reported in the *2023 LTRA*. This capacity includes generators that are confirmed for retirement through retirement planning processes or that have indicated plans to retire to an ISO/RTO or Planning Coordinator.

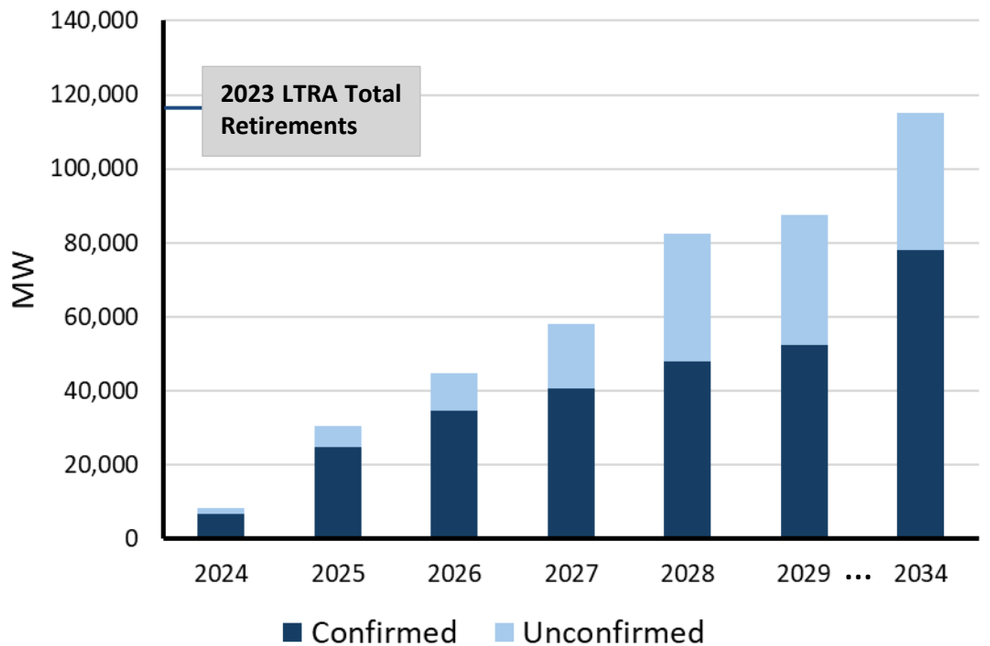


Figure 14: Projected Generation Retirement Capacity through 2034

Additional fossil-fired generator retirements are expected and would result in further loss of existing capacity. Generator Owners often announce plans to retire generator units before initiating the

interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. Wholesale electricity market areas, where merchant electric generators make up a large part of the generating fleet, have more uncertainty around future generator retirements, making resource planning and adequacy assessment difficult. **Figure 15** shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] This total of confirmed and announced-potential retirements over the next 10 years is over 115 GW (3 GW lower than 10-year projections in the *2023 LTRA*).

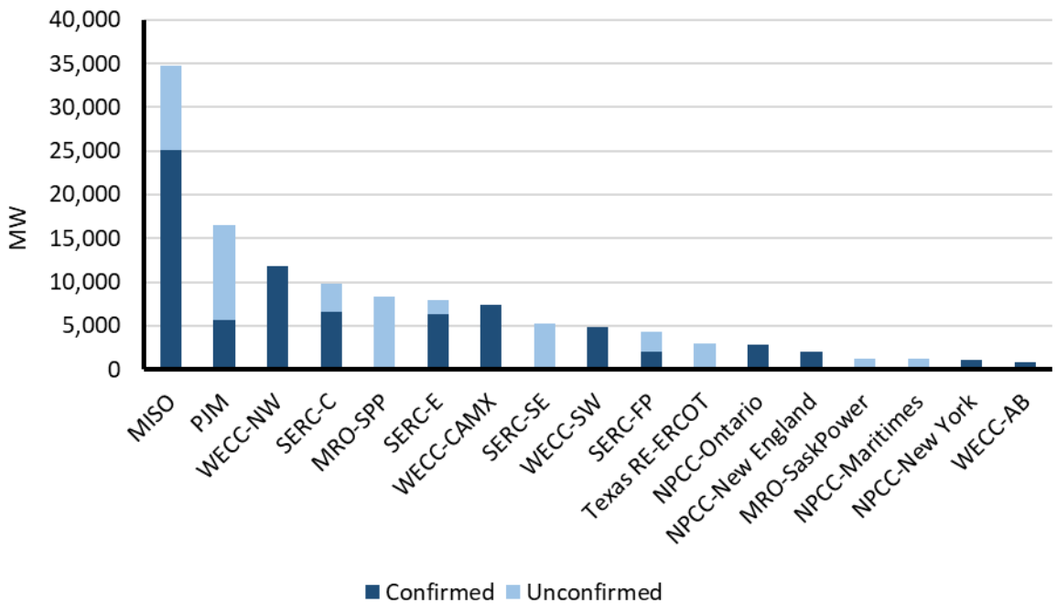


Figure 15: Projected Capacity Retirements of Nuclear and Fossil Generation 2024–2034

Natural Gas Fuel Reliance Trends

Natural-gas-fired generators are and will remain a critical resource for BPS reliability in many areas over the 10-year assessment period, especially during winter. These generators provide many necessary reliability attributes that are exiting the system as traditional generators retire and inverter-based renewable resources take their place in the resource mix. Natural-gas-fired generators are dispatchable and provide the ERSs of inertia, frequency response, and ramping flexibility. In winter, when peak demand in most areas occurs during early morning hours, natural-gas-fired generation is at its highest contribution to the resource mix in many areas. Severe winter weather events in 2021 and 2022 provided stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure supplies during times of extreme electricity demand.

As the generation resource mix evolves and becomes more weather-dependent, fuel assurance becomes increasingly critical when conducting reliability assessments. Until recently, comparing seasonally available capacity to a predetermined PRM level has sufficed as a means to assess resource adequacy. However, resource adequacy is now only the first step of a meaningful reliability assessment. Energy adequacy must now be layered on top to assess the risk that available capacity may be rendered unavailable due to phenomena including low wind or solar output and/or natural gas supply and transportation issues.

This year, the Energy Information Administration (EIA) projected that more than 40% of delivered natural gas would be consumed by power generators, more than 0.6 Bcf/d higher than was consumed by power generators in 2023 and 7% higher than what the EIA had projected for 2024 in the fall of last year. Natural-gas-fired power plants generated 42% of the electrical energy consumed by end-use electricity customers in 2023 and are on track to maintain that share of generation this year. A significant percentage of natural-gas-fired power plants rely upon as-available, non-firm gas supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas by both generators and natural gas distribution companies (generally firm shippers) can at the same time dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability, and when winter weather impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can put at risk even firm pipeline customers as preparatory linepack is rapidly depleted.

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2024 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

The *2024 LTRA* projects that an additional 6,500 MW of new natural-gas-fired generation will be added in North America over the next five years. While some assessment areas project net decreases in natural-gas-fired capacity, other areas report increases ranging from 3% to over 50%.

In the United States, 8 out of 13 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to over 10 GW of new natural-gas-fired power capacity. Altogether, those additions translate to an increase in natural gas use for power generation of more than 84 Bcf (245 MMcf/d). Whether this increase in natural gas generation capacity is sufficient to meet the increase in net internal demand projected for these same assessment areas remains to be seen, but based on the capacity additions alone, some areas are set to see an insufficient increase in gas pipeline capacity, as per the EIA's database of nationwide U.S. gas pipeline projects. (see **Figure 16**).

PJM is one such area, projected to see a 3% increase in natural-gas-fired generation capacity (+2,500 MW). Net internal electricity demand in PJM is forecasted to rise by 25 GW over the planning horizon at the same time that non-variable resources are expected to shrink their share of the capacity mix from 96% to 88%. To the extent that variable resources are uncertain during times of peak stress on the grid, there is a risk of gas delivery capacity being insufficient for the amount of natural gas supply that could be required to meet the demand increase. SPP is another assessment area where natural-gas-fired power capacity is set to rise, by 5%, or roughly 1,500 MW. In both PJM and SPP, there is a risk of a shortfall in natural gas pipeline capacity that could facilitate delivery of the additional fuel that is necessary to meet their capacity expansion plans.

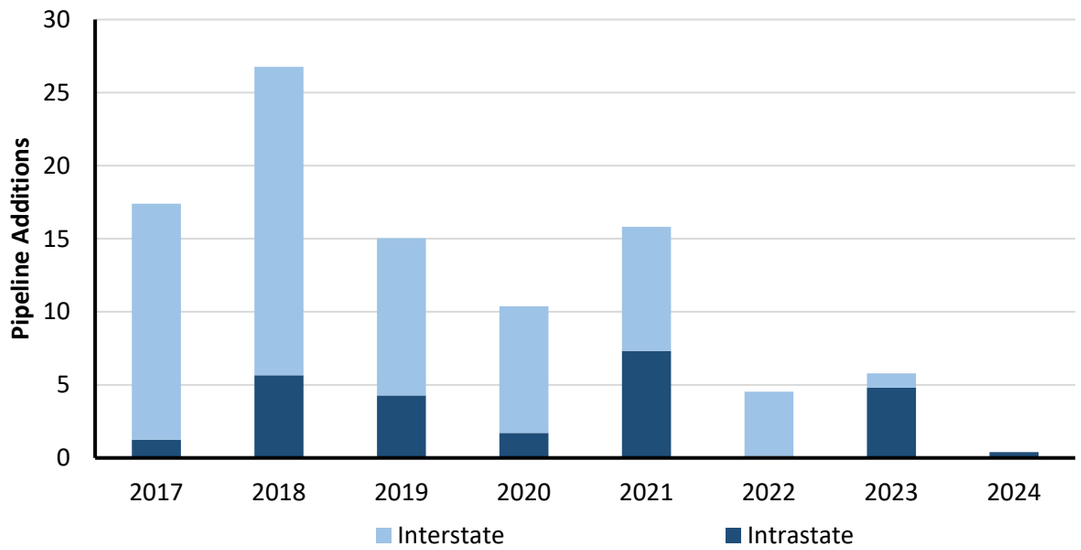


Figure 16: Annual U.S. Natural Gas Pipeline Capacity Additions by Type (2017–2024) Bcf/d (Source: U.S. Energy Information Administration)

Reliability Implications

The addition of variable resources, primarily wind and solar PV, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. With electricity supplies coming increasingly from VERs and natural-gas-fired generators, there is a growing risk that supplies can fall short of demand during some periods. Geographically diverse wind and solar resources and loads can help reduce these risks, but they require robust transmission networks, comprehensive energy and transfer capability analysis, and effective operating procedures and market mechanisms.

Maintaining ERSs for Grid Support

For the grid to operate reliably, it needs resources that are not only sufficient for meeting demand and energy requirements but also capable of controlling voltages, maintaining stable frequency across the system, and flexibly ramping up or down to dispatch control at all times. Conventional generators, such as nuclear, coal, and natural gas-fired generators, provide much of the ERSs that support reliable operation today. New resources on the grid are almost all IBRs, which have different physical and operating characteristics that affect the level of ERSs that they can provide. Without the spinning mass or traditional excitation systems providing the voltage control of a hydroelectric or thermal generator,

most IBRs have limited capability for maintaining system voltages and stability. Batteries, with their fast response time, have some ERS capability that wind and solar do not. They are useful in regulating system frequency and are helping to balance variability from VERs in ERCOT and California where wind and solar make up a large portion of the resource mix.[20] As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

Accelerated generator retirements, especially unanticipated requests for deactivation, can cause ERS-related reliability issues in parts of the system due to the future loss of the generator's reliability attributes. This reduction in the level of ERSs can result in voltage violations or system instability. System planning and generator deactivation processes evaluate these changes to the system and ensure plans proceed only when reliability criteria, including ERS-related considerations, are met. For example, PJM's deactivation process identified reliability concerns to the system as a result of the requested deactivation of the Brandon Shores power plant (1,280 MW) in 2023. Until necessary system upgrades are completed to address identified system voltage and other reliability issues that would occur with the deactivation, PJM has requested that the Brandon Shores generators at the plant remain in service through the reliability-must-run process.[21]

To ensure the future system can operate reliably, market operators, system planners, regulators, and policymakers need to ensure effective mechanisms are in place to provide for the ERS needs of the future system. Long-term activities can provide incentives to generators with needed reliability attributes. Effective backstops will also be needed to prevent the loss of critical generators when analysis finds deactivation would violate reliability criteria.

Specific and actionable recommendations are contained in the **Recommendations and ERO Actions Summary** section of this report.

[20] See the *2023 Special Report on Battery Storage* from the California ISO.
[21] Information on this and other proposed deactivations in PJM are found on PJM's Generator Deactivations page.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. The aggregated assessment area summer peak demand forecast is expected to rise by over 132 GW, and aggregated winter peak demand forecasts are increasing by 149 GW. The growth rates of forecasted peak demand (see **Figure 17**) and energy (see **Figure 18**) continue to rise sharply since the 2022 LTRA, reversing an almost two-decade trend of falling or flat growth rates. See **Figure 17** for seasonal peak demand growth over the current and prior assessment periods and **Figure 18** for net energy growth. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 19**.

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2023 LTRA*, peak season CAGR has risen in all assessment areas except two: NPCC-Maritimes' winter CAGR fell from 0.98% to 0.63% and WECC-BC's winter CAGR fell from 1.05% to 0.28%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Large Commercial and Industrial Loads

Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. Emerging large loads, such as data centers (including crypto and AI) and hydrogen fuel plants, present unique challenges to forecasting and planning for increased demand. Earlier this year, NERC's RSTC established a Large Loads Task Force to better understand the reliability implications of growth in large loads and develop solutions.

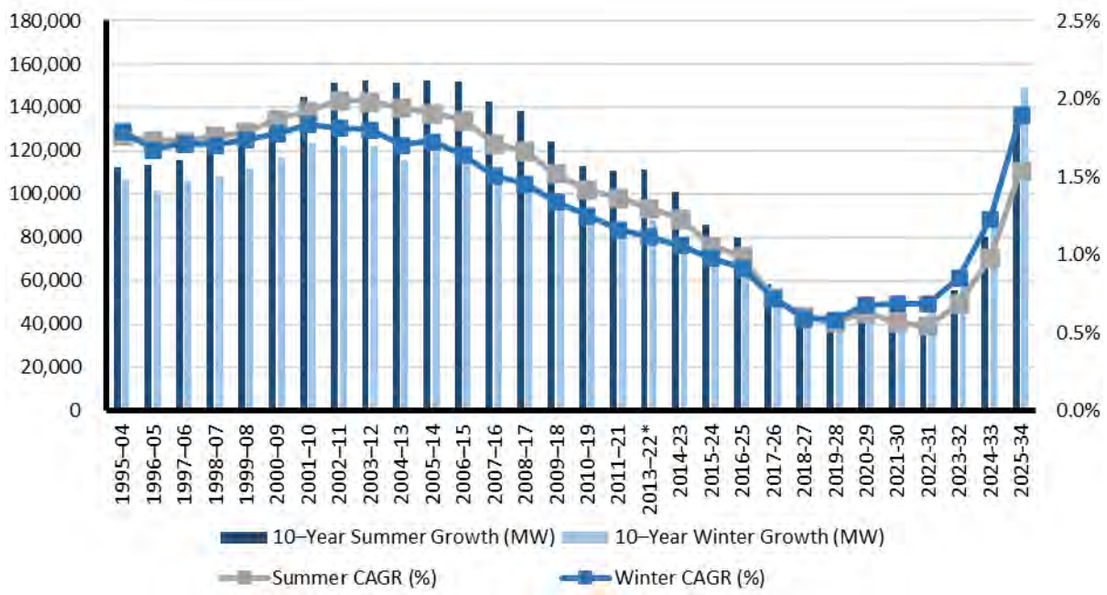


Figure 17: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

Figure 18: Net Energy for Load Growth and Rate Projections

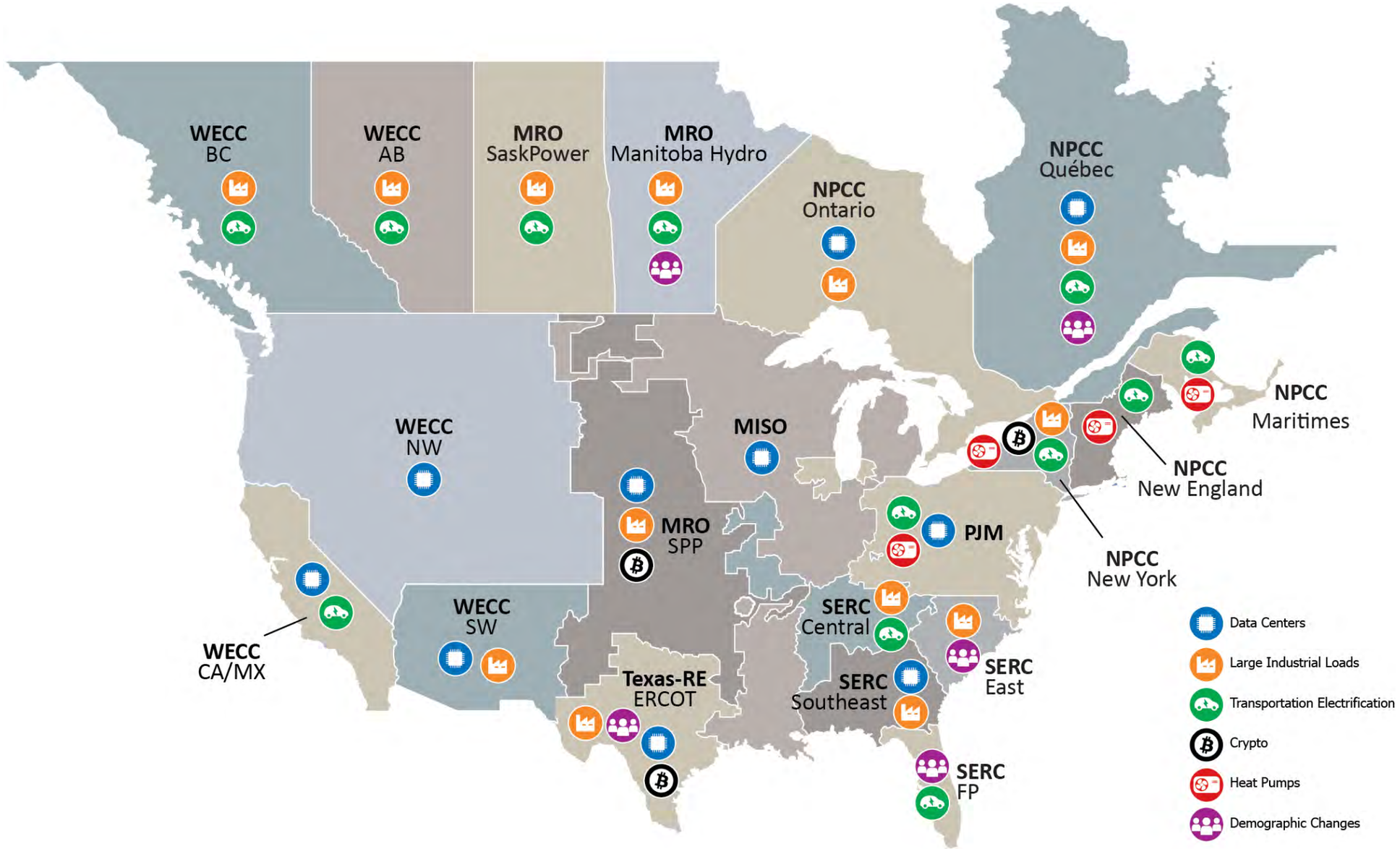


Figure 19: Primary Demand Drivers by Assessment Area

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from a summer-peaking system to a winter-peaking (or dual-season peaking) system and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (mid to late-2030s)
- NPCC-Ontario (2030)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer.

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and distributed energy resource performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year had a noticeable effect on resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 28,275 miles of transmission (>100 kV) in construction or stages of development for the next 10 years (see **Figure 20**) is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

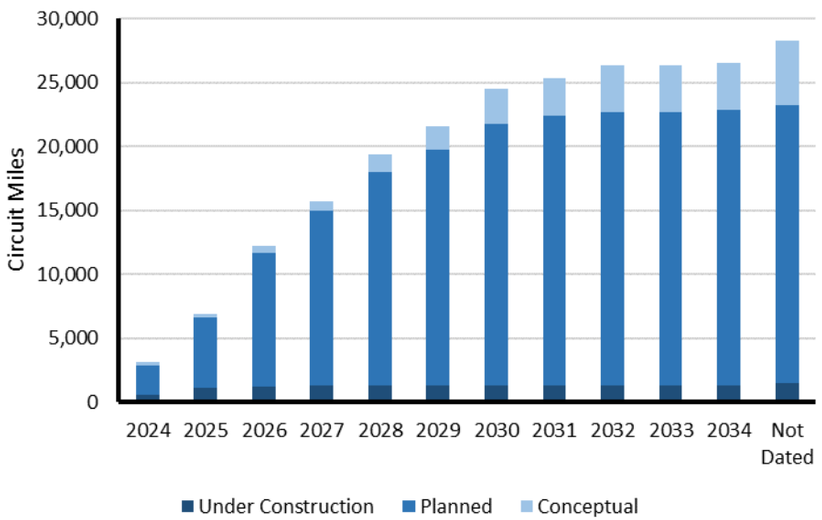


Figure 20: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 21** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria. Some substantial new projects to integrate renewable generation are also in development or are entering planning processes. Nearly 70 of the 1,160 transmission projects in development are for tie-lines and tie-line upgrades, which support transfer capability between neighboring Balancing Authority areas. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

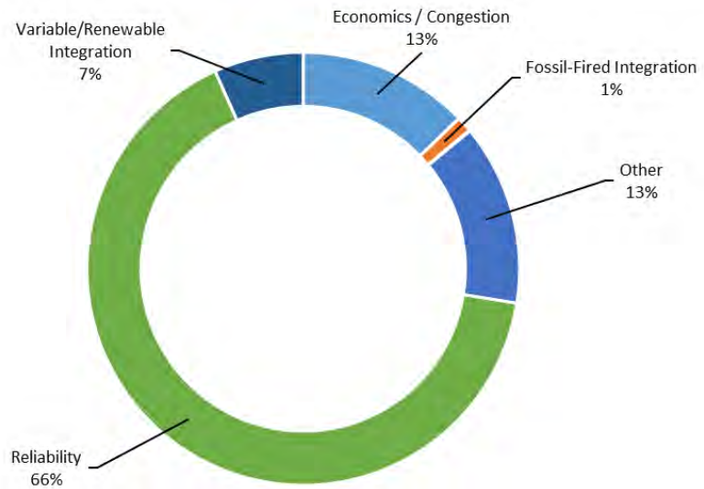


Figure 21: Future Transmission Circuit Miles by Primary Driver

Transmission development in some areas is hampered by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, over 110 projects are currently delayed from their expected in-service dates. Siting and permitting issues are the most common cause for delays, affecting 68 projects (totaling 1,230 miles of new transmission). Other reasons for delays include economic impacts, planning and construction issues, or changing needs.

Interregional Transfer Capability Study (ITCS)

The Fiscal Responsibility Act of 2023[22] required NERC to conduct a comprehensive study of existing and future interregional transfer capability between each Transmission Planning Region[23] (TPR) to make recommendations for prudent additions to the amount of power that can be moved or transferred between neighboring TPRs and to make recommendations on how to meet and maintain transfer capability. In addressing this legislation, NERC identified additions to transfer capability that could support energy adequacy.[24] NERC filed the completed study report with FERC on November 19, 2024.[25]

Transfer Capability is the measure of the ability of the interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all the transmission lines (or paths) between those areas under specific system conditions. The units of transfer capability are in terms of electric power, generally expressed in MW.

To provide further opportunities for stakeholder engagement and consultation, the project was divided into several stages, each with an accompanying report.

- **Overview of Study Need and Approach[26]:** Provided background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Transfer Capability Analysis (Part 1)[27]:** Addressed the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring TPRs, as well as the simultaneous import capability of each TPR. (published in August 2024)
- **Prudent Additions Recommendations (Part 2) and Meet/Maintain Recommendations (Part 3)**: Contained an energy margin analysis and resulting recommendations for prudent[28] additions to the transfer capability between neighboring TPRs to improve energy adequacy during, for example, extreme weather events. It also discussed how to meet and maintain transfer capability as enhanced by these prudent additions.
- **Canadian Analysis:** Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces.[29]

Transfer Capability Analysis (Part 1)

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuel and energy for wind and solar, the ability to transfer electrical energy from areas of surplus to areas experiencing fuel or energy constraints has become essential to maintaining reliable delivery of electricity to end-use customers.

The ITCS is a congressionally mandated study to evaluate transfer capability and recommend additions to strengthen reliability.

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the electrical characteristics, or impedance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR but over many routes, some of which

[22] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[23] For the purposes of the ITCS, this term refers to the study regions as described in ITCS Overview of Study Need and Approach, Chapter 2.
[24] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.
[25] NERC filing of the Interregional Transfer Capability Study, FERC Docket AD25-4-000.
[26] The ITCS Overview of Study Need and Approach can be found here.
[27] The ITCS Transfer Capability Analysis (Part 1) report can be found here.
[28] FERC defines prudence as the determination of whether a reasonable entity would have made the same decision in good faith under the same circumstances at the relevant point in time. See, e.g., New England Power Co., 31 FERC ¶61,047 at p. 61,084 (1985); and PotomacAppalachian Transmission Highline, LLC, 140 FERC ¶61,229 at P 82 2012 (Sept. 20, 2012).
[29] The ITCS Part 1 evaluated transfer capability from Canada into the United States.

may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

Part 1 Key Findings

- Transfer capability varies seasonally and under different system conditions that limit transmission loading—it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and Mid-Atlantic areas but relatively lower in the Mountain States, Great Plains, Southeast, and Northeast. There is limited transfer capability between interconnections

The transfer capability results in the Part 1 report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

Recommendations for Prudent Additions (Part 2) and to Achieve Transfer Capability (Part 3)

Part 2 of the ITCS evaluated the energy adequacy of the BPS should past weather conditions occur again in 2033. Specifically, the study applied 12 past weather years to the 2033 loads and resource mix using the current transfer capabilities as calculated in Part 1. The Part 2 study then evaluated the impact that additional transfer capability could have in mitigating the identified resource deficiencies[30] during extreme events, thereby improving energy adequacy. Using a six-step process, the ITCS developed a list of recommended additions to transfer capability. **Figure 22** shows the existing and potential new interfaces where additional transfer capability is recommended. While there are several factors that Transmission Planners consider, including reliability, economics, and policy objectives, given NERC's role as the ERO, the ITCS focused solely on reliability, specifically in terms of energy adequacy, for these recommendations.

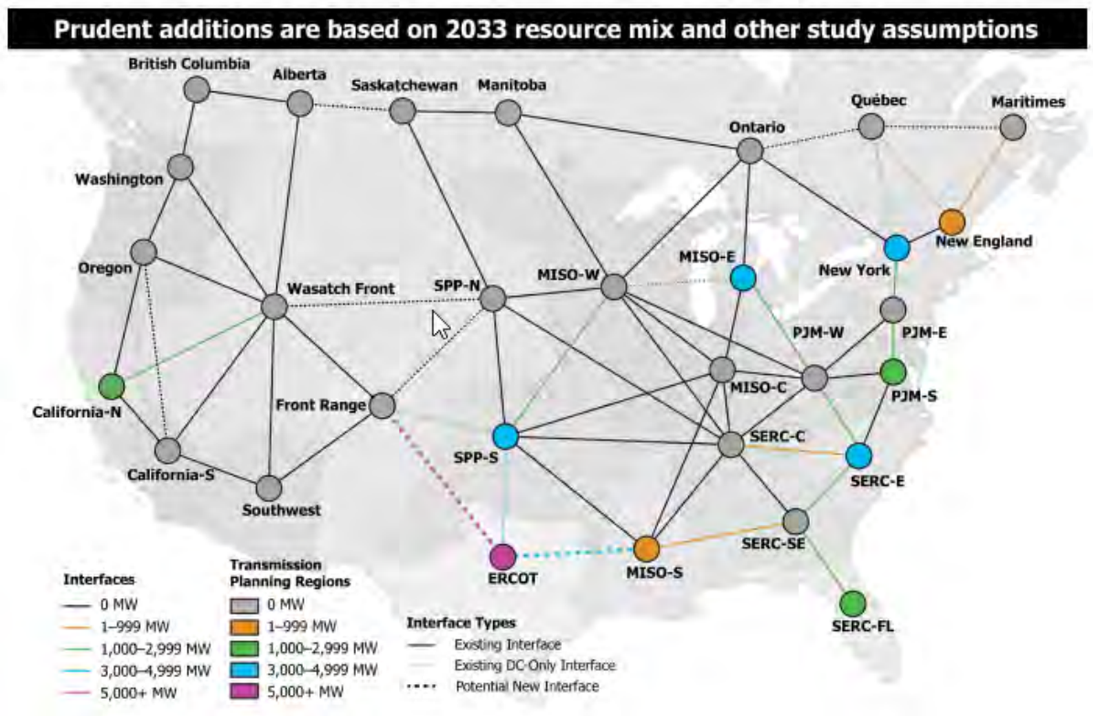


Figure 22: Prudent Additions to Transfer Capability

[30] For the purposes of this study, "resource deficiency" is used to describe instances where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus minimum margin level.

The resulting recommendations for prudent additions to transfer capability (Part 2 study) were published in a report along with recommendations to meet and maintain transfer capability as enhanced by the prudent additions (Part 3).[31] Planners have multiple options for reducing the energy adequacy and extreme weather risks. In addition to the transmission enhancements that were in scope for the ITCS, due consideration should also be given to constructing local generation and storage, demand-side management approaches, and grid resilience projects. The ITCS recommended that planners consider all options and balance reliance on external resources vs. internal resources, noting that there may be better options than an over-reliance on one or the other.

Part 2 Key Findings

- Import capability required to reliably serve customers during extreme conditions varied significantly across the country, so a one-size-fits-all requirement would be inefficient and ineffective.
- Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied.
- 35 GW of additional transfer capability is recommended across the United States to improve energy adequacy under extreme conditions.
- Some identified transmission needs could be alleviated by projects already in the planning, permitting, or construction phases. If completed, these projects could mitigate several risks highlighted by the ITCS, reinforcing their importance for grid resilience.
- The ITCS provides foundational insights for further discussion, and decisions. Transmission upgrades alone will not fully address all risks, and a broader set of solutions should be considered, emphasizing the need for local resources, energy efficiency, demand-side, and storage solutions.

See the *ITCS Final Report* for Detailed Key Findings

[31] The ITCS report *Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)* can be found here.

Emerging Issues

While developing this LTRA, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS over the next 10 years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Data Centers and Large Industrial Load

Growth in large load parcels like data centers and industrial facilities pose various challenges for system planners and operators, in addition to fueling rapid demand growth discussed elsewhere in this report. **Figure 23** shows one estimate of data center growth in the United States by 2027.[32] Other types of large industrial loads include smelters, manufacturing centers, hydrogen electrolyzers, and future electrified mass transit or shipping charging stations. Adding large parcels of load on the system can add new uncertainties to peak and hourly load forecasting. For example, data centers have longer operating hours and require more heating and cooling than other commercial buildings. In Texas, crypto mining facilities have connected in recent years that scale their operations (and thus electricity demand) depending on electricity prices. The behavior of large data centers during normal grid faults is also an emerging concern because customer-initiated automatic disconnecting of sizeable load can cause operating issues. Sudden and unexpected disconnecting load during a grid fault is analogous to well-known IBR performance issues and poses similar reliability risks. Planners and operators need to consider the characteristics of these loads as they begin to proliferate and support NERC RSTC's Large Loads Task Force to share best practices.

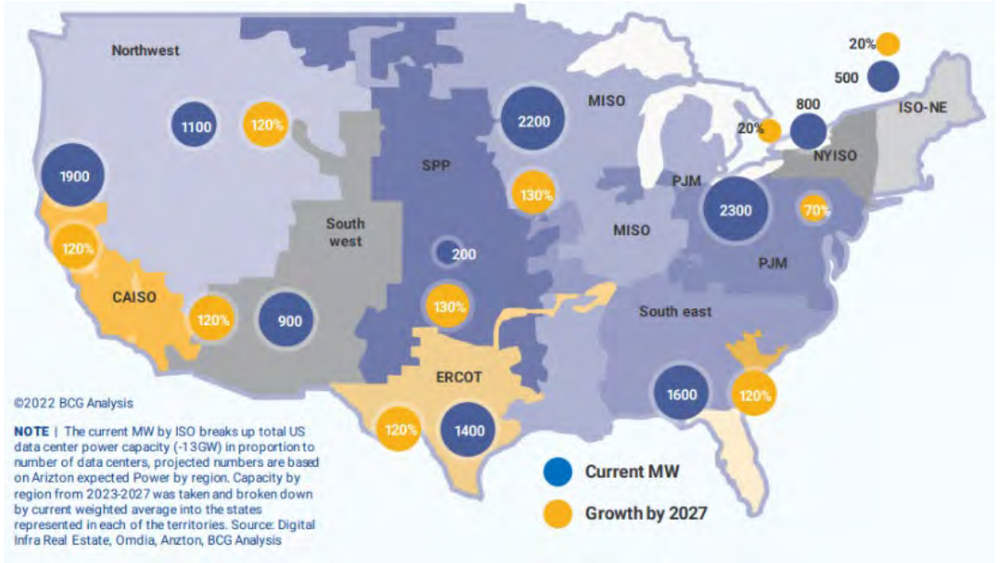


Figure 23: Projected Growth in Data Centers in the United States

Battery Energy Storage Systems

Planners and operators are focused on requirements to model, study, and operate the BPS with increased BESS and hybrid resources. BESS are increasingly being relied upon in areas with substantial amounts of solar PV resources to reduce ramping requirements on other resources by discharging in late afternoon as solar PV output rapidly declines. BESS are also often used for ancillary services, such as frequency response. Accurately accounting for BESS in operating and planning studies is a challenge because it requires assumptions and modeling capabilities for battery charging and discharging behavior. In real-time operations, system operators often do not have visibility into battery state-of-charge, a necessary condition for reliably integrating batteries into system operating plans. Without such information, operators may be surprised should battery resources fail to deliver when needed. In Texas, where battery resource growth is among the highest in North America, ERCOT uses a battery storage data collection program to obtain operational information and is pursuing market rules for state-of-charge accounting in unit commitment processes. System planners in many areas will be counting on new BESS facilities to manage variability and demand and resources. Obtaining the benefits of these resources requires careful integration into operating, planning, and market designs.

[32] *Grid Strategies: The Era of Flat Power Demand is Over*: https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Electric Vehicles and Electric Load

With increased adoption of electric vehicles (EV), which use batteries to store energy, there is a need to understand the impact of battery charging on system performance. EV forecasting is important for resource adequacy and system planning to account for changing load and load patterns. It is also important for system studies to include EV modeling and parameterization that account for the behavior of battery charging systems on system performance. In January 2024, NERC released the *EV Charging Study*, noting that the behavior of large amounts of EV chargers in operation can affect the BPS response to common outages. The RSTC established an EV Task Force to promote collaboration among the electric power industry and automotive representatives on areas of grid reliability.

Energy Drought

More reliance on wind, solar, and hydro resources in the resource mix has the potential to expose the electric system to supply shortages under abnormal weather patterns. When two or more resource types are simultaneously affected by conditions that cause below-normal resource output, operators can face challenges in meeting demand. Analysis of U.S. historical hourly generator data indicates that there are regional patterns to energy drought that can be expressed in terms of duration, magnitude, and seasonality (See **Figure 24**). There is also a higher likelihood for energy droughts to be more likely occur during high-load periods than at other times, underscoring the importance in considering such events in planning for resource and storage needs.[33]

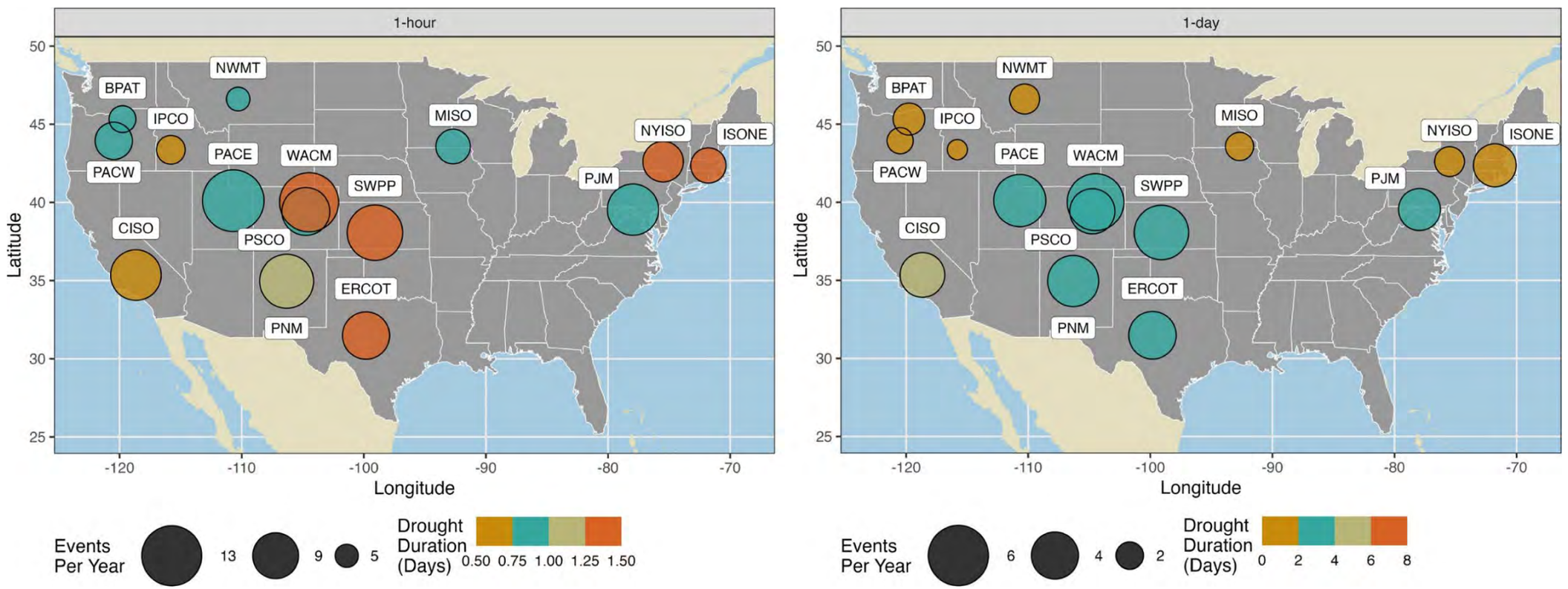
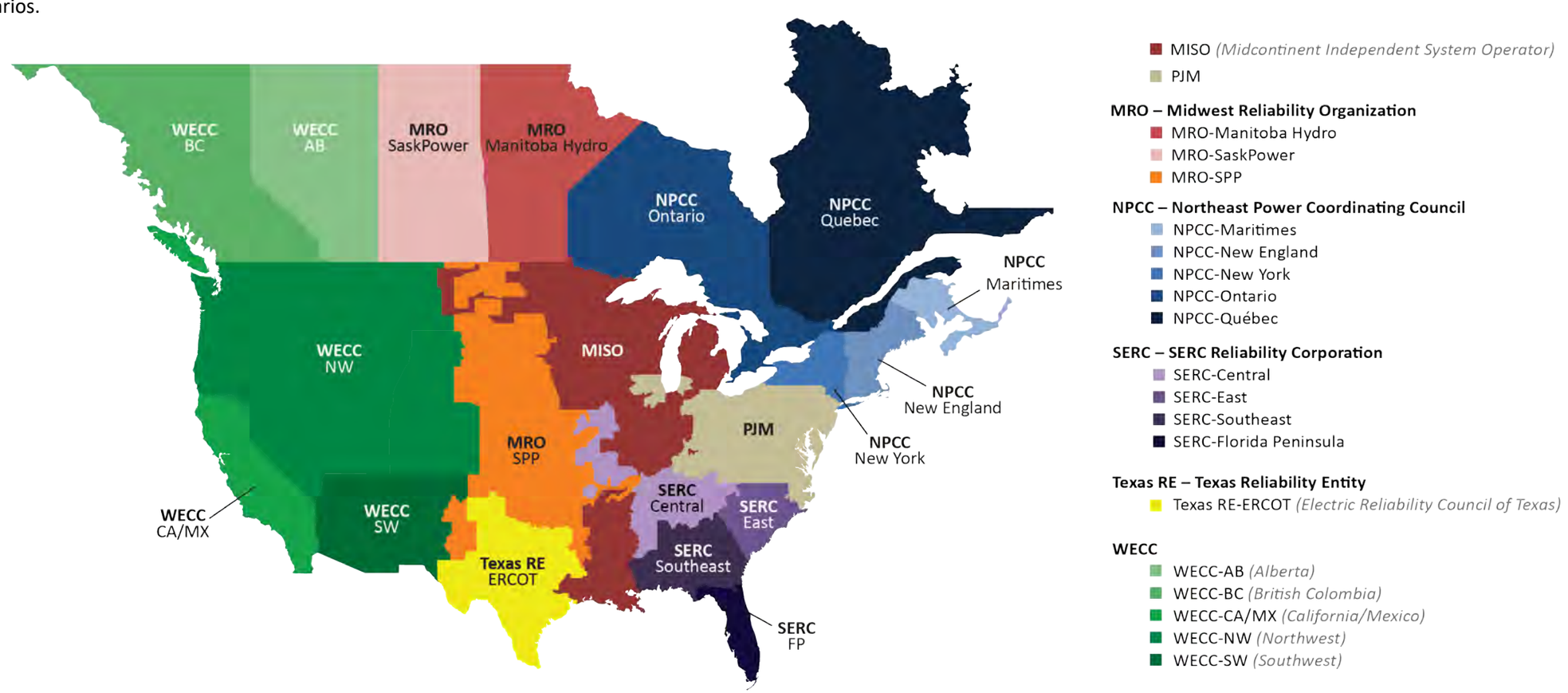


Figure 24: Frequency and Duration of Hourly (Left Panel) and Daily (Right Panel) Energy Droughts. Source: Pacific Northwest National Laboratory

[33] See Standardized benchmark of historical compound wind and solar energy droughts across the Continental United States

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Demand Assumptions and Resource Categories** table. On-Peak Reserve Margin bar charts show the ARM compared to the RML established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the Demand and Resource Tables), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the Demand and Resource Tables) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



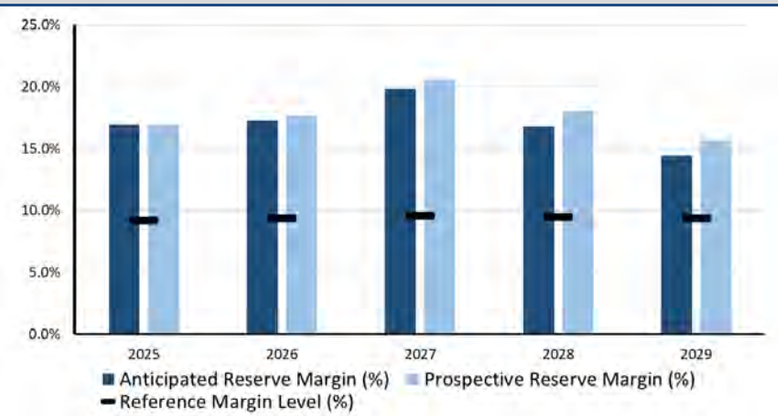
MISO

Midcontinent Independent System Operator, Inc. (MISO) is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

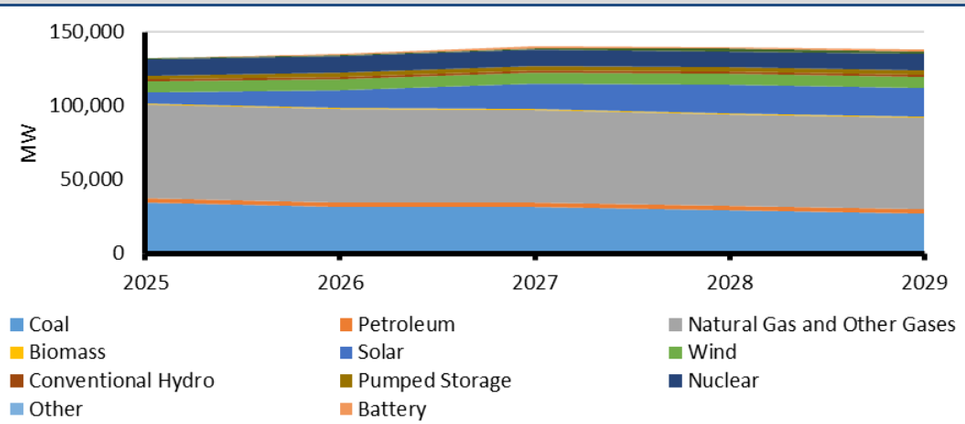
Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	122,328	124,343	126,073	128,700	129,401	130,120	130,493	131,327	131,952	131,952
Demand Response	8,205	8,221	8,058	8,065	8,074	8,077	8,079	8,075	8,075	8,075
Net Internal Demand	114,122	116,122	118,015	120,635	121,327	122,043	122,414	123,252	123,877	123,877
Additions: Tier 1	4,959	11,376	18,275	21,501	22,205	22,205	22,205	22,205	22,205	22,205
Additions: Tier 2	19	464	916	1,486	1,486	1,486	1,486	1,486	1,486	1,486
Additions: Tier 3	803	3,686	8,252	13,017	15,546	16,399	16,542	16,608	16,659	16,659
Net Firm Capacity Transfers	1,320	1,270	1,165	925	855	750	549	549	549	549
Existing-Certain and Net Firm Transfers	128,520	124,787	123,153	119,397	116,669	112,823	110,273	110,273	106,838	106,838
Anticipated Reserve Margin (%)	17.0%	17.3%	19.8%	16.8%	14.5%	10.6%	8.2%	7.5%	4.2%	4.2%
Prospective Reserve Margin (%)	17.0%	17.7%	20.6%	18.0%	15.7%	11.9%	9.4%	8.7%	5.4%	5.4%
Reference Margin Level (%) (Summer)	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%	9.7%

Note: See **Figure 3** for summer reserve margins with historically average resource additions in MISO based on results from the 2024 Organization of MISO States (OMS)-MISO Survey.



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO's capacity resource turnover continues to occur with coal unit contributions being primarily replaced by solar, wind, and battery facilities. Furthermore, generation installation delays result in uncertainty throughout the assessment timeframe. As a result of these factors, MISO is facing capacity shortfalls in the next five years.
- MISO's reduction in capacity resources since the *2023 LTRA* has primarily been in the coal fleet with a reduction of 6,200 MW in the first year of the assessment.
- MISO has continued the seasonal capacity auction construct and has found growing evidence of risk in non-peak (e.g., spring and fall) seasons. Countering the risk during these off-peak seasons requires more resources to be available, and this can result in less opportunity for generators to pursue their maintenance needs. During peak seasons when high levels of generator availability are expected, short-notice unplanned outages and higher forced outages could occur as a result of deferred maintenance and challenge reliability.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	34,637	31,706	31,618	29,067	26,841
Coal*	27,450	24,362	23,203	17,977	16,744
Petroleum	3,065	3,058	3,060	3,050	3,050
Petroleum*	2,992	2,990	2,992	2,992	2,992
Natural Gas	63,051	62,977	62,616	62,394	62,009
Natural Gas*	62,576	61,543	62,396	62,394	62,009
Biomass	577	571	553	481	481
Solar	8,091	12,538	17,318	19,174	19,763
Wind	6,954	7,236	7,536	7,632	7,660
Conventional Hydro	1,527	1,527	1,527	1,527	1,527
Pumped Storage	2,528	2,528	2,578	2,578	2,578
Nuclear	11,027	11,127	11,127	11,127	11,127
Other	72	72	72	72	72
Battery	208	582	1,011	1,358	1,377
Total MW	132,159	134,892	140,263	139,973	138,018
Total MW*	124,423	126,048	131,562	128,826	127,864
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to MISO are removed from the resource projection where marked.					

MISO Assessment

Planning Reserve Margins

The planning reserves across the MISO footprint in the summer are projected to fall below reserve margin requirements as new generation coming on-line could be insufficient to make up for generator retirements and load growth. It is important to note that there is 56 GW of generation with signed generation interconnection agreements that are yet to come on-line as of July 5, 2024, so there is an opportunity to accelerate installation speeds. However, if resource additions remain at or near historically average levels (approximately 2.3 GW/year average over the last 3 years), PRMs in MISO will fall below the RML reserve margin requirements much faster. Summer PRMs with average resource additions are shown in **Figure 3** as **Reserve Margin-Avg Addition**.

Increased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources. Resource adequacy is a key function of MISO, and the MISO annual planning resource auction (PRA) provides a mechanism for capacity sellers to provide resources that meet the needs of load-serving entities for each of the four seasons in the upcoming year. MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy.

Note: Capacity values for existing resources in tables on p. 41–42 reported by MISO reflect the Seasonal Accredited Capacity (SAC) for Summer. Adjustments and derates are applied to account for factors affecting expected resource output. The RML in the Demand, Resources, and Reserve Margins table on p. 41 is the Unforced Capacity (UCAP) RML, consistent with the reported capacity values.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The introduction of the seasonal PRA and inputs to the process provide more granularity and reliability planning for non-peak hour times during the year. In addition to that change, MISO conducts seasonal resource assessments evaluating generation availability, outage rates, and forecasted load variation across all four seasons. Refer to MISO's Resource Adequacy page.

Probabilistic Assessments

To establish RMLs that define the minimum reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. In recent years, MISO improved its LOLE study modeling by including seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. The LOLE study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they prescribe the minimum PRM that will meet an LOLE of 1 day in 10 years. For more information on the seasonal LOLE Study, visit: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

MISO also performed a probabilistic analysis for the 2024 ProbA. Because MISO used the same model for both the ProbA and the LOLE study, transmission limitations were not included explicitly in the simulations. It is appropriate for MISO to make this assumption for the LOLE study and for determining capacity needs in the MISO system because MISO accounts for transmission limitations elsewhere in the resource adequacy process. However, for an adequacy assessment like the ProbA, the assumption can overvalue resource performance by not accounting for transmission constraints on the deliverability of energy resources. The resulting 2024 ProbA metrics in the table below can understate the risk of unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	68.8	**0.000**	**0.000**
EUE (PPM)	0.108	**0.000**	**0.000**
LOLH (hours per year)	0.393	**0.000**	**0.000**
Operable On-Peak Margin	13.9%	**11.3%**	**11.3%**

* Provides the 2022 ProbA Results for Comparison

MISO is an elevated risk in the *2024 LTRA* because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. All-hours probabilistic studies of the MISO system performed apart from the 2024 ProbA show that shortfall risks can also occur during spring and fall in months that are not peak demand seasons for MISO. The 2022 NERC ProbA Regional Risk Scenario Sensitivity Case included seasonal forced-outage rates and correlated cold weather outages instead of annual average outage rates. MISO found that not only did EUE increase in this sensitivity, but it was also spread throughout the year. Since this study, MISO implemented enhancements to its LOLE study and PRA to address seasonal resource needs.

Demand

The peak demand forecast has increased from the *2023 LTRA* by close to 3 GW (~2.5%), and, while the load forecasts still vary across year to year, the load at the end of the study horizon is ~5 GW higher (~4%). Load-serving entities do not include DR resources in the load forecast, and MISO does not have much insight into the amount of electrification built into the load forecasts. There are other studies at MISO investigating electrification and transportation industry impacts to load forecasts

through the MTEP report. MISO contracted with Applied Energy Group (AEG) to evaluate the MISO footprint's electrification potential. This is documented in the report and has been utilized to update the MISO Futures Report.

Demand-Side Management

DR programs continue to play a significant role in providing capacity to MISO. DR is steady around 8 GW in the summer and 6.5 GW in the winter and is projected to remain constant during the study horizon. MISO's transition to seasonal auctions highlights accreditation of DR and availability during non-summer seasons.

Distributed Energy Resources

Behind-the-meter generation (BTMG) resources contribute about 4.2 GW of capacity across the study horizon, of which ~1.2 GW are distributed PV. MISO's transition to seasonal auctions highlights the availability of DERs across the four seasons, and MISO is working with stakeholders to derive adequate methods of aggregating, reporting, and allowing DER participation in MISO markets.

Generation

The departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years. Solar continues to rise in capacity contributions with a growth of 1,200 MW since the *2023 LTRA* and growth of 3,200 MW in the first year of the study.

There are ~56 GW installed capacity (ICAP) of generation (predominantly solar and battery) with signed generation interconnection agreements in MISO that are projected to come on-line over the next few years. There have been some supply chain and tariff issues that have delayed the commercial operation of these resources.

Due to the large size in the MISO interconnection queue, in the 2022 LTRA (similarly to the OMS-MISO Survey), prospective generation in the queue gets multiplied by a factor based on the study phase and likelihood of that resource coming on-line and gets added into the footprint over time. This reduction is utilized to minimize the impact of prospective generation projects that will not come to fruition through the queue cycle. MISO continues to pursue queue reform efforts to expedite the process by ensuring projects being studied are of adequate certainty.

Transmission

The MISO Transmission Expansion Plan (MTEP) 2021 included the Long-Range Transmission Plan (LRTP) tranche 1 projects totaling $10.3 billion in investment for reliability and economic benefits estimated at $23–52 billion across the MISO footprint while also facilitating the integration of ~53 GW of new resources. In MTEP22, $4.3 billion in transmission projects were approved with $550 million going toward integrating new resources, $550 million going toward baseline reliability projects, and the age and condition category for the rest. MTEP23 includes a further $9 billion investment into the MISO footprint to address the local needs of the region. MISO is also pursuing LRTP tranche 2 with an expected investment of $18-23 billion to implement a 765 kV backbone into the northern portion of the footprint. These projects are expected to be included as part of MISO's MTEP24 project portfolio. In MTEP24, $6.7 billion in transmission projects have been submitted for board approval. MISO is also pursuing LRTP tranche 2.1 with an expected investment of $21.8 billion to implement a 765 kV backbone into the midwestern portion of the footprint. Tranche 2.1 brings reliability and economic benefits estimated at $51.7–101 billion across the MISO Midwest footprint, facilitating integration of ~115.7 GW of new resources.

Energy Storage

MISO's energy storage resources are still primarily in the future with only 84 MW of on-line storage. The MISO interconnection queue does have a significant amount of energy storage upcoming, but these are primarily Tier 3 resources at present.

Capacity Transfers

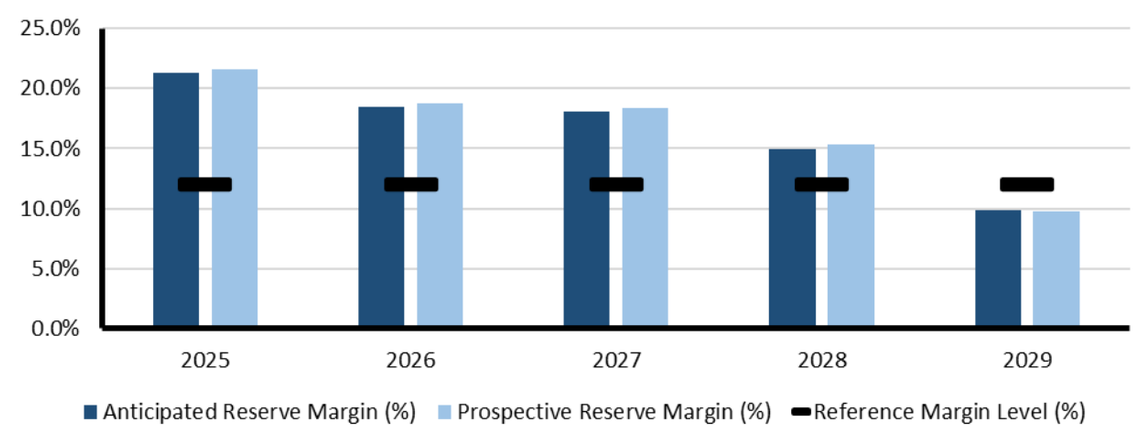
MISO benefits from significant transfer capacity with neighboring assessment areas due to the geographic location. MISO and SPP continue to finalize the Joint Targeted Interconnection Queue (JTIQ) portfolio to resolve the binding constraints that have traditionally delayed the interconnection process. MISO's utilization of capacity transfers is identified in the LOLE report and memorialized through the MISO PRA.

MRO-Manitoba Hydro

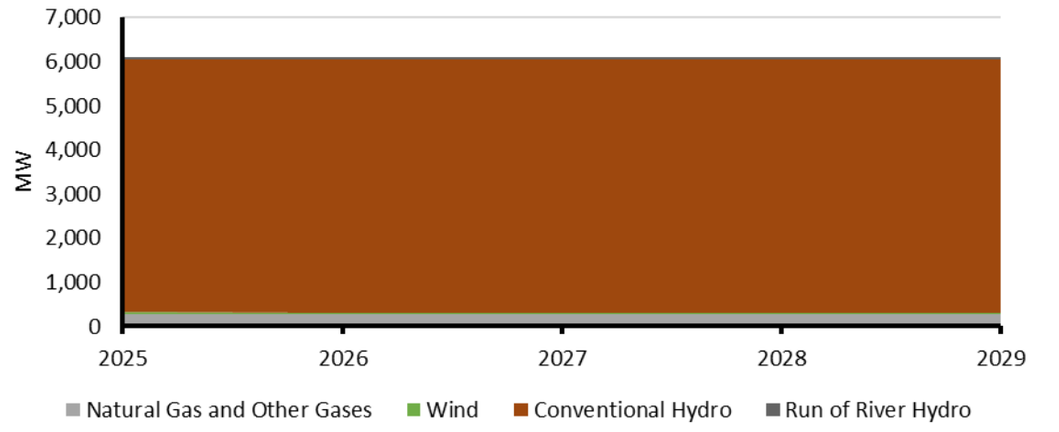
Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 616,000 electric customers in Manitoba and provides approximately 296,000 customers with natural gas in southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	4,797	4,923	4,968	5,037	5,268	5,366	5,427	5,486	5,556	5,629
Additions: Tier 1	30	51	64	64	64	64	64	64	64	64
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-113	-93	-167	-172	-565	-565	-565	-565	-565
Existing-Certain and Net Firm Transfers	5,786	5,780	5,800	5,726	5,721	5,328	5,328	5,328	5,328	5,328
Anticipated Reserve Margin (%)	21.3%	18.4%	18.0%	15.0%	9.8%	0.5%	-0.6%	-1.7%	-2.9%	-4.2%
Prospective Reserve Margin (%)	21.6%	18.8%	18.4%	15.3%	9.8%	0.5%	-0.6%	-1.7%	-3.0%	-4.2%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The electricity demand forecast in the province of Manitoba has increased since the *2023 LTRA*, driven by expected economic activity and adoption of EVs. Resource projections have not changed significantly.
- The ARM falls below the RML of 12% beginning in Winter 2029–2030 due to load growth and the reduction of winter import capacity transfers. Manitoba Hydro is performing analysis to inform its integrated resource plan and support future decisions for resources.

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Natural Gas	278	278	278	278	278
Wind	52	31	31	31	31
Conventional Hydro	5,705	5,726	5,739	5,739	5,739
Conventional Hydro*	5,705	5,726	5,739	5,739	5,721
Run of River Hydro	856	856	856	856	856
Total MW	6,094	6,094	6,107	6,107	6,107
Total MW*	6,094	6,094	6,107	6,107	6,089
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-Manitoba Hydro Assessment

Planning Reserve Margins

The winter ARM falls below the Reference Margin Level of 12% in 2029–2030. No resource adequacy issues are anticipated until Winter 2029–2030. A Tier 1 project to replace eight older and smaller hydro units is being planned for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation. No Tier 2 or Tier 3 resources have been assumed to come into service during the assessment period.

The ARM falls below the Reference Margin Level of 12% beginning in Winter 2029–2030 due to net load growth and the reduction of winter import capacity transfers. Manitoba Hydro's Integrated Resource Plan was published in Summer 2023. Further analysis is underway and will help inform Manitoba Hydro's future resource decisions for resources in the 2029 timeframe.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. As the operator of a predominantly hydro system, Manitoba Hydro frequently performs an all-hours energy adequacy analysis of the near-term through seasonal time periods to manage reservoir energy storage and meet system demand. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements for maintaining Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to coincide with peak demand hours**.**

There are a number of influencing factors associated with Manitoba Hydro's resource adequacy performance, such as the water resource conditions, energy and capacity exchanges with neighboring jurisdictions, forecast load level, uncertainties in load forecast and load variation profiles, demand responses, wind penetration, and generation fleet availability. Most of Manitoba Hydro's generating facilities are use-limited or energy-limited hydro units. The annual energy output of these facilities is mostly dependent on the availability of the water resource. In the 2024 ProbA, Manitoba Hydro examines the impact of the most significant factor over the long run—variations in water conditions.

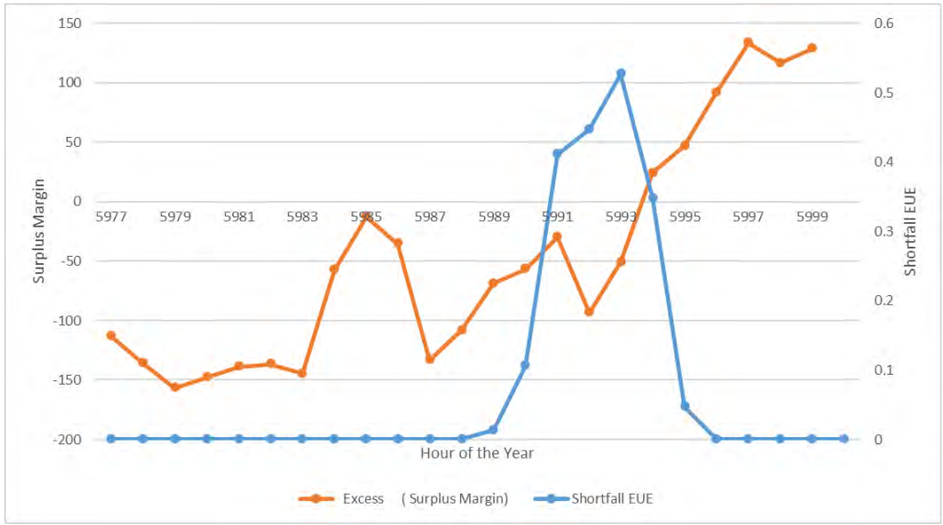
Nonzero LOLH and EUE are observed for both reporting years of 2026 and 2028 and shown in the table below. The LOLH and EUE indices are higher compared to the 2022 assessment mainly due to the increase in the forecast peak demand. Water flow conditions of 10th percentile or lower tend to increase the LOLH and EUE. As a small winter-peaking system on the northern edge of a large summer peaking system (MISO), there generally is assistance available, particularly in MISO's off-peak hours, to provide energy to supplement hydro generation in low-flow conditions in winter. Management of energy in reservoir storage in accordance with good utility practice provides risk mitigation under low water flow conditions.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	7.23	**4.711**	**68.870**
EUE (PPM)	0.29	**0.176**	**2.504**
LOLH (hours per year)	0.01	**0.059**	**0.914**
Operable On-Peak Margin	13.5%	**18.8%**	**15.6%**

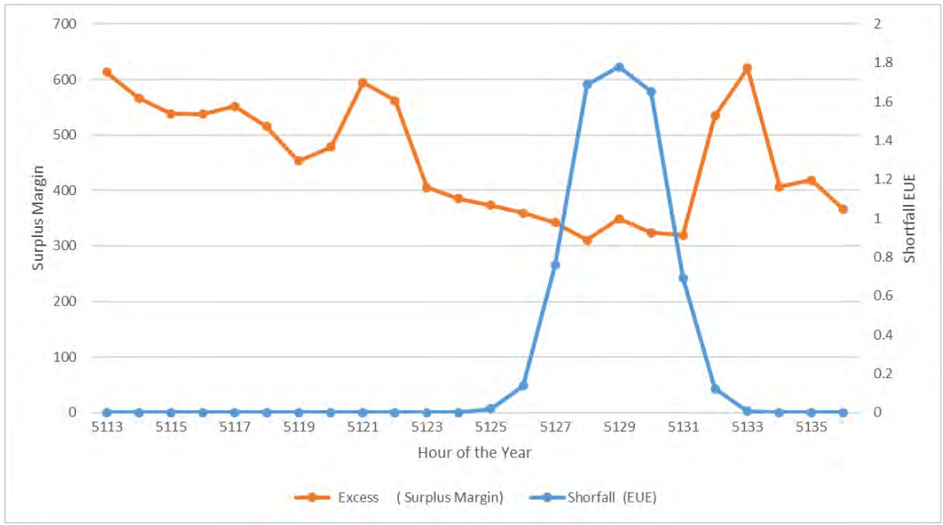
* Provides the 2022 ProbA Results for Comparison

The Monthly EUE and LOLH for 2026 and 2028 show that the highest LOLH and EUE contribution are from July and November, respectively, for 2026 and 2028.

The two graphs below show the hourly energy availability on the Manitoba Hydro system during the ProbA's highest risk days in 2026 and 2028. Surplus energy and shortfall EUE are plotted for the day when the highest loss of load event happens in the ProbA analysis. The Probability Weighted Average (PWA) surplus margin is negative, which indicates possible loss of loads for 2026. However, the PWA surplus energy is higher for 2028 during the day when the highest loss of load event is observed. This is because the surplus is an average for different water year data and the average surplus may not represent the event when loss of load occurs.

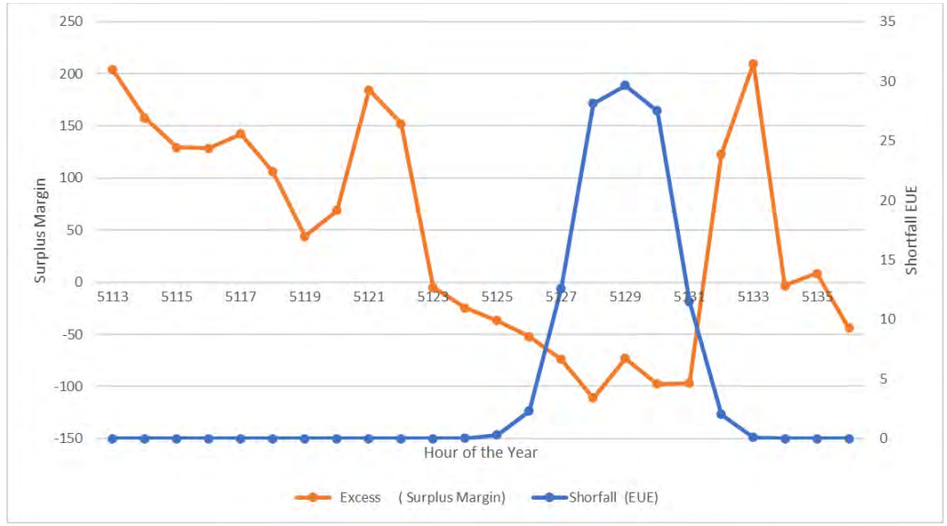


Hourly PWA Surplus Margin and Shortfall EUE for 2026 Representative Risk Day (Summer)



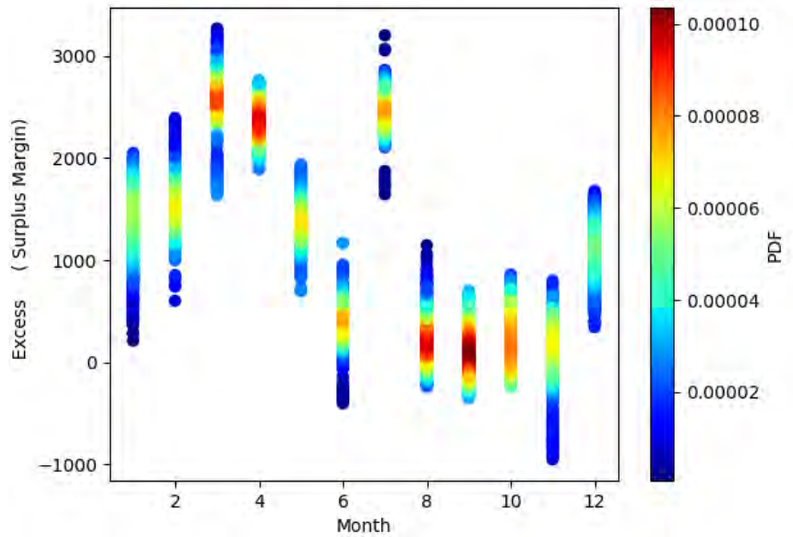
Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer)

The figure below shows the surplus margin and shortfall EUE for 2028 under extreme drought conditions. It can be seen that the loss-of-load event occurs when the surplus margin becomes negative. This surplus energy shown in the figure is the average value for this hour for the entire simulation. It may not represent each individual loss-of-load event during simulation. By plotting the hourly surplus and unserved energy for the low-water years, it is possible to see what risk periods are likely to emerge during extreme drought.



Hourly PWA Surplus Margin and Shortfall EUE for 2028 Representative Risk Day (Summer) During Extreme Drought Condition

The scatter plots of surplus energy vs. month for 2026 and 2028 are shown in the figures below. In the months of June and August to November, the PWA surplus energy is relatively lower compared to the other months due to less import from MISO. The PWA surplus energy in July 2026 is high due to higher hydro energy availability for July. However, since PWA is the result of averaging, positive surplus energy does not mean that there will be no loss-of-load events.



PWA Surplus Energy Versus Month for 2026

Demand

Manitoba Hydro's load-growth forecast is up around 3.2% over the assessment period in comparison with the forecast used for the *2023 LTRA*. Factors considered in load-growth projections include economic activity, EV adoption, and demand-side management programs in Manitoba operated by Efficiency Manitoba. EV adoption in Manitoba is being driven in part by proposed federal regulations that are expected to require that at least 20 percent of new vehicles sold in Canada will be zero-emission by 2026, at least 60 percent by 2030, and 100 percent by 2035.

Manitoba Hydro is anticipating load growth of 1.3% over the last half of the assessment period. Limited surplus firm generation resources (resource adequacy) have the potential to slow the connection of very large new industrial loads. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management

Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five minutes notice. The program is intended for peak load management. In addition, one product provides 50 MW of contingency reserves, also on five minutes' notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Distributed Energy Resources

Manitoba is not currently experiencing large additions of wind and solar resources being seen in other regions; hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated in the next five years. Additions of energy storage resources in the next 10 years are not anticipated at this time. There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DER may be dependent on solar PV subsidies and/or incentives.

Generation

Manitoba Hydro is monitoring federal and provincial policy/strategies/regulations related to electricity/energy. The Canadian federal government is considering significant carbon emission regulations. Through Environment and Climate Change Canada, it is taking multiple steps to develop clean electricity regulations that aim for Canadian electricity generation to achieve net-zero greenhouse gas emissions by 2035 by requiring generating units to meet a stringent emissions intensity standard (measured in tons CO2 equivalent per GWh) and pay a price for any remaining emissions. The proposed regulations are still in development and not proposed to be fully implemented until 2035, so it is too early to determine any potential impacts. The Province of Manitoba is developing a provincial energy strategy/policy which may be released in Fall 2024. As details are not yet available, it is too early to determine any potential impacts.

Energy Storage

Manitoba Hydro currently has no energy storage resources, and none have been committed to over the next 10-year period.

The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources online are hydro generation resources which therefore serve most operational, reliability, and economic functions.

Capacity Transfers

Manitoba Hydro has coordination and tie-line agreements with neighboring assessment areas, such as MISO, SaskPower, and the IESO. In accordance with these agreements, planning- and operating-related issues are discussed and coordinated through respective committees. In addition to this planning and operating committee work, Manitoba Hydro engages with the neighboring utilities of Minnesota Power, Xcel Energy, Otter Tail Power, Minnkota Power Cooperative, SaskPower, and Hydro One regularly to share information, discuss issues, and coordinate activities. Manitoba Hydro also coordinates planning studies (for example, transmission service request studies and requests for generation interconnections) with its neighboring assessment areas. In addition, capacity transfers are verified from a resource adequacy perspective with adjacent regions/entities. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts but only in extreme conditions occurring simultaneously.

Transmission

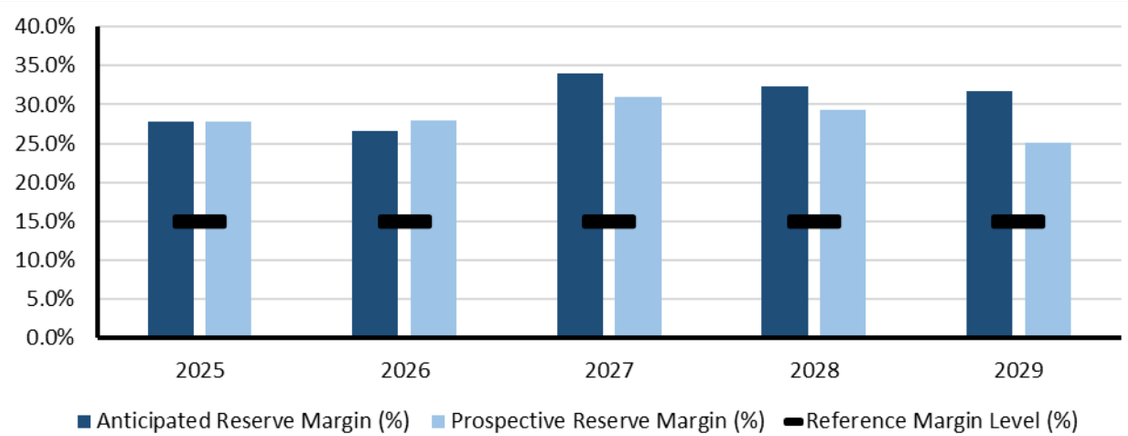
Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue that is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end of life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

MRO-SaskPower

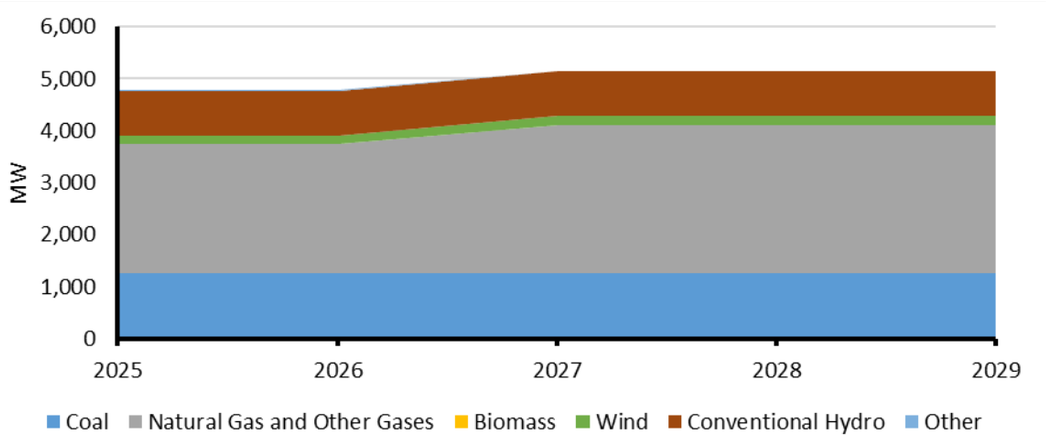
MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles), with a population of 1.2 million and approximately 550,000 customers. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown Corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System (BES) and its interconnections.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	3,917	4,025	4,149	4,189	4,210	4,242	4,271	4,315	4,359	4,408
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,845	3,953	4,077	4,117	4,138	4,170	4,199	4,243	4,287	4,336
Additions: Tier 1	507	507	883	883	883	883	883	883	883	883
Additions: Tier 2	0	55	175	175	928	928	928	928	928	928
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	290	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,407	4,497	4,582	4,566	4,566	4,489	4,490	4,490	4,552	4,566
Anticipated Reserve Margin (%)	27.8%	26.6%	34.0%	32.4%	31.7%	28.8%	28.0%	26.6%	26.8%	25.7%
Prospective Reserve Margin (%)	27.8%	28%	31.0%	29.3%	25.1%	22.3%	20.8%	19.5%	19.8%	18.7%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- SaskPower's ARM is above the RML throughout the assessment period. No resource adequacy issues are anticipated.
- Saskatchewan is adding approximately 1,064 MW of generation under Tier 1 within the next five years. This includes a 200 MW wind generation facility, two new 377 MW gas generation facilities, and the expansion of two existing natural gas facilities totaling 90 MW. The remaining capacity addition comes from geothermal and flare gas.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Coal	1,249	1,249	1,249	1,249	1,249
Coal*	1,249	1,249	1,088	1,088	188
Natural Gas	2,487	2,487	2,863	2,863	2,863
Biomass	3	3	3	3	3
Wind	164	164	162	162	162
Conventional Hydro	856	856	856	856	856
Other	22	17	17	1	1
Total MW	4,781	4,775	5,150	5,134	5,134
Total MW*	4,781	4,775	4,989	4,973	4,073
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses a criterion of 15% as the reference reserve margin and has assessed its PRM for the upcoming 10 years considering the summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available demand response for each year. Saskatchewan's ARM ranges from approximately 19% to 34% and does not fall below the Reference Margin Level.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. Saskatchewan evaluates non-peak hour risks and diminishing capacity credits associated with higher penetration levels of VERs as part of the long-term planning process.

Results of the 2024 ProbA are provided in the table below. Based on the deterministic calculations within this assessment, Saskatchewan's ARM is 27.8% and 34.0% for years 2026 and 2028, respectively. Since the 2022 ProbA, the reported forecast reserve margin for 2026 has remained consistent. The minor variation in the reserve margin is due to a slight change in the schedule of generator outages. EUE is also comparable to the 2022 ProbA, with some variation attributed to updated hydro energy dispatch, which is able to reduce the EUE in the months where it was highest in the prior ProbA.

Base Case Summary of Results			
	2026*	2026	2026
EUE (MWh)	117.0	**75.641**	**8.553**
EUE (PPM)	4.4	**2.807**	**0.300**
LOLH (hours per year)	0.9	**0.547**	**0.078**
Operable On-Peak Margin	24.6	**24.4%**	**30.5%**

* Provides the 2022 ProbA Results for Comparison

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix consists of baseload and fast ramping generation resources, with little penetration of VERs. The main factor contributing to EUE is the amount of planned generator outages. When these short-term reliability issues are identified in advance, they can be mitigated by rescheduling the maintenance. The hourly EUE heat maps in the following figures show that risk of unserved energy is at its highest in the summer months. Risk can also be found in months before or after summer and be driven by unseasonable temperatures driving above-normal demand that coincides with generator maintenance periods. Winter risks of shortfall are associated with extreme cold weather and unexpected generator outages.

Hourly EUE Heat Map : 2026																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Feb-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-26	1.2	1.2	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.8	1.7	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.6	1.5	1.3
Jun-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jul-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Sep-26	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.8	0.9	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.4	1.5	1.7	1.3	1.0	0.7
Oct-26	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.4	0.3	0.3
Nov-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Dec-26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1

Hourly EUE Heat Map : 2028																								
EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb-28	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar-28	0.0	0.0	0.0	-	-	-	-	0.0	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jun-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Jul-28	0.0	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
Aug-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sep-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct-28	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Nov-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Dec-28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0

Hourly EUE Heat Maps (in MWh)

Demand

Saskatchewan experiences its peak-season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. The average annual summer and winter peak demand growth is expected to be approximately 1.35% throughout the assessment period.

Demand-Side Management
Saskatchewan's EE and energy conservation programs include incentive-based and education programs focusing on installed measures and products that provide verifiable, measurable, and permanent reductions in electrical energy, and demand reductions during peak hours.

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based under conditions specified in demand response programs. The first of these programs provides a curtailable load, currently up to 72 MW, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours notification time.

Distributed Energy Resources
The current BTM DER installed capacity in Saskatchewan is approximately 50 MW, which includes approximately 48 MW of solar PV and the remaining approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. BTM DER installations are incorporated into the load forecast models, which are used in supply and transmission planning study models.

Small power producers contribute an additional 5 MW installed DER capacity (non-BTM) in Saskatchewan. There is currently an existing 8 MW and a potential for up to 20 MW of DERs being added in the next 2 years based on the currently approved Power Generation Partner program. These projects are included as generation additions, but currently their capacity is not considered in reliability planning.

Generation
Saskatchewan is adding approximately 1,064 MW into its resource mix of generation under the Tier 1 category within the next five years. The includes a 200 MW wind generation facility, expansion of two existing natural gas facilities totaling 90 MW, two new natural gas facilities totaling 754 MW, 15 MW of flare gas generation, and 5 MW of geothermal generation.

Under Tier 2, over 1,717 MW of new generation is projected in the assessment period. This includes 754 MW of natural gas, 600 MW of wind generation, 300 MW of utility-scale solar generation, and 63 MW of co-generation.

Generating resources being planned as Tier 2 and Tier 3 will replace generators planned for retirement prior to deactivation. Therefore, Saskatchewan is not expecting any long-term reliability impacts due to generation retirements.

Energy Storage
SaskPower currently has its first battery storage system, a 20 MW/20 MWh unit, under commissioning. There are plans to expand this site by an additional 60 MW/60MWh capacity. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/voltage control, primary frequency control, and blackstart.

Capacity Transfers
SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro, as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation is in place through SaskPower's emergency operating procedure that will allow one or more measures such as short-term imports from other available interfaces (for example Alberta or SPP), initiating demand response and short-term load shedding.

Transmission
SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 650 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 kilometers of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, and installation of two phase-shifting transformer interfaces and two static var systems are being added.

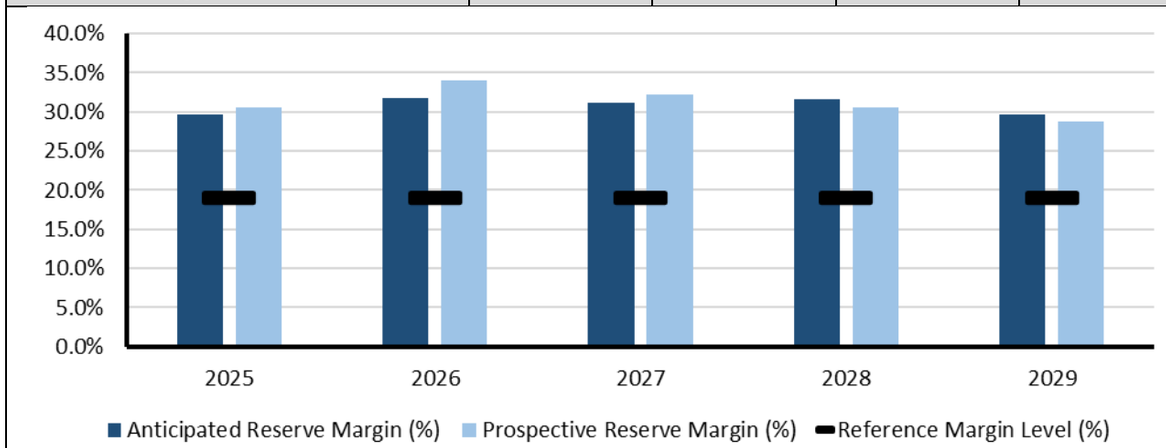
The remaining other transmission projects (approximately 460 circuit kilometers) are under the planning and conceptual phase in the 5-to-10-year planning horizon. These projects are driven by load growth, new generation additions, and reliability needs.

MRO-SPP

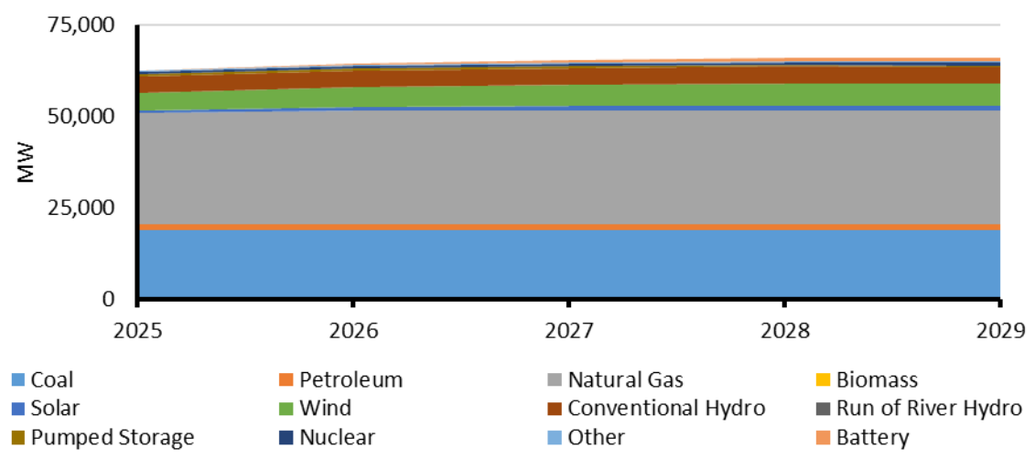
The Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	55,669	57,171	59,031	59,764	60,596	61,963	62,490	63,287	63,764	64,172
Demand Response	1,463	1,771	2,057	2,124	2,172	2,222	2,259	2,465	2,467	2,472
Net Internal Demand	54,206	55,400	56,975	57,640	58,424	59,741	60,231	60,822	61,297	61,700
Additions: Tier 1	2,123	4,966	6,750	7,843	7,957	7,957	7,957	7,957	7,957	7,957
Additions: Tier 2	1,239	2,454	2,756	2,756	2,756	2,756	2,756	2,756	2,756	2,756
Additions: Tier 3	6,823	16,770	22,655	28,948	28,948	28,948	28,948	28,948	28,948	28,948
Net Firm Capacity Transfers	-1,097	-1,077	-1,136	-1,131	-1,131	-1,131	-1,131	-1,133	-1,133	-1,133
Existing-Certain and Net Firm Transfers	68,157	68,039	67,981	67,984	67,799	67,749	67,253	67,175	67,055	67,094
Anticipated Reserve Margin (%)	29.7%	31.8%	31.2%	31.6%	29.7%	26.7%	24.9%	23.5%	22.4%	21.6%
Prospective Reserve Margin (%)	30.6%	34.1%	32.2%	30.6%	28.7%	25.2%	23.3%	22.0%	20.6%	19.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- There are over 8 GW of coal and gas-fired generators that have indicated they plan to retire over the next 10 years in SPP. Without sufficient dispatchable generation, SPP can experience energy shortages when output from wind resources is low.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	18,952	18,952	18,919	18,919	18,919
Coal*	17,934	16,647	16,614	14,062	14,062
Petroleum	1,629	1,629	1,631	1,631	1,631
Petroleum*	1,629	1,629	1,575	1,575	1,575
Natural Gas	30,471	31,098	31,098	31,098	31,098
Natural Gas*	29,896	30,220	29,924	29,812	29,812
Biomass	20	20	20	20	20
Solar	495	864	1,149	1,283	1,283
Wind	4,974	5,456	5,928	6,117	5,909
Conventional Hydro	4,526	4,541	4,573	4,605	4,628
Pumped Storage	472	472	472	472	472
Nuclear	769	769	769	769	769
Other	281	281	281	281	281
Battery	41	290	555	930	1,044
Total MW	62,630	64,370	65,392	66,124	66,053
Total MW*	61,037	61,188	61,858	59,925	59,855
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

Planning Reserve Margins

The Existing-Certain and Net Firm Transfers Reserve Margin for the SPP assessment area is projected to fall below the current coincident summer season RML of 19% in 2027. The current summer season reserve margin target for SPP is 15%, but that is based on the non-coincident peak demand of load-responsible entities (LRE) in the SPP assessment area. For purposes of NERC assessments, the 15% target is converted, along with forecasted demand values, to an SPP coincident peak representation based on the latest calculated diversity factor. This results in an RML of 19%. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to be above the 19% RML for the 10-year horizon.

Like the generation unavailability scenario in NERC's *2024 Summer Reliability Assessment*, SPP shows the potential to utilize all the current projected capacity and there could be times of capacity shortfall based on performance impacts during high-load periods. While the potential to all available capacity has a lower probability, the assumptions and projections are based around historical unavailability during peak periods. Current LTRA projections are based on the latest resource adequacy data submittals, which are provided by the LREs and Generator Owners in SPP.

SPP performs a biennial LOLE study to establish a reserve margin target such that the LOLE for the applicable planning year (3- and 6-year study) does not exceed 1 day in 10 years, or 0.1 day per year. The target is determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand with load uncertainty to ensure that the LOLE does not exceed 0.1 day per year.

SPP's 2023 LOLE study results indicate that separate PRMs and capacity requirements are needed for the summer and winter seasons to recognize the seasonal balance of risk. Also, as colder temperature outages increase with the incorporation of additional wind and solar resources, the loss-of-load risk shifts to the winter season. Due to the shift in seasonal risk, it would be appropriate to consider a maximum LOLE threshold for the winter season or incorporation of an EUE reliability metric to complement the LOLE metric.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

As the resource mix continues to change from a standard base load conventional thermal and hydro resources to VERs and short-term energy storage resources (ESR), SPP is incorporating energy adequacy metrics (i.e., EUE) in the determination of PRMs, RMLs, additional reliability policies, and resource accreditation enhancements.

SPP will begin performing a yearly energy adequacy assessment and assessment of reliability attributes (inertia, primary frequency response, ramp, regulation, contingency reserves, voltage and reactive support capability, fuel assurance, flexibility, and blackstart capability). Results of the analysis will be presented annually to SPP stakeholders. The results will also be used to identify needs for new market products, changes to market functionality, or changes to resource adequacy policies and requirements.

The 2024 ProbA performed for the NERC LTRA used assumptions and methods that reflect SPP's Loss of LOLE studies. Results are shown in the following table.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.84	0.00	6.61
EUE (PPM)	0.00	0.00	0.02
LOLH (hours per year)	0.00	0.00	0.01
Operable On-Peak Margin	19.6%	19.5%	16.0%

*Provides the 2022 ProbA Results for Comparison

With the current SPP fleet, there was no loss of load for the 2026 study that included Tier 1 resource additions and 600 MW in generator retirements. The 2028 analysis included both Tier 1 and Tier 2 resource additions and 2,700 MW in generator retirements. The result was a small amount of EUE (6.61MWh) and LOLH (0.01hr/year). The loss of load/hour occurred mostly during the summer season (0.007hr/yr), while the winter season had 0.0004hr/yr. SPP is a summer-peaking region, and the results also supported that. The demand was highest in the afternoons between 13:00 and 19:00 during July and August.

Study improvements for 2024 from the previous NERC ProbAs include additional weather years, seasonal forced-outage modeling, and incremental cold weather outages.

SPP uses the Strategic Energy & Risk Valuation Model (SERVM) for the ProbA. It is a production-cost modeling tool that uses the Monte Carlo method to solve LOLE. Each weather year was simulated 300 times to simulate a multitude of random forced outage draws. Taking 300 draws for each weather year (43) and multiplying by 8,760 hours gets to a total of over 113 million simulated hours, from 1980 to 2022. Each iteration was performed on an 8,760-hour basis.

The study input model consisted of multiple modeling assumptions including multiple historical weather years (1980–2022); hourly load, solar, and wind profiles; load forecast uncertainty; random forced outages draws and variability; physical and economic resource parameters; resource retirements; future resource additions; zonal transmission limitations; and incremental conventional resource forced outages due to extreme cold temperature.

The generating resources modeled in the Probabilistic Assessment reflect the data supplied in the *2024 LTRA*. Existing and projected resources were included in the Probabilistic Assessment along with reported confirmed retirements. As mentioned previously, wind and solar resources, as well as historical weather years, were modeled at historical hourly values using 2012 to 2022 weather years. There were six study zones, and SPP modeled a projected 8,760 hourly demand profile for each area to provide load variability and volatility for chronological hours during simulation. Each local resource zone was modeled with an import and export limit based on a separate power flow transfer analysis. SPP used unit-specific outage rates within the analysis based on NERC Generation Availability Data System (GADS) data from 2015 to 2022. External assistance only included firm contracts from external entities with firm transmission service.

Demand

SPP peak load occurs during the summer season; the 2024 net internal demand forecast is projected to peak at 53,094 MW, which is projected to increase compared to the previous year's LTRA forecast for the 2022 summer season. The diversity factor used to convert the non-coincident peak demand forecast to an SPP coincident peak demand forecast was consistent with the ~3.5% applied in the *2023 LTRA*. SPP forecasts the coincident annual peak growth based on member submitted data over the 10-year assessment timeframe. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has observed.

Demand-Side Management

SPP's energy efficiency (EE) and conservation programs are incorporated into the reporting entities' demand forecasts. There are no known impacts to the SPP assessment area's long-term reliability related to the forecasted increase in EE and DR across the assessment area. In addition, SPP is constructing a new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources

The SPP Model Development, Economic Studies, and Supply Adequacy working groups are developing policies and procedures around DERs. SPP resource adequacy implemented policies for DERs that mandate certain testing, reporting, and document requirements for resources and programs not registered in the SPP Integrated Market. Accreditation methodology policies are being constructed and are planned to be approved in late 2024.

Generation

SPP currently has approximately 900 MW of installed solar generating facilities. In the ARM calculation, SPP is reporting nameplate capacity of approximately 11 GW of Tier 1, 2, and 3 wind resources, approximately 18 GW of Tier 1, 2, and 3 solar resources, approximately 9.8 GW of Tier 1, 2, and 3 battery resources and approximately 2.7 GW of Tier 1, 2, and 3 gas resources.

In 2024, SPP filed conventional based performance accreditation and effective load carrying capability (ELCC) methodology for wind and solar resources. The goal is for these policies to become effective in the 2026/2027 timeframe for both the summer and winter seasons.

There are concerns of drought conditions impacting the Missouri River and other water sources for generation resources that rely on once-through cooling processes. Low water can impact the generation's capacity output and reduce its ability to support congestion management and serve load. An additional concern could be the impact of river conditions on coal shipments, which could cause generators to run at a derated level to conserve supplies.

Energy Storage

Currently, SPP is studying approximately 17,000 MWs of energy storage and hybrid resource projects in the generator interconnection queue process. There are approximately 50 MWs of energy storage under contract by SPP members. These resources are being modeled as generation in the planning assumptions both near and long term.

Capacity Transfers

The SPP assessment area coordinates with neighboring areas to ensure that adequate transfer capabilities will be available for capacity transfers. On an annual basis during the model build season, SPP staff coordinate the modeling of transfers between Planning Coordinator footprints. The modeled transactions are fed into the models created for the SPP planning process.

SPP and ERCOT executed a Coordination Plan that superseded the prior coordination agreement. The Coordination Plan addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the

Coordination Plan based on the latest discussions and business decisions, and it was updated in June 2024.

Transmission

In the 2023 ITP Assessment, SPP approved 44 transmission projects, including 150 miles of new transmission. Additionally, the study calls for 93 miles of transmission to be rebuilt.

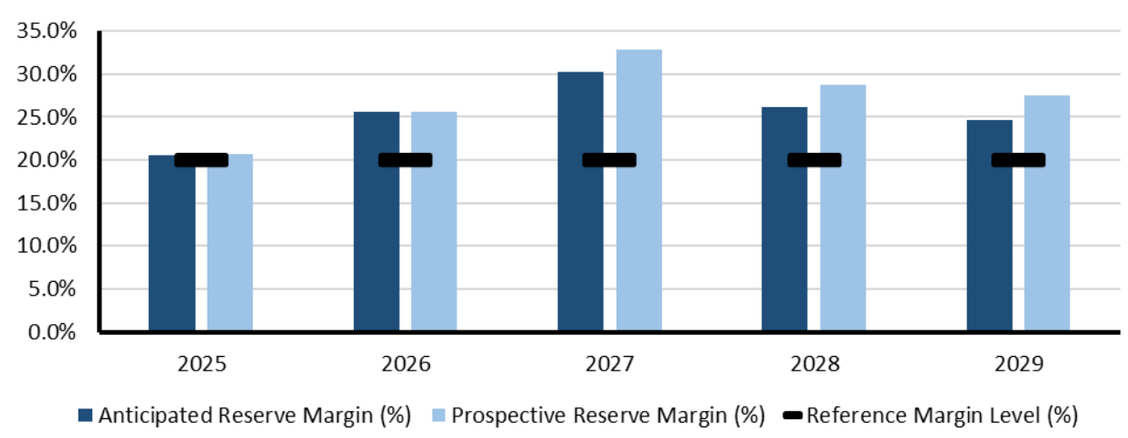
SPP is observing a number of transmission projects that are currently delayed. SPP is actively tracking these projects and discussing them throughout its stakeholder process. Many delays are driven by supply chain issues or increasing length of construction times. The delays of these transmission projects do not currently seem to be driving reliability issues.

NPCC-Maritimes

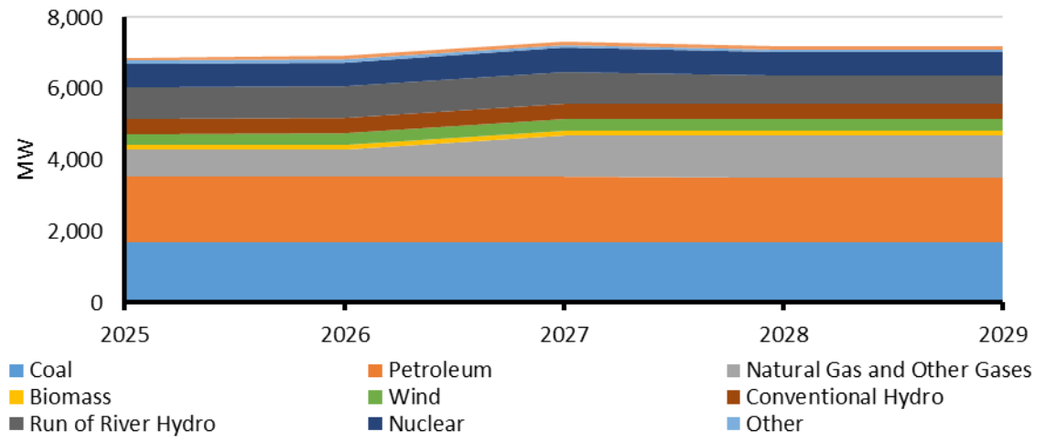
The Maritimes assessment area is a winter peaking NPCC sub-region with a single Reliability Coordinator and two Balancing Authority Areas (New Brunswick and Nova Scotia). It is comprised of the Canadian provinces of New Brunswick (NB), Nova Scotia (NS), and Prince Edward Island (PEI) and the northern portion of Maine (NM), which is radially connected to NB. The area covers 58,000 square miles with a total population of 2 million people.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	6,201	6,056	6,095	6,141	6,216	6,272	6,331	6,398	6,474	6,560
Demand Response	274	293	309	317	317	317	317	317	317	318
Net Internal Demand	5,927	5,763	5,786	5,825	5,899	5,954	6,014	6,081	6,157	6,242
Additions: Tier 1	108	171	579	579	579	579	579	579	579	579
Additions: Tier 2	6	4	447	600	1,398	1,398	1,398	1,398	1,398	1,398
Additions: Tier 3	0	13	80	127	197	255	267	279	291	291
Net Firm Capacity Transfers	289	322	215	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	7,038	7,063	6,959	6,771	6,771	6,771	6,679	6,665	6,665	6,752
Anticipated Reserve Margin (%)	20.6%	25.5%	30.3%	26.2%	24.6%	23.4%	20.7%	19.1%	17.7%	17.4%
Prospective Reserve Margin (%)	20.7%	25.6%	32.8%	28.8%	27.5%	26.3%	23.5%	21.9%	20.4%	20.1%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Since the *2023 LTRA*, the overall resource outlook has improved with expected new natural-gas-fired generators coming into service in 2027. Winter peak demand forecasts for this assessment area have risen through 2030; however, ARMs are currently projected to remain above the RML of 20% until 2031 when the ARM dips to 19.7%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,396	1,248	467
Petroleum	1,831	1,831	1,825	1,819	1,819
Natural Gas	757	757	1,157	1,157	1,157
Biomass	148	148	148	148	148
Solar	5	5	5	5	5
Wind	293	321	329	329	329
Conventional Hydro	412	412	412	412	412
Run of River Hydro	902	902	902	791	791
Nuclear	663	663	671	671	671
Other	77	77	77	77	77
Battery	72	99	99	99	99
Total MW	6,856	6,911	7,321	7,204	7,204
Total MW*	6,856	6,911	7,021	6,756	5,975
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The NPCC-Maritimes assessment area is comprised of NB, NS, PEI, and NM. The RML for the assessment area is 20%; however, this reserve margin is not mandated. The ARM over the study period for the Maritimes area ranges between 17% and 30% during the winter period and between 88% and 93% during the summer period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

During off-peak hours, the Maritimes area has surplus generation and no constraints with converting the capacity to energy.

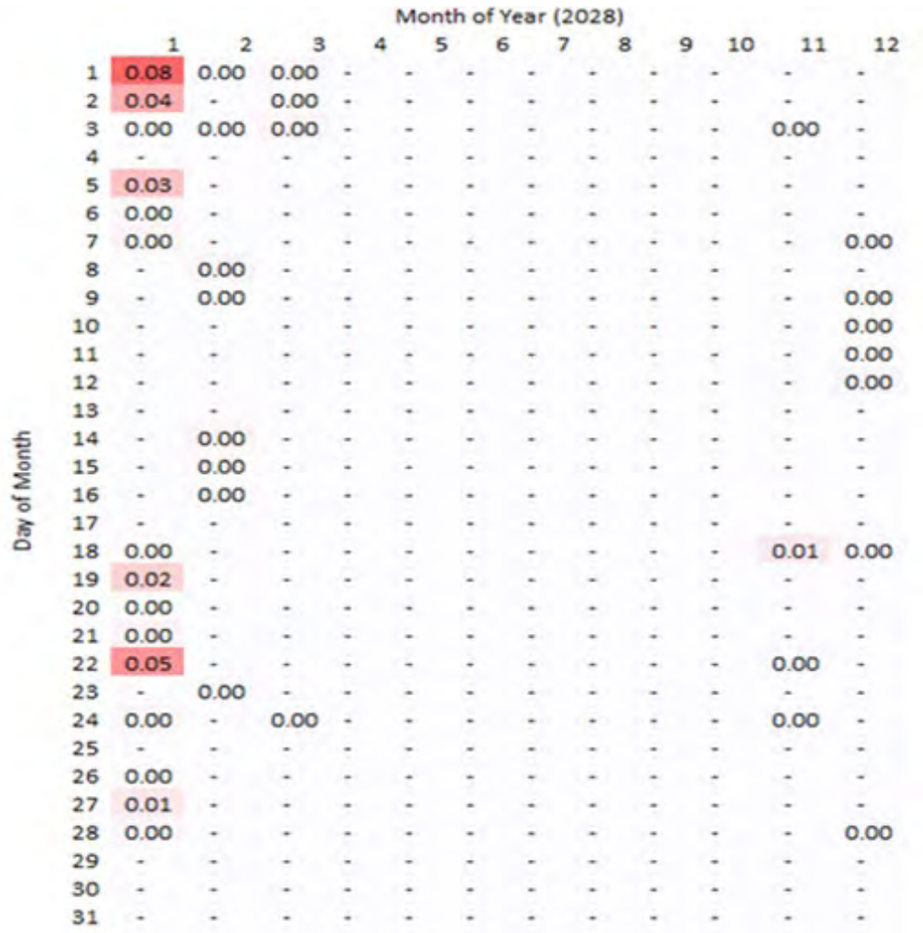
Probabilistic Assessments

Two Balancing Authorities within the Maritimes area are members of NPCC and jointly prepare annual probabilistic assessments that cover three- to five-year forward-looking periods and evaluate the adequacy of the Maritimes' transmission system and resources. In addition, the Maritimes area also supports NERC's annual seasonal ProbAs, which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves. Results of the 2024 ProbA are in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	3.87	**5.02**	**0.28**
EUE (PPM)	0.14	**0.17**	**0.01**
LOLH (hours per year)	0.07	**0.09**	**0.02**
Operable On-Peak Margin	22.9%	**17.9%**	**29.0%**

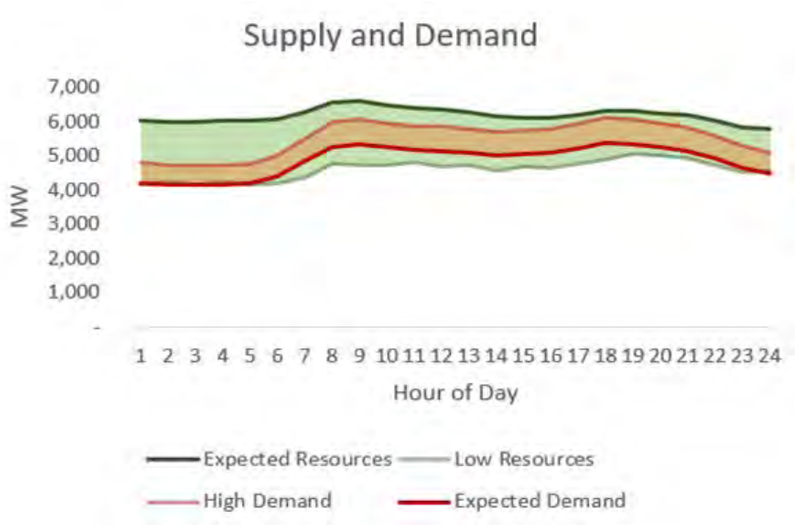
* Provides the 2022 ProbA Results for Comparison

The following table of LOLH for 2028 provides a depiction of risks across the calendar year and highlights the concentration of risk in winter. Most load-loss risk occurs in winter months of December–February, with some additional risk occurring in shoulder months. 2026 has a similar risk distribution.



Day of Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0.08	0.00	0.00	-	-	-	-	-	-	-	-	-
2	0.04	-	0.00	-	-	-	-	-	-	-	-	-
3	0.00	0.00	0.00	-	-	-	-	-	-	-	0.00	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	0.03	-	-	-	-	-	-	-	-	-	-	-
6	0.00	-	-	-	-	-	-	-	-	-	-	-
7	0.00	-	-	-	-	-	-	-	-	-	-	0.00
8	-	0.00	-	-	-	-	-	-	-	-	-	-
9	-	0.00	-	-	-	-	-	-	-	-	-	0.00
10	-	-	-	-	-	-	-	-	-	-	-	0.00
11	-	-	-	-	-	-	-	-	-	-	-	0.00
12	-	-	-	-	-	-	-	-	-	-	-	0.00
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	0.00	-	-	-	-	-	-	-	-	-	-
15	-	0.00	-	-	-	-	-	-	-	-	-	-
16	-	0.00	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	0.00	-	-	-	-	-	-	-	-	-	0.01	0.00
19	0.02	-	-	-	-	-	-	-	-	-	-	-
20	0.00	-	-	-	-	-	-	-	-	-	-	-
21	0.00	-	-	-	-	-	-	-	-	-	-	-
22	0.05	-	-	-	-	-	-	-	-	-	0.00	-
23	-	0.00	-	-	-	-	-	-	-	-	-	-
24	0.00	-	0.00	-	-	-	-	-	-	-	0.00	-
25	-	-	-	-	-	-	-	-	-	-	-	-
26	0.00	-	-	-	-	-	-	-	-	-	-	-
27	0.01	-	-	-	-	-	-	-	-	-	-	-
28	0.00	-	-	-	-	-	-	-	-	-	-	0.00
29	-	-	-	-	-	-	-	-	-	-	-	-
30	-	-	-	-	-	-	-	-	-	-	-	-
31	-	-	-	-	-	-	-	-	-	-	-	-

Hourly demand and resource projections for a typical risk-day in 2026 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, the greatest risk for this assessment area is in the form of lower-than-expected resource contributions. If this were to occur, expected demand for all hours would not be met. This risk would be exaggerated by the addition of a higher-than-expected demand event. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The area peak loads are expected to increase by 4.2% during summer and by 6.4% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.4% in summer and 0.6% in winter. The Maritimes Area annual energy forecasts are expected to increase by a total of 5.9% during the 10-year assessment period for an average growth of 0.6% per year.

Demand-Side Management

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 20 MW to 169 MW while the annual amounts for winter peak demand reductions rise from 168 MW to 629 MW.[34]

Distributed Energy Resources

The DER installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff, and BTM solar.

LTRA wind capacity for NB, NS, and PEI is derated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. BTM solar is assumed to have an ELCC of 0% during winter period. The Maritimes area has shown embedded BTM solar PV projections of 149 MW in 2024 rising to 881 MW by 2034. These projects include distributed small-scale solar (mainly rooftop) that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of the area's system peak, which occurs either before sunrise or after sunset in the winter period.

Generation

NB assumes extending 28 MW of diesel-fired generator starting in 2025 and recently upgraded 290 MW of natural-gas-fueled resource completed in 2023. There are 25.2 MW of wind power purchase agreements (PPA) also slated to start in 2025. An anticipated replacement PPA contract, a long-term firm energy contract from a neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

NB Tier 1 resources include 71 MW of wind and 400 MW of combustion turbines. Tier 2 resources include 200 MW of wind resources and Tier 3 includes 400 MW of wind.

In NS, Tier 1 resources include wind projects with a total nameplate capacity of 473 MW phased in from 2024–2027 with an ELCC of 10%, 150 MW battery storage, 4 MW tidal power, 2 MW biomass unit, and a small 0.14 MW solar farm. Tier 2 resources in NS include 250 MW of battery storage (2026–2032), 600 MW of combustion turbines (2027–2033), a 150 MW conversion of a coal-fired unit to natural gas (2028), 450 MW in conversion of coal-fire units to oil (2030), 220 MW of solar generation,

[34] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

and 416 MW of wind generation. Tier 3 resources in NS include natural gas additions (combustion turbines) of 50 MW in 2029 and new wind generation with a nameplate capacity of 850 MW phased in from 2026–2033. These Tier 3 resource additions are anticipated to facilitate the retirement of additional coal-fired generation by 2030. However, these retirements have not been included in the assessment due to their uncertainty.

Small amounts of new solar generation capacity (Tier 1) of up to 21 MW were being installed in PEI in 2024, along with 10 MW of new hybrid energy storage (Tier 1). PEI also has 30 MW of Tier 2 wind, 111 MW Tier 3 wind, and 140 MW of Tier 3 petroleum-based generation and 10 MW of Tier 3 batteries.

NB derates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI derate wind capacity to 18% and 17%, respectively, of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid-based solar is estimated at zero since the Maritimes area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource phased in from 2026 through 2032. This grid-scale project will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 1 resource starting summer of 2024 and another 10 MW nameplate capacity energy storage system as a Tier 3 resource. This project will provide a storage option for the output from the 10 MW solar facility that is planned to come online during the same time frame. This project will provide fuel savings and may assist in providing additional reliability if a generation outage occurs.

NB Power has not included any energy storage resources in the *2024 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest for new renewable generation sources including 200 MW of wind, 15 MW of solar, 5 MW of tidal, and 50 MW of 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources, such as wind, to provide additional flexibility to the system.

Capacity Transfers

ProbA studies show that the Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission

NS has multiple new transmission line projects compared to the *2023 LTRA*; most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues

The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual fuel oil/gas, tie benefits, and biomass with no single one type feeding more than about 27% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges for resources during this assessment period.

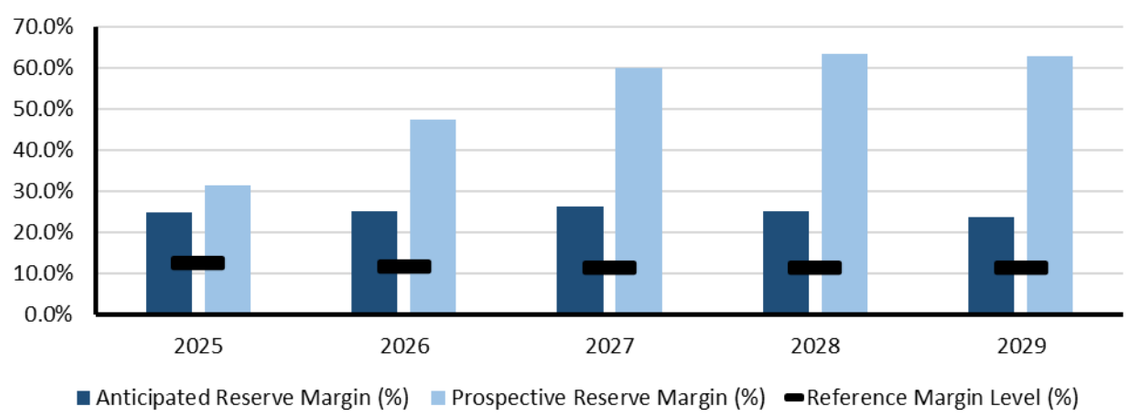
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. Note: Northern Maine is not directly connected to the transmission system administered by ISO-NE.

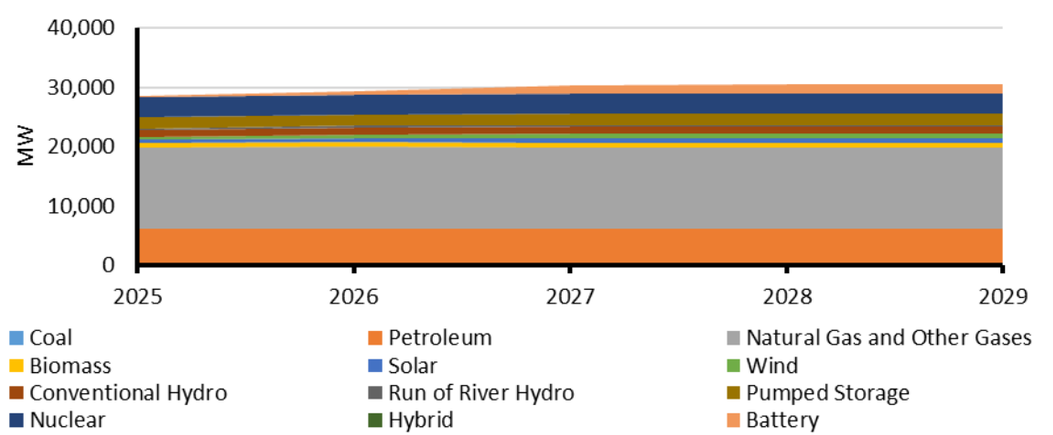
The New England BPS serves approximately 15.1 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	24,579	24,702	24,845	25,076	25,364	25,706	26,100	26,547	27,052	27,567
Demand Response	566	588	544	544	544	544	544	544	544	544
Net Internal Demand	24,013	24,114	24,301	24,532	24,820	25,162	25,556	26,003	26,508	27,023
Additions: Tier 1	660	1,492	2,374	2,748	2,748	2,748	2,748	3,168	3,168	3,168
Additions: Tier 2	337	3,089	5,911	7,084	7,425	7,766	7,766	7,766	7,766	7,766
Additions: Tier 3	1,404	1,765	5,106	7,906	9,221	9,355	9,721	10,432	10,432	10,432
Net Firm Capacity Transfers	1,248	567	465	84	84	84	84	84	0	0
Existing-Certain and Net Firm Transfers	29,354	28,658	28,327	27,946	27,946	27,946	27,946	27,946	27,862	27,862
Anticipated Reserve Margin (%)	25.0%	25.0%	26.3%	25.1%	23.7%	22.0%	20.1%	19.7%	17.1%	14.8%
Prospective Reserve Margin (%)	31.4%	47.3%	60.1%	63.3%	62.8%	62.0%	59.5%	58.3%	55.0%	52.0%
Reference Margin Level (%)	12.7%	11.8%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- New England is forecast to have sufficient ARMs to meet consumer demand for electric energy for the first five years (2025–2029) of the assessment period and not require any Tier 2 resources.
- ISO-NE is addressing the issues brought on by grid transformation through several planning, operational, and market measures. A significant project is the redesign of the capacity market from a forward, annual auction to a prompt, seasonal auction with resource accreditation. The Capacity Auction Reforms (CAR) project began in Q2 2024 and is expected to be in place for the 19th Capacity Commitment Period (CCP 19) beginning on June 1, 2028. Additionally, New England has made tariff modifications to its Longer-Term Transmission Planning process to facilitate the New England states' achievement of their policy-based goals by enabling the development of transmission infrastructure. ISO-NE is also working with regional stakeholders to develop a regional energy shortfall threshold (REST) that defines the region's tolerance for energy shortfalls during low-probability extreme weather conditions.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[35]					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	541	541	541	541	541
Coal*	445	445	445	7	7
Petroleum	5,703	5,703	5,687	5,687	5,687
Natural Gas	13,651	13,724	13,708	13,708	13,708
Biomass	780	780	780	780	780
Solar	533	663	663	663	663
Wind	391	594	819	819	819
Conventional Hydro	1,209	1,209	1,209	1,209	1,209
Run of River Hydro	289	289	289	289	289
Pumped Storage	1,860	1,860	1,860	1,860	1,860
Nuclear	3,331	3,331	3,331	3,331	3,331
Hybrid	34	35	35	35	35
Other	74	74	74	74	74
Battery	159	584	1,242	1,616	1,616
Total MW	28,553	29,385	30,237	30,611	30,611
Total MW*	28,458	29,290	30,141	30,077	30,077
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to ISO-NE are removed from the resource projection where marked.					

[35] MW totals reflect Existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet the ISO-NE and NPCC resource adequacy reliability criterion of an LOLE of 0.1 day/year. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period. The latest ICR calculations result in an annual RML of 12.70% in 2025, 11.82% in 2026, and 11.33% in 2027, expressed in terms of the annual 50/50 peak demand forecast published in the *2024 Capacity, Energy, Loads, and Transmission (CELT) Report*. For the years 2028 through 2034, which are beyond the current forward capacity market timeframe, ISO-NE continued to use the last available RML value of 11.33%. The ISO-NE RML is relatively low compared to other regions due to the impact of reflecting external assistance from neighboring control areas and the continued increase in BTM solar facilities.

Non-Peak Hour Risk, Energy Assurance, and Probabilistic-Based Assessments

ISO-NE routinely prepares 21-day energy forecasts. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the forecasted regional supply/demand balance is negative, projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential energy shortfalls is expected to inform market participants such that actions can be taken to increase the expected availability of generating resources as needed.

ISO-NE recently completed work with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. This tool is a framework that has three major steps (weather modeling, risk screening/scenario generation, and 21-day energy assessment), which were subsequently applied to assess the summers and winters of 2027 and 2032.

Probabilistic Assessments

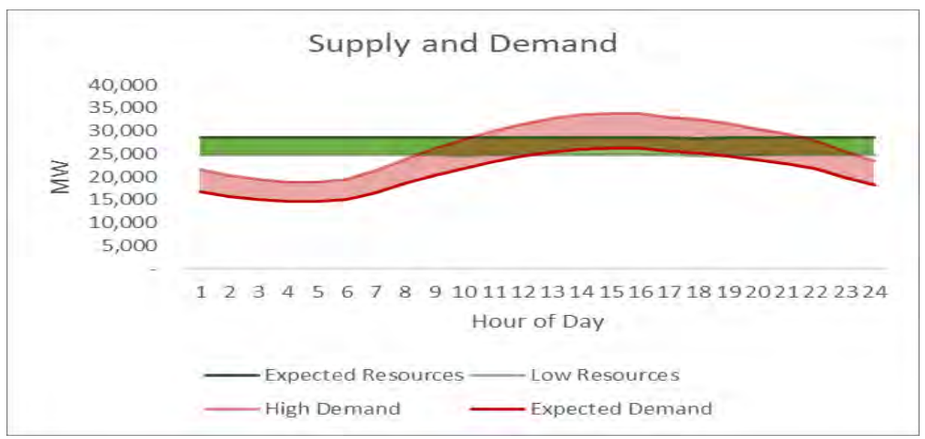
ISO-NE conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC/NERC reliability requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with neighboring systems will continue and help support the New England states' policy objectives of providing access to a greater diversity of clean resources to meet environmental compliance obligations. Results from the 2024 ProbA, shown in the table below, reveal a slight increase in load-loss and unserved energy risk from the 2022 analysis, but values remain small. ISO-NE is considered to have sufficient resources for the planning horizon to meet NPCC resource adequacy criteria.

Base Case Summary 2024 ProbA of Results			
	2026*	2026	2028
EUE (MWh)	0.551	**10.69**	**7.40**
EUE (PPM)	0.004	**0.09**	**0.06**
LOLH (hours per year)	0.002	**0.07**	**0.03**
Operable On-Peak Margin	27.8%	**12.4%**	**13.7%**

* Provides the 2022 ProbA Results for Comparison

NPCC's ProbA results indicate that the risk of unserved energy in New England is concentrated in summer months (June–August).

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contributions meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 25–30% higher than expected, which could cause strain on the system from the hours beginning 10:00 a.m. through 10:00 p.m. Also, below-normal resource performance from unexpected generator outages or low solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from the hour beginning 12:00 p.m. through 7:00 p.m. on a typical peak day. Reliance on external assistance may be necessary in these extreme conditions. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

Fuel availability during extreme winter conditions is a persistent reliability concern in New England that is not modeled in detail in the ProbA. Potential natural gas transportation constraints can affect supply to generators during extreme cold temperatures, when natural gas demand for space heating is also peaking. Most natural-gas-fired generators in the area do not have firm natural gas transportation service and can be subject to supply curtailment during peak conditions. Many natural-gas-fired generators in New England can also operate with stored oil, providing for assured electricity supply in extreme winter conditions while oil stores are procured and maintained. Scenarios of extended and extreme cold weather that affect the availability of natural gas and oil replenishments present a reliability risk and were not modeled in the 2024 ProbA.

Demand

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,988 MW from 24,579 MW in 2025 to 27,567 MW in 2034 (roughly 2% decrease from the 2023 forecast in the later years). The corresponding net internal winter peak demand increases by 7,342 MW from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (roughly a 2.5% decrease from the 2023 forecast). Net energy for load is forecast to grow by 24,701 GWh from 119,285 GWh in 2025 to 143,986 GWh in 2034 (roughly 10% decrease from the 2023 forecast). The changes from the 2023 forecast were in part due to continued enhancements of the heating and transportation electrification forecasts.

The higher winter peak growth rate due to anticipated electrification results in significant convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by this time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management

For the summer of 2025, ISO-NE forecasts 566 MW of controllable and dispatchable demand-side management (DSM) resources, and that amount is projected to decrease by 22 MW to 544 MW by 2034. For the summer of 2025, ISO-NE forecasts 1,873 MW of passive DSM resources (EE and conservation). Demand-side resources are projected to peak in 2030 at 2,117 MW and then begin to decrease to 1,978 MW by 2034. This decrease in the later years is due to expiring EE measures outpacing new passive DSM additions.

Distributed Energy Resources

For summer months, the BTM PV forecast is incorporated as estimated reductions to the ISO-NE gross demand forecast. In 2025, New England forecasts 1,141 MW of peak load reduction (4,533 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,299 MW of peak load reduction (8,217 MW nameplate) by 2034. The BTM PV peak load reduction values are calculated as a percentage of ac nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of peaks later in the day. The BTM peak load reduction decreases from 25.2% of nameplate in 2025 to 15.8% in 2034.

ISO-NE recently adopted a new planning procedure (PP12) to formalize and standardize data collection for DERs. Under this procedure, distribution providers would be responsible for providing installation-level data on DERs connected to their system. Additionally, transmission providers would be responsible for providing basic data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits that this procedure will lead to is "*proper accounting for the location, size, and type of DER which will lead to more accurate study outcomes.*"

Generation

The largest change that will impact New England's generation fleet is ISO-NE's CARs.

Specifically, to better ensure power system reliability and cost efficiency as New England's resource mix evolves, ISO-NE is proposing a CAR that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms. This initiative has three primary components that would be in place for the Capacity Commitment Period (CCP) scheduled to start on June 1, 2028.

- Prompt auction: Instead of taking place three years in advance, the capacity auction would take place shortly before the CCP, reflecting more accurate information about projected electricity supply and demand.
- Seasonal CCP: The CCP changes from annual to sub-annual (seasonal) commitment periods to better address the distinct reliability challenges of winter and summer, as well as variations in resource performance from season to season.
- Accreditation reforms: Work began in 2022 via the former "Resource Capacity Accreditation in the Forward Capacity Market" project to identify and implement methodologies that will more accurately reflect resource contributions to resource adequacy in the capacity market. It is critical to the reliable and efficient clean-energy transition that the accreditation methodologies are updated to reflect resources' capabilities and how those capabilities contribute to resource adequacy. This work continues through CAR in the context of the proposed market constructs.

Energy Storage

New England currently has a total of 1,899 MW of energy storage capacity. This number includes about 39 MW of battery storage (BESS) and hybrid solar/battery storage. The largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,860 MW of quick-start 10-minute operating reserve capability, and with full reservoirs, and can deliver over 11,800 MWh of energy to the BPS.

Over the next five years (2025–2029), the nameplate capacity of energy storage devices (BESS, integrated-hybrid, and co-located-hybrid) are projected to increase significantly (Tier #1 [1,607 MW], Tier #2 [5,047 MW], and Tier #3 [4,955 MW]). No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase from the five-year projection. All the above capacity totals reflect summer seasonal claimed capability ratings.

Capacity Transfers

New England is interconnected with the three BAs of Québec, the Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to reduce the installed capacity requirement to meet the regional resource adequacy criterion. Assumed assistance from tie benefits ranges from 1,830 MW in 2025 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 1,248 MW in the summer of 2025 down to 465 MW in the summer of 2027. There is one long-term firm import contract of 84 MW that extends through the summers of 2028 through 2032. There are currently no firm imports projected for the summers of 2033 and 2034. In addition, there are no firm exports identified over the 10-year assessment.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs using IBRs, and changes to mandatory planning criteria promulgated by NERC, NPCC, and regional stakeholders have driven the need for longer-term transmission assessments.

The future reliable and economic performance of the BPS is expected to be maintained as a result of approximately $1.5 billion of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of IBR technologies, and issues rising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. Interregional import capability will also increase with the completion of the 1,200 MW HVdc New England Clean Energy Connect (NECEC) tie line between Québec and Maine, scheduled to be in service by the beginning of 2026.

In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. Transmission assessments and resultant plans are being developed throughout the region to meet these future system needs.

Reliability Issues

New England's BPS is transitioning to a system with unprecedented demand growth, due to electrification of heating and transportation, and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE is engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall BPS reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected in service dates for system upgrades due to supply chain issues. In these cases, ISO-NE develops operating plans to work around any issues caused by these delays. Additionally, the New England Transmission Owners have indicated that supply chain issues are causing a notable increase in project costs.

New England has already experienced constraints on electric energy production due to constraints on fuel infrastructure that have an impact on the power sector during winter. In response, ISO-NE has been a key player at the national level in promoting BPS reliability through sharing of lessons learned, best practices, and, more recently, through the performance of more detailed and in-depth BPS energy assessments. Additionally, to address winter energy security challenges, ISO-NE and regional stakeholders developed and put in place a two-year program to compensate certain resources that provide energy security during the winters of 2023–2024 and 2024–2025 (from December to February). ISO-NE's Inventoried Energy Program (IEP) is a voluntary program designed to provide incremental, winter-period compensation for participants that maintain inventoried energy for their assets during extreme cold periods when energy security is most stressed.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy—either through long-term energy storage solutions that can capture and store renewable power or through the use of dispatchable resources.

ISO-NE is actively working on numerous major projects to prepare for the clean energy transition and ensure continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

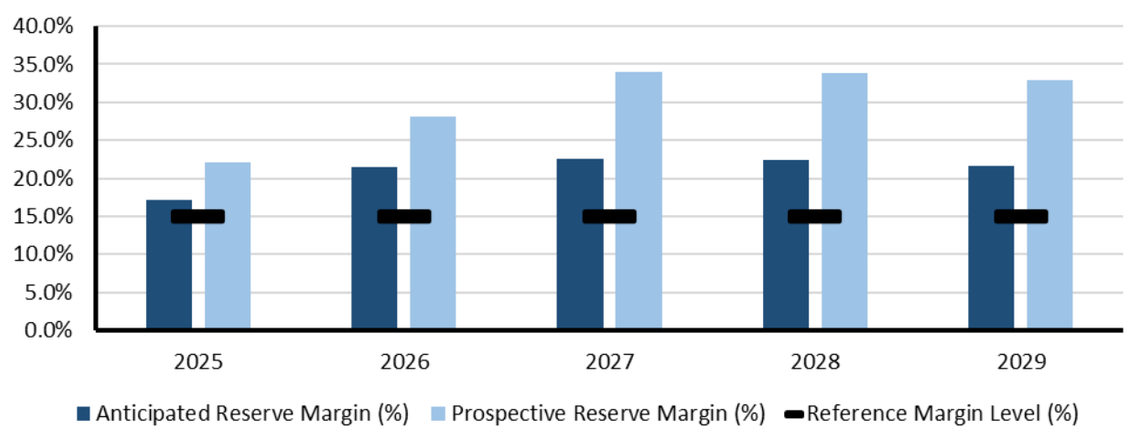
- **CAR Project**
- **Operational Impacts of Extreme Weather Events**
- **Regional Energy Shortfall Threshold**
- **Day-Ahead Ancillary Services Initiative**
- **Economic Planning for the Clean Energy Transition (EPCET)**
- **Extended-Term Transmission Planning Tariff Changes**
- **Longer-Term Transmission Studies**
- **Storage As Transmission Only Asset (SATOA)**
- **FERC Order No. 1920 Project**
- **FERC Order No. 2023 & 2023-A Project**
- **FERC Order No. 2222 Project**
- **FERC Order No. 881 Project**

NPCC-New York

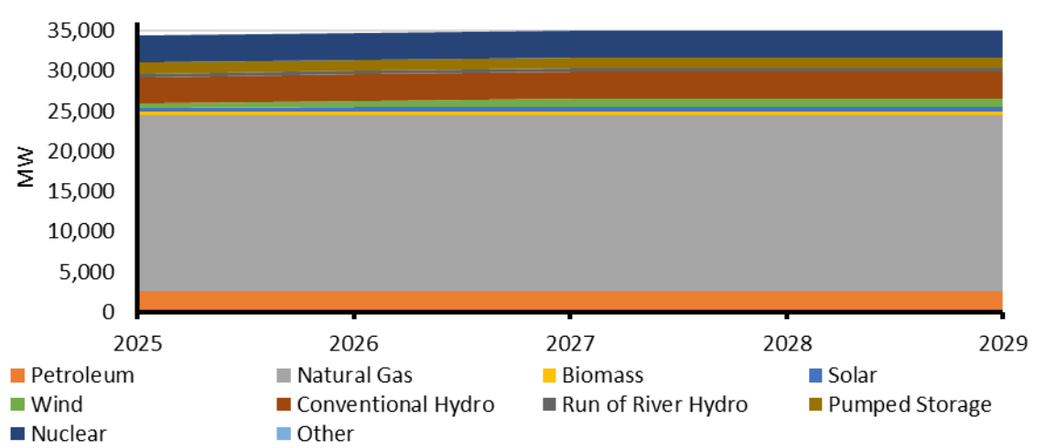
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	31,650	31,900	32,110	32,130	32,340	32,580	32,880	33,320	33,830	34,210
Demand Response	897	897	897	897	897	897	897	897	897	897
Net Internal Demand	30,754	31,004	31,214	31,234	31,444	31,684	31,984	32,424	32,934	33,314
Additions: Tier 1	495	858	1,144	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Additions: Tier 2	1,558	2,090	3,572	3,572	3,572	3,572	3,572	3,572	3,572	3,572
Additions: Tier 3	1,381	4,384	6,384	7,928	8,383	8,383	8,383	8,383	8,383	8,383
Net Firm Capacity Transfers	1,600	2,880	3,186	3,186	3,186	3,186	3,186	3,186	3,186	3,186
Existing-Certain and Net Firm Transfers	35,511	36,790	37,096	37,097	37,097	37,097	36,687	36,687	36,687	36,687
Anticipated Reserve Margin (%)	17.1%	21.4%	22.5%	22.4%	21.6%	20.7%	18.3%	16.7%	14.9%	13.6%
Prospective Reserve Margin (%)	22.1%	28.2%	34.0%	33.9%	33.0%	32.0%	29.5%	27.7%	25.7%	24.3%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Public policies, such as New York state's 2019 Climate Leadership and Community Protection Act (CLCPA), are driving rapid changes in New York's electric system, impacting how electricity is produced, transmitted, and consumed. The transition to a cleaner grid in New York is leading to an electric system that will be increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation.
- Recent assessments reveal that reliability margins are shrinking. Electrification programs are increasing the demand for electricity and placing New York on a trajectory to be a winter-peaking system in the future. Largely in response to public policies, fossil fuel generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience of the New York grid.
- NYISO's reliability studies identified actionable reliability needs starting 2025 in New York City. The reliability need is primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by state legislation and regulations promulgated by the New York State Department of Environmental Conversation, commonly known as the Peaker Rule,[36] to limit emissions. Following a solicitation for proposed solutions to the reliability need, NYISO retained several plants in New York City that would have otherwise been deactivated to comply with the Peaker Rule. NYISO's 2024 Reliability Needs Assessment (RNA), targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations.
- Driven by public polices, new supply, large loads, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest. Planning for new transmission to support offshore wind is underway in NYISO's Public Policy Transmission Planning Process.
- To achieve the mandates of the CLCPA, new dispatchable emission-free resources (DEFR) with the necessary reliability services will be needed to replace the capabilities and attributes of today's generation. These types of resources, which can achieve the necessary attributes by a combination of solutions, must be significant in capacity and have attributes similar to traditional generation plants, such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, provide ERSs, and adapt to meet rapid, steep ramping needs. Such new emission-free supply is not yet available on a commercial scale.
- New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition. Wholesale electricity markets are open to significant investment in wind, solar, and battery storage as well as distributed energy resources. Demand management programs are also under development as a measure to facilitate achievement of CLCPA targets. By lowering the peak load and avoiding system buildout to serve the highest demand hour, fewer DEFRs will be needed and fewer fossil fuel-fired plants will be needed to meet lower peaks during the transition.

[36] Subpart 227-3 of Title 6 of the New York Codes, Rules an3,323d Regulations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	2,631	2,631	2,631	2,631	2,631
Petroleum*	2,628	2,628	2,628	2,628	2,628
Natural Gas	21,907	21,907	21,907	21,907	21,907
Biomass	334	334	334	334	334
Solar	545	586	586	586	586
Wind	461	785	1,070	1,070	1,070
Conventional Hydro	3,323	3,323	3,323	3,323	3,323
Run of River Hydro	413	413	413	413	413
Pumped Storage	1,410	1,410	1,410	1,410	1,410
Nuclear	3,330	3,330	3,330	3,330	3,330
Battery	50	50	50	50	50
Total MW	34,405	34,769	35,054	35,054	35,054
Total MW*	34,401	34,765	35,051	35,051	35,051
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to NYISO are removed from the resource projection where marked.					

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% with the exception of year 9 (2033) and year 10 (2034). However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's 2024 Reliability Needs Assessment, which is underway and targets completion in Q4 2024, will likely identify reliability criteria violations.

NYISO also provides support to the NYSRC in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the NPCC and NYSRC resource adequacy criterion of "1 day in 10 years." The current IRM for the 2024–2025 capability year is 22% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 22%. Additionally, the NYISO performs an annual study to identify the locational minimum installed capacity requirements (LCR) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's CLCPA mandates to decarbonize span over all major industries and are a main driver for the electric system changes. NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments, including a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement and certain combined cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes as well as to determine annual IRM LCRs. NYISO also pursued capacity accreditation market rules to more accurately reflect capacity market suppliers' contributions to resource adequacy. These new market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The groundbreaking proposal was accepted by FERC in May 2022. The CAFs will reflect the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

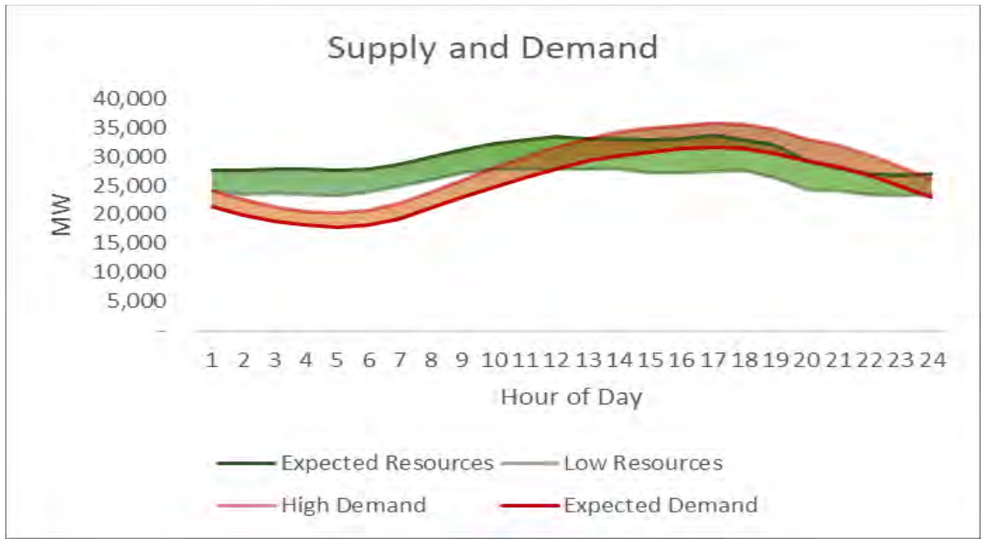
Additionally, NPCC provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2024 by NPCC are shown below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.06	1.91	1.30
EUE (PPM)	0.00	0.01	0.01
LOLH (hours per year)	0.00	0.01	0.01
Operable On-Peak Margin	16.7%	14.0%	15.0%

* Provides the 2022 ProbA Results for Comparison

Most load-loss and unserved energy risk is in the summer months of late June through August.

Hourly demand and resource projections for a typical summer risk day in 2026 are shown in the figure below. Although expected resource contribution is enough to meet expected demand, there is risk that above-normal peak demand could exceed resources. Demand could be 10–13% higher than expected, which could cause strain on the system from the hours beginning 2:00 p.m. through 11:00 p.m. Also, below-normal resource performance from unexpected generator outages or low-solar output could also cause supply shortfalls. If resource contributions are less than expected, strain on the system could be seen from hour beginning 12:00 p.m. through 12:00 a.m. on a typical peak day. Reliance on external assistance may be necessary in these events. A risk day in 2028 has a similar profile.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

NPCC's Directory 1 defines a compliance obligation for the NYISO, as a Resource Planner and Planning Coordinator, to perform a resource adequacy study evaluating a five-year planning horizon. NYISO delivers a report every year under this study process to verify the system against the 1-day-in-10-years LOLE criterion, which is usually based on NYISO's latest available reliability assessment results and assumptions. NYSRC Reliability Rules have recently included a requirement defining NYISO's obligation to deliver a Long-Term Resource Adequacy Assessment Report every year during which the NYISO publishes a Reliability Needs Assessment (RNA) and an annual update in the intervening year between RNAs.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as EV charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, policy scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+0.8%) growth rates are higher than last year's forecast. Increases in growth rates relative to the prior forecast are primarily attributed to the significant impacts of interconnecting large load projects. Baseline energy and coincident peak demand increase significantly throughout the 30-year forecast period, driven largely by large load project growth in the early forecast years and electrification of space heating, non-weather sensitive appliances, and EV charging in the outer forecast years. New York is projected to become winter-peaking in future decades due to space heating electrification and EV penetration. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO is working on developing market concepts to encourage the participation of flexible load, which will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy policies. Many of New

York's utilities are piloting several load management programs (e.g., smart EV charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

DR participation for the summer capability period has increased slightly from 1,234 MW to 1,281 MW since the *2023 LTRA*. There are currently 425 MW of DR participating in ancillary services programs and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

NYISO has implemented in 2024 a plan to integrate DERs, including DR resources, into the markets it administers. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

The pace of renewable project development and existing generation retirement is unprecedented and driving a need to increase the pace of transmission expansion, clean dispatchable generation, and demand management programs development. In general, resource and transmission expansion take many years from development to deployment. Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. Significant new resource development will be required to achieve energy targets under the CLCPA. The total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply. The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unparalleled.

Currently, NYISO's interconnection process contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

For the 2024 RNA, gas availability is derated during winter to further account for cold weather risks.

To achieve the CLCPA mandate of an emission-free grid by 2040, DEFRs must be developed and deployed throughout New York. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially available today.

ERSs usually provided to the system by synchronous fossil generation will continue to be necessary. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation. In May 2023, the New York State Public Service Commission (PSC) initiated a process to examine the need for resources to ensure the reliability of the CLCPA mandate for a zero-emissions electric grid by 2040. The PSC seeks to identify innovative technologies to ensure the reliability of a zero-emissions electric grid. Numerous other initiatives at both state and federal levels are in progress and may impact the grid of the future.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is developing a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resources models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with the neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO employs limiting emergency assistance from neighbors by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighbors.

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring grids. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring states will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City
- The AC Public Policy Transmission Projects that consist of upgrading transmission corridors in central New York and the lower Hudson Valley, which projects target completion of the majority of the components by December 2023
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new dc tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emissions-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

The 2024 RNA, targeting completion in the fourth quarter of 2024, identifies transmission security violations of reliability criteria primarily driven by a combination of forecasted increases in peak demand, limited additional supply, and the assumed retirement of generation in New York City in response to state law and regulations. Accounting for these factors, the planned bulk power transmission system will not be able to securely and reliability serve the forecasted demand in New York City. When accounting for forecasted economic growth and policy-driven increases in demand, the New York City (Zone J) will be deficient starting in summer 2033 by as much as 17 MW for 1 hour and increasing to 97 MW for 3 hours in summer 2034 on the peak day during expected weather conditions. The Reliability Need occurs within the transmission district owned by Consolidated Edison Company of New York, Inc. ("Con Edison"). Con Edison is designated as the Responsible Transmission Owner in the NYISO's transmission planning process and required to submit a regulated backstop solution to address the need, which may be triggered if sufficient market-based solutions do not materialize.

Prior to the 2024 RNA, the NYISO completed the 2023 Q2 STAR on July 14, 2023. This assessment found a reliability need beginning in summer 2025 in New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the New York Department of Environmental Conservation (DEC) Peaker Rule. The reliability need is a deficiency in the transmission security margin. Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions (95 degrees Fahrenheit) when accounting for forecasted economic growth and policy-driven increases in demand. To ensure the continued reliability of electric service in New York City, NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as necessary for reliability to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the need are in place, for an initial period of up to two years (May 1, 2027).

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The

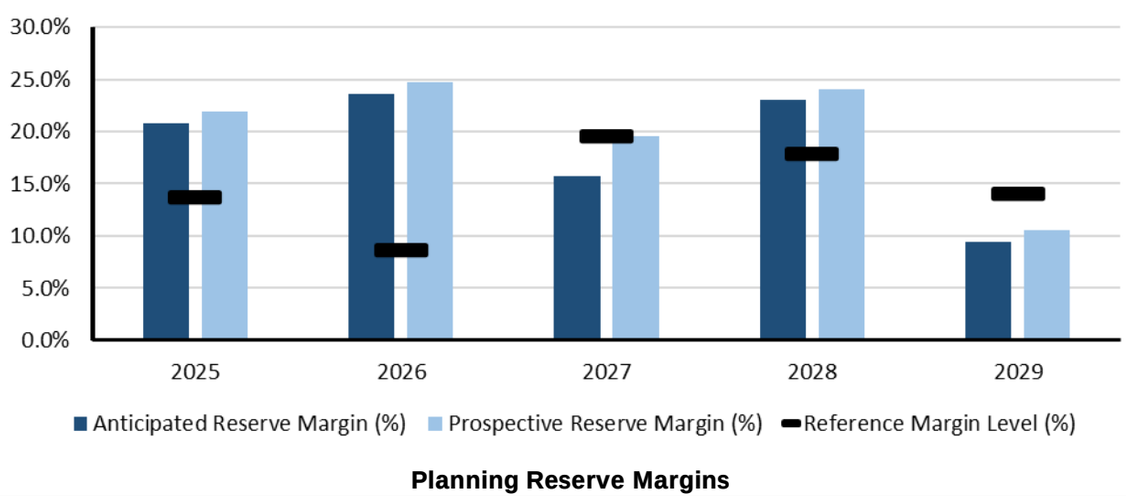
system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

NPCC-Ontario

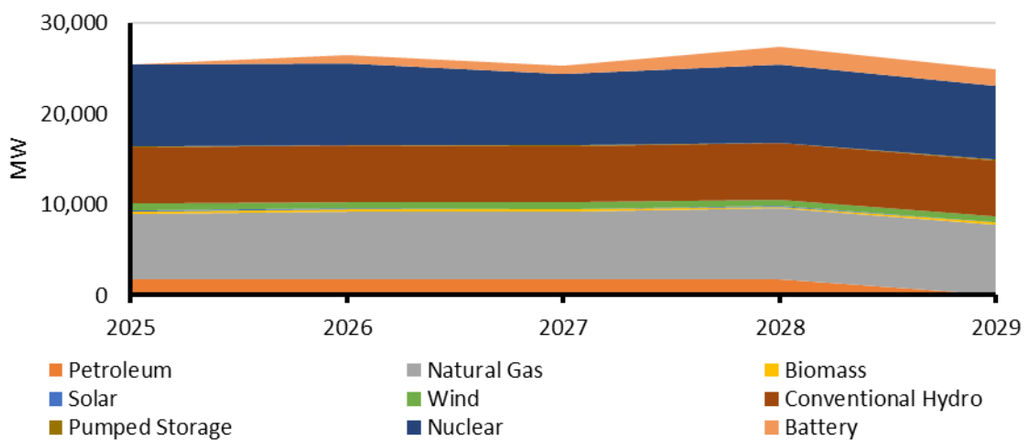
NPCC-Ontario is an assessment area in the Ontario province of Canada. The IESO is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	23,385	23,860	24,264	24,627	25,248	26,038	26,473	27,373	27,974	28,789
Demand Response	1,791	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914	1,914
Net Internal Demand	21,594	21,946	22,350	22,713	23,333	24,123	24,559	25,458	26,060	26,875
Additions: Tier 1	617	1,737	1,735	3,012	3,302	3,300	3,843	4,385	4,384	5,128
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	600	600	500	600	600	600	600	0	0	0
Existing-Certain and Net Firm Transfers	25,470	25,394	24,133	24,924	22,242	22,051	20,660	20,705	20,671	20,257
Anticipated Reserve Margin (%)	20.8%	23.6%	15.7%	23.0%	9.5%	5.1%	-0.2%	-1.4%	-3.9%	-5.5%
Prospective Reserve Margin (%)	22.0%	24.8%	19.5%	24.1%	10.5%	6.1%	0.8%	-0.5%	-2.9%	-4.6%
Reference Margin Level (%)	13.7%	8.6%	19.5%	17.8%	14.1%	9.4%	17.2%	8.1%	6.8%	8.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- While potential reserve margin shortfalls are forecast for 2027 and 2029, they are mainly driven by changes in the IESO's resource adequacy assessment methodology since the *2023 LTRA*. Last year, reserve margin calculations included the continuation of existing resources (following contract expiry) for the entire outlook period. For this LTRA, reserve margins reflect the contribution of existing resources only until the end of their contract or commitment period. This change to the methodology is more conservative and helps to better identify system needs in the IESO's planning assessments to establish resource acquisition targets and address anticipated needs.
- The IESO has two capacity sharing agreements with Hydro-Québec providing firm summer capacity, which will help to address future shortfalls this decade.
- The IESO has completed a broad set of actions to secure new capacity for this decade to ensure that Ontario's power system needs are met during a period of nuclear retirements and refurbishments and economy-wide demand growth. This includes securing long-term commitments amounting to 2,195 MW of new capacity to be on-line by 2028, with early operation incentives anticipated to bring a portion on-line as early as 2027 to help alleviate the reserve margin gap.
- The annual capacity auction, which helps to meet needs in the short term by securing capacity for up to one year at a time, has historically secured more capacity than targeted. Trends suggest that this should continue, as the November 2024 auction (which will help to ensure reliability through summer 2025 and winter 2025–2026) also secured more capacity than targeted.
- The IESO is taking steps that will address future shortfalls around the end of this decade and heading into the 2030s. The next round of medium- and long-term procurements was recently launched to ensure that capacity and energy needs continue to be met. The second medium-term procurement aims to re-commit existing resources with contracts expiring over the 2026–2029 period, while the second long-term procurement aims to secure capacity and energy from new resources (to be online as early as 2029), to meet needs emerging in the early 2030s.
- The IESO is also responsible for implementing new provincial policy as outlined in the Ontario government's July 2023 Powering Ontario's Growth report, which includes developing new nuclear projects, transmission expansions, and expanded conservation and demand management programs. The IESO will also incorporate changes stemming from the federal release of the final Clean Electricity Regulations, anticipated toward the end of 2024.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Petroleum	1,695	1,695	1,695	1,695	5
Natural Gas	7,275	7,465	7,465	7,847	7,761
Biomass	297	294	257	209	209
Solar	100	100	100	100	100
Wind	743	722	711	711	602
Conventional Hydro	6,215	6,212	6,212	6,212	6,202
Pumped Storage	38	38	38	38	38
Nuclear	9,008	9,008	7,895	8,639	8,142
Battery	118	998	996	1,886	1,885
Total MW	25,487	26,531	25,368	27,336	24,944

Planning Reserve Margins

The ARM falls below the RML starting in 2027. While expected nuclear retirements, the ongoing nuclear refurbishment program, and demand growth are resulting in increased needs this decade, the reserve margin shortfalls indicated in 2027 and 2029 are primarily driven by the change in the IESO's resource adequacy assessment methodology described above.

Mid-decade capacity needs that were identified in the 2022 *Annual Acquisition Report* have been met through a series of competitive procurements. Since May 2023, the IESO has secured over 3,600 MW of new capacity from battery storage, natural gas, and biogas facilities, expected to come on-line between 2025 and 2028. In addition, the 2023 capacity auction secured 1,867 MW of summer capacity and 1,311 MW of winter capacity above targets of 1,400 and 850 MW, respectively. The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

Ongoing refurbishments at Bruce Nuclear Generating Station (NGS) and Darlington NGS will see between one and three reactors concurrently off-line through Summer 2033. Refurbishments remain on or ahead of schedule and outages continue to be managed to limit impacts to the grid. Following the return to service of refurbished units at Bruce, each unit is expected to be uprated, with the additional capacity anticipated to be available in the early 2030s.

The Ontario government has also announced a plan to deliver three additional small modular reactors in addition to the 300 MW unit already underway (anticipated on-line in 2029). The provincial government's July 2023 Powering Ontario's Growth plan directed the IESO to conduct an impact assessment on potentially adding 4,800 MW of large-scale nuclear capacity to Bruce NGS. Approval was granted from the federal nuclear regulator in October 2024 to extend operation of four units at Pickering NGS (previously scheduled for decommissioning in 2025) through September 2026. The government is also supporting the refurbishment of the four units at Pickering, with refurbishment of the first unit anticipated to be completed in 2031.

To address resource adequacy needs emerging mid-decade due to the combined effect of nuclear retirements and refurbishments, as well as expiring generation contracts, the IESO has employed competitive acquisition mechanisms from the Resource Adequacy Framework in part via the capacity auction referenced above. The IESO's first long-term procurement concluded in May 2024 and secured long-term commitments from 10 battery storage facilities for 1,784 MW of new capacity and three natural gas/biogas facilities for 411 MW of new capacity. Facilities are anticipated to be in service as early as May 2027.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide an LOLE that is at or below 0.1 days per year. The reserve margin requirement in the *2024 LTRA* is derived from the capacity requirement in the 2024 APO, plus any material changes to demand and supply following APO publication.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy adequacy assessments are conducted annually for the APO by using a deterministic approach in the IESO's economic dispatch model. In addition, the IESO's capacity adequacy assessments consider the system's ability to serve load in all hours of the year (i.e., during peak hours as well as non-peak load hours).

As demand requirements increase, nuclear refurbishments continue, and some units at the Pickering NGS retire in 2024, Ontario's energy needs are expected to be met this decade by the resources secured through the IESO's recently completed procurements. The second medium-term procurement, which was recently launched, aims to secure capacity and energy from existing resources reaching contract end; this is expected to help alleviate energy risks in the latter half of this decade. The second long-term procurement that is underway aims to acquire new capacity and energy-producing resources and is anticipated to alleviate energy risks in the early 2030s.

Factors that could increase energy adequacy risks include aging resources and the potential for decreased performance, market exit of resources reaching contract end, extreme weather, and decarbonization policies and risks presented by new resources, including in-service delays or a high risk of forced outages during the initial period of operation. Deliverability challenges for new resources and long lead times required to build new transmission may also increase energy adequacy risks. Demand-side factors include materialization of data centers, increased industrial automobile production and EV supply chain loads, and climate change impacts on weather-sensitive load.

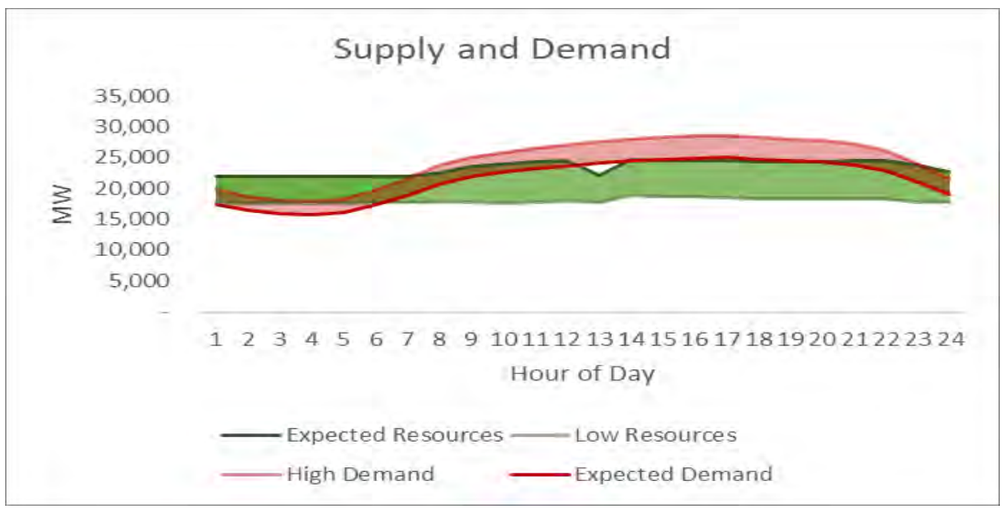
Looking forward, with the federal government's proposed Clean Electricity Regulations to decarbonize Canada's electric system by 2050, the IESO is assessing the role of natural gas generation as a flexible resource in the interim as new sources of non-emitting supply are added to the system.

The IESO conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and to comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table on the next page. The low risk of unserved energy is concentrated in the summer peak period, which typically occurs in late August.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	72.16	**0.04**	**4.97**
EUE (PPM)	0.49	**0.00**	**0.03**
LOLH (hours per year)	0.44	**0.00**	**0.01**
Operable On-Peak Margin	-6.7%	**13.3%**	**9.5%**

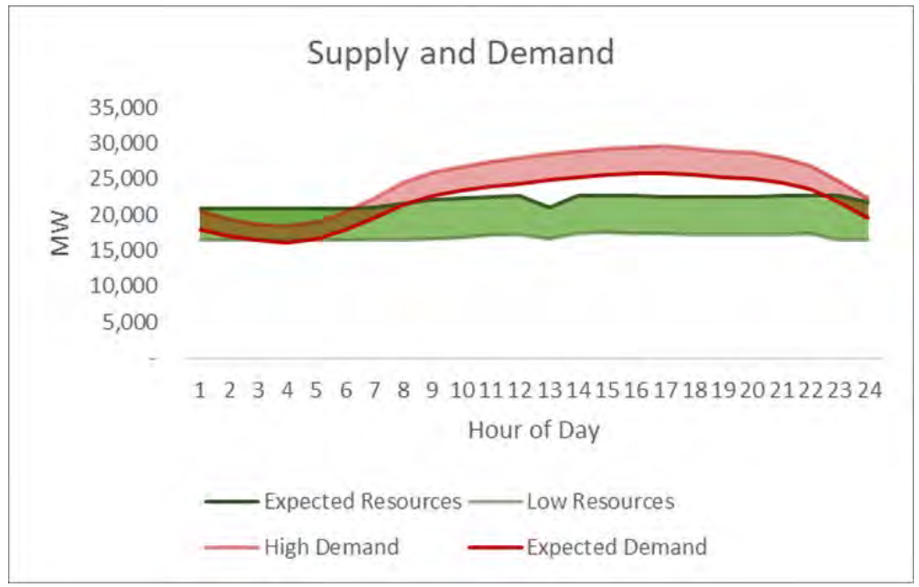
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a representative summer risk-day in 2026 are shown in the figure below. Expected resource contributions are not sufficient to meet expected demand on the risk day. The risk could be exacerbated by either a lower-than-expected resource contribution event or a higher-than-expected demand event, with greater risk being due to a larger variability in resource contribution. There is expected strain on the system from the hours beginning 12:00 p.m. through 8:00 p.m. If resource contributions are less than expected, strain on the system at expected demand conditions could be seen for almost all hours of the day beginning at 7:00 a.m. Reliance on external assistance may be necessary during peak conditions.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2026

In 2028, the EUE and LOLH are higher than 2026. Risk occurs during the same summer peak period but also during winter peak conditions in December. Demand growth that is forecasted to occur between 2026 and 2028 contributes to higher loss-of-load risk compared to the 2026 result. The risk day in 2028 has the same drivers as the 2026 result noted above.



Hourly Probabilistic Assessment Results | Representative Summer Risk Day 2028

Demand

Forecasted demand for this *2024 LTRA* outlook period (relative to the *2023 LTRA* outlook period) indicates 10% higher annual energy demand, 8% higher summer peak demand, and 9% higher winter peak demand.

With an expanding agricultural and greenhouse sector, along with increasing electricity use for home heating and transportation, summer and winter peaks are anticipated to converge over the forecast period, leading Ontario to be dual-peaking by 2030. In the near term, the peak magnitude is expected to increase slightly as the province exits the remnants of the post-pandemic inflationary cycle, and new industrial projects supporting decarbonization begin commercial operation. Over this assessment period, the IESO projects total internal demand growth to increase at a compound annual growth rate of 2.34% for summer and 2.75% for winter. Offsetting the growth in demand are reductions from conservation, including savings from EE programs and codes and standards regulations, electricity price responsiveness and increased output by embedded generation.

Ontario's Industrial Conservation Initiative (ICI) acts as a critical peak pricing program leading to reductions in demand at peak and is expected to reduce around 1,500 MW if the hour of annual system peak demand occurs in the summer or around 1,000 MW if it occurs in the winter. It is expected to scale based on increased industrial growth in future years, with reductions in 2034 of 2,000 MW for a summer peak demand hour and over 1,400 MW for a winter peak demand hour.

Demand-Side Management

DR capacity, from both dispatchable loads and hourly DR resources (e.g., residential or commercial and industrial load), is procured through the IESO's annual capacity auction. Starting with the 2023 capacity auction, the IESO implemented a capacity qualification process for all resource types eligible to participate, which applies resource-specific calculation methodologies to determine the amount of unforced capacity (UCAP) each resource is eligible to offer into the auction.

In June 2023, the IESO launched Peak Perks, a residential DR program where participants help reduce demand by up to 150 MW through brief, time-limited thermostat adjustments during periods of peak electricity demand in the summer months.

In July 2023, the IESO launched an interruptible rate pilot to provide large-load customers with an interruptible rate in exchange for agreeing to temporarily reduce demand when directed by the IESO. The pilot spans a three-year period and up to 15 events of up to four-hour duration can be called, primarily in the day-ahead timeframe but also on shorter notice.

Forecast savings from the IESO's 2021–2024 Conservation and Demand Management Framework were included in the forecast and resulted in a decrease in demand. Savings from the 2021–2024 CDM framework are expected to persist beyond the end of 2024. In February 2024, Ontario's minister of energy asked the IESO to examine options and analysis for a post-2024 EE framework and programs.

Distributed Energy Resources

The IESO estimates that contracted DERs contributed more than 3,400 MW of capacity and 5.3 TWh of energy in 2023, more than half of which is solar PV, one-third wind, and modest contributions from hydroelectric and biomass resources. While the IESO has little insight into uncontracted DERs, it has observed energy contributions of approximately 2 TWh in 2023.

Generation

Recent generation procurements are provided in the PRM section.

The transmission-connected supply mix in Ontario has shifted over the past decade from having only synchronous generation facilities to one with more IBRs including wind, solar, and storage. Previous assessments performed by the IESO indicate that Ontario is expected to have sufficient inertia and frequency response to ensure stable operation up to 2025.

Going forward, the addition of over 2,900 MW of new battery storage resources in the next few years will increase the proportion of IBRs on the system. With the shift toward a higher proportion of IBRs, further areas that will be explored include the sufficiency of the resource mix to provide system inertia, primary frequency response, operating reserve, ramping capability, reactive support, and voltage control. If needs are identified, the IESO's procurements may be used as one avenue to acquire resources that can provide the required services.

The IESO has also been taking a proactive approach to dealing with challenges posed by IBRs. This includes working to optimize the location of IBR resources acquired through the IESO's procurements to minimize performance issues and initiating a review of the IESO's Market Rules to align with the latest IEEE 2800 standard, which aims to establish uniform technical minimum requirements for interconnection, capability, and lifetime performance of IBRs.

Energy Storage

By May 2028, over 2,900 MW of new battery storage resources are expected to come on-line, including the 250 MW/1,000 MWh Oneida battery storage facility (expected to be operational in June 2025), and 2,714 MW of battery storage resources secured through the IESO's first set of long-term procurements. Of this, 930 MW is expected to reach commercial operation by May 2026 and the remaining 1,784 MW by May 2028. These standalone battery storage resources (with a minimum four-hour duration) are expected to support the reliable operation of Ontario's electric system through the ability to be dispatched by the IESO and ramp up and down quickly. The resources are also located in areas of Ontario where transmission security or resource adequacy needs were identified.

Newly acquired energy storage facilities through the IESO's first set of long-term procurements will be required to be available during peak hours.

Capacity Transfers

Firm capacity imports and exports with neighboring jurisdictions are included in the IESO's planning studies. For non-firm imports, the IESO assumes a limited amount for the purposes of its reliability assessments. Non-firm imports are assumed to be 250 MW for summer and 240 MW for winter, an amount considered likely to flow throughout the year, including under tight supply conditions and prices.

In November 2024, the IESO and Hydro-Québec finalized a new capacity sharing agreement for a swap of a minimum of 600 MW of capacity per season. Under this agreement, the IESO will deliver capacity

to Québec during the winter period and Hydro-Québec will deliver capacity to Ontario during the summer period. The agreement commences in the Winter 2024–2025 season and runs to October 2031, with an option for an extension for an additional three years. Other terms of the agreement are expected to include the option for the IESO to increase the minimum amount provided to Québec each year and to bank any amount of the 600 MW from Québec for use in a future summer period over the term of the agreement.

The 2023 capacity auction secured 300 MW of system-backed imports from Québec for the Summer 2024 obligation period. As part of the 2016 capacity sharing agreement between Ontario and Québec, the IESO may call on a total of 500 MW of firm imports from Hydro-Québec, which may be requested all in one summer or in smaller amounts over multiple summers. The IESO's recent assessments indicate the intention to utilize the 500 MW of firm imports from June to September 2027 to help meet resource adequacy needs. However, depending on the outcomes of the ongoing procurements and changes to Ontario's resource adequacy outlook, the IESO may choose to utilize this capacity in another year.

Transmission

The existing transmission system in northeastern Ontario has insufficient capability to reliably supply forecasted load growth; as such, the IESO has recommended several new transmission reinforcements in the region to address this need. Several of the recommended reinforcements are in the early project development stage and one is undergoing a transmitter selection process.

The IESO recently recommended additional transmission reinforcements in southwest Ontario to support the area's medium-term needs, including a double circuit, 230 kV line from Lambton transmission station to Chatham substation, expected in-service by 2028, and a new 500 kV transmission line connecting Longwood and Lakeshore transmission stations, to be in-service by 2030. These projects will ensure that transfer capability continues to be sufficient as additional load continues to connect in the area.

Reliability Issues

Nuclear refurbishment over the next decade is a major resource risk that requires additional attention. The IESO has regular meetings with nuclear operators to assess probable delays and take appropriate mitigation actions.

For long-term planning purposes, the IESO carries an additional level of nuclear refurbishment reserve to account for the risk of refurbishment delays and increased forced outage rates pre- and post-refurbishment. In addition, advanced outage approvals are provided solely when Ontario is adequate under extreme weather.

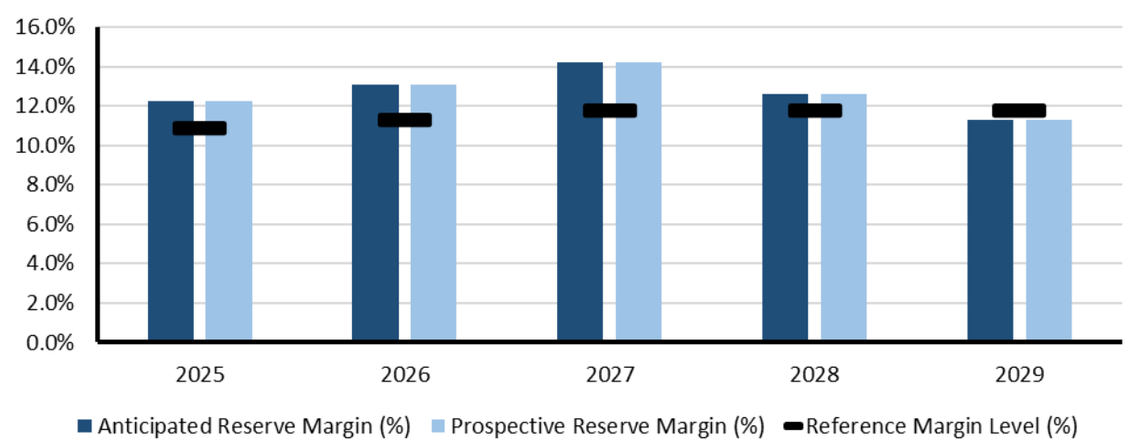
Other factors that may pose reliability risks include supply chain issues, conditions in neighboring jurisdictions, extreme weather, decarbonization-driven changes to supply and demand, policy and regulatory uncertainty, asset health, and potential market exit of existing resources.

NPCC-Québec

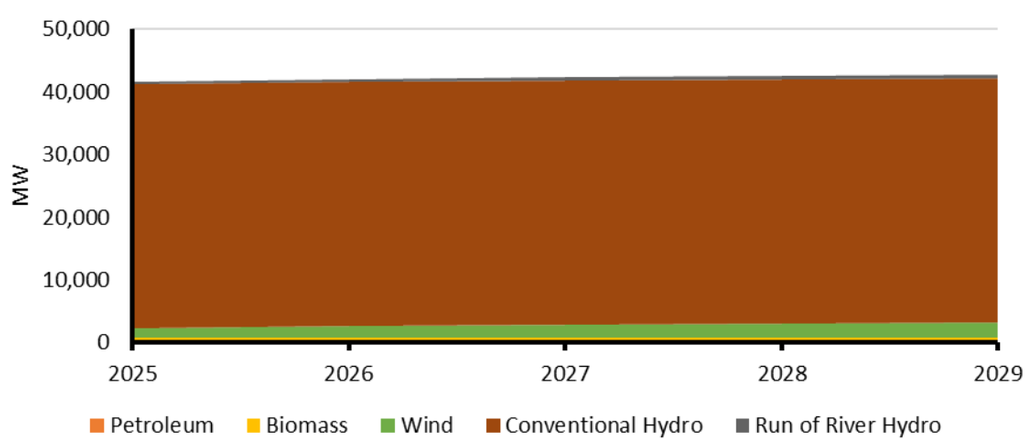
The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of 8.5 million. Québec is one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes. These ties consist of either HVdc ties, radial generation, or load to and from neighboring systems.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	41,497	41,954	42,476	43,385	44,070	44,784	45,577	46,635	47,828	49,041
Demand Response	4,732	4,896	5,068	5,258	5,322	5,377	5,388	5,388	5,388	5,388
Net Internal Demand	36,765	37,058	37,408	38,127	38,748	39,408	40,189	41,247	42,440	43,652
Additions: Tier 1	73	469	665	835	1,016	1,016	1,016	1,016	1,016	1,016
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-390	-145	455	455	455	600	0	0	0	0
Existing-Certain and Net Firm Transfers	41,185	41,429	42,066	42,103	42,103	42,256	41,656	41,656	41,656	41,656
Anticipated Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Prospective Reserve Margin (%)	12.2%	13.1%	14.2%	12.6%	11.3%	9.8%	6.2%	3.5%	0.5%	-2.2%
Reference Margin Level (%)	10.9%	11.3%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM and PRM remain above the RML until 2029 (winter 2029–3030).
- A total of 4,048 MW wind generation capacity (1,016 MW capacity value at peak time) is expected to be in service by 2030.
- Two new transmission projects connecting Québec with New England and New York are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Petroleum	429	429	429	429	429
Biomass	400	400	400	400	400
Wind	1,449	1,807	2,002	2,173	2,354
Conventional Hydro	38,925	38,962	38,999	39,036	39,036
Run of River Hydro	446	446	446	446	446
Total MW	41,648	42,043	42,276	42,483	42,664

NPCC-Québec Assessment

Planning Reserve Margins

The ARM is based on existing and anticipated generating capacity and firm capacity transfers. The Québec area projects an ARM above the RML over the first five winters of the assessment period (2024–2025 to 2028–2029). The ARM is under the RML for the winters 2029–2030 to 2034–2035 mainly due to the demand growth.

The RML is derived from the NPCC 2023 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on December 5, 2023. The demand uncertainty captured in the reserve ratio reflects both weather and economic uncertainty. The methods and assumptions can be found in the *Comprehensive Review* report available on the NPCC website.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2023 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2023.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

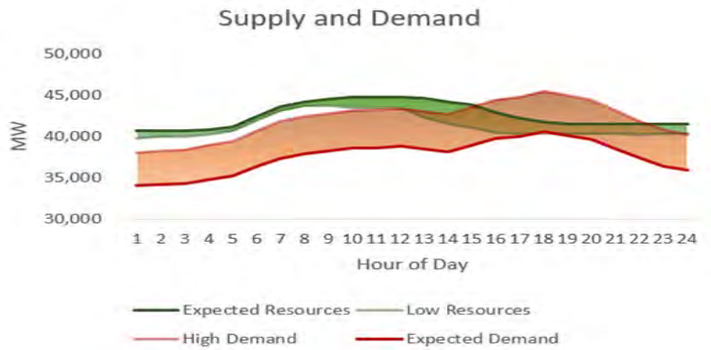
The main energy risk for the Québec area is associated with a series of dry years, hence the energy reliability criterion established by the Régie de l'énergie. This risk surpasses the energy risk associated with the other renewable resources over the horizon of this study. The potential impact of climate change on the water inflows could be an issue for energy reliability and is therefore the subject of various ongoing internal studies.

Hydro-Québec conducts probabilistic resource adequacy assessments annually in conjunction with NPCC to identify regional capacity resource needs and comply with NPCC and NERC reliability requirements. Results from the 2024 ProbA are shown in the table below. The low risk of unserved energy is concentrated in the winter peak period, which typically occurs in late January to early February.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**8.21**	**4.97**
EUE (PPM)	0.00	**0.04**	**0.03**
LOLH (hours per year)	0.00	**0.01**	**0.01**
Operable On-Peak Margin	-2.3%	**9.8%**	**11.9%**

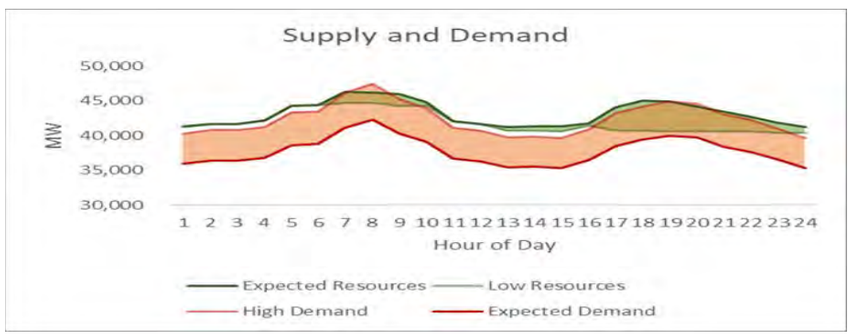
* Provides the 2022 ProbA Results for Comparison

Hourly demand and resource projections for a typical winter risk day in 2026 are shown in the figure below. Although expected resource contribution is expected to be enough to meet expected demand, there is risk that above-normal demand could exceed resources. Demand could be 10–15% higher than expected, which could strain the system from the hours beginning 3:00 p.m. through 10:00 p.m. Also, if resource contributions are less than expected, the peak hour beginning at 6:00 p.m. could lead to a loss-of-load situation. Reliance on external assistance may be necessary in these events.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Hourly demand and resource projections for a typical winter risk day in 2028 are shown in the figure below.



Hourly Probabilistic Assessment Results | Representative Winter Risk Day 2026

Demand

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand.

Demand-Side Management

The Québec area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2,784 MW on winter 2024–2025 peak demand. The area is also expanding its existing interruptible load program for commercial buildings, which will grow from 611 MW in 2024–2025 to 889 MW by the end of the period study. Another similar program for residential customers is in operation and should gradually rise from 166 MW for Winter 2024–2025 to 621 MW for Winter 2028–2029.

New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 371 MW for Winter 2024–2025 and 445 MW for Winter 2034–2035. Moreover, data centers specializing in blockchain applications are required to reduce their demand during peak hours at Hydro-Québec's request. Their contribution as a resource is expected to be around 269 MW over the study period. Finally, another DR resource consists in a voltage reduction scheme allowing for a 250 MW peak demand reduction. EE and conservation programs are integrated in the assessment area's demand forecasts.

Distributed Energy Resources

Total installed BTM capacity (solar PV) is expected to increase to 862 MW in 2035. Solar PV is accounted for in the load forecast. Nevertheless, since Québec is a winter-peaking area, DERs' on-peak contribution ranges from 2 MW for Winter 2024–2025 to 5 MW for the last winter period. No potential operational impacts of DERs are expected in the Québec area considering their low contribution.

Generation

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned in 2024–2025. The second project (1,144 MW divided into 6 wind farms) is expected to be commissioned in December 2026. The third project is Des Neiges (1,200 MW) and is divided into three phases (400 MW each). The first phase is expected to be operational in the winter of 2026–2027. The second and third phases are expected to be in service for the 2027–2028 and 2028–2029 winters, respectively. The fourth project is made of 1,500 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027–2028, 2028–2029 and 2029–2030, depending on the location.

In addition to wind projects, unit replacement projects at existing hydroelectric facilities are being studied. Up to 2,000 MW of capacity could be added by replacing generating units with most recent models, as outlined in Hydro-Québec's Action Plan 2035.

Energy Storage

No energy storage facilities are planned to be commissioned during the assessment period.

Capacity Transfers

The governments of Québec and Ontario have signed an MOU of an agreement that allows a seasonal capacity exchange between the two areas for the next seven years except for the year 2027 (no exchange is allowed). The technical details of the agreement will be completed by Fall 2024 and will be in place from Winter 2024–2025 to winter 2030–2031. This agreement will be firm and allow Québec to import 600 MW from November to April. In summer, Québec will export 600 MW of firm capacity to Ontario from May to October.

Transmission

Appalaches-Maine Interconnection

This project, expected to increase transfer capability between Québec and Maine by 1,200 MW, has resumed construction. The project will connect to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320 kV dc transmission line about 100 kilometers (62 miles) long from the Des Appalaches 735/230 kV substation to the Canada-United States. border. From the international border crossing, the dc transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from dc to ac. The project in Québec also includes the construction of an dc to dc converter at the Des Appalaches substation and triggers the need of thermally upgrade two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

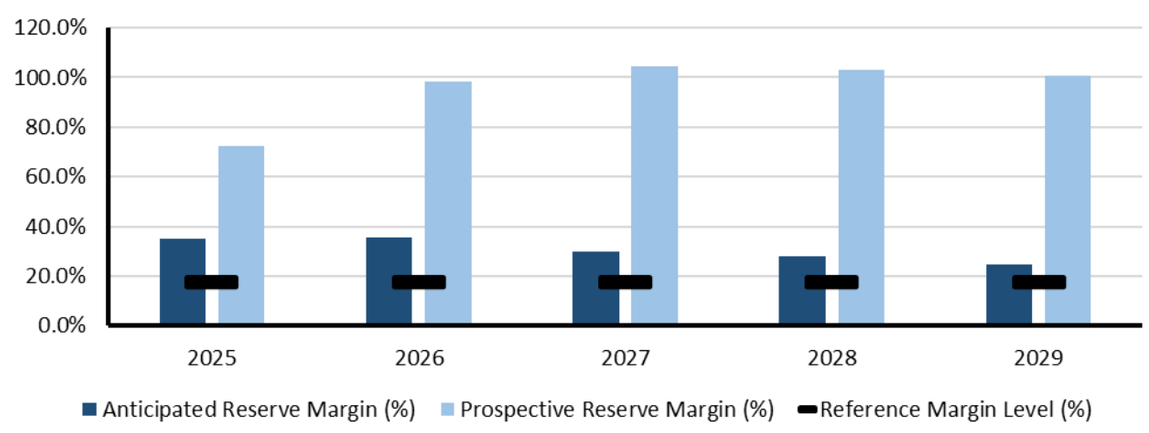
This project, expected to increase transfer capability between Québec and New York by 1,250 MW, is under construction. It involves the construction of a ±400 kV dc underground transmission line about 60 kilometers (37 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada-United States border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York state. From the international border crossing, the dc transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from dc to ac. The project in Québec also includes the construction of an ac to dc converter at the Hertel substation. The project is expected to be in service in May 2026.

PJM

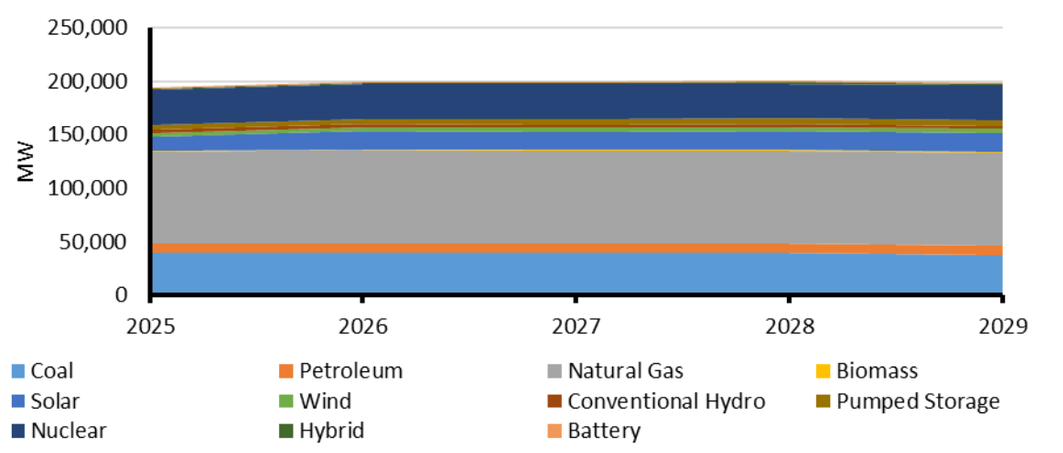
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822
Demand Response	7,554	7,693	7,808	7,913	8,000	8,083	8,162	8,230	8,312	8,400
Net Internal Demand	145,939	149,110	152,051	155,059	157,681	159,790	161,846	163,879	166,054	168,422
Additions: Tier 1	11,056	17,047	17,139	17,784	17,911	18,155	18,155	18,155	18,155	18,155
Additions: Tier 2	55,112	93,845	112,827	122,781	127,059	131,113	131,287	133,652	133,652	133,652
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	4,502	4,347	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	185,828	185,270	180,552	180,552	178,577	178,577	178,577	178,577	178,577	178,577
Anticipated Reserve Margin (%)	34.9%	35.7%	30.0%	27.9%	24.6%	23.1%	21.6%	20.0%	18.5%	16.8%
Prospective Reserve Margin (%)	72.4%	98.3%	104.7%	103.3%	100.5%	96.5%	94.1%	92.9%	82.1%	79.5%
Reference Margin Level (%)	17.7%	17.7%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2034 when it falls below the 17.6% RML level.
- PJM implemented a number of changes to the 2023 load forecasting process to improve model accuracy, switching from an annual to monthly end-use model for PJM's sector models to better determine heating, cooling, and other non-weather-sensitive load and moving to an hourly model to better capture new technologies and peak shifting. Additionally, higher expectations for data center loads now incorporate 15-year forecasts from impacted electric distribution companies (EDC).
- PJM's review of recent policies (e.g., state laws and federal environmental initiatives) indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by these state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Conversely, there are multiple mandates with renewable portfolio standards (RPS) that account for the majority of over 150 GWs submitted projects.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	39,735	39,735	39,325	39,325	37,747
Coal*	39,394	39,394	33,313	28,240	25,124
Petroleum	8,810	8,514	8,514	8,514	8,117
Natural Gas	85,541	87,245	87,245	87,245	87,245
Natural Gas*	85,541	87,245	87,228	87,228	87,228
Biomass	928	928	928	928	928
Solar	13,349	16,770	16,908	17,621	17,754
Wind	3,017	3,512	3,507	3,507	3,507
Conventional Hydro	2,934	2,922	2,934	2,934	2,944
Pumped Storage	5,189	5,189	5,189	5,189	5,189
Nuclear	32,535	32,535	32,535	32,535	32,535
Hybrid	1,315	1,742	1,739	1,739	1,739
Battery	393	982	982	994	994
Total MW	193,747	200,074	199,807	200,532	198,699
Total MW*	193,406	199,733	193,779	189,430	186,060
*** Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins

The ARM does not fall below the RML in PJM until 2034. PJM's growing demand profile and a change in resource mix that favors VERs, however, present a new level of risk.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

PJM is forecasting around 30% installed reserves (including expected committed demand resources), which is well above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. Due to the current low penetration of energy-limited and VERs in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand. To address future reliability concerns due to growing VER penetration and limitations associated with the performance of those resources, PJM's Effective Load Carrying Capability methodology calculates the reliability and energy contribution of limited and variable resources.

Some of PJM's assumptions for determining the resource mix to use in the ProbA differ from those used in developing the LTRA. Only a portion of the Tier 1 resource additions are used in the ProbA to more accurately reflect historical rates of development. Additionally, more generator retirements are used in the ProbA based on PJM's generator forecasting. These assumptions are more consistent with the assumptions included in official studies performed by PJM to support its capacity market. In addition, the information in the ProbA for winter seasons refers to the Winter 2026–2027 and Winter 2028–2029 because PJM's studies are based on "delivery years," which start on June 1 of a year and end on May 31 of the subsequent year.

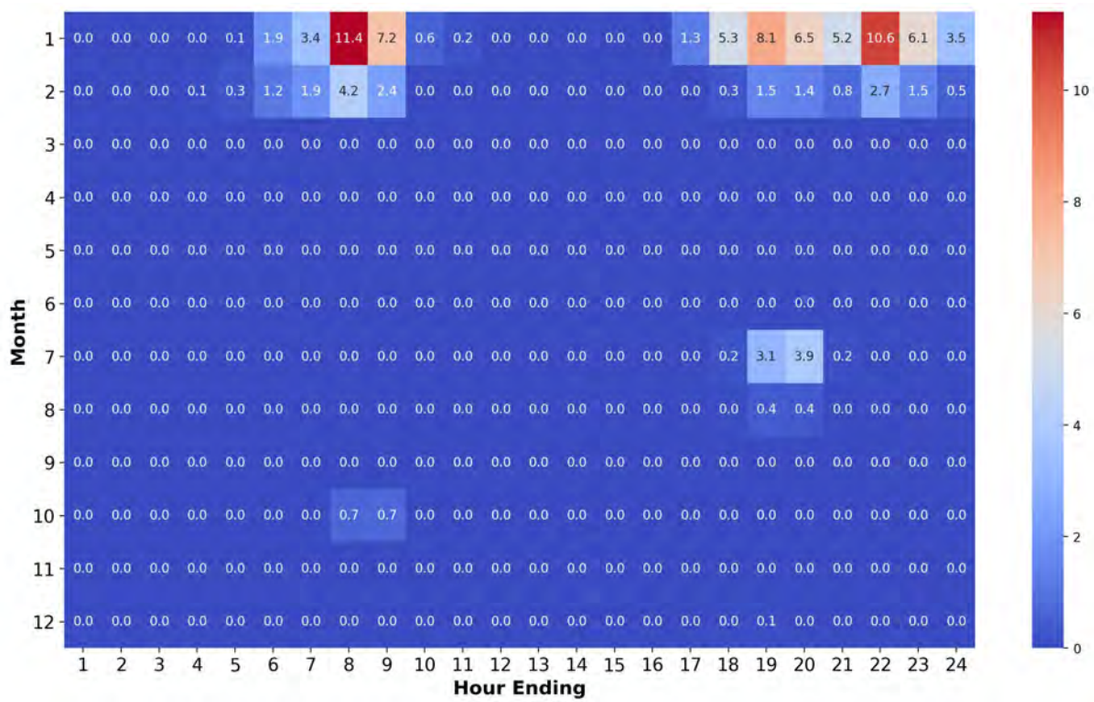
Results of the 2024 ProbA are provided in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**537.52**	**1043.44**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.11**	**0.22**
Operable On-Peak Margin	29.0%	**17.8%**	**17.7%**

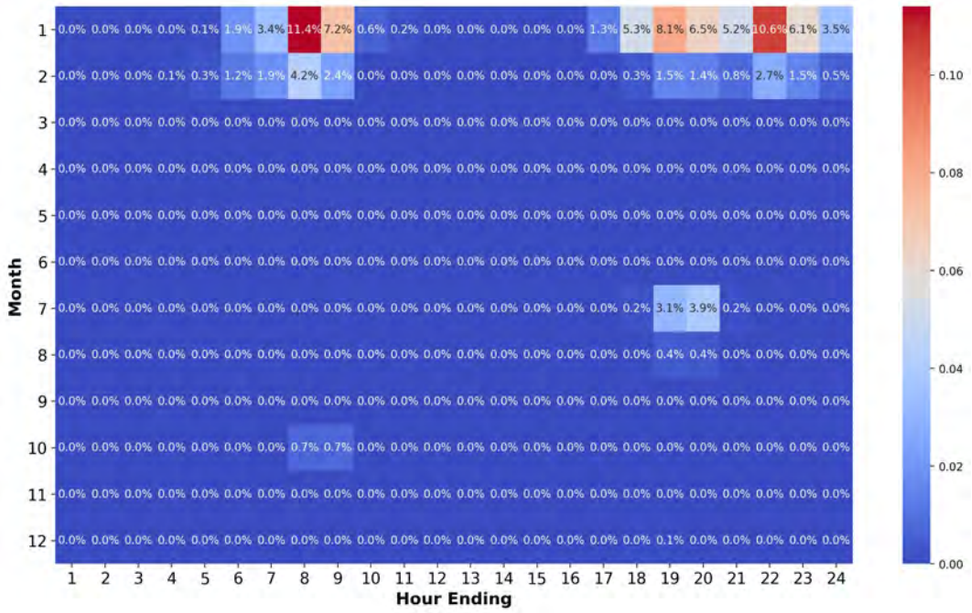
* Provides the 2022 ProbA Results for Comparison

In both 2026 and 2028, most EUE and LOLH are concentrated in the winter months (especially January), as shown in the following EUE heat maps. The risk occurs in days when temperatures are very low, which results in high loads across the assessment area. If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.

The smaller shares of EUE and LOLH observed in the summer period for 2026 and 2028 are associated with high temperatures and high loads across the assessment area that drive load-loss events in the evening (hours ending 19 and 20) as grid-connected and BTM solar resource output declines. Low performance of wind resources and, to a lesser extent, slightly worse performance of thermal resources, also contribute to the load-loss events in the analysis.



2026 EUE Heat Map (Share of Annual EUE in %)



2028 EUE Heat Map (Share of Annual EUE in %)

PJM implemented capacity reforms (approved by FERC) at the start of 2024, which include using the loss-of-load model employed to perform the ProbA, as well as accreditation reforms based on the risk patterns identified by said model, for the capacity auctions starting with delivery year 2025–2026.

Demand

PJM is experiencing large growth in data centers that are in turn driving higher demand forecasts. Loudoun County, Virginia, in the PJM assessment area, is home to "Data Center Alley," the largest concentration of data centers in the world. Electrification in transportation, heating, and industrial sectors is also spurring demand growth.

The PJM Interconnection produces an independent peak load forecast of total internal demand using econometric regression models with daily load as the dependent variable and independent variables including calendar effects, weather, economics, and end-use characteristics. PJM annually reviews its load forecast methodology and implements changes when improvements are identified.
Summer peak load growth in PJM is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5% with a median of 0.5%.

Winter peak load growth for PJM is projected to average 1.9% per year over the next 10-year period and 1.8% over the next 15 years. The PJM regional transmission organization winter peak load in 2033–2034 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038–2039, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.0% with a median of 0.7%.

Net energy for load growth for PJM is projected to average 2.3% per year over the next 10-year period and 2.2% over the next 15 years. Total PJM energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10-year growth rates for individual zones range from 0.1% to 7.3% with a median of 0.7%.

Demand-Side Management

DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during summer peak season from 7,550 MW in 2025 to 8,400 MW in 2034.

Distributed Energy Resources

PJM expects 4,470 MW of solar DERs at the time of the peak in 2029 and 5,103 MW in 2034. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

Generation

Overall, new generation is coming on-line slower than anticipated. Generator retirements are outpacing the new generation replacing them. As a result, PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load. PJM could be at risk of facing resource adequacy challenges if these trends continue. PJM has applied an 11% reduction to the nameplate value of Tier 1 resources to reflect the historical rate of slower-than-anticipated addition of new generation.

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. Of new and expanded generation resources submitted in Queue A (1999) through December 31, 2023, 74,294 MW (or 15.8%) reached commercial operation, 33,166 MW (or 7%) were withdrawn from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,560 MW (or 0.3%) were withdrawn after wholesale market participant agreement (WMPA) execution but before construction. Overall, 20.4% of projects that requested uprates to existing capacity reached commercial operation.

Stakeholders at the June 6, 2023, Interconnection Process Subcommittee meeting approved an issue charge to examine how to enhance transfer of CIRs, which allow new generation to interconnect as a capacity resource, from deactivating resources to new generation. The goal is to develop a solution that both improves the efficiency of the process and clarifies that it applies to all energy-injecting capacity resource types. The existing provisions in the PJM Tariff, and related defined terms included in the Reliability Assurance Agreement (RAA), governing the CIR transfer process will be clarified to reduce confusion as to which capacity resource types the transfer process applies.

PJM's existing installed capacity reflects a fuel mix consisting of approximately 48% natural gas, 22% coal, and 18% nuclear. Hydro, wind, solar, oil, and waste fuels constitute the remaining 12%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility. Totaling nearly 125,000 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the new service requests in PJM's generation interconnection queue. State policies encouraging renewable generation are contributing to the rise in solar generation interconnection requests.

PJM's review of recent policies indicates over 32 GWs of potential deactivations through 2034. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generators to comply or retire. See *Energy Transition in PJM: Resource Retirements, Replacements, and Risks* (February 2023). Conversely, there are multiple mandates with RPS that account for the majority of over 150 GWs in submitted projects. Growing levels of intermittent and limited duration resources, such as wind, solar, and battery storage, do not replace conventional large-scale generation installations megawatt-for-megawatt but rather require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity. Looking out over the next 8 to 10 years of the energy resource transition, maintaining an adequate level of generation resources with operational and physical characteristics that support reliability will be crucial for PJM's ability to serve electrical demand reliably.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Today, there are approximately 177 GWs of solar, wind, battery, and hybrid in the PJM interconnection queue. Hybrid resources make up approximately 26 GWs and standalone storage makes up approximately 28 GWs.

Some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land but each has its own connection to the grid) or hybrid (in which the storage facility and generator share a common connection to the grid).

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if transfers were dropped to zero.

Transmission

PJM's Regional Transmission Expansion Plan (RTEP) continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by new wind and solar generating units driven by federal and state renewable incentives, generating plant deactivations, and market impacts introduced by DR and EE programs. As of December 31, 2023, renewable resources continue to represent a significant portion of PJM's new services requests.

The PJM board approved 48 new baseline projects during 2023 at an estimated $6.6 billion to ensure that fundamental system reliability criteria across the grid are met. The board also approved the inclusion of 93 new network transmission projects at an estimated $180 million into the RTEP.

Reliability Issues

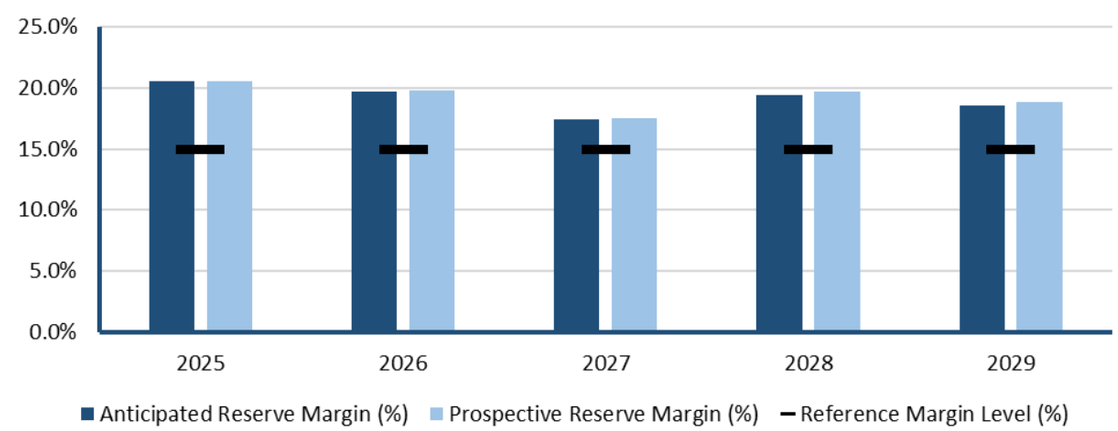
PJM's 2023 *Load Forecast Report* addressed the impact of industry changes that are reshaping system hourly loads. As a result, the level and timing of coincident peak and non-coincident peak demands across PJM have begun to shift. Solar-power penetration, expected impacts of EVs, state electrification programs, home battery storage, and a significant increase in data center loads are markedly increasing the complexity of PJM's load forecasting process. Driven by discrete and localized load growth, like Data Center Alley in Loudoun County, Virginia, in 2022, PJM and stakeholders conducted a review of data center load growth and identified growth rates of over 300% in some instances. As a result, the 2023 PJM *Load Forecast Report* incorporates adjustments to specific zones for data center load growth.

SERC-Central

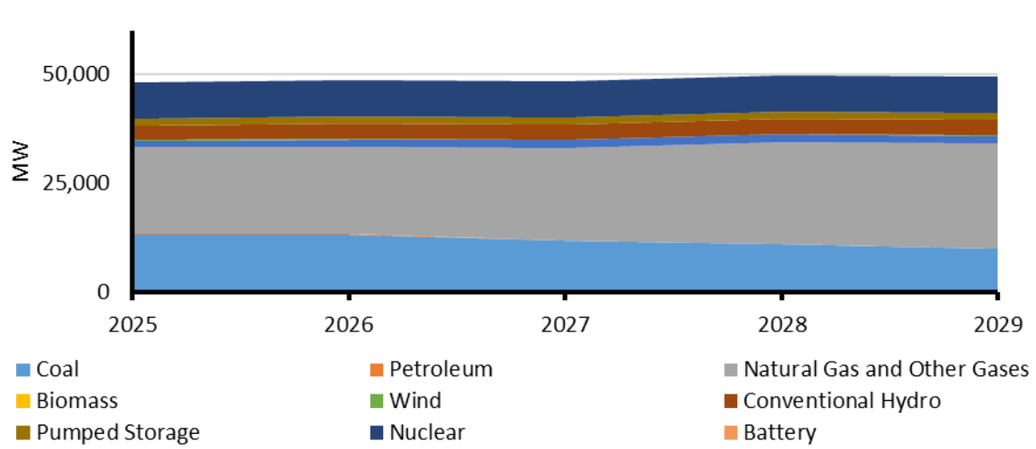
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	42,983	43,202	43,399	43,384	43,440	43,636	43,725	43,913	44,077	44,316
Demand Response	1,859	1,856	1,852	1,849	1,847	1,844	1,842	1,840	1,839	1,837
Net Internal Demand	41,124	41,346	41,547	41,535	41,593	41,792	41,883	42,074	42,239	42,479
Additions: Tier 1	1,123	1,540	2,970	4,983	5,841	5,841	5,841	7,609	8,935	9,598
Additions: Tier 2	20	20	20	120	120	120	120	120	120	120
Additions: Tier 3	135	263	415	1,118	3,395	4,198	4,965	5,368	5,745	6,198
Net Firm Capacity Transfers	1,240	765	190	-288	-288	-288	-288	-287	-287	-287
Existing-Certain and Net Firm Transfers	48,437	47,962	45,813	44,608	43,478	43,191	43,191	42,224	42,224	41,153
Anticipated Reserve Margin (%)	20.5%	19.7%	17.4%	19.4%	18.6%	17.3%	17.1%	18.4%	21.1%	19.5%
Prospective Reserve Margin (%)	20.8%	20.0%	17.7%	19.7%	18.9%	17.6%	17.4%	18.8%	21.4%	19.8%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.
- New transmission line additions total 209 miles through 2028. The entities also plan to upgrade 185 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,348	13,348	11,774	11,047	9,917
Coal*	13,048	13,348	11,146	10,013	8,883
Petroleum	148	148	148	148	148
Natural Gas	19,857	19,857	21,287	23,300	24,158
Natural Gas*	19,476	19,476	20,906	22,919	23,777
Biomass	36	36	36	36	36
Solar	1,338	1,706	1,706	1,706	1,706
Wind	172	172	172	172	172
Conventional Hydro	3,393	3,393	3,393	3,393	3,393
Pumped Storage	1,673	1,673	1,673	1,673	1,673
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	75	125	125	125	125
Total MW	48,319	48,737	48,593	49,879	49,607
Total MW*	47,639	48,356	47,584	48,464	48,192
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins
The future reserve margins are above the RML for SERC-Central.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load-loss. Analysis of detailed ProbA outputs shows that that this negligible risk occurring in 2026 is associated with hot summer conditions and upper levels of economic load forecast models.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.10**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	18.4%	**13.2%**	**14.9%**

* Provides the 2022 ProbA Results for Comparison

Demand
Drivers of load growth are commercial expansion, electrification of heating and transportation, and growth in residential load. Entities expect to continue to have increased economic growth that will drive both population and employment to the SERC-Central assessment area, but these gains in employment are slightly offset by improvements in efficiency.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation
Projected coal generation retirements total 4,399 MW in the next 10 years. Resource additions include 6,838 MW of natural gas, 75 MW of BESS, and 760 MW of solar generation over the next 10 years.

Generator retirements are carefully managed by entities in the SERC-Central assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers
Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

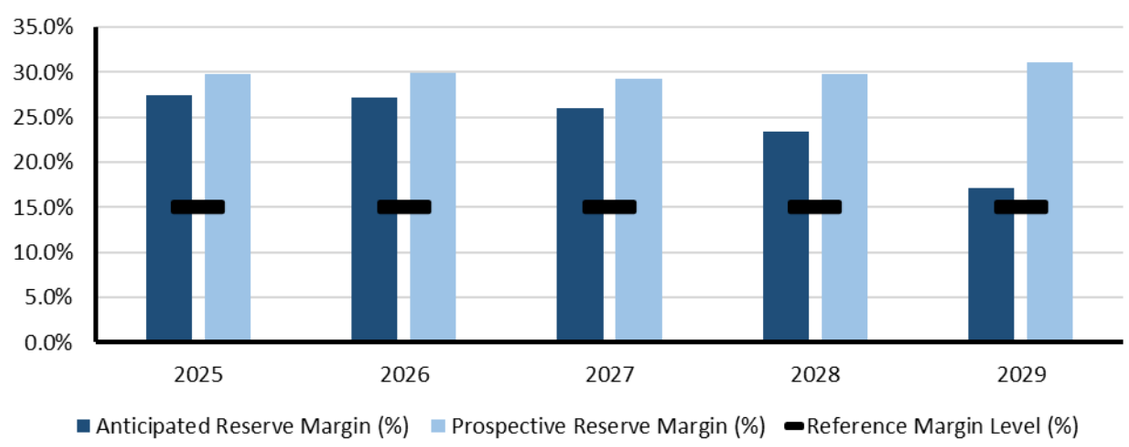
Transmission
The entities reported a total addition of 209 miles of new transmission lines until 2028. The entities are also planning to upgrade 185 miles of transmission lines in the next 10 years to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

SERC-East

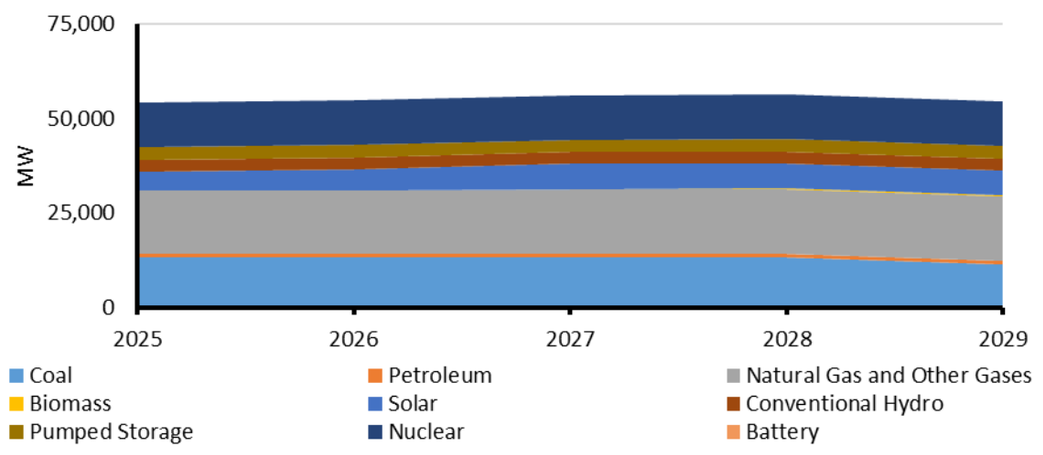
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	44,099	44,789	46,308	47,378	48,286	49,533	50,349	50,896	51,741	52,155
Demand Response	1,092	1,186	1,214	1,225	1,228	1,229	1,230	1,231	1,232	1,233
Net Internal Demand	43,007	43,603	45,094	46,153	47,058	48,304	49,119	49,665	50,509	50,922
Additions: Tier 1	772	1,330	2,777	2,818	2,818	2,818	2,818	2,818	2,818	2,818
Additions: Tier 2	38	217	506	1,975	5,577	8,032	9,766	11,595	13,978	16,767
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	593	593	593	593	593	593	593	593	593	593
Existing-Certain and Net Firm Transfers	54,039	54,129	54,045	54,118	52,301	52,395	51,316	49,998	49,998	48,636
Anticipated Reserve Margin (%)	27.4%	27.2%	26.0%	23.4%	17.1%	14.3%	10.2%	6.3%	4.6%	1.0%
Prospective Reserve Margin (%)	29.8%	30.0%	29.3%	29.8%	31.1%	33.0%	32.1%	31.7%	34.2%	35.9%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the RML until 2030 when it falls below the 15.0% RML level.
- Since the *2023 LTRA*, solar PV resources have grown from 1.5 GW to an expected 4.7 GW by the end of 2024.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,150	13,150	13,150	13,150	11,333
Coal*	13,108	12,564	12,564	11,910	10,093
Petroleum	1,044	1,044	992	992	992
Petroleum*	1,044	1,044	868	868	868
Natural Gas	16,627	16,717	17,061	17,121	17,121
Natural Gas*	16,601	16,691	17,061	17,121	17,121
Biomass	176	176	176	176	176
Solar	4,995	5,553	6,624	6,665	6,665
Conventional Hydro	3,102	3,102	3,102	3,102	3,102
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,795	11,808	11,808
Battery	6	6	6	6	6
Total MW	54,218	54,866	56,229	56,343	54,526
Total MW*	54,150	54,254	55,519	54,979	53,162
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins
The ARM falls below the RML starting in 2030 for SERC-East. Projected demand is expected to increase around 8.75% from 2024 to 2028 in the footprint.

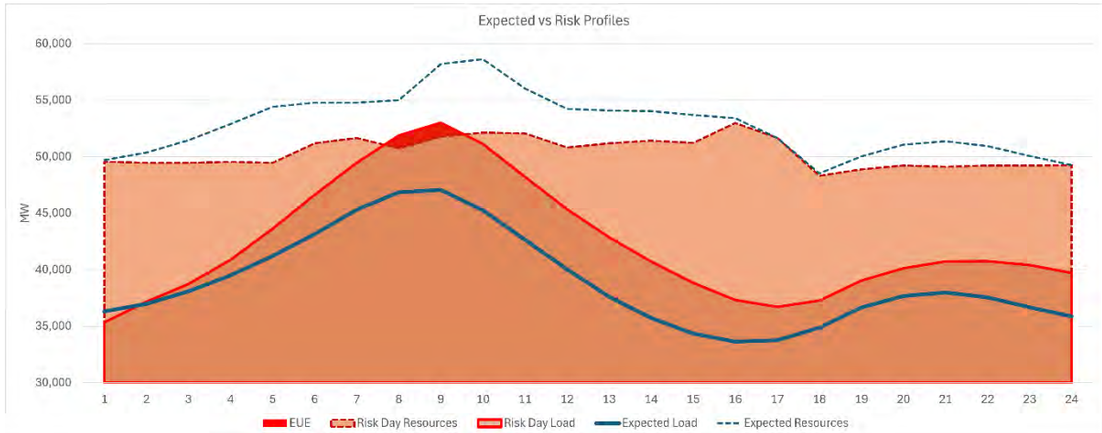
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
SERC-East has an elevated risk of energy shortages based on results of the 2024 ProbA shown in the table below.

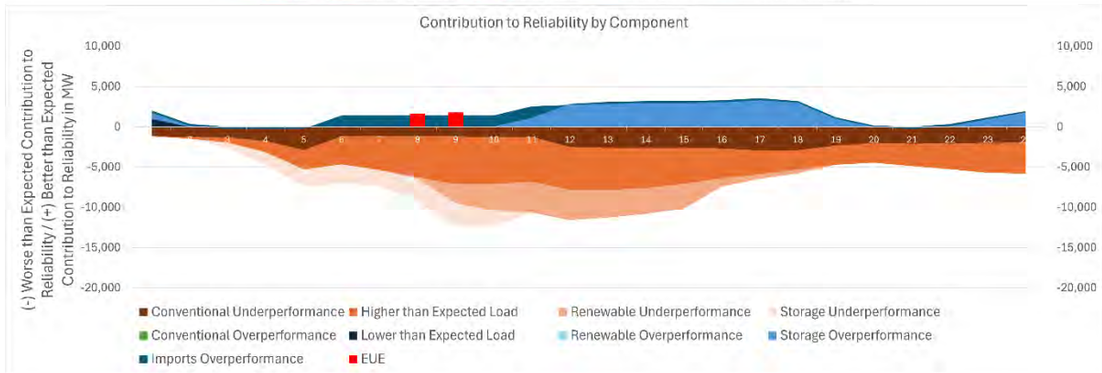
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	92.49	**143.35**	**207.26**
EUE (PPM)	0.39	**0.60**	**0.81**
LOLH (hours per year)	0.08	**0.09**	**0.17**
Operable On-Peak Margin	16.1%	**14.2%**	**11.1%**

* Provides the 2022 ProbA Results for Comparison

SERC-East has changed from a summer-peaking assessment area to a dual-peaking assessment area, with both a summer and winter peak. The addition of solar PV generation shaves off summer peak demand, and a trend toward electrification of heating drives up winter peak demand. The ProbA results for 2026 indicate some risk for SERC-East in the winter months of January and February. The annual EUE is 143.35 MWh but for a very short, expected duration of 0.09 hours. The risk occurs during winter morning hours around 8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. For extreme cold weather events that might impact a wide geographical footprint, there is also a limit on imports from neighboring areas.

For 2028, SERC-East continues to show winter risk with 207.26 MWh of EUE and 0.17 hours of LOLH. The load is expected to grow by over 2%. The load-loss events in the analysis are for very few hours and short duration, occur around 8:00 a.m., and are tied to extreme weather, higher forecasted load levels, and lower resource performance. This can be seen in the following figures showing the risk profile and resource performance for a likely event-day.





Demand
Population growth is driving demand forecast increases in SERC-East. Entities expect faster-than-average growth in the urban areas and overall increasing energy and demand in the 10-year forecast. While the economic indicators used in the forecast have growth rates that vary during each year, the economic outlook will contribute to increased energy and demand over the 10-year forecast. Some entities project their EE adoption to impact roughly 1% of annual retail sales (after opt-outs) during the 10-year forecast.

There are also many large commercial/industrial loads accounted for in the forecast that have been announced or in discussions with the entities to locate in the service territory. If the large sites come to fruition, it will drive significant increases in energy and demand during the later part of the 10-year forecast.

The projected EV adoptions are driving energy and demand increases during the later part of the 10-year forecast window. EVs are currently the most significant contributor of all electrification sources (e.g., heating, industrial) in the 10-year forecast.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

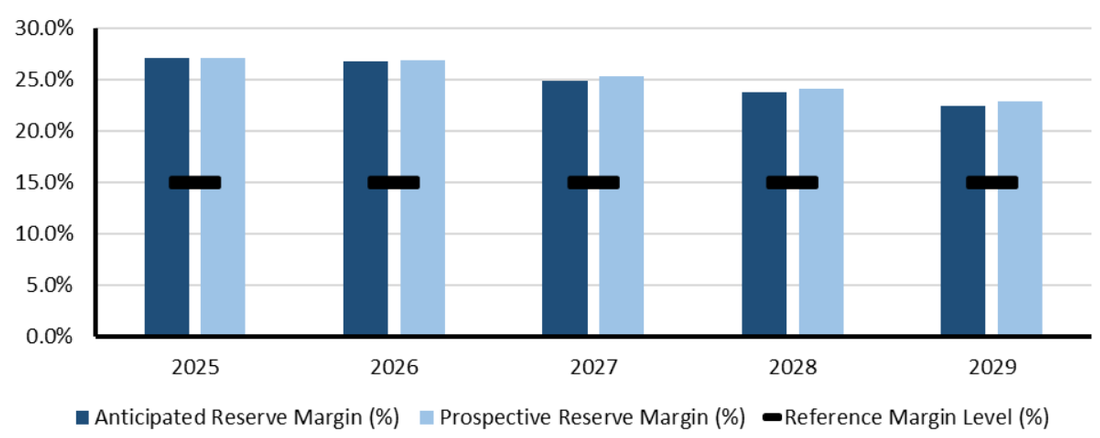
The entities reported a total addition of 286 miles of new transmission lines through 2028. The entities are also planning to upgrade 515 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability. Entities do not anticipate any transmission limitations or constraints with significant impacts on reliability.

SERC-Florida Peninsula

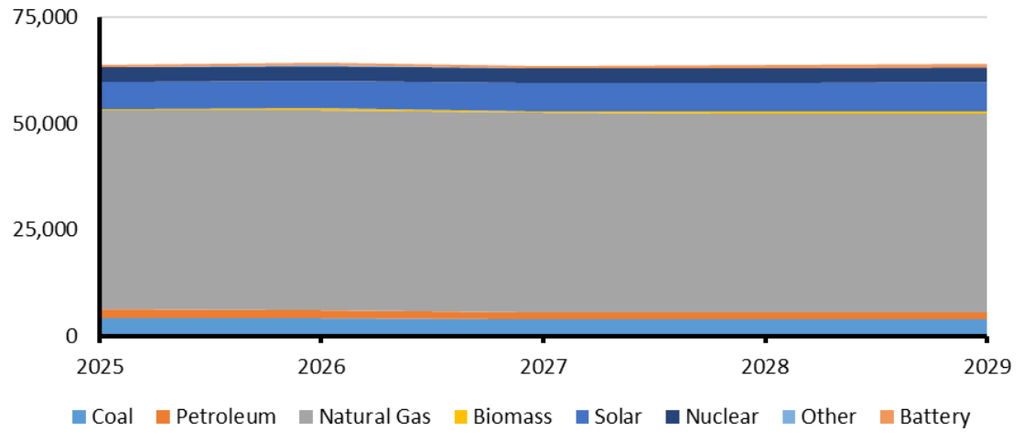
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	53,509	53,795	54,015	54,551	55,250	55,879	56,593	57,612	58,631	59,679
Demand Response	2,840	2,834	2,837	2,820	2,806	2,795	2,783	2,771	2,761	2,748
Net Internal Demand	50,669	50,961	51,178	51,731	52,444	53,084	53,810	54,841	55,870	56,931
Additions: Tier 1	871	1,497	1,573	1,785	2,018	3,421	3,927	4,545	4,547	4,549
Additions: Tier 2	0	40	200	200	200	200	200	200	200	200
Additions: Tier 3	0	39	39	39	39	39	39	39	39	39
Net Firm Capacity Transfers	494	293	293	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	63,521	63,121	62,366	62,230	62,230	61,725	61,725	61,493	61,493	61,493
Anticipated Reserve Margin (%)	27.1%	26.8%	24.9%	23.7%	22.5%	22.7%	22.0%	20.4%	18.2%	16.0%
Prospective Reserve Margin (%)	27.1%	26.9%	25.3%	24.1%	22.9%	23.1%	22.4%	20.8%	18.6%	16.4%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.
- Projected coal generation retirements total 459 MW in the next 10 years. Tier 1 additions include 484 MW of natural gas, 1,560 MW of BESS, and 1,792 MW of solar generation over the next 10 years.
- New transmission line additions total 668 miles through 2030. The entities also plan to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,367	4,367	3,908	3,908	3,908
Coal*	3,341	3,779	2,851	2,851	2,851
Petroleum	1,957	1,852	1,724	1,724	1,724
Petroleum*	1,892	1,786	1,477	1,477	1,477
Natural Gas	46,860	47,012	46,844	46,801	46,801
Biomass	310	310	310	310	310
Solar	6,255	6,635	6,711	6,853	6,997
Nuclear	3,502	3,502	3,502	3,502	3,502
Other	9	9	9	9	9
Battery	638	638	638	708	797
Total MW	63,898	64,324	63,646	63,815	64,048
Total MW*	62,807	63,671	62,343	62,512	62,745
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

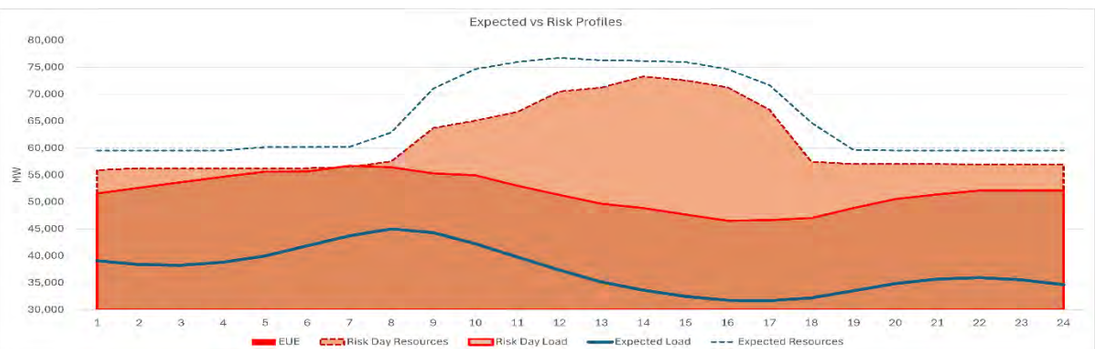
Planning Reserve Margins
The ARM is not expected to fall below the RML for any period of the assessment period.

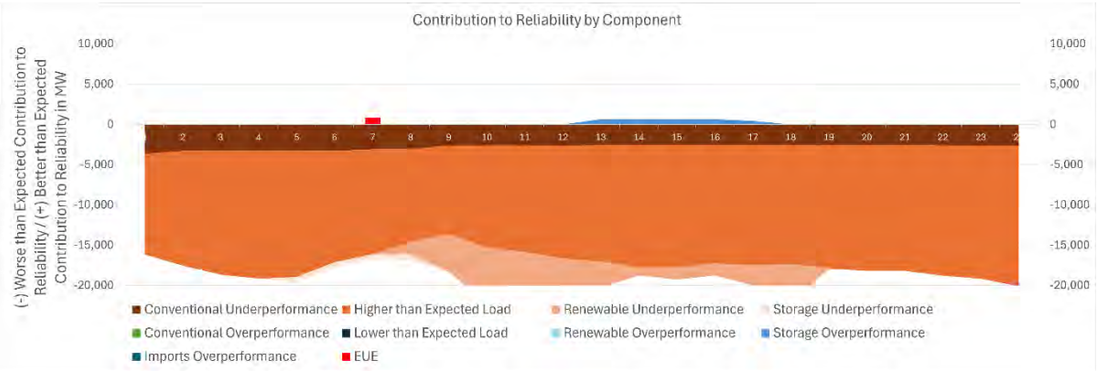
Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss. Analysis of detailed ProbA outputs shows that that the negligible risk in year 2026 is associated with hot late-summer or early fall conditions, high generator forced outages, and upper levels of economic load forecast models. The risk occurs in evening hours around 7:00 p.m. when contribution from solar generation is limited.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1.13	**2.18**	**16.28**
EUE (PPM)	0.00	**0.01**	**0.06**
LOLH (hours per year)	0.00	**0.01**	**0.02**
Operable On-Peak Margin	18.6%	**19.2%**	**16.3**

* Provides the 2022 ProbA Results for Comparison

For study year 2028, the ProbA results shows very low risk with 16.28 MWh of EUE and 0.02 LOLH hours. The driver of the risk is mainly extreme winter weather, similar to conditions from 1989, when Florida experienced one of the worst winter freezes on record. With higher load levels and lower resources in 2028, the low risk shifts to late December, occurring in morning hours when contribution from solar generation is limited, and is associated with winter freeze events that limit imports.





Demand
The individual entities within the FL-Peninsula Subregion develop their load forecasts and the Florida Reliability Coordinating Council (FRCC) then aggregates these forecasts to calculate a non-coincident seasonal peak for the subregion. Each entity adjusts their forecasts annually to account for their actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and energy efficiency efforts, and electric appliances usage patterns. Based on the data reported in the 2023 FRCC Regional Load and Resource Plan, the net energy for load (NEL) and summer peak demands are forecasted to grow when compared to previous forecasts. The current average annual growth rate for the NEL is 0.97% per year. Firm summer and winter peak demand growth are expected to increase to 1.19% and 1.17%, respectively.

Demand-Side Management
Controllable DR from interruptible and dispatchable load management programs within the FL-Peninsula Subregion is treated as a load-modifier, and it is projected to be constant at approximately 6% of the summer and winter total peak demands for all years of the assessment period.

Distributed Energy Resources
SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Florida Peninsula assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Energy Storage

Electricity storage (ES) is still a growing capacity contributor in the assessment area. Over the next 10 years, a total of approximately 2,900 MW of ES generation is projected to be in service by 2032 and is included in the utilities' 10-year site plans (approximately 775 MW by 2029).

Individual entities in the assessment area that have installed or are projecting the installation of ES are developing operating protocols on the use and dispatch of these facilities. ES units are studied as part of the normal generation interconnection process and included in other FRCC studies and processes with members providing individual dispatch profiles and study levels in order to identify potential operational impacts.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

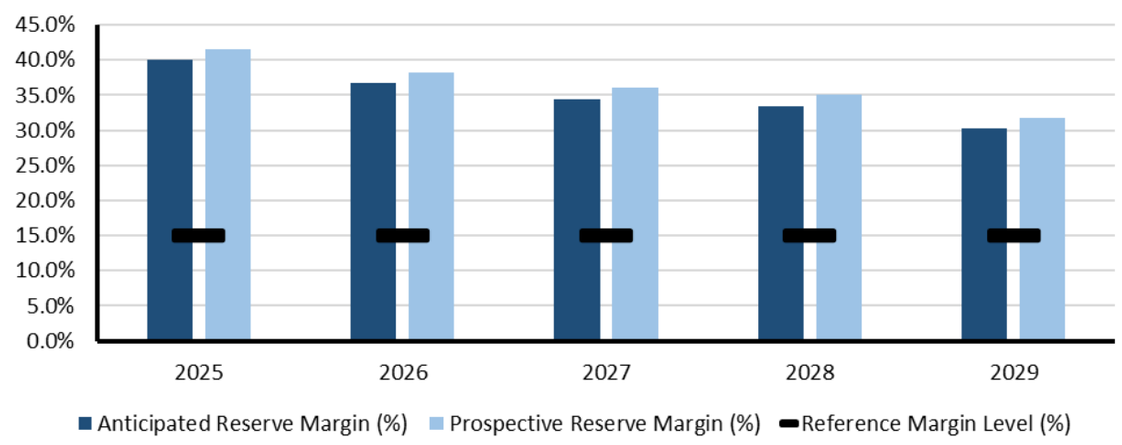
The entities reported a total addition of 668 miles of new transmission lines through 2030. The entities are also planning to upgrade 256 miles of transmission lines through 2031 to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

SERC-Southeast

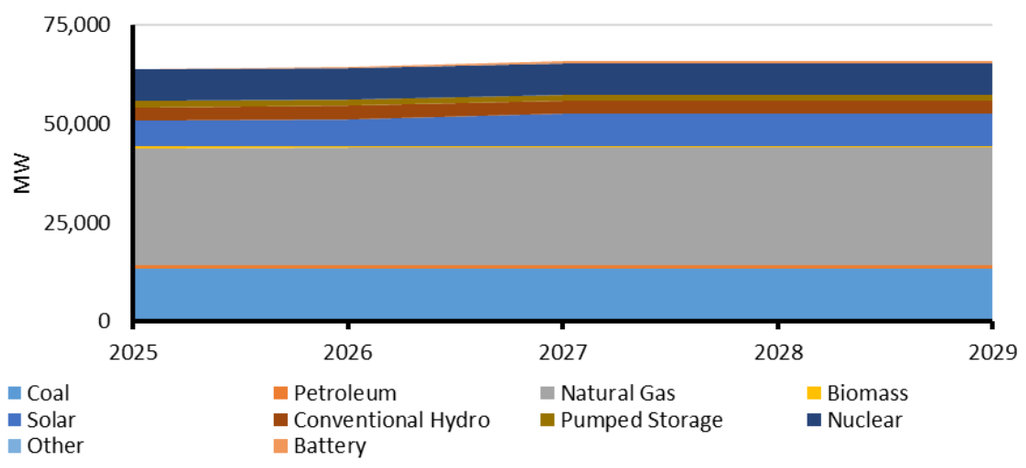
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	46,984	48,384	50,467	50,852	51,974	53,031	53,794	54,233	54,677	55,078
Demand Response	1,633	1,666	1,723	1,755	1,875	1,876	1,875	1,875	1,876	1,876
Net Internal Demand	45,351	46,718	48,744	49,097	50,099	51,155	51,919	52,358	52,801	53,202
Additions: Tier 1	1,248	1,486	3,050	3,050	3,050	3,129	3,129	3,129	3,129	3,129
Additions: Tier 2	105	105	218	218	218	218	218	218	218	218
Additions: Tier 3	366	366	366	366	366	366	366	366	366	366
Net Firm Capacity Transfers	-392	-392	-392	-392	-684	-684	-684	-684	-684	-684
Existing-Certain and Net Firm Transfers	62,257	62,413	62,472	62,472	62,180	62,180	62,180	62,180	62,180	62,180
Anticipated Reserve Margin (%)	40.0%	36.8%	34.4%	33.5%	30.2%	27.7%	25.8%	24.7%	23.7%	22.8%
Prospective Reserve Margin (%)	41.5%	38.2%	36.0%	35.0%	31.7%	29.2%	27.3%	26.2%	25.1%	24.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM remains above the 15% target RML for the assessment period.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	13,275	13,275	13,275	13,275	13,275
Coal*	13,275	13,275	12,271	10,321	10,321
Petroleum	915	915	915	915	915
Petroleum*	915	915	915	899	899
Natural Gas	29,639	29,795	29,854	29,854	29,854
Natural Gas*	29,564	29,387	29,446	28,426	28,426
Biomass	424	424	424	424	424
Solar	6,597	6,835	8,021	8,021	8,021
Conventional Hydro	3,293	3,293	3,293	3,293	3,293
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	105	105	483	483	483
Total MW	63,897	64,291	65,914	65,914	65,914
Total MW*	63,822	63,883	64,502	61,516	61,516
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Southeast Assessment

Planning Reserve Margins

The future reserve margins are above the RMLs for SERC-Southeast.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The 2024 ProbA results shown in the table below indicate negligible unserved energy and load loss.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0.00	**0.00**	**0.00**
EUE (PPM)	0.00	**0.00**	**0.00**
LOLH (hours per year)	0.00	**0.00**	**0.00**
Operable On-Peak Margin	30.8%	**29.6%**	**25.6%**

* Provides the 2022 ProbA Results for Comparison

Demand

Data centers, cryptocurrency facilities, and large commercial and industrial load are driving demand forecast growth in the assessment area. Metro areas are experiencing a higher growth rate compared to rural areas.

Demand-Side Management

Entities within the SERC-Southeast assessment area use a variety of controllable and dispatchable DR programs to reduce peak demand. One entity manages a voluntary DSM water heater program designed to allow system operators to control the appliances' usage during peak demand periods. Another entity monitors and dispatches DR programs commensurate with contract terms. Annual ELCC simulations are performed to determine the capacity value for each unique and active DR program. An adjustment to that capacity value is then made based on predicted customer response when the program is called or dispatched.

Distributed Energy Resources

SERC entities continue to monitor DER penetration levels, assess the impacts of DERs, and incorporate these impacts in system studies. Unlike directly modeled transmission-connected resources, DERs (e.g., rooftop solar, plug-in EVs) are netted against load in the Energy Management System and transmission planning models. Some entities are beginning to use software to develop DER projections of rooftop solar. DER resource output is modeled at various levels to account for load scenarios. The overall amount of rooftop solar is small compared to the utility-scale projects.

Generation

Generator retirements are carefully managed by entities in the SERC-Southeast assessment area. Entities perform studies to determine the impacts of confirmed or unconfirmed retirements. Entities incorporate these studies into resource plans that highlight the significance of future generation projects. Additionally, there are no significant retirement plans that will affect reliability.

Capacity Transfers

Entities participate in the SERC committees and study groups to perform power transfer studies of the system within the SERC geographic area. These studies include evaluating transfer limitations between all assessment areas within the Region for the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, such that all facility loading is within normal ratings and all voltages are within normal limits.

Transmission

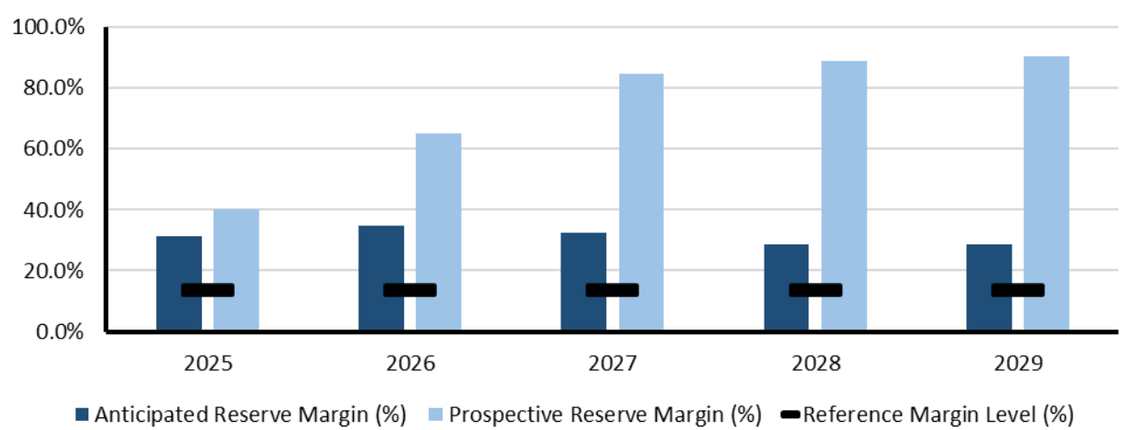
The entities reported a total addition of 1,078 miles of new transmission lines in the next 10 years. The entities are also planning to upgrade 694 miles of transmission lines during this time to enhance system reliability by supporting voltage and relieving challenging flows. Other projects include adding new transformers, upgrading existing transmission lines, storm hardening, and other system reconfigurations/additions to support transmission system reliability.

Texas RE-ERCOT

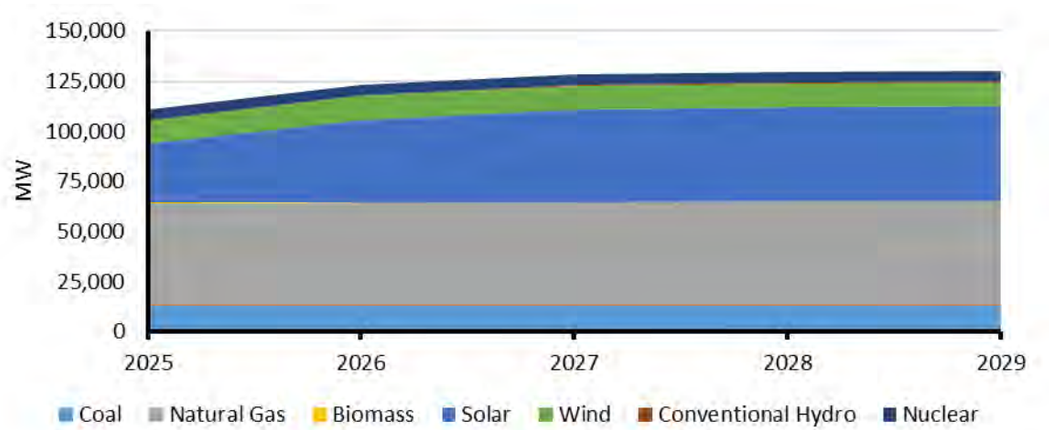
The Electric Reliability Council of Texas (ERCOT) is the ISO for the Texas Interconnection and is located entirely in the state of Texas; it operates as a single BAand performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	88,873	95,721	101,405	105,417	106,365	106,951	106,772	106,463	106,062	106,961
Demand Response	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Net Internal Demand	86,220	93,069	98,753	102,765	103,713	104,298	104,119	103,811	103,410	104,309
Additions: Tier 1	11,187	23,684	28,725	29,226	29,903	29,903	29,903	29,903	29,903	29,903
Additions: Tier 2	7,281	27,876	51,414	62,225	65,786	65,939	65,939	65,939	65,939	65,939
Additions: Tier 3	7,252	17,627	29,082	41,174	45,318	47,062	47,062	47,062	47,062	47,062
Net Firm Capacity Transfers	20	20	20	20	20	20	20	20	20	20
Existing-Certain and Net Firm Transfers	101,906	101,645	102,003	103,088	103,338	103,338	103,338	103,338	103,338	103,338
Anticipated Reserve Margin (%)	31.2%	34.7%	32.4%	28.8%	28.5%	27.8%	28.0%	28.3%	28.8%	27.7%
Prospective Reserve Margin (%)	40.3%	65.2%	84.6%	88.8%	90.3%	88.8%	89.1%	89.7%	90.4%	88.8%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- Generation resources, primarily solar PV, continue to be added to the grid in Texas in large quantities, increasing ARMs but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation. The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV.

- The Public Utility Commission of Texas (PUCT) established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. ERCOT will begin performing reliability assessments required by the new standard in 2026.

- ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	**2026**	**2027**	**2028**	**2029**
Coal	13,568	13,568	13,568	13,568	13,568
Coal*	13,568	13,568	12,913	12,353	12,353
Petroleum	10	10	10	10	10
Natural Gas	50,568	50,694	50,845	51,458	51,458
Natural Gas*	49,709	49,928	48,823	49,436	49,436
Biomass	163	163	163	163	163
Solar	29,557	41,201	45,984	46,485	47,163
Wind	11,332	11,908	12,166	12,166	12,166
Conventional Hydro	458	458	458	458	458
Nuclear	4,973	4,973	4,973	4,973	4,973
Total MW	110,628	122,975	128,167	129,281	129,958
Total MW*	109,769	122,208	125,490	126,044	126,721
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The summer ARM is above the RML (13.75%) for all 10 years of this assessment period (2025–2034). The ARM peaks at 34.7% by Summer 2026, reflecting the expected addition of about 23,680 MW of Tier 1 capacity, most of which is solar PV. However, the high reserve margin belies concerns over the continuing trend toward less fully dispatchable resources and more IBRs like solar PV and wind. While thermal resource availability and adequate gas supplies are still concerns during extreme winter weather events, the fleet performed well during Winter Storm Heather in January 2024, indicating that new weatherization standards, fully implemented in 2023, are effective.

Non-Peak Hour Risk and Energy Assurance

The PUCT established a reliability standard and accompanying reliability assessment process in August 2024. The reliability standard is based on multiple probabilistic reliability measures that capture the different dimensions of loss-of-load events: average event frequency (LOLE), maximum event duration, and maximum event magnitude. The latter two measures have an "exceedance tolerance," which is the maximum acceptable percentage frequency of loss-of load events that exceed the permissible thresholds based on a probabilistic simulation.

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at hour ending (HE) 9:00 p.m.—based on probabilistic modeling of monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. The summer peak load hour continues to be 5:00 p.m. For winter, the peak load hour is HE 8:00 a.m. Risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 a.m. to 9:00 a.m.) as well as the early evening hours.

ERCOT is experiencing transmission limitations as a result of load growth and resource development that affect energy delivery. On March 1, 2024, ERCOT introduced four new Interconnection reliability operating limits (IROL) in the South Texas region. This consists of two South Texas import constraints and two South Texas export constraints, which, if violated, could result in a thermal cascading condition. This is the first thermal IROL that could lead to a cascading condition in the Texas RE-ERCOT Region and has been attributed to the increase in generation capacity in South Texas and the rapid load growth in central Texas. To manage the South Texas export constraint, generation in South Texas must be curtailed to maintain transmission line flows below 100% of the impacted lines' thermal ratings. The risk of such curtailments, which is highest for the hours with the highest net peak loads (early evening), is included in the monthly probabilistic reserve risk assessments. ERCOT has approved two San Antonio Reliability projects that are expected to be completed in 2027 and should help alleviate some of risk drivers associated with these IROLs.

Probabilistic Assessment

Results of the 2024 ProbA are shown in the table below.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,235	**11,090**	**781**
EUE (PPM)	2.63	**18.95**	**1.12**
LOLH (hours per year)	0.30	**1.57**	**0.16**
Operable On-Peak Margin	35.9%	**28.8%**	**46.9%**

* Provides the 2022 ProbA Results for Comparison

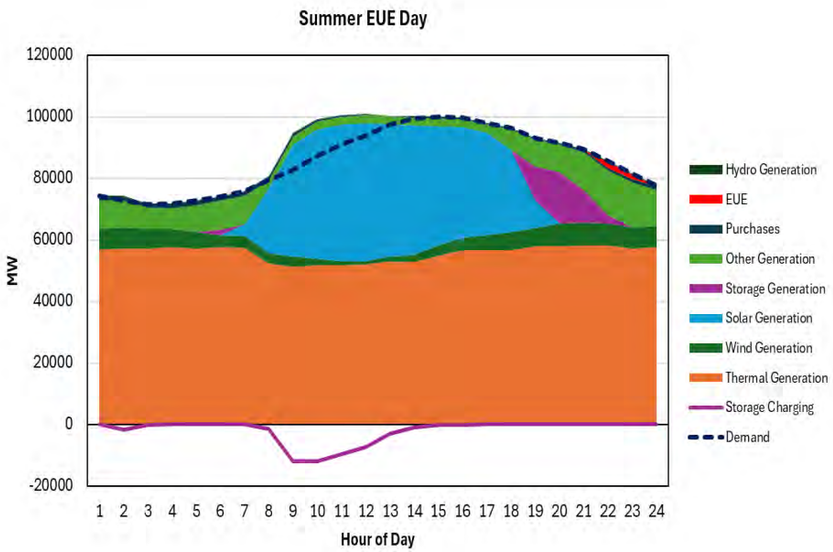
Increasing reliability risk in ERCOT is primarily driven by increasing large load demand anticipated from data centers, Bitcoin operations, continued load growth in oil and gas-producing areas (such as the Permian Basin), and growth in industrial facilities. Over 20 GW of newly contracted large loads, in addition to other organic load growth, is projected to be added to ERCOT by 2028. ERCOT also anticipates 1,860 MW of fossil-fueled plant capacity to be retired by Summer 2028. New planned units are primarily renewable and storage, which exhibit declining marginal reliability contributions. The reliability forecasts provided by this ProbA assessment for 2028 include resource capacity contributions from expansion planning analysis conducted for ERCOT's 2024 *Long-Term System Assessment*. While there is uncertainty around the deployment of these resources, the large load demand growth is also uncertain and large loads are subject to various requirements for being integrated into the grid.

All SERVM simulations for ERCOT and surrounding regions impose all relevant generator temporal constraints, including operating limitations on conventional units as well as state-of-charge on batteries, so this assessment accounts for energy adequacy. However, this assessment does assume fuel for conventional units will be available when needed.[37]

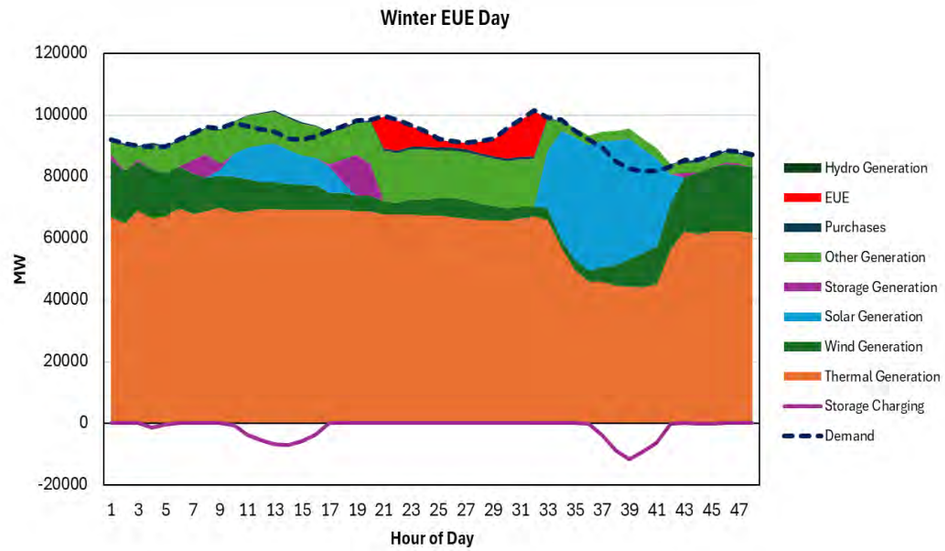
The unique characteristics of winter risk vs. summer risk can be seen in the following charts of a representative risk day. While peak winter loads can persist for 48 hours or longer, peak summer

[37] ERCOT and several other entities used SERVM software tool to perform the ProbA. Information about SERVM can be found at the company's website.

periods generally only last for a few hours. This has significant implications for the duration and depth of firm load-shed events in the winter as well as for the reliability contribution of energy limited and non-dispatchable resources. The most extreme winter event modeled for 2026 was 16 hours in duration and 29 GW in depth. The illustration below indicates a winter EUE event with duration >12 hours while most summer events were 1–2 hours in duration.



Metric	2026 Summer	2026 Winter	2028 Summer	2028 Winter
LOLE (days/year)	0.38	0.51	0.05	0.04
LOLH (hours/year)	1.41	1.57	0.18	0.16
EUE (MWh)	10,985	11,090	857	781
Max Hourly EUE (MWh)	29,124	29,266	17,762	16,851
Max EUE Duration (Hr)	15	16	12	11



From the hourly event data, ERCOT provided a multi-metric summary of the largest event showing the highest magnitude and longest-duration, as shown in the following figure.

Demand

ERCOT's long-term load forecast consists of the following individual components: (1) a base forecast that uses an econometric model with estimation data comprising 15 historical weather years, economic drivers, calendar information, and historical loads, (2) a roof-top PV forecast, (3) an EV forecast, a large flexible load forecast (crypto-mining facilities), and new "large loads" with a signed interconnection contract with their transmission or distribution service provider. Forecasts are provided for eight weather zones as well as system coincidental and non-coincidental demands. ERCOT's summer peak demand is forecast to increase by 4.6% per year from 2025 through 2029. In

comparison, the five-year summer peak demand growth projection for the *2023 LTRA* was 1.1%. This high growth level is driven by a large amount of newly contracted loads planned for interconnection during this period. These contracted loads are mainly comprised of Permian Basin oil and gas production facilities, data centers, crypto-mining operations, and industrial facilities. (A negligible amount of new contracted loads reported by transmission service providers occur past 2029). The base peak load, which excludes these new contracted loads as well as load reductions due to rooftop solar installations, grows at a more modest 1.4%.

A major load forecasting change from last year is a new Texas Legislature requirement to include non-contracted loads in transmission planning studies. Non-contracted loads lack a signed Interconnection or facility expansion agreement. ERCOT's previous practice had been to exclude these more speculative loads from the load forecast. The non-contracted loads total about 3.6 GW for summer 2025 and reach about 31.7 GW by 2029. The non-contracted loads are not included in the LTRA's peak load forecast. ERCOT is evaluating how these non-contracted forecasted loads will be handled for future resource adequacy and other planning activities.

Demand-Side Management

Most of the demand-side resources available to ERCOT are dispatchable in the form of noncontrollable load resources providing responsive reserve service and ERCOT's Emergency Response Service. The ERCOT Emergency Response Service consists of 10- and 30-minute ramping DRs and distributed generation that can first be deployed when physical responsive reserves drop to 3,000 MW and are not projected to be recovered above 3,000 MW within 30 minutes following the deployment of non-spin reserves. Responsive reserve is provided by industrial loads and is procured on an hourly basis in the day-ahead market. During 2023, load resources started to participate in two other ancillary services, the Non-Spinning Reserve Service and ERCOT Contingency Reserve Service (ECRS), which are used to help balance the system during periods when there may be net-load ramps that cannot be met with conventional supply-side resources.

The remaining dispatchable DR available to ERCOT is from the transmission and distribution service providers' (TDSP) load management programs. These programs provide price incentives for voluntary load reductions from commercial, industrial, and residential loads during energy emergency alert events.

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member TDSPs to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year timeframe.

A bill was approved in the 88th Texas Legislature (HB 3390) that outlines new DER reporting responsibilities. The bill authorizes ERCOT to require TDSPs to provide unregistered DER information that ERCOT deems necessary for grid reliability assessment. ERCOT is now developing annual data collection and maintenance processes.

A multi-phase aggregated DER (ADER) pilot program was implemented in 2022. As of May 2024, there were two ADERs with 13 MW of dispatchable capability actively participating in the pilot project with another nine ADERs in various stages of registration/qualification.

Generation

Natural-gas-fired generation makes up approximately 45% of the available generation inside the ERCOT footprint. Approximately 6% of the natural-gas-fired generation demonstrates firm fuel capabilities as part of ERCOT's Firm Fuel Supply Service required by the PUCT.

ERCOT has established formal working relationships with grid generators' fuel suppliers to gather operational and delivery information useful for its control room operators. ERCOT has focused the efforts on two fronts: (1) obtaining real-time (or near real-time) information on the health of the natural gas systems that serve the generators and (2) maintaining communication with pipelines to notify ERCOT of any planned or unplanned events that could impact deliveries to generators.

After the 2021 Odessa event, ERCOT intensified its efforts to find corrective measures to enhance the ride-through performance of IBRs and improve overall system resilience. The study, which recommended installing synchronous condensers at six locations in West Texas, has been completed, and the ERCOT board of directors endorsed the project in December 2023. The project is expected to be in service in 2027.

ERCOT has proposed new grid code requirements for IBRs to improve voltage ride-through (VRT) performance to align with IEEE Standard 2800. The proposed grid code requirements are continuing to go through ERCOT's stakeholder approval process. Until new rules go into effect, IBRs will be expected to maximize VRT capability and address existing performance failures (such as by reducing maximum output).

To provide an incentive to build new dispatchable resources, the PUCT adopted a new rule to establish a generation loan program, one of four incentive programs under the recently established Texas Energy Fund (TEF). The other three programs within the TEF include completion bonus grants for new dispatchable generation projects that consistently provide power generation over a 10-year period, grants for companies to establish or secure backup power resources, and grants to improve the resiliency and availability of electric utility service outside the ERCOT region. The TEF has $5 billion

available for all four programs. These loans and grants have thus far resulted in 72 applications seeking funding under the TEF loan program. The PUCT staff-recommended portfolio represents 9,781 MW in potential new generation if all recommended applicants were to execute a loan agreement at the requested loan amounts.

Energy Storage

The current installed BESS capacity is 9,149 MW. These systems participate in ERCOT's Energy and Ancillary Service markets. Most have durations in the one-to-two-hour range. ERCOT is seeing an increase in longer-duration systems (three to four hours) to take advantage of energy-shifting and capacity-firming opportunities arising from continued high renewable generation penetration. For the first half of 2024, energy storage provided 87% of ERCOT's regulation up and 91% of responsive reserve service from primary frequency response (RRS-PFR). In June 2023, ERCOT implemented a new ancillary service, the ERCOT Contingency Reserve Service (ECRS), which, in part, is designed to address the ramping needs of the system. This ancillary service product provides additional opportunities for BESS ancillary service participation. To support larger BESS penetration levels, ERCOT submitted new proposed rules for state-of-charge accounting in energy dispatch and reliability unit commitment that are planned for implementation this year.

Based on the latest developer information for projects that are in the interconnection queue, ERCOT expects about 10,500 MW of additional battery energy storage capacity to be operational by year-end 2025. This capacity constitutes projects for which developers have posted financial security to build the interconnection facilities. By year-end 2029, the additional cumulative Tier 1 planned capacity reaches about 20,000 MW.

ERCOT currently assigns a 0% on-peak contribution for battery energy storage. ERCOT has changed its rule to adopt an ELCC methodology for battery storage of various durations. Extending the proposed ELCC methodology for BESS to current and forecasted resources in ERCOT would improve the anticipated reserve margins in the future.

Capacity Transfers

ERCOT has coordination plans in place with neighboring grids. These plans cover dc tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers.

Transmission

In September, the PUCT approved ERCOT's Permian Basin Reliability Plan. The plan consists of new and upgraded local transmission projects as well as building new import paths to load centers in other areas of the Texas RE-ERCOT region, including options for extra high voltage (EHV) infrastructure operating at 345 kW or 765 kV. The plan supports Permian Basin load growth that is currently expected to reach 24 GW by 2030 and over 26 GW by 2038.

ERCOT's 2023 Regional Transmission Plan (RTP) identified 173 reliability projects, with the majority consisting of 138 kV and 345 kV system upgrades. The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using production cost savings and generator revenue reduction tests.

The substantial increase in new loads from a year ago is expected to present challenges for transmission planning. The forecasted pace of the load growth could exceed the pace at which transmission capacity can be built to support it. ERCOT is working on major changes to its transmission planning process to address these challenges. For example, ERCOT is investigating a "generation hub" concept to indicate optimal generation location to address regional load growth and optimize transmission investments.

A new biennial report on grid resiliency—the Grid Reliability and Resiliency Assessment—evaluates extreme weather scenarios considering different levels of thermal and renewable generation availability and the potential outages caused by extreme weather conditions. The assessment also includes proposed transmission projects that may mitigate regional resiliency risks. The first report will be released by December 31, 2024.

New minimum deliverability criteria were included in ERCOT's 2023 RTP to ensure the deliverability of 100% of generation resource capacity and energy storage resources with a duration greater than or equal to two hours. For storage systems with a duration less than two hours, a prorated deliverability was ensured. Corrective action plans (CAP) were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

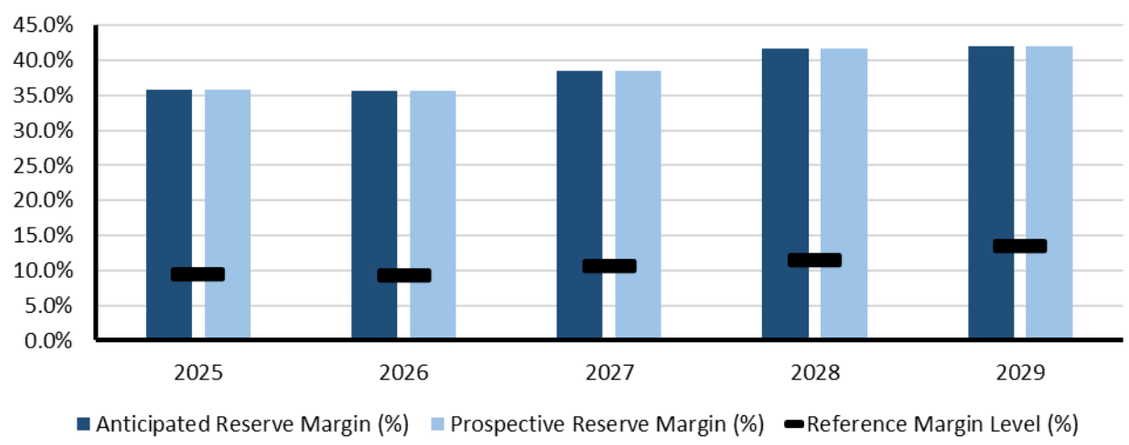
ERCOT has also started implementing the PUCT's amended rules relating to certification criteria and is in the process of integrating a new congestion cost savings test for economic projects evaluation.

WECC-AB

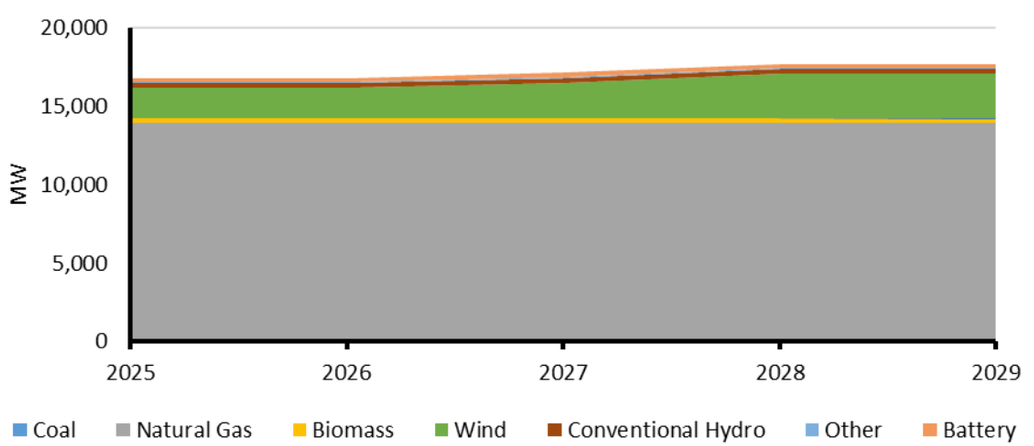
WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,411	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076
Additions: Tier 1	3,275	3,275	3,405	3,541	3,537	3,342	3,537	3,441	3,273	3,273
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	1,031	1,680	1,824	2,247	2,700	2,502	3,068	3,096	2,744	2,744
Net Firm Capacity Transfers	43	96	69	0	68	396	409	0	0	0
Existing-Certain and Net Firm Transfers	13,578	13,631	13,822	14,182	14,244	13,931	14,585	13,867	13,330	13,330
Anticipated Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Prospective Reserve Margin (%)	35.8%	35.6%	38.5%	41.7%	41.9%	35.4%	41.2%	33.6%	27.8%	27.0%
Reference Margin Level (%)	9.4%	9.4%	10.6%	11.5%	13.6%	9.2%	13.2%	11.3%	9.0%	9.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- The peak hour of demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's.
- Despite low resource adequacy risk, operational risk is still present. Ensuring sufficient frequency response capability has been identified as the region's highest priority. Frequency response has been declining in the region due to the increasing share of IBR resources and declining baseload resources. This under frequency load shedding risk is exacerbated in islanded or near-islanded situations.
- Alberta's two remaining coal-fired generators completed their conversion to natural gas this year.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	13,932	13,932	13,941	13,930	13,920
Biomass	336	336	336	336	336
Wind	1,912	1,912	2,232	2,811	2,799
Conventional Hydro	285	285	303	302	312
Other	81	81	81	81	81
Battery	264	264	264	264	263
Total MW	16,810	16,810	17,157	17,723	17,713

WECC-AB Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. From the 2032–2033 winter onward, Alberta shows a shortfall of existing-certain and net firm transfers. This indicates that imports may be necessary during this timeframe if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the one-day-in-ten-year (ODITY) level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

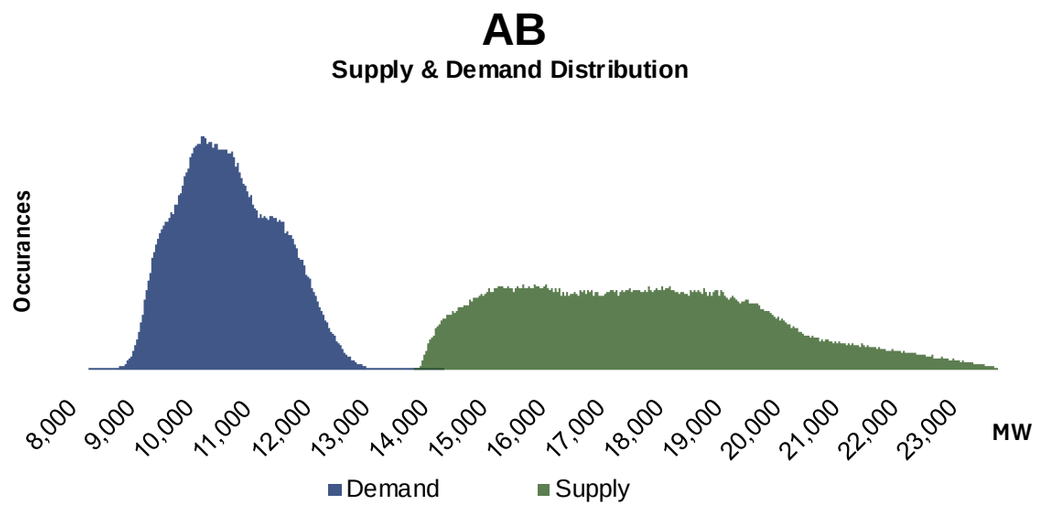
Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	0	0	0
EUE (PPM)	0	0	0
LOLH (hours per year)	0	0	0
Operable On-Peak Margin	26.1%	41.6%	42.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the Multi-Area Variable Resource Integration Convolution (MAVRIC) model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. WECC also produces an annual reliability assessment called the *Western Assessment of Resource Adequacy* (WARA).[38]

The availability and demand distributions in the ProbA simulations do not overlap, indicating an extremely low probability of Alberta not being resource adequate over the next four years. For 2026 and 2028, the peak hour occurs in December at HE 18:00. Alberta does not show LOLH nor EUE in the LTRA forecast horizon. The gap between the demand distribution and the supply distribution shown in the figure below emphasizes that there is minimal resource adequacy risk in Alberta. The ARM appears to further validate this, as it is far above the RML for 2026 and 2028.



Demand

Peak demand for Alberta occurs in the winter. The peak hour for total internal demand is expected to grow from about 12.3 GW in 2024 to 13.1 GW in 2034, a 6.5% load growth over the forecast horizon. The average year-to-year growth rate is 0.62%. There is a slight increase in the load forecast for this year's LTRA versus last year's. Near-term load growth is driven by industrial loads, such as oil sands production, pulp and paper mills, and gas and oil processing. Long-term demand growth is driven by electrification of transportation and buildings as well as potential growth in emerging industries, such as hydrogen production.

[38] See WECC Reliability Assessments.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. AESO released its updated 2022 Plan for DER Roadmap Integration Activities.

Generation
Over 6 GW of nameplate capacity are being added in Alberta through the end of 2028. There is significantly more solar, wind, and energy storage in this year's planned capacity additions than in the last LTRA. Additionally, several states and provinces in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions. Alberta's two remaining coal units have been converted to natural gas this year.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
In WECC's analysis, Alberta is not showing significant changes to capacity transfers. There is a slight increase in exports between 5:00 p.m. and 10:00 p.m. and in the later years of the assessment period.

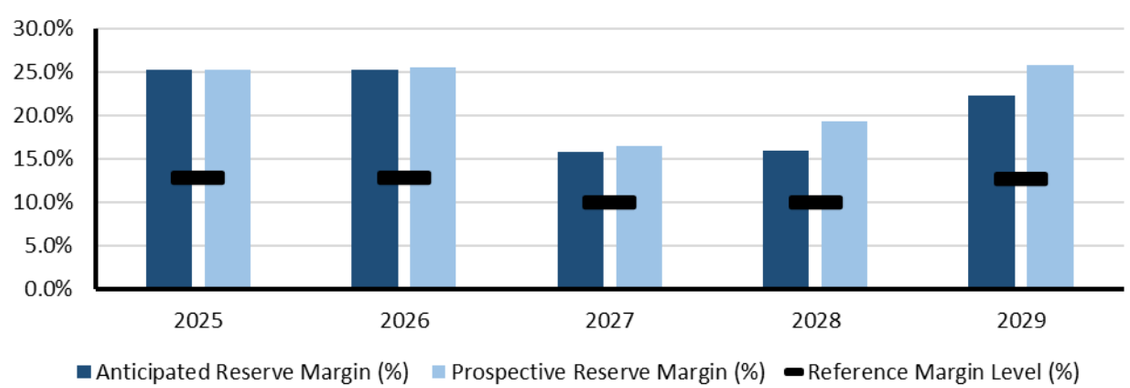
Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-BC

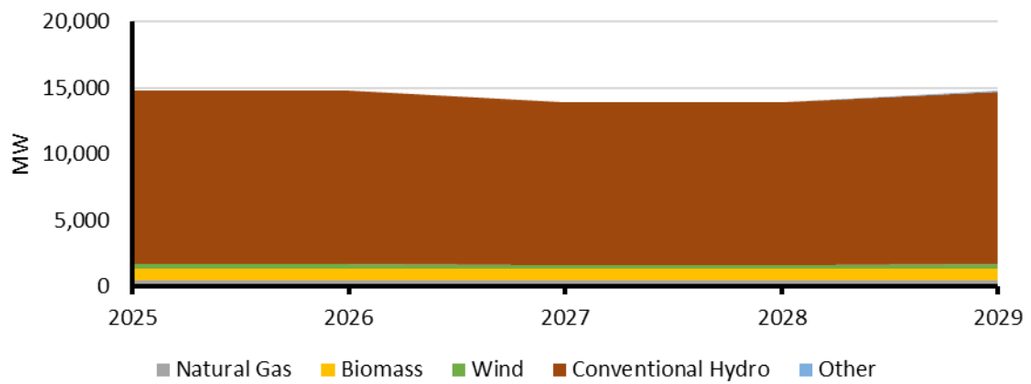
WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of BC, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and BC in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035
Total Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,986	11,959	12,015	11,983	12,075	12,082	12,130	12,174	12,237	12,305
Additions: Tier 1	956	956	893	893	956	956	956	956	893	956
Additions: Tier 2	0	41	79	398	419	748	1,077	1,077	1,012	1,405
Additions: Tier 3	0	5	5	5	6	6	59	59	56	59
Net Firm Capacity Transfers	184	188	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	14,054	14,022	13,019	12,998	13,812	13,795	13,795	13,795	12,982	13,795
Anticipated Reserve Margin (%)	25.2%	25.2%	15.8%	15.9%	22.3%	22.1%	21.6%	21.2%	13.4%	19.9%
Prospective Reserve Margin (%)	25.2%	25.6%	16.5%	19.2%	25.8%	28.3%	30.5%	30.0%	21.7%	31.3%
Reference Margin Level (%)	12.8%	12.8%	10.0%	10.0%	12.7%	12.7%	12.6%	12.6%	9.8%	12.5%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML during the 2024–2034 timeframe.
- BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from the winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.
- The peak hour of demand for BC occurs in the winter. BC shows the lowest demand growth rate in the west. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the previous LTRA forecast. This is an average annual growth rate of 0.28%, and a 2.8% load growth over the forecast horizon.
- BC is showing hours of demand at risk that are not fully mitigated by the addition of Tier 3 resources. Supply chain performance will play a significant role in BC's ability to reliably meet energy needs. Seasonal and daily fluctuations of hydro resource availability is also a risk. LOLH and EUE correlate with periods when river flows are at their lowest.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025–2026	2026–2027	2027–2028	2028–2029	2029–2030
Natural Gas	459	459	456	456	459
Biomass	920	920	914	914	920
Wind	279	279	268	268	279
Conventional Hydro	13,145	13,110	12,253	12,232	13,087
Other	22	22	22	22	22
Total MW	14,825	14,790	13,912	13,891	14,768

WECC-BC Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2024–2034 timeframe. BC shows a shortfall of existing-certain and net firm transfers for the 2027–2028 winter and the 2028–2029 winter. Shortfalls are also projected from winter of 2033–2034 onward. This indicates that imports may be necessary during these periods if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. In 2028, however, WECC's analysis identified over five hours where resources, including imports from neighbors, fall below margins for system reliability.

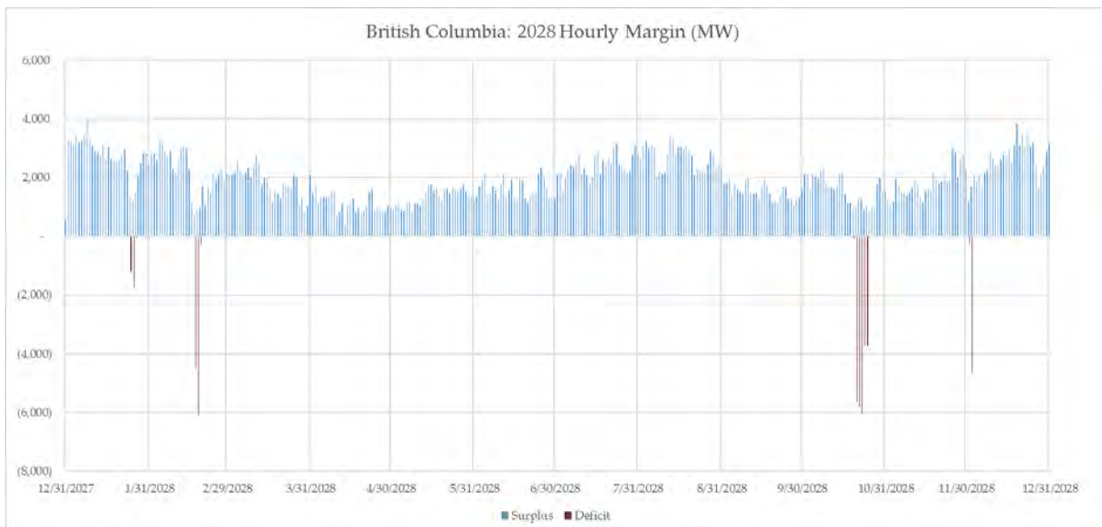
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	24	0	103,132
EUE (PPM)	0.71	0	1,457
LOLH (hours per year)	0.002	0	5.52
Operable On-Peak Margin	12.7%	16.9%	9.4%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

For both 2026 and 2028, the peak hour occurs in December at HE 19:00. LOLH and EUE are not forecast in 2026 but do appear in 2028. No LOLH or EUE occurs at the peak hour. 88% of the EUE in 2028 occurs overnight between the hours of 23:00 and 4:00.

In 2026, the peak summer hour is HE 17:00 in September, and in 2028 the peak hour is HE 17:00 in August. There is no LOLH projected for 2026 or during peak hours. LOLH occurs in 2028 between the hours of 17:00 and 20:00.



Icicle Plot with Hourly Surplus and Deficits for British Columbia in 2028

WECC's interconnection-wide analysis simulates the probabilistic performance of resource types using historic hourly output data to identify future risk periods. Operators of systems with large hydroelectric storage facilities make adjustments to generation based on the level of demand and shape the water use within the day, week, month, or between years. These actions help posture hydroelectric generation for expected conditions and can reduce energy shortfall risks.

	1	2	3	4	5	6	7	8	9	10	11	12
0	(0)	(5)	-	-	-	-	-	-	-	(10)	-	-
1	(1)	(5)	-	-	-	-	-	-	-	(12)	-	-
2	(1)	(6)	-	-	-	-	-	-	-	(20)	-	-
3	(3)	(5)	-	-	-	-	-	-	-	(14)	(0)	-
4	(0)	(1)	-	-	-	-	-	-	-	(0)	(0)	-
5	-	(0)	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	(0)	-	-
8	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
9	(0)	(0)	-	-	-	-	-	-	-	-	-	(0)
10	-	(0)	-	-	-	-	-	-	-	-	-	(0)
11	-	-	-	-	-	-	-	-	-	-	-	(1)
12	-	-	-	-	-	-	-	-	-	-	-	(3)
13	-	(0)	-	-	-	-	-	-	-	-	-	(5)
14	-	-	-	-	-	-	-	-	-	-	-	(1)
15	-	(0)	-	-	-	-	-	-	-	-	-	(0)
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-
20	-	(0)	-	-	-	-	-	-	-	-	-	-
21	-	(0)	-	-	-	-	-	-	-	-	-	-
22	-	(0)	-	-	-	-	-	-	-	(0)	-	(0)
23	-	(2)	-	-	-	-	-	-	-	(5)	-	-

2028 Heat Map EUE (GW) - British Columbia

Demand

BC's average annual load growth in its forecast has fallen to a rate below Alberta's. The peak hour total internal demand for BC occurs in the winter. The peak demand is expected to grow from about 12.0 GW in 2024 to 12.3 GW in 2034, slightly less than in the last forecast. This is an average annual growth rate of 0.28% and a 2.8% load growth over the forecast horizon. BC's load growth is lower due to updated monthly profiles that reflect current trends and aggressive DSM which it includes as a demand reduction in the demand forecasts provided to WECC. Load growth in BC is primarily driven by EV and gas sector load growth and is partially offset by a decline in demand from the forestry sector.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. BC Hydro has net metering. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

Across WECC, several states and provinces as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

In BC, hydro and wind resources are being added to the system. The BC Hydro Authority (BCHA) is taking steps to mitigate risks associated with climate change by improving coastal watershed inflow forecasting to an hourly level and increasing investment in capital projects to increase the resiliency of its hydro-dominant portfolio. Drought conditions in BC have led to water conservation measures, such as encouraging generation at facilities located in less drought-impacted areas, revising discharge plans at storage capable sites, and importing power when available to reduce water consumption.

Capacity Transfers

WECC's probabilistic analysis indicates that BC's need for imports is increasing during the assessment period.

Transmission

Three transmission projects with voltage design of 500 kV and higher are planned in the BC region.

Reliability Issues

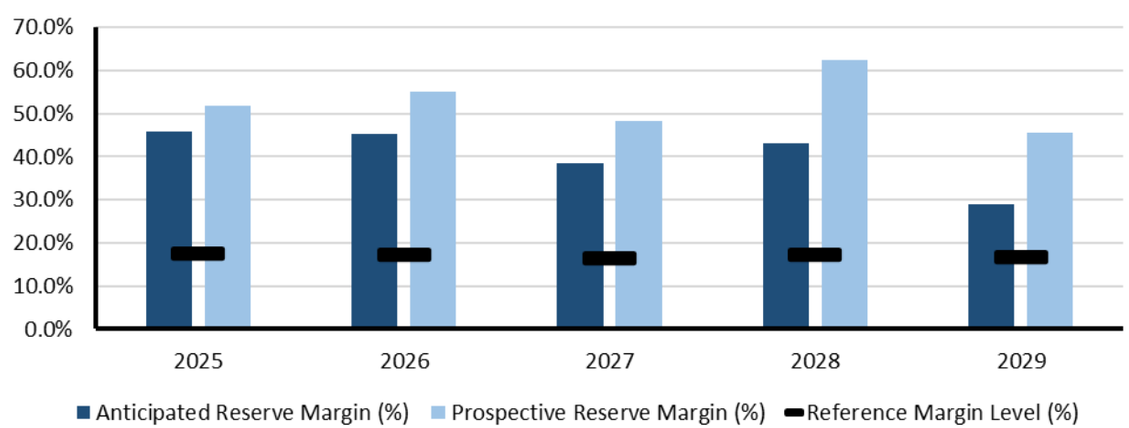
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-CA / MX

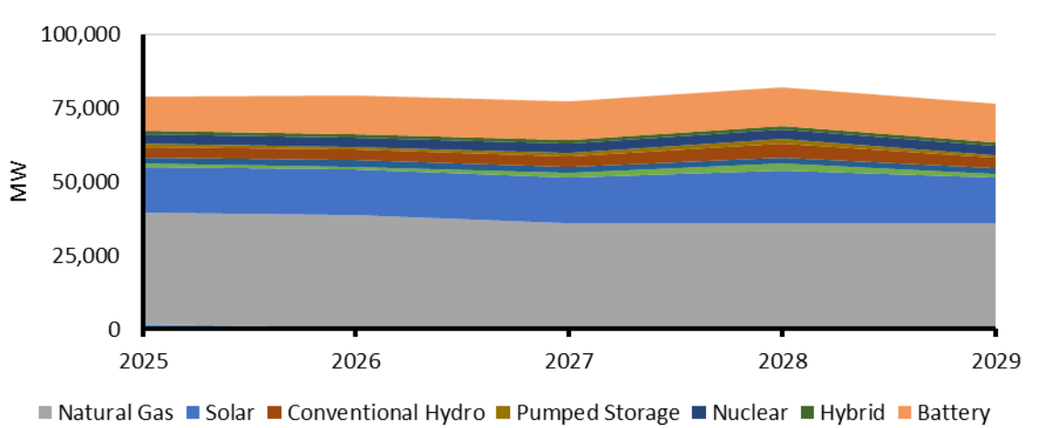
WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	56,619	57,274	59,291	60,131	61,289	61,067	62,336	65,876	67,251	69,064
Demand Response	795	797	793	793	793	794	794	794	794	794
Net Internal Demand	55,824	56,477	58,499	59,338	60,496	60,273	61,542	65,082	66,457	68,269
Additions: Tier 1	9,700	11,074	11,128	11,546	11,074	11,990	11,990	12,437	12,047	11,990
Additions: Tier 2	3,349	5,628	5,727	11,483	10,121	17,017	17,017	22,135	23,212	24,650
Additions: Tier 3	9	19	19	22	19	321	321	326	322	321
Net Firm Capacity Transfers	1,509	1,828	2,760	1,953	448	357	342	898	317	314
Existing-Certain and Net Firm Transfers	71,707	70,921	69,827	73,373	66,866	66,142	63,916	68,939	64,533	63,888
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	17.4%	17.4%	16.4%	17.4%	16.6%	16.4%	16.1%	16.3%	14.9%	15.3%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML in Summer 2034, but the RML is covered by the PRM, which includes Tier 2 resource additions.
- Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers. However, with planned generation resource additions the shortfalls are eliminated. Imports may be necessary if the new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 2 resources and primarily correspond with the evening down ramp of solar and lingering demand after peak.
- The peak hour of demand for CA/MX occurs in the summer. Total internal demand at peak hour is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%.
- Diablo Canyon, a 2.2 GW nuclear site, will no longer be retired by 2025 and is now slated to be retired in 2030.

WECC-CA/MX Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	1,572	466	466	465	466
Coal*	1,122	16	16	15	16
Petroleum	185	185	185	184	185
Natural Gas	38,180	38,180	35,565	35,504	35,506
Biomass	726	726	727	726	726
Solar	15,464	15,464	15,501	17,990	15,464
Wind	1,158	1,158	1,428	2,144	1,158
Geothermal	2,004	2,059	2,061	2,056	2,059
Conventional Hydro	3,582	3,582	3,838	4,727	3,582
Pumped Storage	889	889	951	1,710	889
Nuclear	3,282	3,282	3,287	3,283	3,282
Hybrid	32	32	34	39	32
Other	32	32	32	32	32
Battery	12,792	14,111	14,119	14,106	14,111
Total MW	79,898	80,166	78,194	82,967	77,492
Total MW*	79,448	79,716	77,744	82,517	77,042
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM falls below the RML in the summer of 2034. With the addition of Tier 2 resources, reserve margins remain above RML. Starting in Summer 2029 onward, CA/MX shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

The California Independent System Operator (CAISO) is responsible for much of the BPS that is in CA/MX. CAISO manages the transmission system, oversees transmission planning, and operates the wholesale electricity market for its territory. Other entities in CA/MX include the Balancing Authority of Northern California (BANC), the Imperial Irrigation District (IID), and Mexico's National Center for Energy Control (CENACE), which operates the connected Baja California system.

CAISO Only: The ARM falling below the RML in Summer 2034 and the shortfall of existing-certain and net firm transfers in Summer 2029 is consistent when looking at CA/MX or solely at CAISO. The RML of CAISO averages 0.7% higher than the CA/MX region RML over the LTRA horizon. This is due to the exclusion of natural gas and coal resource energy contributions from CA/MX entities outside of CAISO. Decreasing baseload generators results in increased variability, which in turn requires a greater RML to maintain the ODITY threshold. However, the gap between the anticipated, prospective, and existing reserve margins and the RML for CAISO are greater than the broader CA/MX region. The proportion of energy availability to anticipated net internal demand is larger for CAISO, accounting for this increase.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk in 2026. After 2026, however, WECC's analysis identified periods of unserved energy and load loss in CA/MX during June through October. Of note, this risk is limited to the Mexico portion of CA/MX (i.e., ProbA results for the CAISO do not indicate LOLH or EUE) until 2029, when the risk extends across the entire assessment area.

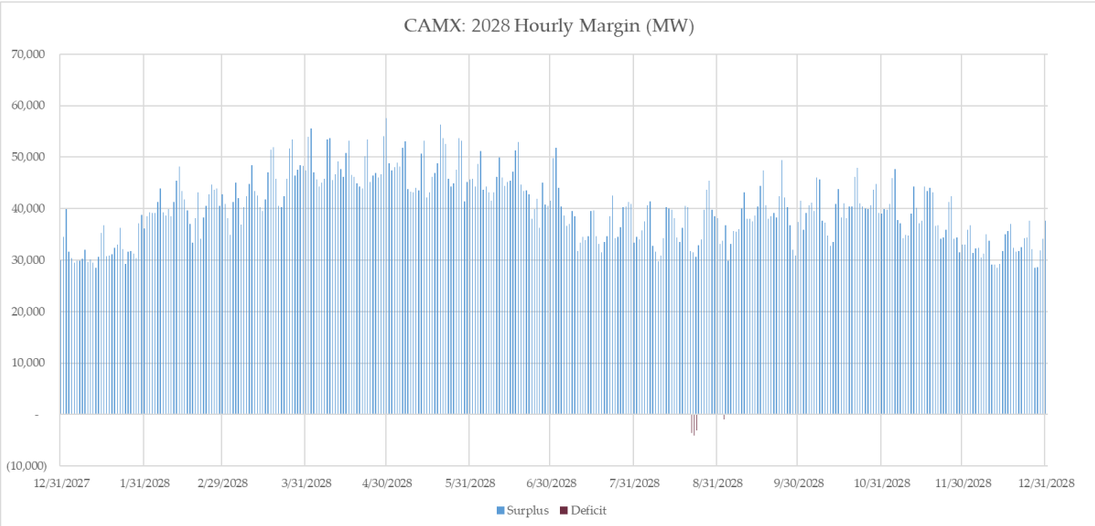
Base Case Summary of Results

	2026*	2026	2028
EUE (MWh)	37,305	0	19,662
EUE (PPM)	136	0	70.07
LOLH (hours per year)	0.721	0	0.38
Operable On-Peak Margin	30.7%	43.2%	41.2%

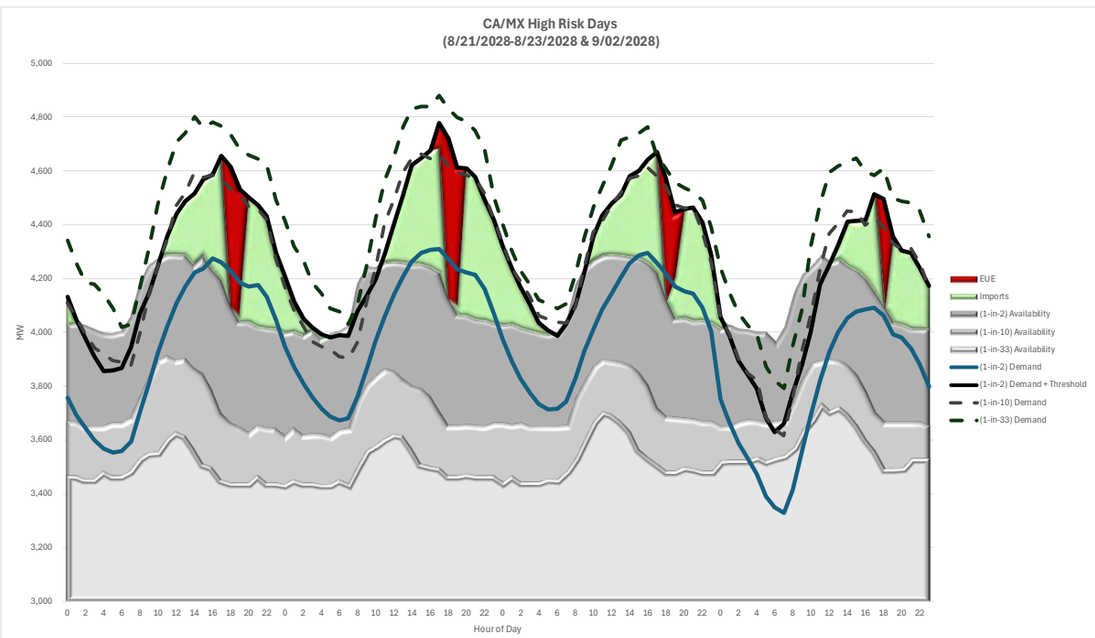
* Provides the 2022 ProbA Results for Comparison

Though the hour and month of peak demand are the same for both CAISO and the broader CA/MX region, CAISO shows the greatest amount of EUE and LOLH in September, whereas CA/MX shows the greatest amount of EUE and LOLH in August. This coincides with the seasonal reduction of solar irradiance in the fall and CAISO having a proportionally larger share of solar resources than the CA/MX region. Excluding regions external to CAISO results in a 96% reduction in LOLH events and EUE over the LTRA horizon.

The hour of peak demand in summer occurs at 5:00 p.m. The hours of highest risk, however, occur during periods after the peak demand hour as solar PV resource output diminishes. There is no LOLH projected for 2026; however in 2028, the ProbA reveals some LOLH between the hours of 5:00 and 8:00 p.m.



Icicle Plot with Hourly Surplus and Deficits for CA/MX in 2028



Demand

The peak demand for CA/MX occurs in the summer. The peak hour for total internal demand is expected to grow from about 56.4 GW in 2024 to 69.1 GW in 2034, a 22.5% load growth over the forecast horizon. The average annual growth rate is 2.07%. Transportation and building electrification are the primary drivers of demand growth.

CAISO Only: The demand forecast for CAISO grows at a slightly higher rate than the broader CA/MX region, with a load growth of 25.2% over the LTRA forecast horizon, and an average annual rate of 2.1%.

Demand-Side Management

A portion of the near-term decline in controllable and dispatchable DR for Summer 2024 is partly driven by regulatory changes in the CA/MX region. This includes making resource adequacy DR crediting adjustments based on historical performance and increasing DR availability requirements. The California Public Utilities Commission (CPUC) determined resource adequacy values of utility DR were overestimated during high load days. In response, the CPUC removed transmission gross-ups and some credits from utility DR resource adequacy values starting in 2024. The CPUC also directed that DR resource adequacy capacity must be available during all days the ISO calls a flex alert or issues a grid warning or on which the governor's office has issued an emergency notice, representing a significant increase in required availability. In addition, the CPUC now requires all DR capacity to be available a minimum of three days per week for at least four hours per day.

For CAISO, energy efficiency and conservation drops significantly when excluding non-CAISO entities from the CA/MX region. The entities outside of CAISO account for an average of 70% of the energy efficiency and conservation DSM for the CA/MX region for the LTRA timeframe.

Distributed Energy Resources

BTM DERs are difficult to measure due to data-gathering barriers. CAISO allows seven DER aggregators as market participants for energy and ancillary services. Additionally, PG&E's Partnership Pilot includes new or existing solar, storage, energy efficiency and demand response used via third party DER providers, vendors, or aggregators.

Generation

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
CA/MX is showing increasing amounts of exports to the northwest, especially during winter months.

Transmission
Seventeen transmission projects with 500 kV and higher are planned.

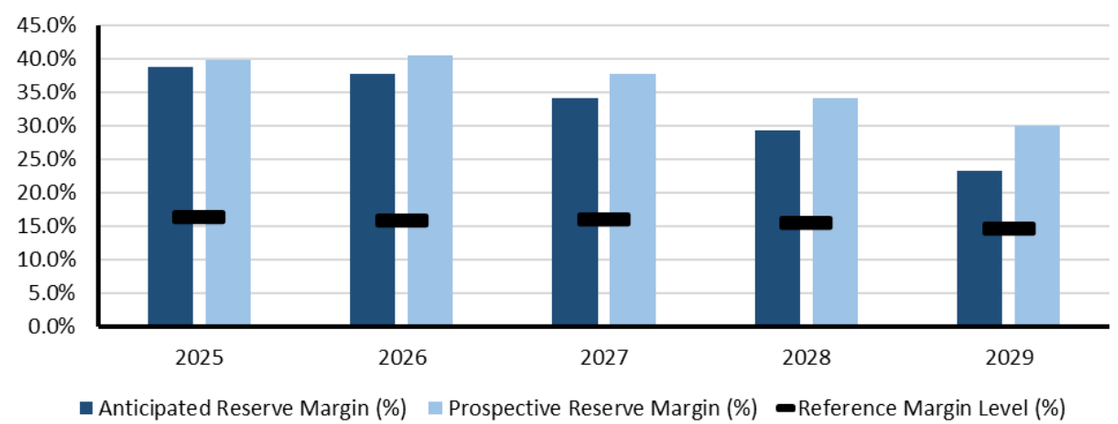
Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

WECC-NW

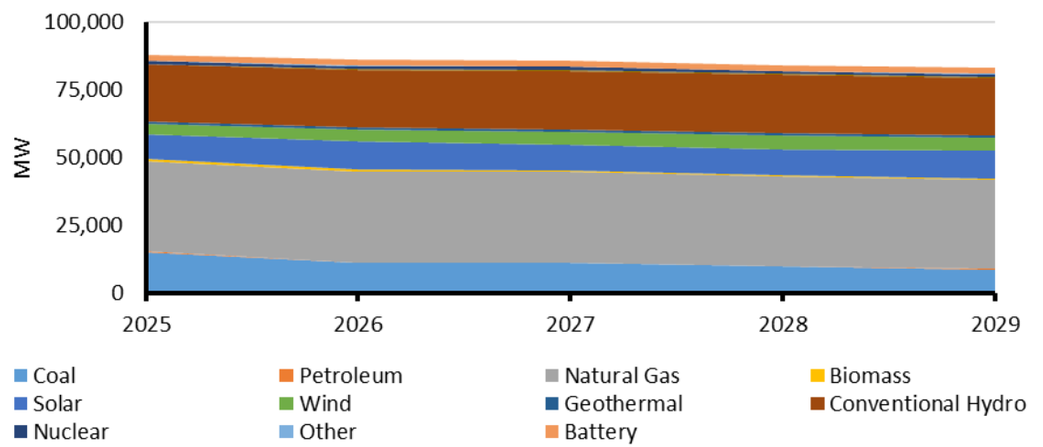
WECC-NW (Northwest) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	68,274	69,745	71,580	73,626	75,079	75,917	76,736	77,462	78,316	78,835
Demand Response	806	808	811	814	806	809	812	814	817	820
Net Internal Demand	67,469	68,936	70,768	72,811	74,273	75,108	75,925	76,647	77,499	78,016
Additions: Tier 1	7,000	9,386	9,295	9,489	9,752	9,752	10,141	10,141	9,915	10,141
Additions: Tier 2	788	1,955	2,628	3,595	5,046	6,593	7,258	7,273	6,935	7,253
Additions: Tier 3	2,945	8,874	14,008	21,247	28,296	33,802	40,239	42,260	41,876	43,809
Net Firm Capacity Transfers	5,627	8,796	9,087	9,863	8,462	6,037	2,783	2,423	2,370	2,140
Existing-Certain and Net Firm Transfers	86,609	85,564	85,605	84,618	81,788	78,094	74,003	73,297	72,810	71,446
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	16.3%	15.8%	15.9%	15.4%	14.7%	14.5%	14.3%	14.2%	14.4%	13.8%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the RML for all years in the LTRA time horizon.
- Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar and wind, supported by BESS. Supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources.
- The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous LTRA. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%.

WECC-NW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	14,965	11,031	11,021	9,667	8,761
Coal*	14,661	10,223	10,607	9,349	8,060
Petroleum	321	321	319	319	316
Natural Gas	33,452	33,636	33,304	32,954	32,749
Biomass	729	723	683	683	604
Solar	9,086	10,191	9,350	9,431	10,379
Wind	3,924	4,566	4,939	4,939	4,561
Geothermal	884	934	933	1,007	997
Conventional Hydro	21,003	21,000	21,542	21,522	20,958
Pumped Storage	373	373	375	375	373
Nuclear	1,096	1,096	1,096	1,096	1,096
Other	64	64	64	64	64
Battery	2,084	2,219	2,188	2,188	2,219
Total MW	87,981	86,154	85,814	84,245	83,077
Total MW*	87,679	85,346	85,398	83,926	82,377
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-NW Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Summer 2031. With the addition of Tier 2 capacity, the PRM stays above the Reference Margin for all years in the LTRA time horizon. Starting in Summer 2029 onward, the Northwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment, as well as WECC's WARA.

Imports to the Northwest from the CA/MX region grow throughout the LTRA forecast horizon. A calm, cloudy, extreme heat event occurring in the Northwest and CA/MX regions simultaneously poses a risk to the Northwest by limiting surplus energy in CA/MX to send northward.

Energy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio. More variability in energy output requires a greater reserve margin to maintain resource adequacy.

For 2026 and 2028, the peak hour occurs in August at HE 17:00. LOLH and EUE are not forecast in 2026 and only occur for a single hour in 2028. The LOLH occurred in August at HE 19:00, slightly after peak. The LOLH corresponds with the declining solar availability in the evening while demand remains high.

Demand

The Northwest is dual peaking, so the peak hour can occur in either the summer or the winter. Probabilistic modeling efforts show a peak in the summer for this LTRA. The summer peak for the total internal demand is expected to grow from about 66.4 GW in 2024 to 78.8 GW in 2034, which is lower than in the previous plan. This represents a nearly 18.7% load growth over the forecast horizon, with an average growth rate of 1.73%. There are significant differences between balancing areas, with some showing large load growth impacts while others showing a slight decrease in demand. Entities reporting large load growth cite new data centers as a primary driver.

Demand-Side Management

In the Northwest, Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows Idaho Power to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year to year based on factors such as the availability of water and program parameters. In 2022, the utility lengthened the season and included additional evening hours, which drove some reduction in participation that carried over to the Summer 2024 availability.

PacifiCorp states in its most recent Integrated Resource Plan (IRP) that it hopes to reach 1,123 MW of demand response by 2042 in its preferred portfolio plan, which is a 21% increase by 2042 from its previous plan. PacifiCorp's dispatchable DR programs include residential, small commercial air-conditioner load control, irrigation load management, and 203 MW of interruptible contracts.

The Public Service Company of Colorado (PSCo) also offers a wide array of DR programs, such as Saver's Switch, which is a program where the air-conditioning unit of a customer may be controlled

remotely and cycled during extreme heat events. Peak Day Partners allows for the direct load control and reduction of customers 0.5 MW or greater in size when system peaking conditions are met. The Interruptible Service Credit Option (ISOC) is a program where customers agree to reduce consumption in return for a rate discount with non-compliance being met with a fee.

Distributed Energy Resources
BTM DERs are difficult to measure due to data-gathering barriers. One example is Idaho Power's filing of annual DER Resources Status Reports by customer class and resource type, such as in 2023.

Generation
Five GW of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and BESS, further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of BESS resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Northwest is showing greatly increasing import needs over the 10-year time horizon, especially in the winter months. Most of the imports in the model simulations come from CA/MX, with a smaller portion coming from BC**.**

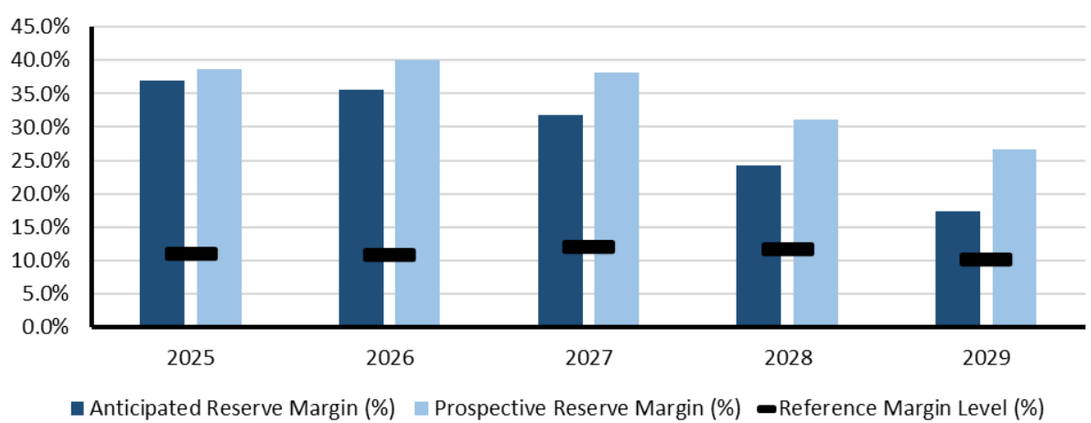
Transmission
Twelve transmission projects with 500 kV and higher are planned.

WECC-SW

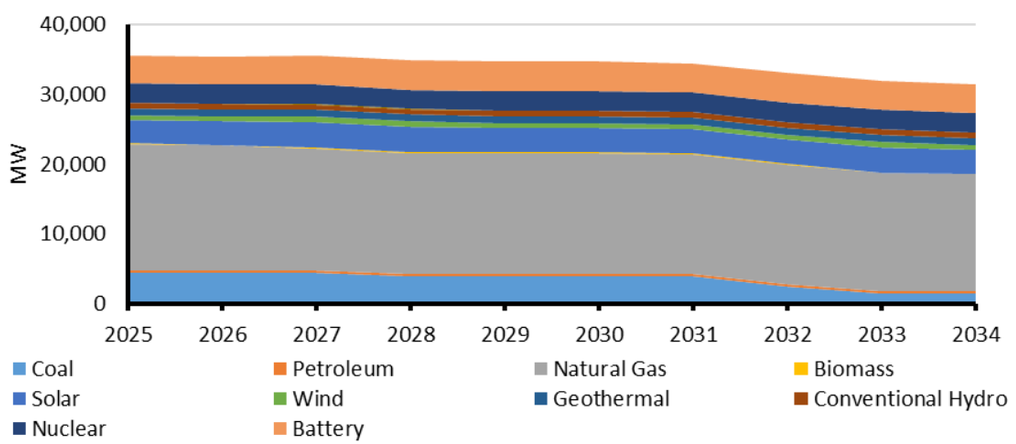
WECC-SW (Southwest) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western U.S. states in between.

Demand, Resources, and Reserve Margins

Quantity	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Internal Demand	28,347	29,184	30,098	30,905	31,684	32,401	33,082	33,676	34,301	34,886
Demand Response	417	392	396	424	373	389	392	396	424	373
Net Internal Demand	27,930	28,792	29,702	30,481	31,311	32,012	32,690	33,279	33,876	34,512
Additions: Tier 1	5,140	5,251	5,656	5,656	5,557	5,557	5,557	5,557	5,656	5,557
Additions: Tier 2	475	1,305	1,899	2,079	2,932	2,932	2,966	2,984	3,221	2,984
Additions: Tier 3	40	677	1,148	2,589	3,113	4,438	5,734	7,479	8,960	10,027
Net Firm Capacity Transfers	2,651	3,556	3,554	2,966	2,045	928	716	320	322	0
Existing-Certain and Net Firm Transfers	33,110	33,784	33,491	32,212	31,187	30,070	29,644	27,787	26,645	25,956
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	11.0%	10.8%	12.0%	11.7%	10.2%	10.1%	9.9%	9.7%	10.8%	9.4%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032.
- Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed. LOLH and EUE are mitigated over the assessment horizon with the addition of Tier 3 resources. Both supply chain and zoning issues have been cited as inhibiting project completion.
- The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%, which is the highest forecasted growth in the WECC region. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.
- Natural gas derates during extreme heat events are a risk for the Southwest as these resources make up a large share of the resource portfolio in the area.

WECC-SW Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2025	2026	2027	2028	2029
Coal	4,436	4,436	4,432	3,939	3,941
Coal*	4,432	4,432	4,148	3,655	3,657
Petroleum	323	323	322	322	323
Natural Gas	18,165	17,933	17,520	17,323	17,343
Biomass	82	82	82	82	82
Solar	3,354	3,354	3,628	3,628	3,479
Wind	628	695	799	799	695
Geothermal	1,047	1,047	1,047	1,047	1,047
Conventional Hydro	721	721	721	721	721
Pumped Storage	104	104	104	104	104
Nuclear	2,724	2,724	2,711	2,711	2,724
Battery	4,016	4,061	4,226	4,226	4,240
Total MW	35,599	35,479	35,593	34,902	34,698
Total MW*	35,595	35,475	35,309	34,618	34,414
*** Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

The ARM does not fall below the RML until Summer 2031, and the PRM falls below the RML in Summer 2032. This indicates that imports may be necessary if new resources were to be significantly delayed, as Tier 3 resources will be required for reserve margins to meet the RML. Starting in Summer 2028 onward, the Southwest shows a shortfall of existing-certain and net firm transfers, meaning that imports may be necessary if new resources were to be significantly delayed.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

WECC performs a probabilistic analysis to evaluate the probability distribution curves of demand and resource availability together. The area where those curves overlap represents the possibility that there will not be enough resources available to serve the demand, or the "demand at risk." The greater the overlap area, the greater the likelihood that this will be the case. For this analysis, WECC sets the risk tolerance threshold to the ODITY level, meaning that 99.98% of the demand for each hour is covered by available resources (i.e., the area of overlap is equal to no more than .02% of the total area of the demand curve for any given hour). The overlap—the demand at risk—increases when one or both curves move due to increases to expected demand or decreases to expected resource availability, or a combination of these (the curves maintain their original shape but move closer together, increasing the overlap). The overlap is also increased through variability. When rare events occur more regularly than predicted, the probability curve changes shape.

Results of the 2024 ProbA shown in the table below indicate negligible unserved energy and load-loss risk.

Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	84	0	19
EUE (PPM)	1	0	0.13
LOLH (hours per year)	0.003	0	0.00
Operable On-Peak Margin	18.3%	33.8%	22.5%

* Provides the 2022 ProbA Results for Comparison

The resource adequacy work performed at WECC uses the MAVRIC model. The MAVRIC model is a convolution based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and Probabilistic Assessment. Another report produced is a WECC report called the WARA.

For 2026 and 2028, the peak hour occurs in July at HE 17:00. LOLH and EUE are not anticipated in 2026 and are minimal in 2028. LOLH was only observed in August at HE 19:00. The LOLH corresponds with the evening down ramp of solar and lingering demand after peak.

Due to the significant share of natural gas resources in the Southwest portfolio, a concern for the Southwest is natural gas derates during extreme heat events. A strategy to assist with resource planning is to construct derate curves for natural gas resources as a function of temperature. Resource procurement practices have also changed to focus on adding resources that have no dependence on temperature.

Demand

The Southwest has the highest rate of load growth in the Western Interconnection for the LTRA horizon. Large industrial and commercial load additions, such as data centers, have been cited as the reason for this growth.

The Southwest's peak demand in summer is forecast to grow at an average of 2.49%. Over the LTRA horizon, the forecast grows by a total of 27.8%. The Southwest's total internal demand forecast is nearly the same as last year's over the near and medium term, with a slight drop from last year's in the longer term, growing from a summer peak of 27.3 GW in 2024 to 34.9 GW by 2034.

Demand-Side Management

Arizona Public Service (AZPS) has numerous DSM pilots and programs, such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. In the Residential Energy Storage Pilot, residents may install a small BESS at their residence and enable it to be dispatched by AZPS in response to grid needs 100 times a year, but not below 20% of its capacity. AZPS is projecting an almost 50 MW increase in available DR from 2024 to 2025.

In 2023, the Salt River Project (SRP) subscribed 87 MW of DR capability through the installation of 76,143 smart thermostats and enrolled over 500 businesses as interruptible customers providing 41 MW of controllable DR capacity. The SRP aims to achieve 300 MW of dispatchable DR capability by 2035.

The Public Service Company of New Mexico (PNM) operates the Peak Saver and Power Saver programs. Peak Saver reduces demand from commercial customers greater than 50 kW in size during peak demand periods, and the Power Saver program cycles the compressor of air conditioners to reduce peak demand in the summer. One hundred hours of curtailment are available for both

programs with a four-hour limit per curtailment, and it was found that both programs combined reduce peak demand by an average of 45 MW per curtailment event.

El Paso Electric (EPE) operates a smart thermostat program to cycle air conditioners with the potential to achieve 50 MW of relief by 2040.

Additionally, AZPS, SRP, PNM, and EPE all offer time of use (TOU) rate structures for their customers.

Distributed Energy Resources
BTM DERs are difficult to measure due to data gathering barriers. In the Southwest, NV Energy has added DER plans to its triennial IRPs.

Generation
Southwest entities have slightly under 10 GW of nameplate capacity Tier 1 solar resources planned between 2024 and 2028. Supply chain issues resulting in project delays or failure of completion are a concern for the Southwest. Zoning issues prohibiting the construction of new solar assets are also an issue.

There is significantly more solar, wind, and energy storage in planned capacity additions than in the last LTRA. Additionally, several states in the region as well as cities and utilities are implementing renewable or carbon-free electricity targets. Retirements tend to be concentrated across three resource types: coal, nuclear, and natural gas. Coal and natural gas units are being retired due to age and emissions.

Energy Storage
Energy storage is being relied on to help mitigate ramping risk from afternoon net demand caused by increasing penetrations of solar. Many additions are being co-located into hybrid PV + storage, but there is also increased standalone battery storage. Learning curves for potential operational challenges to mitigate energy storage risks include further real-world testing under extreme weather conditions, especially extended high temperatures such as during heat waves, and exploring solutions to mitigate the risks of fire.

Capacity Transfers
The Southwest is not showing a significant increase in reliance on imports in the model, with peak exports occurring between 5:00 p.m. and 10:00 p.m.

Transmission
Twelve transmission projects with 500 kV and higher are planned.

Reliability Issues
WECC notes that supply chain issues impacting transformers, circuit breakers, transmission cables, switchgears, and insulators continue to be a risk to generation and transmission development and are an ongoing reliability concern.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[39] for the summer and winter of each year.[40] Projected total internal demand is based on normal weather (50/50 distribution)[41] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-AB	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-BC	Winter	Noncoincident	
WECC-CA/MX	Summer	Noncoincident	
WECC-NW	Summer	Noncoincident	

[39] Glossary of Terms Used in NERC Reliability Standards.

[40] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).

[41] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.

[42] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[42]**	**Load Forecasting Entity**
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[43]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[44]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[45]

[43] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[44] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[45] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[46]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[47]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[46] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[47] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[48]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[49] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[50] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[51] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[52]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

[48] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[49] BES Definition
[50] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[51] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[52] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: The ARM is greater than RML.

Marginal: The ARM is lower than the RML and the PRM is higher than RML.

Inadequate: The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[53] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

Normal Risk: Negligible amounts of LOLH and EUE.

Periods of Risk: LOLH < 2 Hours and EUE < 0.002% of total annual net energy.

Significant Risk: LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
- **Planned** (any of the following):
  - Permits have been approved to proceed
  - Design is complete
  - Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”

Other projected lines that do not meet requirements of “Under Construction” or “Planned”

[53] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2024-2025 Summer: 9.0% Fall: 14.2% Winter: 27.4% Spring (2025): 26.7%	Planning Reserve Margin	Yes: Established Annually[54]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[55]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	11.3–12.7%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[56]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	8.6–19.5%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	10.9–11.8%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	17.6–17.7%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[57]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[54] In MISO, the states can override the MISO PRM.

[55] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[56] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[57] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2025–2029)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[58]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[59]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[60]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	9.0–13.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[61]
WECC-BC	9.8–12.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-CA/MX[62]	14.9–17.4%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-NW	13.8–16.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]
WECC-SW	9.4–12.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[53]

[58] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[59] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[60] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[61] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[62] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.
2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[63] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[64] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[65] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[66,67]
3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold-weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[68] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[69]

[63] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[64] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[65] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[66] NERC IBR Activities
[67] Order No. 901 Work Plan
[68] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[69] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[70]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	New cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and Balancing Authorities for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation. NERC and the industry are currently developing the remaining Reliability Standard enhancements to address the staff report. Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* on NERC's standards development page.[71]	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[72] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[70] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[71] Project 2021-07

[72] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered bulk power system-connected IBRs.[73] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[74]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 5. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
Interregional Transfer Capability Study (ITCS)	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC will extend the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis will be published in 2025. See **Interregional Transfer Capability Study (**ITCS).	ERO Study and Recommendations

[73] FERC Order Issued November 17, 2022
[74] RSTC Approved Documents

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

6. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.

7. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.

8. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [75]

9. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.

10. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[76]

[75] NERC ERS Measure 6 Forward Tech Brief

[76] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2024 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[77] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[78] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[79]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The status of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[80]	Reliability Standards Reliability Guidelines Educational Webinars
4: Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[77] ERAWG
[78] Project 2022-03
[79] Project 2023-07
[80] DER Activities

Errata

In June 2025, NERC, MRO, and MISO determined that incorrect RMLs were used in the 2024 LTRA for MISO.[81] After applying the correct RMLs, the following changes have been made:

- Figure 1 Risk Area Summary 2025–2029 (p. 6) | MISO changed from High Risk to Elevated Risk
- Table 1: Capacity and Energy Risk Assessment Summary (p. 7)| MISO changed from High Risk to Elevated Risk and Risk Summary updated
- Figure 2: Projected Reserve Margin Shortfall Areas with Announced Generator Retirements (p. 8) | MISO year of shortfall changed from 2025 to 2028 and caption updated
- High Risk Area Details and Elevated Risk Area Details (p. 12) | Removed the description of High Risk, moved relevant discussion of MISO risks to Elevated Risk Area Details, and updated text.
- Figures 3 and 4: MISO Planning Reserve Margins for Summer and Winter (p.13)| Updated with correct RMLs
- Table 12: Anticipated Reserve Margins with Announced Retirements (p. 40) | Footnote added to identify use of UCAP reserve margins for MISO
- MISO Demand, Resources and Reserve Margins (p. 41) | Updated the Reference Margin Level (%) row in the table and updated the Planning Reserve Margins bar graph with correct RMLs; added a note and reference to OMS-MISO Survey
- MISO Highlights (p. 42) | Changed MISO projected capacity shortfall from *2025* to *within the next five years* in the first bullet
- MISO Assessment (p. 43) | Removed the shortfall capacity value in the Planning Reserve Margins section and added a note on the capacity values for existing resources in the MISO tables; removed the statement of ARM falling below RML in the Probabilistic Assessments section

[81] See the *Statement on NERC's 2024 Long-Term Reliability Assessment* issued on June 17, 2025.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-25-14

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit KK: Division, *Operating Permit No. 96OPMF155* (July 1, 2021)

Colorado Department of Public Health and Environment

OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

96OPMF155

FACILITY ID: 081/0018

RENEWED: July 1, 2021
EXPIRATION DATE: July 1, 2026
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON
Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010
And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

FACILITY CONTACT PERSON
Name: Mike Tomasovic
Title: Environmental Supervisor
Phone: (970) 824-4411

SUBMITTAL DEADLINES –
Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Reports: Due February 1 & August 1
Annual Compliance Periods: January 1 – December 31
Annual Compliance Certification: Due February 1

Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

4.1 Based on the information provided by the Source, this facility is subject to the provisions of the Accidental Release Prevention Program in Section 112(r) of the Federal Clean Air Act (CAA).

5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling and Storage – Unit 3	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse
			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

Table 1 - Craig Station Emission Unit Summary

SECTION II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.) 4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1) SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)		CEMS	Continuous
Acid Rain	1.11	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual NO_x limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **NO_x limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV) 0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2) NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)		CEMS	Continuous
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 3 – Unit 2 Emissions and Requirements Summary

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

2.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

2.5 **Opacity**

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

2.10 **Colorado Regulation No. 23, Regional Haze**

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da) 0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 4 – Unit 3 Emissions and Requirements Summary

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10})** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of SO_2**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of SO_2 per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are

monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 **6,752 tons of NO_x per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly

NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

3.6 **Opacity**

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 5 - Subpart UUUUU Table 2 Requirements

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 6 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	6.4	See Condition 6.4			
Equipment Operation	6.5	See Condition 6.5			
NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6	

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and PM_{10} emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 8 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		

		F102g F102l				
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	7.4	See Condition 6.4				
Required Controls	7.5	See Condition 7.5				
NSPS Y	7.6	Opacity not to exceed 20%			See Condition 7.6	
CAM	7.7	Condition 7.7				

Table 9 - P102 Emissions and Requirements Summary

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 10 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Limestone Delivery	8.1			Recordkeeping	Annually
PM & PM_{10}	8.2	F201a	PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4			
Equipment Operation	8.5	See Condition 8.5			
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%			

Table 11 – P201 Emissions and Requirements Summary

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 12 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 14 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Ash Processed	10.1			Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c	PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4			

Table 15 – P203 Emissions and Requirements Summary

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 16 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%	
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28		

				Unpaved: 3.6 EF in lb per vehicle mile traveled		
Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4				

Table 17 – P204 Emissions and Requirements Summary

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 18 – S401 & S402 Emissions and Requirements Summary

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 19 – S403 Emissions and Requirements Summary

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **SO_2, NO_x (and diluent), CO_2, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet SO_2 and CO_2 monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **SO_2, NO_x, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

	2016	2017	2018	2019	2020	2021
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149
NO_X Limits	C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2))					

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Non-Applicable Requirement	Justification
B001 & B002 - Units 1 & 2	Construction Permit 10MF579 reference to May 1, 1973 Subpart D	The Units are subject to the most current version of Subpart D.
Facility-Wide	Colorado Regulation No. 1, V	Applies to coke ovens at Iron and steel plant operations only.
	Colorado Regulation No. 1, VII	Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado
	Colorado Regulation No. 1, VIII	Applies to listed stationary sources in the Denver PM_{10} nonattainment area only.
	Colorado Regulation No. 1, IX	Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide
	Colorado Regulation No. 4, and General Condition 31 of this permit	Sale and use of wood burning devices does not apply to the Craig Station
	Colorado Regulation No. 7, except for Part B, Section III	Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only.
	Colorado Regulation No. 8, Part D	Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision
	Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program	Subject matter does not cover the Craig facility.

	Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions	Geographic area of applicability does not include the Craig facility.
	Colorado Regulation No. 13 - The Oxygenated Fuels Program	Area of geographic applicability does not include the Craig facility.
	Colorado Regulation No. 16 - Street Sanding	Geographic area of applicability does not include the Craig facility.
	5CCR 1001-20 - Nonattainment Areas	Craig facility is not located in geographic areas classified as nonattainment.
	Colorado Regulation No. 19 - Lead Based Paint Abatement	Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards
	40 CFR Part 55 - Outer Continental Shelf Air Regulations	Craig facility is outside the geographic scope of this provision.
	40 CFR Part 56 - Regional Consistency	Relates to authorities within the various offices of the EPA.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Emission Unit Description & Number	Applicable Requirement	Justification
Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent.
Section II, Conditions 3.2.2 & 3.3.3	NSPS Da definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition.
Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Required quarterly reports	The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27%	This requirement is less strict than the BACT limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu	This requirement is less strict than the BACT PM limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements	Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits	Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations	The opacity condition has been streamlined out under BACT wherein records are already required
Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu	This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits.
Section II, Condition 4 (Units 1, 2, & 3)	NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2)	So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements.

Section II, Condition 13.1	Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * 10^6 gallons/year	This limit is merely the annualized PTE of the short term limit.
Section II, Condition 17.2 (Units 1 & 2)	Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing	Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent.
Section II, Condition 19 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section IV – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1, 2, & 3)	40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 (NO_x, SO_2, CO_2, and flow)	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.

SECTION V - General Permit Conditions (ver 1/21/2020)

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

A. Appendix A - Inspection Information

A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

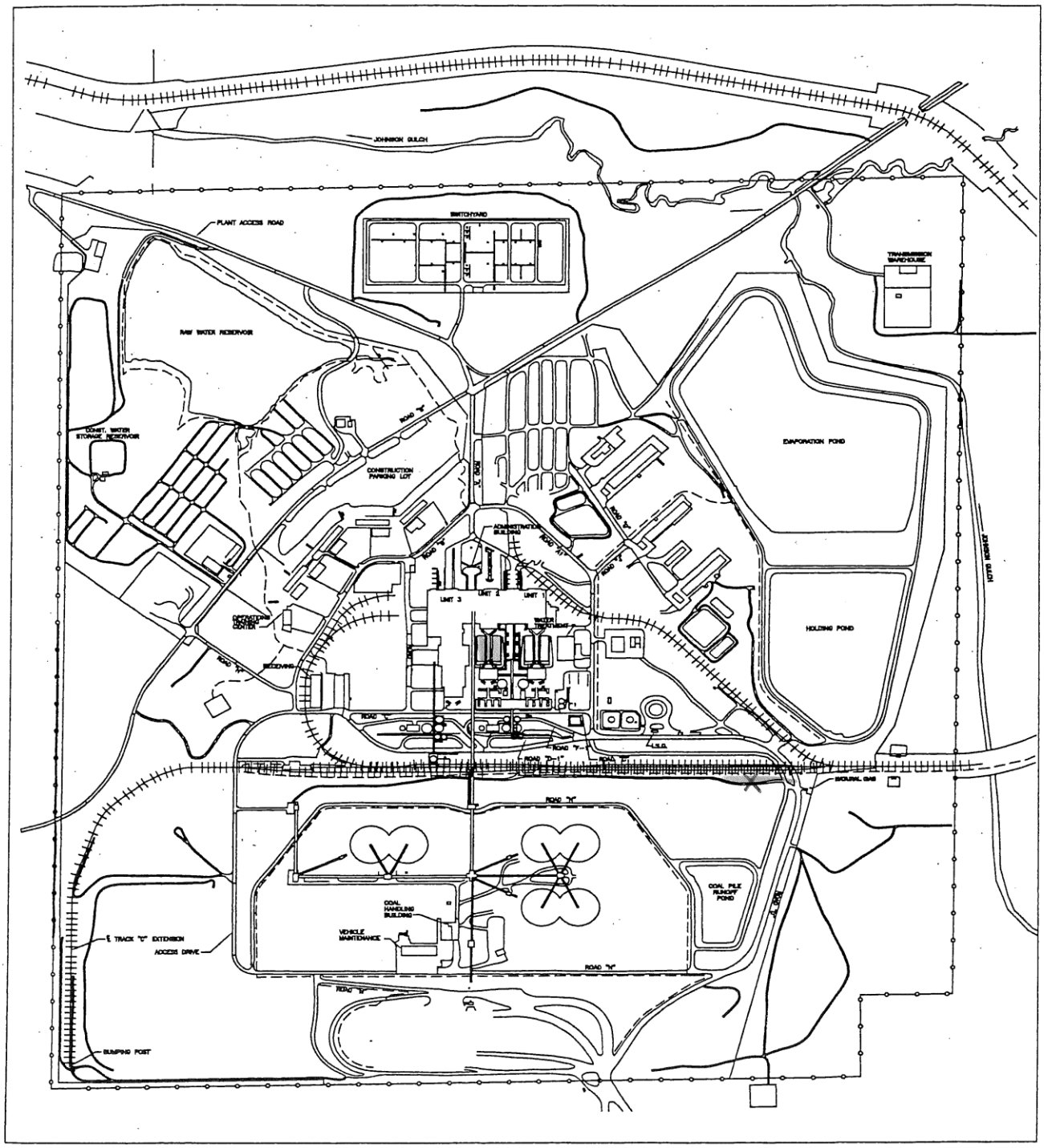
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

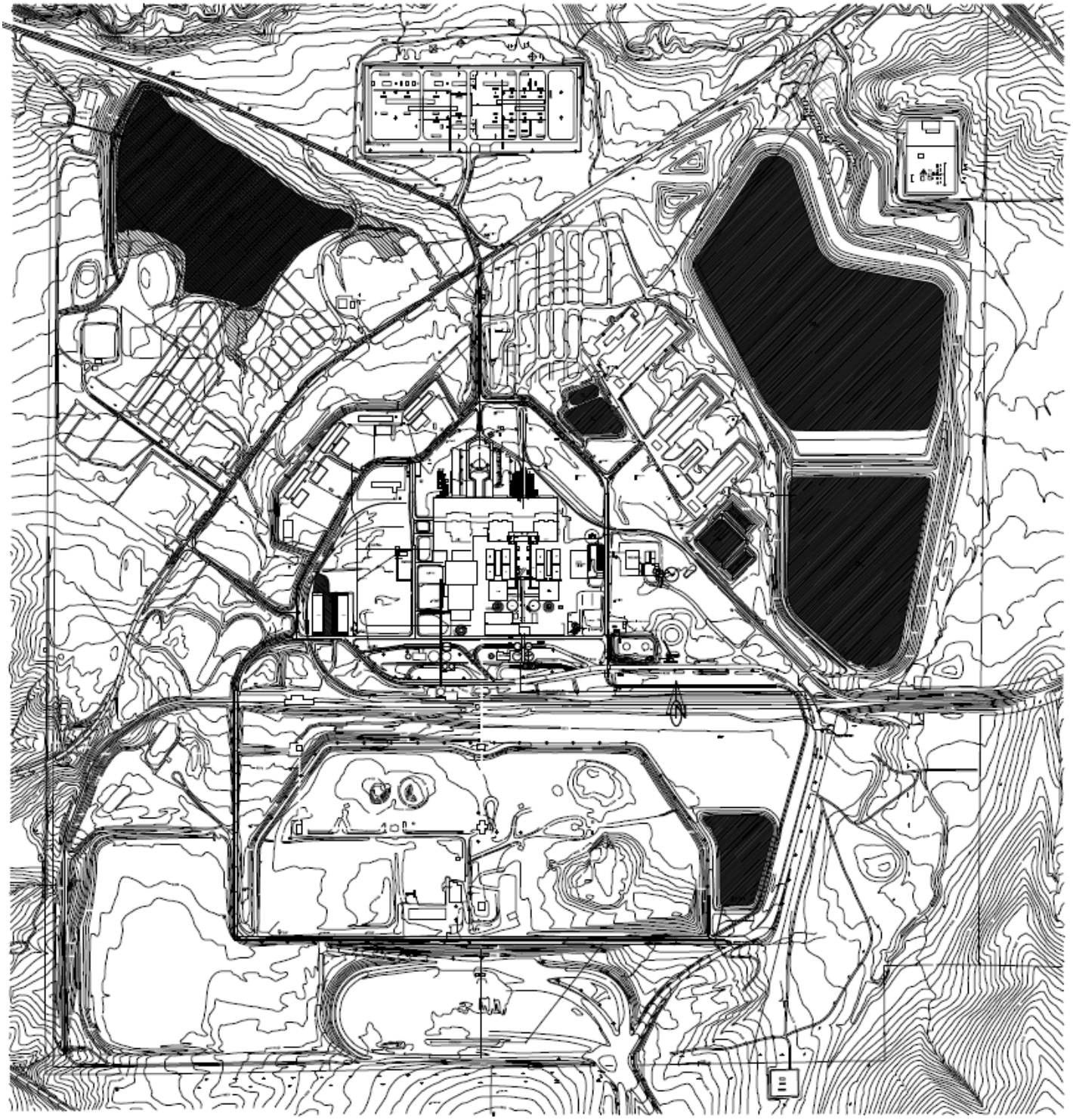
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
TRANSMISSION WAREHOUSE
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
EVAPORATION POND
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
HOLDING POND
RECEIVING
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
ROAD "I"
ROAD "J"
ROAD "K"
ROAD "L"
ROAD "M"
ROAD "N"
ROAD "O"
ROAD "P"
ROAD "Q"
ROAD "R"
ROAD "S"
ROAD "T"
ROAD "U"
ROAD "V"
ROAD "W"
ROAD "X"
ROAD "Y"
ROAD "Z"
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUNSPND POST



B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

Emission Unit	Facility ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/Emergency Condition Reported During Period?	
			YES	NO		YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157					
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156					
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602					
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2					
		F101b – Coal unloading to grizzly – Units 1 & 2					
		F101c – Coal surge pile					
		S101d – Primary coal crushing – Units 1 & 2					
		S101e – Secondary coal crushing building – Units 1 & 2					
		S101f – Common Coal Transfer Building Belt A					
		S101g – Common Coal Transfer Building Belt B					
		S101h – Coal stackout building – Units 1 & 2					
		F101i – Coal stackout – Units 1 & 2					
		F101j – Coal storage piles – Units 1 & 2					
		S101k – Coal reclaim A – Units 1 & 2					

		S101l – Coal reclaim B – Units 1 & 2					
		S101m – Coal tripper deck & silos – Units 1 & 2					
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2					
		S203b – Ash storage silo B – Units 1 & 2					
		F203c – Ash truck loading – Units 1 & 2					
		S203d – Silo B dry ash unloading – Units 1 & 2					
		S203e – Silo A dry ash unloading – Units 1 & 2					
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling					
		S201b – Limestone truck unloading					
		S201c – Limestone silo #1 – Units 1 & 2					
		S201d – Limestone silo #2 – Units 1 & 2					
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3					
		S102b – Coal conveyor portal building – Unit 3					
		S102c – Coal conveyor portal building – Unit 3					
		S102d – Secondary coal crushing (2 crushers) – Unit 3					
		S102e – Coal stackout building – Unit 3					
		F102f – Coal stackout – Unit 3					
		F102g – Coal storage pile – Unit 3					
		S102h – Coal reclaim system – Unit 3					
		S102i – Coal tripper deck & silos – Unit 3					
		S102j – Loadout coal to railcars – Unit 3					
		S102k – Common coal transfer building extension					
		F102l – Coal train loading					
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3					
		F204b – Ash truck loading – Unit 3					
		S204c – Recycle ash truck					
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3					
Lime Handling – Unit 3	P202	F202a – Lime hauling					
		S202b – Lime unloading					
		S202c – Lime conveying and silo					

		S202d – Lime day bin					
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74					
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74					
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79					
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower					
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower					
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower					
General Conditions							
Insignificant Activities							

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

B.II. Appendix B – Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction ____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

B.III. Appendix B – Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature of Responsible Official Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Emission Unit	Facility ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
			Previous	Current	YES	NO	YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157						
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156						
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602						
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2						
		F101b – Coal unloading to grizzly – Units 1 & 2						
		F101c – Coal surge pile						
		S101d – Primary coal crushing – Units 1 & 2						
		S101e – Secondary coal crushing building – Units 1 & 2						
		S101f – Common Coal Transfer Building Belt A						
		S101g – Common Coal Transfer Building						

		Belt B						
		S101h – Coal stackout building – Units 1 & 2						
		F101i – Coal stackout – Units 1 & 2						
		F101j – Coal storage piles – Units 1 & 2						
		S101k – Coal reclaim A – Units 1 & 2						
		S101l – Coal reclaim B – Units 1 & 2						
		S101m – Coal tripper deck & silos – Units 1 & 2						
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2						
		S203b – Ash storage silo B – Units 1 & 2						
		F203c – Ash truck loading – Units 1 & 2						
		S203d – Silo B dry ash unloading – Units 1 & 2						
		S203e – Silo A dry ash unloading – Units 1 & 2						
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling						
		S201b – Limestone truck unloading						
		S201c – Limestone silo #1 – Units 1 & 2						
		S201d – Limestone silo #2 – Units 1 & 2						
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3						
		S102b – Coal conveyor portal building – Unit 3						
		S102c – Coal conveyor portal building – Unit 3						
		S102d – Secondary coal crushing (2 crushers) – Unit 3						
		S102e – Coal stackout building – Unit 3						
		F102f – Coal stackout – Unit 3						
		F102g – Coal storage pile – Unit 3						
		S102h – Coal reclaim system – Unit 3						
		S102i – Coal tripper deck & silos – Unit 3						
		S102j – Loadout coal to railcars – Unit 3						
		S102k – Common coal transfer building extension						
		F102l – Coal train loading						
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3						
		F204b – Ash truck loading – Unit 3						

		S204c – Recycle ash truck						
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3						
Lime Handling – Unit 3	P202	F202a – Lime hauling						
		S202b – Lime unloading						
		S202c – Lime conveying and silo						
		S202d – Lime day bin						
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74						
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74						
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79						
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower						
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower						
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower						
General Conditions								
Insignificant Activities[4]								

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

D. Appendix D – Notification Addresses

D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

E. Appendix E – Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
SO_2 - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

F. Appendix F – Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

G.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).
II. Indicator Range	An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13.

G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM/PM_{10} requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons PM_{10}/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable PM/PM_{10}, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

H.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average.

H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

I.II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions	Differential Pressure Monitoring
Measurement Approach	Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active.	The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold.

	Indicator 1	Indicator 2
II. Indicator Range	An excursion is defined as any visible emissions seen during the Method 22 test. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria		
a. Data Representativeness	Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device.
b. Verification of Operational Status	The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation.	The pressure measurement system will alert the operator if the system is not functioning properly.
c. QA/QC Practices and Criteria	Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained.	The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source.
d. Monitoring Frequency	Monthly	Daily
e. Data Collection Procedures	The EPA Reference Method 22 procedures shall be followed.	The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged.
f. Averaging Time	N/A	N/A

I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

J. Appendix J – Units 1 and 2 Wet Limestone SO_2 Scrubbers Compliance Assurance Monitoring Plan

J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous SO_2 emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control SO_2 emissions.

J.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)

	Indicator 1
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control SO_2 emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with SO_2 CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 Regional Haze limits is acceptable monitoring for CAM.

J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

K. Appendix K – Unit 3 Lime Spray Dryer SO_2 Compliance Assurance Monitoring Plan

K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of SO_2, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of SO_2 per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous SO_2 emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control SO_2 emissions.

K.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu or any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control SO_2 emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an SO_2 CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 BACT and Regional Haze limits are acceptable monitoring for CAM.

K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous NO_x emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of NO_x emissions.

L.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control NO_x emissions.

L.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a NO_x CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous NO_x emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of NO_x emissions.

M.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control NO_x emissions.

M.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream.

M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a NO_x CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

N.I. Coal Sampling

N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

N.II. Sample Preparation and Laboratory Analyses

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

N.III. Chain-Of-Custody Method

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

N.IV. Coal Shipment and Sample Analysis Records

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.